Pacific Gas and Electric Company ™

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November 1, 2021

Caroline Thomas Jacobs, Director
Office of Energy Infrastructure Safety
715 P Street, 20th Floor
Sacramento, CA 95814

Re: 2021 Wildfire Mitigation Plan – Progress Report (Docket #2021-WMPs)

Director Thomas Jacobs:

Consistent with the Final Action Statement issued by the Office of Energy Infrastructure Safety (Energy Safety) on September 22, 2021 (Final Action Statement), Pacific Gas and Electric Company (PG&E) respectfully submits the following Progress Report for its revised 2021 Wildfire Mitigation Plan (2021 Revised WMP) submitted on June 3, 2021.

The Progress Report includes PG&E's response to 28 of the 29 Remedies identified in the Final Action Statement. Remedy PG&E-21-29 was previously provided to Energy Safety on September 30, 2021.

PG&E's Progress Report includes:

1. Response to Remedies PG&E-21-01 through PG&E-21-28

2. Public versions of the Attachments to the Remedy responses

3. A confidentiality declaration concerning confidential material in some of the Attachments

Some of the Remedy response attachments include confidential information. A zip file containing all the public, redacted versions of the attachments is available on PG&E's

WMP website[1] and a confidential version of these attachments will be provided to Energy Safety through their SharePoint.[2]

Finally, the California Public Utilities Commission (CPUC) resolution ratifying Energy Safety's approval of the 2021 WMP also required that PG&E file and serve its Progress Report in PG&E's 2023 General Rate Case (Application 21-06-021). PG&E will be separately filing and serving the Progress Report and public versions of the attachments in that proceeding.

Sincerely,

Nick Noyer

Nicholas Noyer
Director, Wildfire Risk Community Wildfire Safety Program PMO

cc: A.21-06-021 service list

[1] www.pge.com/wildfiremitigationplan
[2] Energy Safety's e-filing system does not allow for the submission of .zip files, and, due to the numerous attachments PG&E is providing with its Progress Report, we did not want to inundate parties and the docket with several individual attachment submissions.

PACIFIC GAS AND ELECTRIC COMPANY

PROGRESS REPORT

RESPONSE TO ENERGY SAFETY REMEDIES

PG&E-21-01 THROUGH PG&E-21-28

NOVEMBER 1, 2021

PG&E®

Assessment and Mapping (Section 5.1)

Utility #: PG&E-21-01

***Issue title**: Unclear inclusion of future climate data into planning.*

***Issue description:** Pacific Gas and Electric Company's (PG&E) 2021 Wildfire Mitigation Plan (WMP) Update does not include PG&E's climate resilience team's evaluation of High Fire Risk Areas (HFRA)[1] map initiatives in order to validate that the maps are consistent with climate projections.*

***Remedies required and alternative timeline if applicable**: PG&E must explain how it incorporates components of its climate resilience team's report into its own risk assessment.*

Response to PG&E-21-01:

Based on the issue description, PG&E understands that this remedy is related to HFRA maps and specifically how climate projections were used in the development of the HFRA maps. We are providing a report prepared by ICF Consulting which addresses how the HFRA maps that we prepared correlate and are aligned with available wildfire climate projections from the California Fourth Climate Assessment, please see Attachment 2021WMP_OEISRemedy_PGE-21-01_Atch01.

Utility #: PG&E-21-02

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

***Issue description:** 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.*

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1 PG&E 2021 WMP Update at p. 85. PG&E identified areas of increased fire risk that are not currently included in the [California Public Utilities Commission (CPUC)]-designated [High Fire Threat District (HFTD)] and defined these as High Fire Risk Areas.

Remedies required and alternative timeline if applicable: *The utilities*[2] *must collaborate through a working group facilitated by Energy Safety*[3] *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.*

Response to PG&E-21-02:

The utilities have prepared a joint response to this Remedy.

On October 5-6, 2021, Energy Safety hosted a two-day workshop on risk modeling. Each of the utilities made presentations on their respective risk modeling approaches and the utilities participated in the Question and Answer section of workshop, as did other intervenors, stakeholders and interested parties including members of the public. At the conclusion of the workshop, Energy Safety requested that the utilities submit reports providing detailed descriptions on more than 30 risk-modeling related issues. These reports were submitted on October 13, 2021.

Energy Safety also requested that stakeholders interested in participating in the risk modeling working group submit application materials by October 14, 2021, and that stakeholders selected for the working group participation would be notified by October 18, 2021. Energy Safety may reach out to academic experts to participate in the working group or provide input on the utilities' risk modeling.

Energy Safety established a 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 impacts of other

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2 Here "utilities" refers to San Diego Gas & Electric Company (SDG&E) and PG&E, 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.

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

issues on modeling such as climate change and ingress/egress. Energy Safety initially scheduled the following meetings and topics:[4]

• October 20, 2021	Modeling baselines, alignment and past collaboration
• November 3, 2021	Modeling components, linkages, and interdependencies
• November 17, 2021	Modeling algorithms
• December 1, 2021	Fault, outage, and ignition data
• December 15, 2021	Asset and vegetation data
• January 5, 2022	Initiative implementation impact, and Public Safety Power Shutoff (PSPS) risk impact
• January 19, 2022	Climate change impacts, suppression and ingress/egress

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.

Utility #: PG&E-21-03

Issue title: *Inadequate speed of improvements made to risk modeling.*

Issue description: *PG&E self-reported a low risk assessment score in the Maturity Model with slower growth in comparison to the other two large investor-owned utilities (IOUs). While this seems to be largely due to lack of automation in many different areas, and while PG&E overhauled its modeling efforts between the 2020 and 2021 WMP submissions, PG&E fails to demonstrate growth at an adequate speed in regard to its risk assessment.*

4 The schedule provided is current as October 29, 2021, and may be subject to change at the direction of Energy Safety.

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

1) *Demonstrate that it is applying automation as quickly as possible, explaining any constraints on progress; and*
2) *Supply its workplan to enhance its modeling efforts.*

Response to PG&E-21-03:

1) In preparation for our 2022 WMP, PG&E’s Risk and Data Analytics team has improved on several aspects of the risk modeling capabilities across the Maturity Survey categories. As these capabilities have improved, our ability to automate the production of the models has also matured. Automation of both the Transmission and Distribution Wildfire Risk Models has improved in the: (1) preparation of modeling input data; (2) development and production of the model algorithms; and (3) display and use of the model output and application of model information to develop workplans. Below, we provide an overview of these three improvements.

   First, model data is now being migrated to a curated data layer in the Palantir Foundry platform. This curation of model data enables repeatability and documentation of the key data sets and lays the foundation for automation of wildfire risk models.

   Second, the next step in automation is to establish a standard modeling framework and code base for both transmission and distribution wildfire risk modeling. With a common code base and framework, production code allows for the automation of model runs. Models currently in development for transmission and distribution wildfire risk are applying this common framework.

   Third, model outputs are now ported to the Foundry platform to be viewed spatially and are available in tabular form. With both spatial and tabular access to model output, the steps from model output to workplan development are occurring in the Foundry platform. In the Foundry platform, each step is recorded, which allows for the automation of post-model steps that are frequently iterated upon during workplan development. Previously these steps were accomplished in individual spreadsheets or code workbooks.

2) Our wildfire risk modeling workplan is focused on improving in five modeling categories and developing modeling capabilities. At a high level, the five modeling category improvements are:

- Ignition Risk Estimation;
- Estimation of Wildfire Consequence on Communities;
- Estimation of Wildfire and PSPS Risk-Reduction Impact of Initiatives;
- Risk-based Grid Hardening and Cost Efficiency; and
- Portfolio-wide Initiative Allocation Methodology.

These improvements, as well as the development of modeling capabilities, are described in detail in our 2021 Revised WMP[5] and summarized in Figure PG&E-4.5-3 of the 2021 Revised WMP. A copy of Figure PG&E-4.5-3 is provided below for ease of reference. The schedule for model development over the next three years is shown below for the Wildfire Distribution Risk Model (WDRM) and Wildfire Transmission Risk Model in Figure PG&E-Remedy-21-03-1 below.

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5 2021 Revised WMP, pp. 148-150.

FIGURE PG&E-4.5-3 PG&E: RISK MODELING CAPABILITIES IN THE MATURITY SURVEY (FUTURE STATE ~2023)

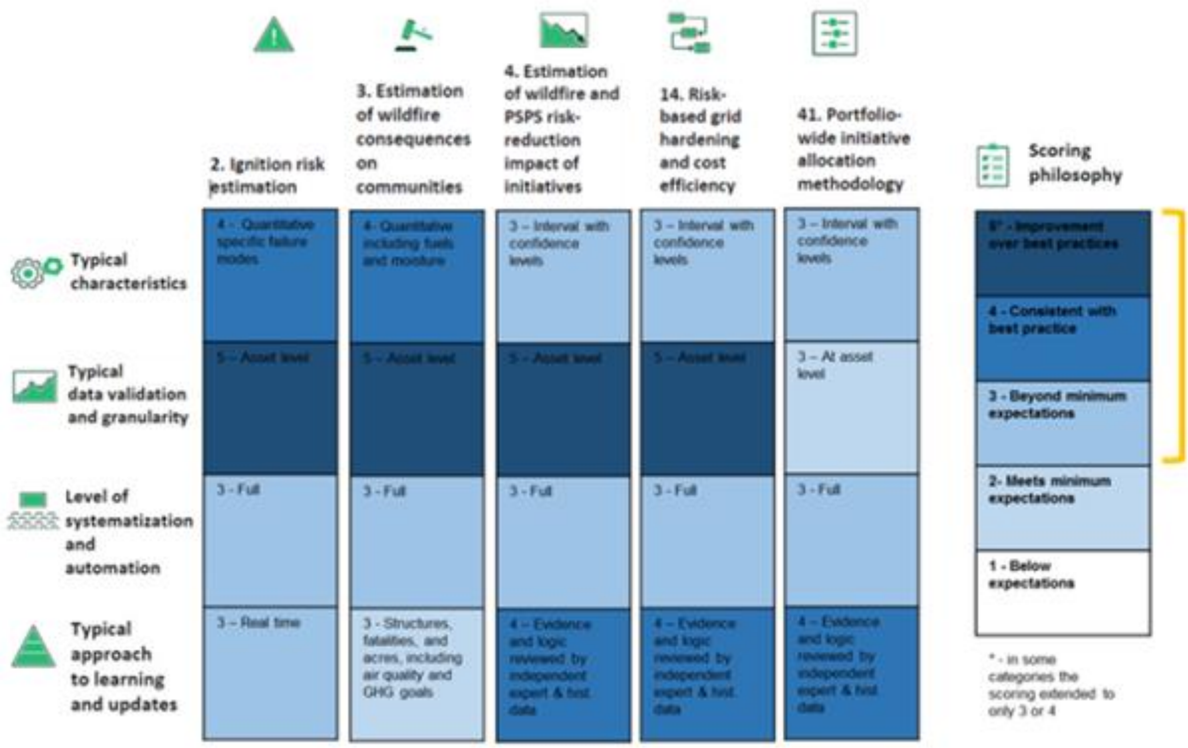
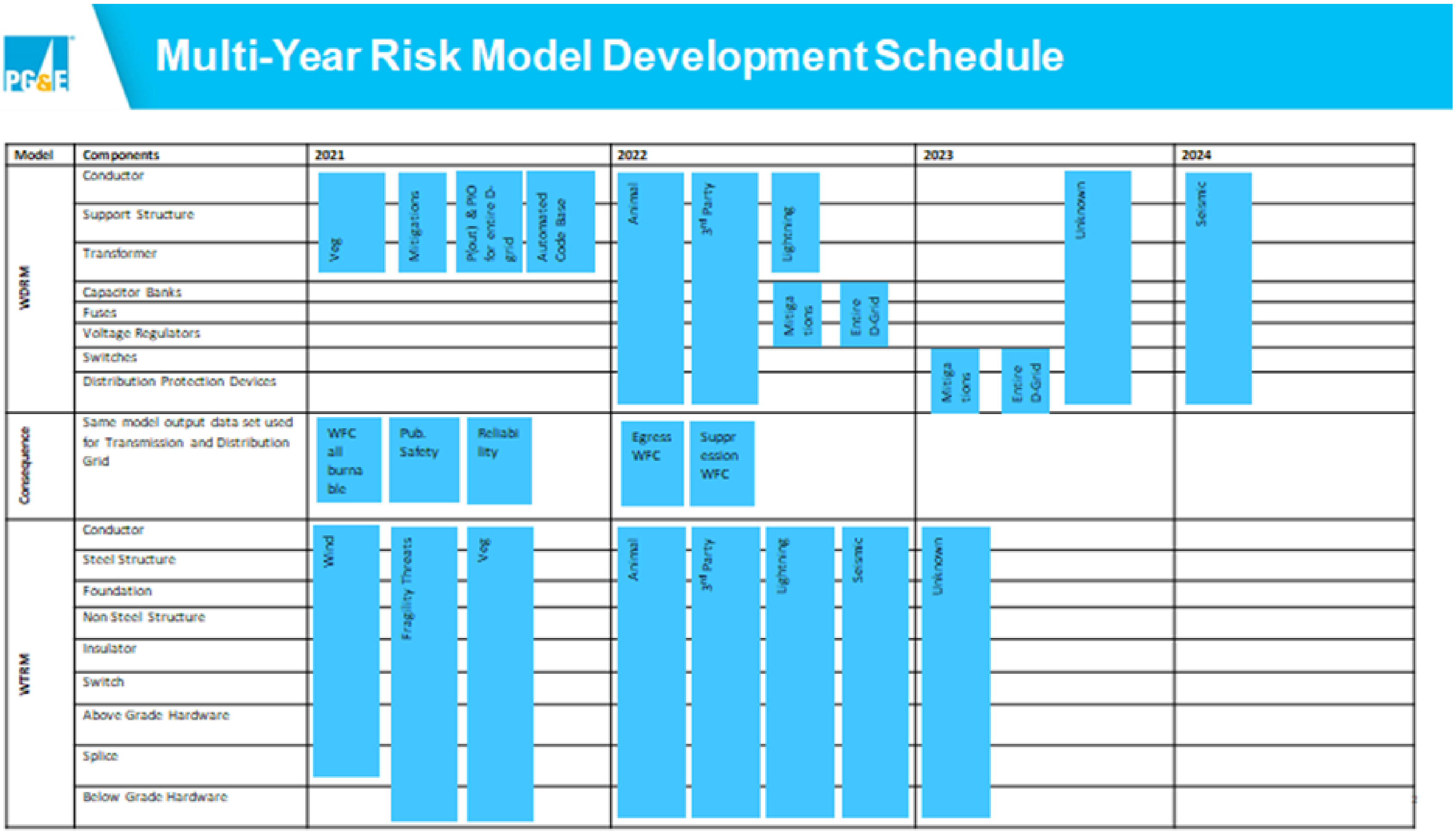


FIGURE PG&E-REMEDY-21-03-1:
SCHEDULE FOR RISK MODEL DEVELOPMENT[6]



6 WFC refers to Wildfire Consequence

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) PG&E appreciates Energy Safety's and parties' focus on the contribution of climate and meteorological data as predictive data sets for wildfire risk. 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 WDRM.[7] 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

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[7] See e.g., 2021 Revised WMP, pp. 165-166.

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.[8]

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 Model 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.

2) We understand that the utilities have taken different approaches to the type of wind speed data used in risk models. Notably, other utilities are continuing to review the wind speed data available for risk modeling. For example, SCE has indicated that it does not have enough wind-driven outage data at the circuit level to make determinations about correlations between wind speeds and outage rates.[9] 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 the data that they use and why they believe this data is the most appropriate data for risk modeling.

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8 2021 Revised WMP, pp. 164-166.

9 *See* California Public Utilities Commission (CPUC) Resolution WSD-20, p. 27, available at: https://energysafety.ca.gov/wp-content/uploads/docs/misc/docket/attachment-1-draft-resolution-sce-word.docx.

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.*[10] *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:

1) PG&E has been developing a PSPS Circuit Consequence Model and has been discussing PSPS model benchmarking and consistency in methodology with other California utilities. These discussions have included topics such as the usage of a longer time frame historical lookback instead of purely actual events and also alignment to generating risk scores based off Multi-Attribute Value Function (MAVF) units. We have made considerable progress on our PSPS Circuit Consequence Model. The current version of the model, as well as future enhancements, are described in Attachment 2021WMP_OEISRemedy_PGE-21-05_Atch01.

   There are two additional items related to this Remedy that we would like to briefly address. First, in the Remedy, Energy Safety asks PG&E to provide an update on the functionality of our PSPS consequence model at a circuit segment level, as opposed to circuit level. This is different from PG&E's commitment in the 2021 Revised WMP to have a PSPS consequence model at the circuit level for the second half of 2021.[11] PG&E is working to develop a PSPS circuit consequence model at a segment level for submission with the 2022 WMP. This timing is

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10 2021 Revised WMP, p. 49.

11 *See* 2021 Revised WMP, p. 258, Table PG&E-5.2-1, Unique ID A.06.

necessary to provide sufficient time for alignment of the circuit segment designations to match that of the next iteration of the WDRM. Given that circuit segments are based off Circuit Protection Zones (CPZ), ensuring that the circuit segments align between the two risk models is important for mitigation activities and communication.

Second, the Issue Description references the incorporation of PSPS consequence risk into total risk reduction of a mitigation initiative. Over the past few months, PG&E has been testing a process to identify, scope, and calculate risk reduction benefits on each circuit for individual projects. Similar to how PG&E scopes System Hardening activities for wildfire mitigation, PG&E is implementing the identification of high impact circuits based on the PSPS circuit consequence model. However, as a result of the additional complication of upstream impacts due to transmission impacts, the circuits identified for mitigation prioritization can vary from a direct 1-N list of most impacted circuits to least impacted circuits. We are also reviewing opportunities to minimize PSPS impacts. This would include reviewing for line removals, sectionalization, remote grids, temporary generation, and underground options to minimize customer impact. Based on the customers impacted, the risk on the circuit, and the cost, risk reduction and risk spend efficiency (RSE) measures can be calculated to inform decision making. We intend to implement this process in 2022 to inform future PSPS impact reduction programs. Further details regarding this effort will be provided in the 2022 WMP.

2) PG&E is in the process of completing upstream activities that support a PSPS circuit segment risk model. The circuit segment model will be based off two upstream data sources. The first data source is the 2021 circuit segment list which was finalized in October 2021. In order to provide consistency between modeling datasets, PG&E is looking to align the PSPS circuit segment model with the latest circuit segments. The second data source is the finalization of the 2021 PSPS guidance historical lookback, which is expected to be finalized in November 2021. While the initial protocols have been established, the finalization of the full 11-year lookback, specifically transmission, will not be available until November. Once this is complete, the customers impacted from transmission and distribution could be accounted for and allocated to each circuit segment accordingly. This overlay effort is anticipated to be completed in December. Finally, we currently intend to finalize

the PSPS circuit segment level risk scores in January 2022, in preparation for the 2022 WMP, as indicated in Table PG&E-Remedy-21-05-1 below.

TABLE PG&E-REMEDY-21-05-1:
PSPS CIRCUIT SEGMENT RISK MODEL PLANNED ACTIVITIES

Month	Activity
October 2021	Finalization of 2021 Circuit Segment List
November 2021	Finalization of 2021 PSPS protocol historical lookback
December 2021	Overlay the 2021 Circuit Segments with the 2021 historical lookback
January 2022	Finalization of PSPS risk scores at the circuit segment

Utility #: PG&E-21-06

Issue title: *Insufficient transparency for modifications to Wildfire Risk Models and circuit segment prioritization.*

Issue description: *Revision Notice Critical Issue RN-PG&E-02 required PG&E to provide further justification of its shift in 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.*

Response to PG&E-21-06:

1) and 2)

The table below was provided in the 2021 Revised WMP and details each of the recommendations from the third-party validation of the 2021 WDRM conducted by E3 and our response and timeline for response.[12] Updates to the table are provided in italics in Columns 2 and 3.

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

Finding	Update on Planned Response	Update on Timeline for Response
Strengthen the critical link between experts and models. Develop an informed decision-making process.	Document work processes and decision-making process. *Developing workplan steps in Foundry platform.*	Q3 2021 as part of 2022 WDRM documentation. *Model completion and documentation moved to Q4.*
Create a roadmap that gives future goals and ties the Risk Model to other models. Consider including: 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. 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 is planned to illustrate both improvements and connections within the risk-model “ecosystem”. *No change.*	Q3 2021 as part of 2022 WDRM documentation. *Model completion and documentation moved to Q4.*

12 2021 Revised WMP, pp. 177-180, Table PG&E-Revision Notice-4.5-5.

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

Finding	Update on Planned Response	Update on Timeline for Response
Include covariates that will provide 'direct line of sight' to the impact of risk mitigation measures. Consider adding more data fields for equipment characterization.	A host of additional equipment data is being prepared for use in the 2022 WDRM. Some of these Include, pole loading, LiDAR [Light Detection and Ranging] data for vegetation as well as asset location. In additional 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 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. *Additional data fields were added to the models in August 2021. Models are currently draft and will be reviewed and approved with documentation in Q4 2021.*
Explore more modeling methods to better support selected algorithms.	In the development of the 2022 model(s), a number of alternative algorithms are under develop with the assets such as poles and transformers are developed as their failure characteristics might be less environmentally driven. Objective that the method that demonstrates the best predictive power will be utilized. 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. *Draft models were developed in September 2021. Models are currently draft and will be reviewed and approved with documentation in Q4 2021.*
Conduct uncertainty analysis around consequence scoring. 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. *Data was provided in July 2021. Model completion and documentation moved to Q4.*

3) We understand this Remedy to be referring to the 2021 WDRM and not to the 2022 WDRM which is currently in development. No changes have been made to the 2021 WDRM since the submission of the 2021 Revised WMP on June 3, 2021.
4) We understand this Remedy to be referring to the 2021 WDRM and not to the 2022 WDRM which is currently in development. No changes have been made to circuit segment prioritizations in WMP workplans due to changes in the 2021 WDRM since the submission of the 2021 Revised WMP on June 3, 2021.

Situational Awareness and Forecasting (Section 5.2)

Utility #: PG&E-21-07

Issue title: *PG&E's DFA and EFD technology pilot outcome is lacking justification for the scope of installment.*

Issue description: *PG&E's pilot project was completed in 2020 for Distribution Fault Anticipation (DFA) and Early Fault Detection (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:

1) PG&E prepared a final report as part of its Electric Program Investment Charge (EPIC) Predictive Risk Identification 2.34 project that contains the details and performance metrics on the outcome of the 2020 DFA and EFD technology. The report can be accessed at the following link and has also been made available to the public on PG&E's website:

   https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-Project-2.34.pdf

   For convenience, a copy of the report is included as Attachment 2021WMP_OEISRemedy_PGE-21-07_Atch01.

   The report was prepared at a technical level and includes conclusions and recommendations from this project. DFA technology is described in the report by its more formal name of Event Classification through Current and Voltage Monitoring (ECCVM) technology and, similarly, EFD technology is described by its formal name of Radio Frequency (RF) Sensor technology.

   Sections 4.2.8 and 4.3.5 of the report provide results and observations from the two technology pilots and are excerpted below for convenience:

4.2.8 Results and Observations (RF Sensors) [EFD]

The predictive risk identification capability of the RF network monitoring system was proven in the trial. The system successfully identified and located a range of common threats to network operation before these developed into faults that could potentially cause interruptions to supply or create safety hazards such as fires or facility damage.

First results followed immediately upon commissioning as pre-existing incipient fault conditions were revealed at locations on Path O-P, the first Circuit 1101 path to be commissioned. New emergent risks continued to be identified throughout the duration of the trial. Not all of the identified threats were high-risk, though all were detected with high signal-to-noise ratio and accurately located by the RF network monitoring system.

Key Results

The RF Sensors detected the following conditions (see report for full details and descriptions).

- Conductor Damage;
- Vegetative Encroachment;
- Damaged Secondary Crossarm and Cable;
- Primary Crossarm Failure;
- Transformer Internal Discharge; and
- Arcing Conductor Clamp.

Key Technical Observations

The system installed for the trial project continues to operate and be monitored. The following findings are based on experience through April 2020.

Good system performance as a predictive risk identifier: The RF network monitoring system performed successfully in the trial to an extent sufficient to deliver material benefits to wildfire risk mitigation reliability. It predictively identified a variety of network risks, many of which were of types known to start fires. They included conductor damage, vegetation encroachment (both primary and secondary), crossarm failures and a loose conductor clamp. All these conditions were found well in advance of their development into network faults. Site inspections confirmed evidence of the presence of the network defects identified by the system.

Good system accuracy in location of risk: The level of risk location accuracy demonstrated by the RF network monitoring system was sufficient for network operational purposes. In many cases, the system located the incipient fault to an accuracy of five or ten feet. In other cases, especially those where the defect was some distance away from the monitored path on a tap-line or secondary service line, accuracy was within 50 to 100 feet on monitored path lengths that ranged up to a little over three miles (16,500 feet). Performance in the trial was consistent with the supplier's specification of a nominal plus or minus thirty feet accuracy.

Good system risk-detection sensitivity and signal-to-noise ratio: The detection sensitivity demonstrated by the RF network monitoring system in the trial was sufficient to detect situations that could pose short-term risk to the network from deteriorated, damaged or compromised network assets. The system exhibited extreme sensitivity and recorded random noise down to the level of one tenth of a picojoule of collected energy, well below the level required to detect and locate impacts of individual raindrops on primary conductors. In detecting defects, it achieved signal to noise ratios of many orders of magnitude when the defect produced high-energy signals, e.g., internal transformer defects. High signal-to-noise ratios (up to a million to one) were also achieved for the lowest-energy defects when data was accumulated over a period of time, e.g., one month. Sensitivity and noise discrimination were sufficient to achieve reliable predictive risk identification.

Adequate system continuous monitoring for risk: The RF network monitoring system produced a signal record every second as designed. All risks it detected showed very intermittent activity, confirming the potential limitations of 'point in time' asset inspection and test methods. Interruptions to system dataflow were caused by loss of cellular data service coverage and by loss of power due to low insolation.

Good system provision of data to identify network risk type: The RF network monitoring system provided data to ascertain the most likely fault-type to guide decisions on field crew attendance priority. It was demonstrated this data could be correlated with data from other sources to create further insights. The system provided risk data including the location of the detected issue (including Pole number, so users could check Geographic Information System (GIS) to ascertain the assets located there, or check Google Earth to ascertain the location of nearby trees or infrastructure), the pattern of occurrence (intermittent activity bursts could be correlated with weather, metering data, field work, likely customer activity, etc.), the phases involved (indicating a primary or secondary problem), signal signature (which could distinguish transformer discharge, conductor damage, loose clamp arcing, etc.).

4.3.5 Results and Observations (ECCVM) [DFA]

Considering the limited number of feeders that had ECCVM deployed and the short period that data was collected, it is impressive the amount and type of data that was collected by the ECCVM sensor technology. Because of this it will not be possible to list and detail every event recorded. The approach for the documenting the results involves two components: an overview will be given on the ECCVM data; and a more detailed presentation for several key results that highlight the capability and performance of ECCVM technology.

Overview

At the end of May 2020, the ECCVM system had collected over 38,000 events from the sensors deployed on the six project feeders. Most of these events can be classified as normal operating events (motor starts, load variations, capacitor switching, regulator steps, etc.) with motors starts being the most common normal operating event (approximately 50 percent of all events captured). This is expected from a device that monitors voltage and current waveforms. Motors are very common on the feeders located in the Napa Valley and motor starts would happen multiple times each day.

Key Results

The ECCVM sensors detected the following conditions (see report for full details and descriptions, https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-Project-2.34.pdf):

- Series-arcing;
- Shunt-arcing;
- Fault-induced Conductor Slap;
- Recurrent faults;
- ECCVM Recorded Fault Induced Conductor Slap (See Figure 17 of report)

- Cable Failure; and
- Operational Visibility:
  - Capacitor Operations;
  - Substation Voltage Regulator Monitoring;
  - Non-downstream Event Detection;
  - Line Sensor Validation; and
  - Hidden Load Detection.

Section 5.3.2 of the report offers recommendations for the use of EFD and DFA technology and explains the reasoning behind those recommendations:

5.3.2 Recommendations

The successful performance of RF network monitoring and the demonstration of ECCVM technology in the current project leads to the following recommendations:

<u>Expand RF Sensor 2 to Larger-scale Trial</u>: Carry out a larger-scale trial of RF network monitoring to better define the challenges of wider adoption and identify strategies to address these challenges so maximum safety and reliability benefits can be delivered to Californian communities. A first step will be to extend the current deployment and testing to refine monitoring and operating techniques. Further expansion will be scheduled to match resources and technology refinement availability. Investigate the feasibility and benefits of RF Technology integration with the Distribution Management System for fault location, root cause analysis and preventative maintenance enhancement, as well as integration with Rapid Earth Fault Current Limiting technology to identify faulted protection zone.

<u>Move ECCVM into a Production Footing</u>: ECCVM is a very cost-effective technology that enables a significant improvement in data resolution and operator situational visibility into PG&E's electric distribution system. This capability should be moved into a staged production path and exercised as part of a risk assessment activity.

2) Section 7.3.2.2.3(4) of the 2021 Revised WMP explains that both technologies are emerging technologies and that both still require process refinement. Thus, in order to determine whether PG&E can deploy DFA/EFD technology across HFTD Tier 2 and Tier 3 areas, we are carrying out a larger scale trial installing approximately 25 RF Sensors (EFD) in two circuits and ECCVM (DFA) technology in 45 circuits in

2021/2022 to better understand challenges and develop strategies for a streamlined deployment process. A preliminary operational viability assessment of deployment is under consideration. Upon confirmation of viability, we would assess deployment of EFD/DFA on 600-800 circuits in HFTD Tier 2 and Tier 3 areas.

Utility #: PG&E-21-08

Issue title: *Weather station program target not met.*

Issue description: *PG&E's 2021 WMP Update originally reported installation of 404 weather stations in 2020, surpassing its program target of 400. However, in PG&E's revised 2021 WMP Update the weather station installations changed to 378 in 2020, falling short of its target without explanation.*

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

1) *Provide details on why PG&E did not meet the targeted 400 weather station installs in 2020; and*
2) *Explain why weather station installation totals in the original 2021 WMP Update differ from the revised 2021 WMP Update.*

Response to PG&E-21-08:

In the 2021 WMP submitted in February, we indicated that 404 weather stations were installed in 2020. The actual physical installation that took place in 2020 was 378 weather stations.

1) and 2)

PG&E's Weather Station team met the 2019 installation goal of 400 weather stations in early September of 2019. A decision was made to continue with the installations during the remainder of 2019 and apply these surplus stations towards the 2020 commitment. As a result, 26 additional installations were completed and applied to 2020 installation goals. This resulted in 404 weather installations being reported for 2020 in the 2021 WMP. In order to standardize its counting procedures, PG&E subsequently determined that any surplus quantitative measurements completed in the previous year should not be counted toward the next year's total. Therefore, it was determined that the 26 weather stations would not be counted in 2020 total. We described this issue in a June 1, 2021 letter to Energy Safety and the Safety and Enforcement Division, which is included here as Attachment 2021WMP_OEISRemedy_PGE-21-08_Atch01.

This issue has been resolved by instituting standardized counting procedures and the development of detailed WMP reporting and confirmation requirements across the entire Community Wildfire Safety Program portfolio to eliminate any future reporting ambiguity. In addition, PG&E remains on target to complete 1,300 weather station installations by the end of 2021.

Grid Design and System Hardening (Section 5.3)

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[13] 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[14] 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 prepared a joint response to this Issue/Remedy.

Introduction:

This Progress Report outlines the utilities' approach, assumptions, and preliminary milestones that will 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. We also provide background information

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

14 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.

concerning covered conductor and discuss assumptions regarding what this workstream is intended to produce and what it is not intended to produce.

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 aerial bundled cable (ABC). The table below provides a snapshot of the approximate amount and types of covered conductor installed in the utilities’ service areas.

TABLE PG&E-REMEDY-21-09-01:
COVERED CONDUCTOR TYPE AND MILES DEPLOYED BY UTILITY

Utility	First covered conductor installation (year)	Type of covered conductor installed	Approx. miles of covered conductor deployed through Sept. 2021	Notes
SCE	2018	Covered Conductor	2,500	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	820	Primary distribution overhead only
	TW installed historically	ABC	3	
SDG&E	2020	Covered Conductor	6	
		Tree Wire	2	
		Spacer Cable	6	
Liberty	2019	Covered Conductor	5	
		Spacer Cable	2	
Pacificorp	2007	Spacer Cable	50	
Bear Valley	2018	Covered Conductor	17	

Overview / Summary of Approach:

The utilities initiated the Covered Conductor Effectiveness Workstream in August 2021 and have held meetings every two weeks since. The initial meetings have focused on identifying the purpose/objective of the workstream, organization and administration of the workstream, sharing of covered conductor practices and updates that are ongoing and planned covered conductor effectiveness efforts, developing an overall approach to meet the remedies, and discussing project timelines. These efforts have led to identification of project management, workstream lead, and subject matter expert (SME) roles, establishing meeting cadence, obtaining utility commitment and resources to contribute, establishing an online workspace to share and collaborate on documents, and building out an initial framework and high-level timelines to assemble and assess the information.

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, discerned, and updated over time. To date, all the utilities have estimated the effectiveness percentages in developing the risk reduction of covered conductor. These estimates have been informed by SME judgement, engineering analyses, testing, benchmarking/research, and/or historical recorded results. To improve and obtain better consistency on the estimated effectiveness of covered conductor, the utilities will be compiling and analyzing existing data sets and capturing additional information within the following sub-workstreams:

- Benchmarking
- Testing / Studies
- Estimated Effectiveness
- Additional Recorded Effectiveness

Each of these sub-workstreams will seek to obtain existing and new information to help refine our understanding of the effectiveness of covered conductor. Additionally, the utilities have identified the following additional sub-workstreams to meet the remedy requirements:

- Alternative comparison
- Potential to Reduce PSPS risk
- Costs

Workstream Scope:

The overall focus is on the long-term effectiveness of covered conductor. 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 effectiveness value for covered conductor that utilities can use 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 can differ based on numerous factors including, for example, the covered conductor system configuration, 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 will focus on a high-level covered conductor cost analysis that can show higher or lower costs based on several factors.

Framework / Approach:

As noted above, the utilities are proposing a holistic framework with multiple sub-workstreams to better understand the long-term effectiveness of covered conductor. These sub-workstreams are further described below.

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.[15] These efforts helped inform SCE's Wildfire Covered Conductor Program (WCCP). The utilities have begun to conduct additional benchmarking. We have developed a survey to understand the current status of covered conductor, if utilities have recorded data demonstrating effectiveness, and what alternatives to covered conductor they may have deployed or are looking to deploy. The survey is being sent to approximately 150 to 200 utilities in the U.S. and abroad. We anticipate receiving the results of this survey in Q4 2021. Based on the survey results, we intend to engage other utility SMEs to learn more about their successes/failures, performance data, alternatives, etc. This may produce additional data sets we can include in our effectiveness assessment as well as potentially data on alternatives to covered conductor. We anticipate reaching out to other utilities prior to the end of 2021 and setting up working sessions in 2022. The results and/or status of this effort will be included in our 2022 WMPs along with future milestones to continuously improve our knowledge of covered conductor effectiveness through benchmarking.

Testing:

Testing has shown that covered conductor will prevent incidental contacts that cause phase-to-phase and phase-to-ground faults caused by vegetation, conductor slapping, wildlife, and metallic balloons.[16] Prior to the initiation of this working group, PG&E, SDG&E, and SCE collaborated on conducting additional research and testing of covered conductor. This effort, now joined by Pacific Corp, Bear Valley and Liberty, has

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15 This information is provided in a Covered Conductor Compendium attached to SCE's response to this remedy. Because the compendium is lengthy and is the same for all of the utilities, we did not duplicate it in our Remedy responses.

16 *See* Covered Conductor Compendium.

two phases. The first phase is to conduct a literature and prior work review to determine if various failure modes by bare wire can be mitigated with covered conductor and if any gaps exist for covered conductor installation. As part of this effort, PG&E previously contracted with Exponent to develop a report for Phase 1, anticipated to be completed in November 2021. The outcome of the Phase 1 report is intended to lead to laboratory testing based on the gaps identified in phase 1. Phase 2, laboratory testing, anticipated to begin in late 2021 / early 2022, will help quantify the behavior of covered conductors in simulated real-world scenarios (e.g., third-party contact, conductor slapping, downed conductor, etc.) to better understand the risk of arcing, electric shock, and wildfire ignition relative to traditional bare conductor. These results will help inform the effectiveness of covered conductor, potential shortcomings, and whether additional testing is needed.

Estimated Effectiveness:

Each utility has estimated the effectiveness of covered conductor to mitigate the drivers, such as contact-from-object (CFO) and equipment and facility failure (EFF), of wildfire risk. The utilities plan to organize and assess the different estimated effectiveness values of covered conductor to mitigate wildfire risk drivers. SMEs from the utilities will then work together to discern a common estimated effectiveness value, that will be informed by existing and future date sets such as the additional benchmarking and testing described above, and the recorded results described below. We expect to complete the initial common estimated effectiveness value prior to the submission of the 2022 WMP. Ultimately, the by-product of the sub-workstreams described above and below will result in an estimated covered conductor effectiveness value that can be updated over time.

Recorded Effectiveness:

The utilities plan to collect recorded faults, ignitions and wire downs on overhead circuits involving utility facilities that have been covered in each of the utilities' service area. Similar historical data on circuits that have not been covered will also be collected to form a baseline. The data sets will need to be analyzed to ensure interoperability and our ability to combine the data. We anticipate completing this initial assessment by the 2022 WMP submission date. Given that the utilities only recently began to deploy covered conductor, the utilities also plan to develop longer-term milestones to continuously update the recorded results over time.

Alternative Comparison:

The utilities plan to determine which mitigations and/or groups of mitigations are viable alternatives to covered conductor. 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. We intend to complete this initial assessment in November 2021. Once we have identified viable alternatives, we intend to mutually assess the effectiveness of these alternatives against the same risk drivers that covered conductor is designed to mitigate. We expect to complete an initial assessment and present the comparison effectiveness in the 2022 WMP. We will also include subsequent milestones to continuously update this effectiveness comparison.

Potential to Reduce the Need for PSPS:

The purpose of this sub-workstream is to compare covered conductor installation to other initiatives in its potential to reduce the need for PSPS. Building off the Alternative Comparison sub-workstream, the utilities intend to identify the viable alternatives and/or groups of mitigations that have potential to reduce the need for PSPS, and will derive a common risk reduction factor, subject to weather conditions, for purposes of this effort. The utilities plan to present the results of this initial assessment in the 2022 WMP. Subsequent milestones to update and and/or improve this analysis will also be presented.

Costs:

Covered conductor installation is managed in a project-oriented manner. Like traditional or underground construction, each overhead span is custom-designed and the total spans for each project are also unique. Additionally, covered conductor is also installed with other equipment and materials and can be combined with other system hardening mitigations and/or reliability efforts. These project costs are typically collected in a work order which accounts for labor, material, contract, and various overhead charges. How each utility manages and accounts for their projects can vary based on numerous factors such as system configuration, resource availability, accounting system, CPUC and FERC rate case decisions, and other operational constraints/efficiencies. These differences can make it difficult to compare the cost of covered conductor deployment across utilities. For this sub-workstream, the utilities intend to engage its cost analysts and other SMEs to develop a simplified approach to compare the costs of covered conductor installation across utilities. This assessment will begin with collecting existing recorded unit cost details and documenting project differences in addition to material, labor, and other cost grouping differences. This effort is not intended to pinpoint all cost changes and instead will be a high-level assessment of the major drivers of cost differences. We intend to complete the initial assessment by the 2022 WMP and will inform on future milestones to update the study. If any field studies are determined to be needed to validate aspects of this study, these would be planned for 2022.

Next Steps

As explained above, the utilities plan to make progress on each of the sub-workstreams described above prior to the 2022 WMP. While this effort is in its early stages, the utilities expect to provide an initial common effectiveness value for covered conductor and a long-term plan to continually update the data sets that inform this value in our respective 2022 WMPs. We also expect to make progress on comparing covered conductor to alternatives, covered conductor's ability to reduce the need for PSPS (in comparison to alternatives), and to have an initial assessment of the differences in costs.

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:

1) PG&E recognizes non-exempt fuses are a potential ignition source and adheres to California Public Resource Code (PRC) Section 4292 to clear vegetation on all non-exempt poles. In addition, we have been working diligently to remove non-exempt fuses. PG&E replaces non-exempt line fuses as part of multiple programs including pole replacements, reliability, capacity, new business, work at the request of others, and fire resiliency projects. In 2019, PG&E established a dedicated non-exempt line fuse replacement program. This program has evolved to maximize effectiveness and incorporate risk driven replacements. In 2019 and 2020, the program targeted 625 locations per year. In 2021, using the Technosylva model, taking into account wildfire risk/consequence, PG&E increased the target to 1,200 locations.[18] Concurrent with the submission of these remedy responses, we

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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).

[18] 2021 Revised WMP, p. 536.

are providing to Energy Safety our Quarterly Initiative Update (QIU) for Q3. In the Q3 QIU, we report that through September 30, 2021, we have installed 724 exempt fuses and are on target to complete the WMP commitment of 1,200 by the end of 2021. For 2022, PG&E will target a minimum of 1,200 locations of non-exempt fuses and may increase this pace depending on resource and materials availability as well as a review of program effectiveness as compared to other wildfire risk mitigation initiatives.

2) Exempt fuse material availability is the current constraint to PG&E's execution of its replacement program. There are a limited number of types of exempt fuses that have been tested and certified by California Department of Forestry and Fire Protection (CAL FIRE). In some cases, currently approved exempt fuse designs may not sufficiently balance system protection requirements (they may not effectively coordinate with other system protection devices like reclosers or other fuses) with ignition risk. In these cases, PG&E is constrained because there are no exempt fuses manufactured and approved by CAL FIRE which meet both the system protection coordination needs and ignition risk requirements. CAL FIRE approval can be a constraint to material availability since CAL FIRE is required to test/certify all new exempt equipment under consideration for use at PG&E. Although CAL FIRE has been a strong partner with PG&E, certification of new exempt equipment can take 2-3 years. In addition to this technology constraint, there may also be qualified resource (i.e., trained employees or contractors able to install exempt fuses) and/or funding constraints that limit our ability to increase non-exempt fuse replacements.

3) Our current plan for 2022 is to continue with the increase replacement rate that we implemented in 2021 of 1,200 replacements per year. We may increase this pace depending on resource and materials availability as well as a review of program effectiveness as compared to other wildfire risk mitigation initiatives.

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:

1) There are two situations where we would install non-exempt fuses in HFTD areas. These two situations are:
    - Emergency Conditions: In this situation, we are not able to replace the cutout and fuse with an exempt fuse without significant engineering analysis and given the urgency of the situation to restore electric service, a non-exempt fuse is installed.
    - Protection Device Coordination: Where an exempt fuse installation would have prevented protection coordination with upstream or downstream equipment creating local protection miscoordination issues. Under this situation, a non-exempt fuse cannot be replaced with an exempt fuse. Instead, a non-exempt fuse is installed for these situations.
2) For 2021 and subsequent years, a non-exempt fuse would only be installed in the situations described in the response to subpart (1) above. In 2021, year-to-date, there have been 13 non-exempt fuses installed in HFTD areas due to the situations described above.

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:

1) and 2)

PG&E has two conductor replacement programs which are identified by separate Maintenance Activity Type (MAT) codes.[19] First, ongoing conductor replacement in non-HFTD areas occurs under MAT 08J, including the replacement of small CU conductor (Non-HFTD Replacement Program). Second, in HFTD areas, small CU conductor replacement occurs as a part of PG&E's System Hardening Program under MAT 08W (System Hardening Program). Both of these programs are described in more detail below.

With regard to the Non-HFTD Replacement Program, as we explained in our *Supplemental Filing Addressing Remedial Compliance Plan and First Quarterly Report Action* Items, submitted February 26, 2021 (Supplemental Filing), the focus of this program is small conductor replacement (i.e., 6 CU, 4 CU, and 4 Aluminum Conductor Steel-Reinforced (ACSR)) with elevated wire down rates.[20] Non-HFTD Replacement Program projects are often recommended following an equipment

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[19] In addition, because the standard conductor sizes no longer include these small wire sizes, projects completed due to new business, capacity enhancements, and work at the request of others may also replace these small conductors as required. These replacements would be in addition to PG&E's two conductor replacement programs.

[20] Supplemental Filing, p. 36.

failure wire down outage. Non-HFTD Replacement Program projects may also result from proactive detection of the potential for deteriorated conductor based on certain criteria (i.e., conductor size/type, corrosive region, past wires down, splice count, and/or overstressed conductor relating to available fault current). If a wire down event occurs or the proactive detection criteria is met, then a project is created to address the segment(s) of conductor with similar attributes indicating a deteriorated state. Since the failure rates of 6 CU, 4 CU, and 4 ACSR in corrosion areas[21] are much higher than the system average failure rates, these conductor sizes and types are targeted for replacement make up the majority of the projects within the Non-HFTD Replacement Program.

For HFTD areas, we replace CU conductor through the System Hardening Program. The System Hardening Program workplan is informed by PG&E's 2021 WDRM. The 2021 WDRM takes into account conductor material and size as factors in determining the prioritization of system hardening projects. Specifically, the Conductor Probability of Ignition Model that is part of the 2021 WDRM includes conductor material and size as covariates (i.e., input variables) in identifying conductor locations with a higher probability of ignition. As seen in Table PG&E-Remedy-21-12-01, small conductor sizes, such as 4 and 6, factor in the probability of ignition estimates as factors 9 and 14. Conductor material, such as ACSR (Factor 3) or CU and Aluminum (Factors 15 and 16), are also variable inputs in the model.

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21 Corrosion areas are areas within the PG&E service territory where accelerated corrosion of metal occurs driven by prevailing westerly winds that can deposit salt and moisture.

TABLE PG&E-REMEDY-21-12-01:
COVARIATES USED IN CONDUCTOR PROBABILITY OF IGNITION MODEL

Rank	Model Feature	Units	Permutation Importance
1	unburnable	%	30.8
2	precipitation_ave	mm	29.8
3	conductor_material_acsr	%	9.7
4	estimated_age	years	8.9
5	tree_height_max	m	4.3
6	splice_record_exists	%	4.3
7	vapor_pressure deficit_ave	kPa	4.0
8	conductor_size_2	%	3.4
9	conductor_size_4	%	1.6
10	100_hour_fuels_ave	%	1.1
11	max_temperature_ave	K	1.0
12	wind_ave	m/s	0.9
13	local_topography	%	0.2
14	conductor_size_6	%	0.1
15	conductor_material_al	%	~0
16	conductor_material_cu	%	~0
17	coastal	%	~0
18	specific_humidity_ave	%	~0

It is important to note that conductor material and size are not the only factors considered in the Conductor Probability of Ignition Model. Other factors such as non-burnable area, tree heights, and average wind speed are critical considerations. However, the conductor size and type of material will directly influence the prioritization of circuit segments in the 2021 WDRM for System Hardening Program work. Thus, CU wire reconductoring is a part of the overall System Hardening Program workplan, which prioritizes the highest risk circuits for system hardening work. Where the small CU conductor failure risks align a circuit segment that is high in the 2021 WDRM and is located in an HFTD, this project is considered in the prioritization of the System Hardening Program (i.e., MAT 08W).

At a system level, Figure PG&E-Remedy-21-12-01 below provides a comparative perspective on the small CU conductor population in September 2019 as compared to September 2021. Small CU in HFTD areas has reduced by approximately 155 miles and small CU in non-HFTD areas has reduced by approximately 126 miles.

TABLE PG&E-REMEDY-21-12-02:
REDUCTION IN SMALL CU CONDUCTOR

Location (4, 6 and 8 CU Conductor)	As of 9/2019 (Miles)	As of 9/2021 (Miles)	Reduction
Tier 2 HFTD	2,775.5	2,707.7	67.8 miles
Tier 3 HFTD	924.7	855.8	68.9 miles
Zone 1	18.98	0.79	18.2 miles
Non-HFTD	15,659.5	15,533.8	125.7 miles

Finally, with regard to tracking the reduction in CU conductor, both conductor replacement programs track completed units on individual projects as total actual feet replaced. PG&E's system of record for our electric distribution facilities is Electric Distribution Geographic Information System (EDGIS). The EDGIS system tracks our entire electric distribution system and, with respect to conductors, keeps a record of conductor material and size. When projects in either the Non-HFTD Replacement Program (MAT 08J) or the System Hardening Program (MAT 08W) are constructed, as-built drawings of the project are prepared, and the project is mapped. These maps are then used to update EDGIS. For example, if EDGIS had a record that there were three miles of 6 CU conductor, and those three miles were replaced in a System Hardening project, EDGIS would be updated to reflect the new conductor and the total amount of 6 CU conductor system-wide would be reduced by three miles. Figure PG&E-Remedy-21-12-01 Reduction in Small CU above reflects the tracking that occurs in EDGIS, indicating the 4, 6 and 8 CU conductor that has been replaced as of two specific points in time. With this approach, we are able to track the amount of small CU conductor in our system at any given time, as well as the decrease in small cooper conductor that occurs over time as projects are built. We are also able to track the location of the small CU conductor so that it can be broken down into Tier 2, Tier 3, Zone 1 or non-HFTD areas.

Utility #: PG&E-21-13

Issue title: *Failure to demonstrate that system hardening plan targets highest risk circuit segments.*

Issue description: *A small percentage of circuit-segments in PG&E's distribution system pose a high percentage of PG&E's wildfire risk.*[22] *However, PG&E does not clearly demonstrate that its system hardening plan targets these segments.*

Remedies required and alternative timeline if applicable: *PG&E must fully demonstrate that its system hardening mitigation efforts efficiently target reducing wildfire risk and PSPS events, including a description of how PG&E determines the order in which circuit segments are scheduled for mitigation.*

Response to PG&E-21-13:

To develop the workplan for our System Hardening Program, we used the 2021 WDRM to identify the highest risk circuit segments (also referred to as CPZs) in HFTD areas. The 2021 WDRM is described in detail in our 2021 Revised WMP,[23] but, at a high level, the 2021 WDRM identifies probabilities of ignition and wildfire consequence scores for the overhead distribution system in HFTDs at the circuit segment level to help prioritize highest wildfire risk miles on PG&E's distribution system in HFTDs. The 2021 WDRM also includes a sub-model that is specifically focused on conductor risk, which is referred to as the Conductor Risk Model.[24]

The 2021 WDRM was used to generate a list of CPZs in risk ranked order as a starting point for our System Hardening Program workplan. Our workplan focuses on addressing the highest risk CPZs first by performing system hardening on these CPZs. However, we did make several modifications so that the work performed was efficient and most beneficial for customers and our communities.[25] First, in some cases, a high risk CPZ was very small (in length) and it would be inefficient to perform system

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22 "2021 Wildfire Mitigation Plan Workshop Grid Design and System Hardening" presented February 23, 2021, p. 4.

23 2021 Revised WMP, pp. 130-135.

24 2021 Revised WMP, p. 136.

25 2021 Revised WMP, pp. 599-600.

hardening work on this limited segment. As a result, CPZs that were less than 1 kilometer in length were not included in the System Hardening Program workplan.

Second, as we indicated in the 2021 WMP, two additional factors considered in developing the System Hardening Program workplan were areas where rebuilding was necessary as a result of an actual wildfire and to reduce the impact of future PSPS events. While CPZs in these categories may not be the highest risk, performing system hardening on rebuild CPZs is reasonable since the wildfire risk has actually materialized. Wildfire rebuild work must occur and rather than installing traditional overhead conductor, it is often prudent in an area previously impacted by a wildfire to rebuild the facilities with either overhead covered conductor or with undergrounding.[26] In addition, for some CPZs, although the CPZ is not itself the highest risk ranked CPZ, performing system hardening work may allow us to mitigate future PSPS events. Given the significant customer impact that PSPS events can have, targeting some system hardening programs to provide PSPS mitigation is also reasonable.

Finally, we also considered factors such as locations with deteriorated overhead conductor or where there are a number of corrective maintenance tags for a specific segment.[27] This is reasonable because deteriorated overhead conductor or a significant number of corrective maintenance tags can indicate a conductor that may fail and cause an ignition leading to a wildfire.

Once a circuit segment is targeted for system hardening, a project is launched for a segment that is no larger than 10-miles long. We develop three primary alternatives for construction: (1) all overhead; (2) all underground; and (3) a hybrid alternative utilizing the specific hardening alternative thought to be the best fit for each section in the project. Line removal options are also considered during this scoping phase and, if feasible, thoroughly evaluated as generally the fastest and lowest-cost approach. A more detailed description of the planning process is included in the 2021 Revised WMP.[28]

Once the design alternatives have been vetted, a final economic analysis is performed determining net present values for the lifetime costs of each design approach, including

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26 2021 Revised WMP, pp. 605-606.

27 2021 Revised WMP, p. 599.

28 2021 Revised WMP, pp. 603-605.

long-term maintenance needs and costs such as annual VM and inspections. A final recommendation and associated documentation are then submitted to PG&E's Wildfire Risk Governance Steering Committee (WRGSC) to review the project scope, RSE and other related analyses. The WRGSC provides guidance and approval for the projects that the System Hardening Program should execute upon and the mitigation action to be taken on each project. Once approved, these projects are scheduled for final design, permitting, and execution.

In response to Remedy PG&E-21-14, we are providing information concerning the system hardening work that has been completed today as well as our short term plans. The information included in the Remedy PG&E-21-14 response also includes the risk ranking of CPZs where system hardening work has been performed, as well as wildfire rebuild and PSPS mitigation work. The information in Remedy PG&E-21-14 regarding system hardening projects that have been completed, as well as projects that are planned for the short-term, demonstrates that our system hardening mitigation efforts efficiently target reducing wildfire risk and PSPS events.

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*[29] *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 LTPs for grid hardening, as well as an update on its progress.*

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29 "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).

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

1) *Provide its short-term*[30] *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;*[31] *and*
    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;*[32] *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.*

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30 "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.

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

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

Response to PG&E-21-14:

1) We are providing in Attachments 2021WMP_OEISRemedy_PGE-21-14_Atch01 and 2021WMP_OEISRemedy_PGE-21-14_Atch02 the information requested in Question 1 of Remedy PG&E-21-14. A few of the columns of information provided in the attachment require some additional detail. First, Column L (2021 Miles Completed) and Column M (2021 Forecast Miles) represent the system hardening miles that would count toward our 2021 System Hardening target of 180 high risk miles. The forecasted miles are based on the most current available data and may change if projects encounter delays as a result of permitting, resource availability and other issues. Thus, the miles in Column M are subject to change. In addition, the miles in Column L have not been fully audited and thus are also subject to change.

   Second, PG&E has included Column V (Old CPZ) and Column X (2018 Risk Rank) for informational purposes. These columns contain information regarding earlier CPZ designations and the ranking of CPZs in earlier risk models (i.e., models that proceeded the 2021 WDRM). These columns are being provided for informational purposes, but the most current information is provided in Column W (CPZ) and Column Y (2021 Risk Rank). Please note that the 2021 Risk Rank is based on the 2021 WDRM.

   Third, PG&E includes in its System Hardening Program the removal of idle line facilities.[33] In Column Z (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 Z and the row in Column Z for idle line facilities is left blank.

   Finally, Columns N and O provide forecasts of system hardening work for 2022 and 2023, respectively. PG&E continues to refine and update its 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.

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33 2021 Revised WMP, p. 600.

2) In our 2021 Revised WMP, we explained that we expect that "the pace of system hardening will increase substantially in 2022 and going forward to between 450 and 500 miles per year."[34] While we are continuing to develop additional details on our 10,000 mile undergrounding plan, our goal is to significantly increase our underground miles annually. We will perform undergrounding in areas where we can reduce wildfire risk and/or reduce impacts from PSPS events. We currently anticipate ramping up to approximately 1,000 miles of undergrounding per year as an end state, but it will take several years for that ramp up to occur. We intend to produce more specific details in our 2022 WMP about the rate of ramp up for undergrounding and the expected number of miles per year that we will be undergrounding based on that ramp up. As a result, we may accelerate the 450-500 miles per year initially forecasted in the 2021 Revised WMP. In order to support the accelerated rate of undergrounding, we currently plan to use an Engineering, Procurement and Construction strategy that will aid in resourcing and work execution. In addition, we will coordinate with the Engineers and Scientists of California and the International Brotherhood of Electrical Workers so that resources are available to execute the work. Resource plans will be more fully developed concurrent with the development of a more detail undergrounding plan.

3) PG&E's decision to underground 10,000 miles of its electric system will not have an immediate impact on the decision-making framework for system hardening because we are currently in the initial stages of program development. However, we expect that our decision-making framework will evolve over time as we finalize the details of the undergrounding program. For System Hardening Program projects through 2023, we have used the existing decision-making framework, which is depicted in Figure PG&E-Remedy-21-14-01 below.

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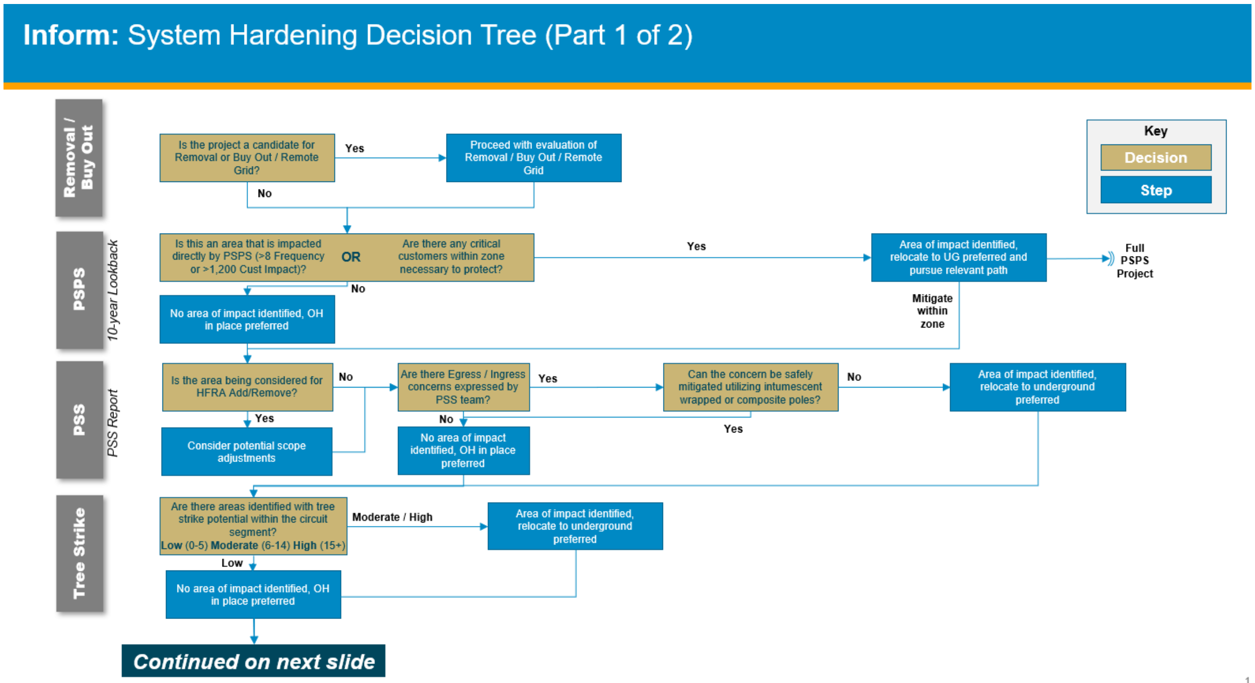
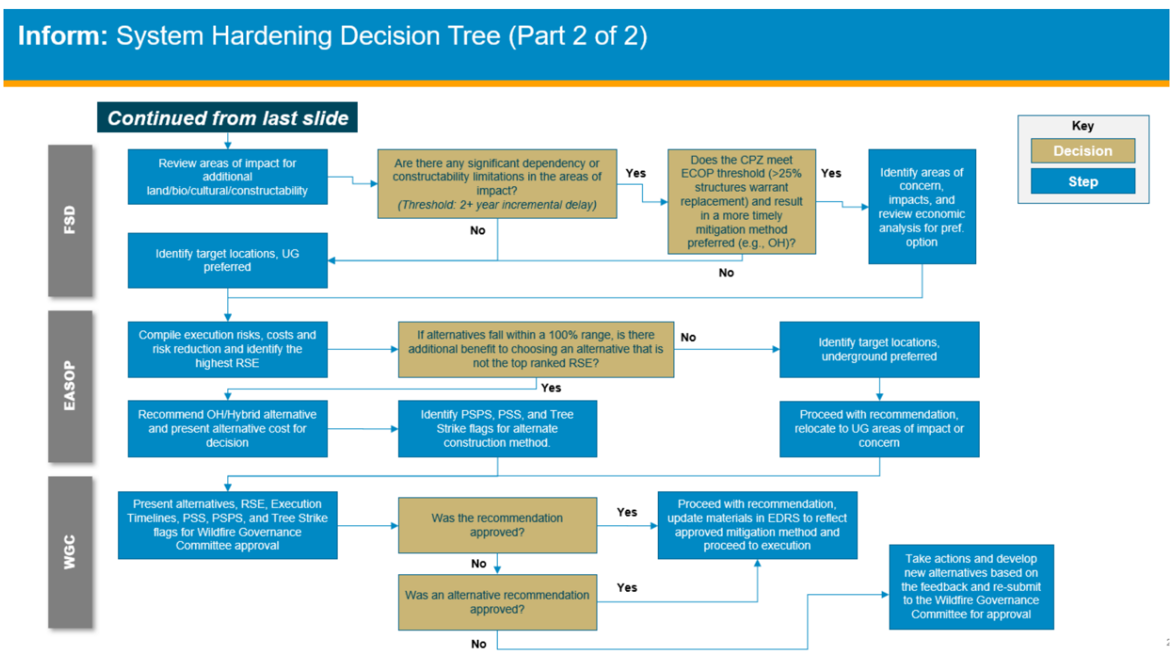
[34] 2021 Revised WMP, pp. 608-609.

FIGURE PG&E-REMEDY-21-14-01:
MITIGATION DECISION TREE FOR SYSTEM HARDENING





However, the framework will evolve over time based on: (1) improvements in our risk modeling; and (2) development of a more detailed plan for our 10,000 miles of undergrounding initiative. The decision-making framework will also be updated to reflect other WMP initiatives and operational changes, such as Enhanced Powerline Safety Settings (EPSS), as well as RSE and financial considerations, such as the unit cost of certain types of system hardening. We do not believe that our 10,000 miles of undergrounding proposal will impact any research or technologies that are under review.[35] We will continue to evaluate and, where appropriate, use these technologies. In addition, we will continue to explore other system hardening solutions in areas that might be feasible for undergrounding.

4) The information responsive to Question 4 is included in Attachment 2021WMP_OEISRemedy_PGE-21-14_Atch01, Column L. Because these remedy responses are being submitted on November 1, 2021, we were not able to provide this information as of November 1st. This information is being provided as of October 14, 2021, which is the latest date possible given the timing for this response and the need to prepare responsive materials. Please also note that PG&E understands Question 4 to be asking about system hardening that was completed in 2021.

5) We intended to provide the requested information as a part of the 2022 WMP.

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35 *See e.g.,* 2021 Revised WMP, pp. 104-110 (describing research and technologies under evaluation and review).

Asset Management and Inspections (Section 5.4)

Utility #: PG&E-21-15

Issue title: *Insufficient detail regarding covered conductor maintenance.*

Issue description: *PG&E states "[c]overed conductor maintenance will be performed anywhere covered conductor is installed and found to have conditions requiring maintenance."*[36] *PG&E does not provide more detail as to what conditions require maintenance. PG&E also does not explain or justify its spend projections for covered conductor maintenance. PG&E's projected spend for covered conductor maintenance is higher in 2021 than in 2022, however the projected line miles to be treated remain the same.*[37]

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

1) *Provide its procedures for determining when covered conductor maintenance is required, including any thresholds and aspects analyzed during inspections; and*
2) *Explain why PG&E's cost projections decrease from 2021 to 2022 despite line mile projections remain the same.*

Response to PG&E-21-15:

1) Covered conductor is a relatively new technology that has not yet been widely adopted and currently there is no professional standard for when covered conductor needs to be "maintained" or repaired. PG&E does not have a special covered conductor maintenance program; however, like bare conductor, it is inspected for visual concerns as part of our standard General Order (GO) inspections. When issues are found, PG&E replaces any degraded or damaged covered conductor rather than attempting to repair it. As such, maintenance of covered conductor is focused on inspection of the conductor and, when necessary, replacement of covered conductor in the event of observations indicating that the wire has been damaged using the standard job aid for inspections (TD-2305M-JA02), please see Attachment 2021WMP_OEISRemedy_PGE-21-15_Atch01. In addition, pilot studies are

36 PG&E 2021 WMP Update at p. 479.

37 PG&E Table 12, Line 40.

underway in collaboration with SDG&E and SCE to develop best practices that would be focused on the maintenance, inspection, and replacement of covered conductor.

2) The initial cost projections for the covered conductor program were based on an assumption regarding the overall maintenance program (MAT KAA) using a snapshot in time in early 2021. At the time of the snapshot, the 2022 forecast for the maintenance program was too low, which also resulted in a decrease to the covered conductor forecast. For 2021, the covered conductor forecast was based on number of tags we had in our work plan. The 2022 forecast for covered conductor did not have the detailed tag information and was pro-rated based on overall MAT KAA forecast, the largest MAT in the overall maintenance program. Since then, the forecast for the overall maintenance program has been refined and updated for our 2023 General Rate Case (GRC), and the 2022 forecast is now in line with annual trends. Table PG&E-Remedy 21-15-01 below provides a comparison of the initial 2021 WMP forecast and the more current 2023 GRC.

**TABLE PG&E-REMEDY-21-15-01:
COMPARISON OF 2021 WMP AND 2023 GRC COVERED CONDUCTOR MAINTENANCE FORECASTS**

Forecast Snapshot	Program	2021	2022	YoY Change
Forecast during WMP	Overall Maintenance Program (MAT KAA)	$49,612,461	$22,276,706	-55%
Forecast during WMP	Covered Conductor Program Portion of KAA	$9,037,894	$4,058,144	-55%
Subsequent Forecast update for GRC	Final GRC Forecast for Maintenance Program (MAT KAA)	$49,612,461	$48,622,465	

Utility #: PG&E-21-16

Issue title: *Insufficient evidence of effective covered conductor maintenance program.*

Issue description: *PG&E does not have a separate covered conductor maintenance program.*

Remedies required and alternative timeline if applicable: *PG&E must provide all supporting material to demonstrate that its maintenance programs effectively maintain its covered conductor, including the following information:*

1) *Pace and quantity of scheduled maintenance; and*
2) *Pace and quantity of inspections.*

If PG&E finds that its existing maintenance programs do not provide effective maintenance for covered conductor, PG&E must:

1) *Enhance its current operations to provide such maintenance;*
2) *Detail the enhancements to its existing programs; and*
3) *Provide all supporting material for the enhancements to its existing program, including the information listed above.*

Response to PG&E-21-16:

1) PG&E does not perform regularly scheduled maintenance on conductors, whether the conductor is covered or not. Instead, PG&E performs detailed inspections of its overhead facilities and, when the inspection identifies a problem or issue with a piece of overhead equipment, including a covered conductor, a tag is created and necessary maintenance is performed. The timing of maintenance is based on the classification of the tag.
2) PG&E uses the TD-2305M-JA02 (see Attachment 2021WMP_OEISRemedy_PGE-21-15_Atch01) as the job aid for overhead inspection that includes a detailed checklist used in the field by staff equipped with electronic tablets. If during these detailed inspections a problem or issue is identified, a maintenance tag is created.
3) See the response to subpart (1).

Utility #: PG&E-21-17

Issue title: *Insufficient evidence of 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 response to this Remedy is focused on the Quality Management activities currently being performed or planned for implementation in 2021/2022 within the System Inspections QC group to track and monitor the performance of contract inspector workforce performing GO165 compliance inspections.

1) The QC team established and successfully implemented its Desktop QC Review program in September 2020. This program currently applies to Overhead Distribution and Transmission Ground inspection methods. All discrepancies found during the QC review are recorded in detail under the specific Inspection checklist section. Specialists provide detailed objective evidence supporting their findings and list procedural or guidance documentation references where applicable. Specialists suggest recommended corrections/corrective actions as "Follow Up" items in the QC form when applicable. Discrepancies identified during the Desktop review are compiled by the QC Analytics team and the two dashboards listed below are

created and shared weekly with the System Inspection Execution leadership team to track and monitor the quality of contract vendors and their inspectors.

- Distribution QC Specialist Dashboard (see Attachment 2021WMP_OEISRemedy_PGE-21-17_Atch01); and
- Transmission QC Specialist Dashboard (see Attachment 2021WMP_OEISRemedy_PGE-21-17_Atch02).

The dashboards provide an array of options to filter, sort through the data, and drill down to get detailed information on the identified non-conformances and observations by the various QC findings codes, specific checklist sections, inspectors, or specific regions, among other things. The dashboard also provides trend charts reflecting the top ten non-conformances in the system. In addition, the QC Analytics team also extracts data from Attainment Report and Centralized Inspection Review Team (CIRT) reports to derive the following Inspector Quality Key Performance Indicator (KPI) trackers:

- Distribution Overhead Inspector KPI Tracker (see Attachment 2021WMP_OEISRemedy_PGE-21-17_Atch03); and
- Transmission Overhead Inspector KPI Tracker (see Attachment 2021WMP_OEISRemedy_PGE-21-17_Atch04).

These trackers measure and monitor overall inspector quality and productivity as it relates to the accurate identification, prioritization, and documentation of newly identified corrective maintenance work. The following contract inspector KPIs were developed – Productivity, Find, Cancel, Upgrade, Downgrade and Agree Rate (based on changes made during CIRT gatekeeping activities). Using a combination of these KPIs, the Dashboard helps identify “outlier” inspectors in the system. Both these dashboards are shared weekly with System Inspection Execution team to assist in easily identifying any negatively trending contract inspector for immediate coaching or other real time field corrective actions.

2) and 3)

As stated in the response to (1) above, the QC team is conducting desktop reviews to identify quality issues, collecting/compiling all quality data within QC/CIRT, and releasing this data to the System Inspection stakeholders to take the appropriate corrective action. Currently, QC is only tracking Vendor Performance. In the near term, the team plans to address vendor quality performance and corrective actions using the Quality Feedback Process which is currently in development. The project is being piloted in Q4 with a small subset of vendor non-conformances. The goal is to implement the project in 2022 and work towards stabilizing the process. The project goals and specific details of this feedback process are described in detail below.

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 as described in Figure PG&E-Remedy-21-17-01 below. The feedback process inputs will be inclusive of both internal and contract inspector work.

FIGURE PG&E-REMEDY-21-17-01:
SYSTEM INSPECTIONS CONTINOUS IMPROVEMENT QUALITY FEEDBACK LOOP

The process will include regular feedback, corrective actions and monitoring of specific quality issues, inspectors, open corrective actions, corrective action effectiveness and quality performance trending. It will provide a platform for System Inspection to perform and document its on-going corrective action activities and overall long-term continuous improvement initiatives. QC will engage and partner with the System Inspection Execution Leadership team and other stakeholders to conduct real time review of quality issues as they are being logged in the system, perform the required investigation to identify cause and develop robust corrective actions to prevent recurrence. This program will strive to engage Asset Strategy, Standards, Engineering, Information Technology (IT) and Compliance to drive continuous improvements in System Inspection processes, standards and procedures, training and technology.

How will the feedback loop address contract inspector/contract vendor quality performance?

With continuous quality data track/trend and monitoring, the feedback process will have the built-in capability to identify underperforming contractors and the associated quality issues. Having easy access to this information will allow the System Inspections team to work with the vendor to take the necessary corrective actions and mitigate any risk. Additionally, all quality issues will be trended at system level by vendor. Quality KPIs will be developed to trend vendor performance and vendors will be provided with their quality scorecard. QC is partnering with Electric Operations (EO) Vendor Performance Management team to develop Quality KPIs and Vendor Scorecards. This project should be implemented in early 2022. The System Inspection team will take appropriate action as part of the feedback corrective action process to address vendors not meeting KPI and exhibiting negative quality trends. A vendor's historical quality performance will also be incorporated as an input into the contract management process to ensure that only vendors who has met the acceptable quality level (AQL) (AQL to be developed as part of the Vendor Scorecard project) is used for future contract work.

QC Programs Growth and Expansion

The QC team plans to expand its 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.

QC has also partnered with the System Inspection Execution team to conduct some post inspection field reviews. A QC Field Verification pilot was recently launched to conduct feasibility studies, and to explore any additional opportunities that may be present with this mode of inspection when compared to the virtual desktop QC reviews. This pilot is in progress for Transmission and Distribution Overhead inspection methods.

Vegetation Management and Inspections (Section 5.5)

Utility #: PG&E-21-18

Issue title: *Minimally planned maturity of VM program.*

Issue description: *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.*

Remedies required and alternative timeline if applicable: 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.*

Response to PG&E-21-18:

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

Capability 21 – Vegetation inventory and condition assessments

Target: PG&E plans to move from a current maturity level of **2.50** to **3.25** by the end of 2022.

Goals: This level of maturity will be obtained by continued enhancement of our Tree Assessment Tool (TAT). Specifically, TAT will maintain a comprehensive inventory of every tree that can strike within Enhanced Vegetation Management (EVM) HFTD miles. Updates to the TAT inventory are expected to occur by Q4 of 2022. Additionally, tree inventory will be updated in PG&E's database on a much more frequent basis. The inventory of trees assessed by TAT is updated every day as new trees and miles are inspected by EVM. The TAT itself is undergoing revision/improvement to its accuracy in identifying trees at risk of failing and to customize the outcomes to the program applied (i.e., TAT will be able to be used on routine program in addition to EVM). This accuracy improvement-based revision is anticipated to be complete in 2022.

TABLE PG&E-REMEDY-21-18-01: CAPABILTY 21

Capability 21: Having an accurate inventory database of vegetation along rights of way, and vegetation with strike potential, including the condition of each vegetation. Higher scores are achieved by more granular information and having a more up-to-date database.			
Capability #	Capability 21 Question	Current Score (2021)	Future Score (2022)
21A	What information is captured in the inventory?	2	4
21B	How frequently is inventory updated?	2	3
21C	Are inspections independently verified by third party experts?	2	2
21D	How granular is the inventory?	4	4
Current Average:		2.5	3.25

Capability 22 – Vegetation inspection cycle

Target: PG&E plans to move from a current maturity level of **1.33** to **2.66** by the end of 2022.

Goals: 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.

Additionally, the development of the tree risk model, referred to as the "LiDAR Risk Score Model" which calculates the relative risk of individual trees within the HFTD that have strike potential to our transmission conductors is a model that will help.

TABLE PG&E-REMEDY-21-18-02: CAPABILTY 22

Capability 22: How the utility determines the cycle with which inspections of the vegetation are conducted. Higher scores are achieved by understanding vegetation growth, characteristics, and failure probability and timing inspections accordingly to maximize risk mitigation efficacy.			
Capability #	Capability 22 Question	Current Score (2021)	Future Score (2022)
22A	How frequent are all types of vegetation inspections?	2	3
22B	How are vegetation inspections scheduled?	1	1
22C	What are the inputs to scheduling vegetation inspections?	1	4
Current Average:		1.33	2.67

Capability 23 – Vegetation inspection effectiveness

Target: PG&E plans to move from a current maturity level of **1.33** to **2.66** by the end of 2022.

Goals: PG&E has established a Quality Assurance (QA) program that helps improve inspection effectiveness. Specifically, QA reviews VM inspection procedures, VM standards, and VM systems of record for any potential gaps in the inspection program and processes. Long-term, PG&E plans to improve patrol procedures for all programs to incorporate additional details and lessons learned to help employees and contract staff members perform better inspections that benefit all customers. This is an effort that will be continuous and carried out well beyond 2025.

TABLE PG&E-REMEDY-21-18-03: CAPABILTY 23

Capability 23: The depth and detail to which inspections are performed and recorded. Higher scores are achieved by having greater ability to identify higher risk areas and vegetation and conducting more in-depth inspections to maximize risk mitigation efficacy.			
Capability #	Capability 23 Question	Current Score (2021)	Future Score (2022)
23A	What items are captured within inspection procedures and checklists?	2	3
23B	How are procedures and checklists determined?	1	3
23C	At what level of granularity are the depth of checklists, training, and procedures customized?	1	2
Current Average:		1.33	2.66

Capability 24 – Vegetation grow-in mitigation

Target: PG&E plans to move from a current maturity level of **1.22** to **1.88** by the end of 2022.

Goals: PG&E has determined that in certain circumstances it is prudent to exceed the GO 95 requirements for tree trimming. For example, instead of the required 4-ft radial clearance around conductors, PG&E is trimming trees from the conductor to sky for overhang clearing. Additionally, through our EVM program, PG&E abates or trims trees outside of the GO 95 prescribed 4-ft clearance where trees more than 4-ft away from a power line are determined to have a defect as identified through the TAT and have a clear path to strike. PG&E will continue to improve upon EVM practices to exceed minimum statutory and regulatory clearances around all lines and equipment.

TABLE PG&E-REMEDY-21-18-04: CAPABILTY 24

Capability 24: The utility's standards and actions for treating vegetation that has grow-in potential around lines and equipment. Higher scores are awarded for utilities that use ignition risk modeling and vegetation growth rates to determine appropriate vegetation clearances and trim cycles.			
Capability #	Capability 24 Question	Current Score (2021)	Future Score (2022)
24A	How does utility clearance around lines and equipment perform relative to expected standards?	2	3
24B	Does utility meet or exceed minimum statutory or regulatory clearances during all seasons?	2	2
24C	What modeling is used to guide clearances around lines and equipment?	3 (None of the Above)	1
24D	What biological modeling is used to guide clearance around lines and equipment	3 (None of the Above)	1
24E	Are community organizations engaged in setting local clearances and protocols?	1	2
24F	Does the utility remove vegetation waste along its right of way (ROW) across the entire grid?	1	2
24G	How long after cutting vegetation does the utility remove vegetation waste along ROW?	2	2
24H	Does the utility work with local landowners to provide a cost-effective use for cutting vegetation?	1	2
24I	Does the utility work with partners to identify new cost-effective uses for vegetation, taking into consideration environmental impacts and emissions of vegetation waste?	2	2
Current Average:		1.22	1.88

Capability 25 – Vegetation fall-in mitigation

Target: PG&E plans to move from a current maturity level of **1.86** to **2.71** by the end of 2022.

Goals: PG&E will expand routine inspection practices in HFTDs to include the inspection of all sides of a tree to identify tree defects that are otherwise hidden from view. Each of the defects identified will be accounted for and included in the decision-making process to abate or not to abate a tree. Additionally, PG&E has a Wood Management program that will help eliminate vegetation waste across the entire grid. Our goal is to decrease waste removal timeframes and work with local landowners to provide cost effective ways for cutting vegetation. PG&E is in the process of developing a comprehensive wood removal strategy for all electric VM programs, and plans to begin piloting this work in 2022.

TABLE PG&E-REMEDY-21-18-05: CAPABILTY 25

Capability 25: The utility's processes for treating vegetation that has strike potential on its grid. Higher scores are awarded to utilities that treat vegetation based on a granular understanding of individual vegetation strike potential.			
Capability #	Capability 25 Question	Current Score (2021)	Future Score (2022)
25A	Does the utility have a process for treating vegetation outside of ROWs?	3	4
25B	How is potential vegetation that may pose a threat identified?	2	3
25C	Is vegetation removed with cooperation from the community?	2	2
25D	Does the utility remove vegetation waste outside its ROW across the entire grid?	1	2
25E	How long after cutting vegetation does the utility remove vegetation waste outside its ROW?	2	3
25F	Does the utility work with local landowners to provide a cost-effective use for cutting vegetation?	1	1
25G	Does the utility work with partners to identify new cost-effective uses for vegetation, taking into consideration environmental impacts and emissions of vegetation waste?	2	2
Current Average:		1.86	2.42

Capability 26 – QA/QC for vegetation maintenance

Target: PG&E plans to move from a current maturity level of **2.20** to **3.00** by the end of 2022.

Goals: PG&E assesses VM work performance using both QA and QV processes. Both QA and QV processes use sampling methodologies to determine which samples to assess. The QA effort is designed to validate program effectiveness and to provide confidence that the desired outcomes, including regulatory goals, are met. For 2021, the Veg QA and QV teams' goal is to conduct approximately 2,000 audits/reviews. The results from the audits/reviews conducted will be used to strengthen vegetation maintenance.

TABLE PG&E-REMEDY-21-18-06: CAPABILTY 26

Capability 26: Having established processes for monitoring the quality of inspection and treatment work across the grid. Higher scores are achieved for having robust processes, trainings, and leveraging technologies to monitor and validate work performed.			
Capability #	Capability 26 Question	Current Score (2021)	Future Score (2022)
26A	How is contractor and employee activity audited?	2	4
26B	Do contractors follow the same processes and standards as utility's own employees?	2	2
26C	How frequently is QA/QC information used to identify deficiencies in quality of work performance and inspections performance?	4	4
26D	How is work and inspections that do not meet utility-prescribed standards remediated?	2	3
26E	Are workforce management software tools used to manage and confirm work completed by subcontractors?	1	2
Current Average:		2.20	3

3) All targets related to Capabilities 24 and 25 will be achieved by Q4 of 2022. Additionally, goals associated with both capabilities are already in the process of implementation and will all be completed by the end of Q4 of 2021.

4) PG&E provides a long-term vision for each VM initiative in Subsection 5 “Future improvements to the initiative” (or similar) including any relevant timelines below:

TABLE PG&E REMEDY-21-18-07:
LONG-TERM VISION AND RELEVANT TIMELINES FOR EACH VM INITIATIVE

Initiative #	Revised 2021 WMP (Response to Section 5 and Action PG&E-25 [Class B])	Additional Information on Long-Term Plans
7.3.5.1	PG&E will continue to communicate and partner with stakeholders regarding this public safety vegetation work and promote fire resistant planting. PG&E informs cities and counties of VM work within their community and works with them to address any questions they may have. Managing community and environmental impacts is one of PG&E's top priorities and will continue to be well beyond the next 10 years. Long-term, PG&E is planning on better partnerships and agreements with agencies to perform VM work on federal or state lands without additional permitting requirements that could slow the mitigation of crucial work activities. PG&E also wants to promote fire-resistant plantings on these agency lands to reduce the community and environmental impacts of continuing to perform VM activities on a regular basis.	In 2022, PG&E will have begun our effort to standardize and enhance agency and customer engagement for electric VM work. This new process incorporates a broader proactive outreach to more effectively partner with our cities, counties and customers. The effort includes consistent stakeholder engagement including notifying our cities and counties of planned work through ProjectWise and conducting customer outreach prior to inspections, pre-tree crew work, and post-tree work through postcards, door hangers and automated calls. PG&E will implement the new approach in phases, starting with EVM, Routine, and Catastrophic Event Memorandum Account (CEMA) programs. By the end of 2022, PG&E plans to fully execute standardizing customer engagement across the remaining electric distribution and transmission VM programs. Long-term, PG&E will continue to improve customer engagement materials and processes by evaluating proactive work notifications, customer constraint resolution timeframes, and work completion. In addition, PG&E will explore opportunities to further refine stakeholder engagement around electric VM programs based on the implementation of this new customer engagement process.
7.3.5.2	Future improvements include, but are not limited to, increasing staff for general oversight and Work Verification (WV), as well as improvements to the QV process described in Section 7.3.5.13(QA/QC of Inspections). Long-term, PG&E plans to improve patrol procedures for all programs to incorporate additional details and lessons learned to help employees and contract staff members perform better inspections that benefit all customers. This is an effort that will be continuous and carried out well beyond 2025. WV and QV processes are projected to continue to expand within the next five years. Expansions of these processes will allow PG&E to use internal audit results to improve inspections of vegetation around distribution electric lines and equipment.	PG&E has begun the long-term effort of updating procedural documents related to patrols. Per TD-84015, all electric guidance documents and manuals must be updated at least once every 7 years, and no document can go without review beyond 5 years. Given the rapid change that VM is currently undergoing, PG&E expects every patrol standard and work procedure to undergo an update by 2026. On a yearly basis between now and 2026, PG&E will perform VM program inspections on approximately 100,000 miles on an annual inspection cycle.

TABLE PG&E REMEDY-21-18-07:
LONG-TERM VISION AND RELEVANT TIMELINES FOR EACH VM INITIATIVE
(CONTINUED)

Initiative #	Revised 2021 WMP (Response to Section 5 and Action PG&E-25 [Class B])	Additional Information on Long-Term Plans
7.3.5.3	Future improvement opportunities include continued improvement of LiDAR Risk Score Model. This model is being reworked, validated, and vetted by a team of internal and consulting experts as well as an industry panel that was assembled by the North American Transmission Forum (see Section 7.3.5.8 concerning LiDAR Inspections of Vegetation Around Transmission Electric Lines and Equipment). Work related to inspections around transmission electric lines and equipment is recurring work that will expand beyond 2030. Due to the higher risk of potential fire ignition exposure in the HFTD Tier 2 and 3 areas, PG&E's goal is to remove vegetation to widen existing 60 kilovolt (kV)/70/kV115/kV ET corridors in Tier 2 and Tier 3 HFTD areas. Throughout this period, PG&E will be evaluating risk associated with the completion of this work and will adjust course as necessary to meet the objective.	ROW Expansion refers to work intended to clear a minimum 20' ROW on lines identified by a number of risk factors, primarily: fire risk, outage frequency and number of times the line was in scope for a PSPS event. The purpose of ROW expansion is reduction of tree-caused outages on the transmission lines most at-risk for tree-caused failure. This will allow PG&E to maintain access to its operated lines to provide safe, efficient, reliable service, safe-and reliable interconnection of the load or generator to PG&E's grid, increase customer satisfaction, and meet renewable energy mandates. ROW expansion will continue to be a program that consists of multi-year projects. ROW line miles could be increased to be worked in the future. Typically, work plans would be discussed every year in Q4 with VM Transmission Operations (Execution team), Vegetation Asset Strategy, and T-Line Asset Strategy. ROW expansion of 200 miles will continue beyond the next 5 years depending on wildfire risk. 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	PG&E has no current plans for improvements to this initiative. However, PG&E will continue to evaluate the process annually by reviewing the execution of the work. As stated in the section above, there are no further improvements planned at this time.	Responding to Red Flag Warning days or other elevated fire weather events is 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.

TABLE PG&E REMEDY-21-18-07:
LONG-TERM VISION AND RELEVANT TIMELINES FOR EACH VM INITIATIVE
(CONTINUED)

Initiative #	Revised 2021 WMP (Response to Section 5 and Action PG&E-25 [Class B])	Additional Information on Long-Term Plans
7.3.5.5	Incoming data will be used to determine effectiveness and RSE of a fuel reduction program. In addition, PG&E will use incoming data to identify the most effective schedule and cycle time. As mentioned, above, PG&E has completed benchmarking with other utility companies. PG&E will be one of the first utility companies developing an official fuel reduction program. In addition, as part of our UDS Program, PG&E is evaluating the use of fire-retardant products to reduce risk of ignition from utility infrastructure. Traditionally, the use of fire-retardant chemicals has been limited to firefighting operations during active wildfires. PG&E is interested in land application of fire-retardant chemicals as a preventative measure to reduce potential ignitions related to utility infrastructure during extreme weather events in HFTDs. In the U.S., there is currently no single regulatory framework for the production, authorization and use of fire retardants. PG&E intends to conduct a review of commercially available fire-retardant products. This review will consist of the following: • Product toxicological and environmental analysis; • Efficacy analysis; • Environmental planning and permitting initial assessment; and • Scope of use including asset protection and proactive application. PG&E's review of fire-retardant chemicals will take place ahead of the 2021 wildfire season. PG&E has not determined a long-term plan yet for this initiative. Depending on the results of PG&E's fire-retardant review, PG&E will establish best management practices for future use of fire retardants. Additionally, PG&E will work with regulatory agencies to secure permits for future product use and application. Long-term plan milestones are still under development with VMs Leadership team.	As part of PG&E's continued utility defensible space (UDS)/fuel reduction efforts, PG&E will continue the work of clearing vegetation and modifying ground and ladder fuels were permitted by customers on approximately 4,117 distribution poles within HFTD areas. Beyond the scope of work described above, future UDS/fuel reduction work will include a scope of 14,697 poles within 550 line miles that have been identified by the Wildfire Risk Management (WRM) team as priority work. PG&E will continue to clear vegetation at prioritized locations over the next five years, while continuing to work with the WRM team to identify other priority locations for UDS.

TABLE PG&E REMEDY-21-18-07:
LONG-TERM VISION AND RELEVANT TIMELINES FOR EACH VM INITIATIVE
(CONTINUED)

<table>
<tr><th>Initiative #</th><th>Revised 2021 WMP (Response to Section 5 and Action PG&E-25 [Class B])</th><th>Additional Information on Long-Term Plans</th></tr>
<tr><td>7.3.5.6</td><td>As stated above, please reference Section 7.3.5.2, Section 7.3.5.3, and Section 7.3.5.13 for more information on future improvements for this initiative.</td><td>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/QC of Inspections) for future improvements regarding this initiative.</td></tr>
<tr><td>7.3.5.7</td><td>Future LiDAR and Remote Sensing initiatives will focus on the continued evaluation of the use of LiDAR in QC and WV for radial clearances in Routine VM.

PG&E will pilot the use of ground-based LiDAR (GBL) datasets for QC in Routine VM in HFTD areas. We will be evaluating future LiDAR and remote sensing initiatives and will utilize lessons learned from previous and upcoming pilots to determine what the long-term path is. Long-term plan milestones are still under development, with the VM Leadership team.</td><td>PG&E is moving forward with the utilization of GBL datasets for QC in Routine VM in HFTD areas. PG&E has laid out the following GBL mileage plan through 2024. Planned mileage is subject to change. The mileage plans for GBL below are based solely on current feedback from utilizing this new technology. If at any point PG&E determines this technology does not effectively support efforts to reduce wildfire risk when compared to other viable approaches or technology, PG&E will pause or discontinue GBL efforts to focus on other avenues to reduce wildfire risk in a meaningful way.

<table><tr><th>Year</th><th>Planned GBL Mileage</th></tr><tr><td>2022</td><td>2000</td></tr><tr><td>2023</td><td>4000</td></tr><tr><td>2024</td><td>6000</td></tr><tr><td>2025</td><td>6000</td></tr></table>
All GBL scans of Electric Distribution assets will be performed along roadside-available ROWs in HFTD areas.</td></tr>
</table>

TABLE PG&E REMEDY-21-18-07:
LONG-TERM VISION AND RELEVANT TIMELINES FOR EACH VM INITIATIVE
(CONTINUED)

Initiative #	Revised 2021 WMP (Response to Section 5 and Action PG&E-25 [Class B])	Additional Information on Long-Term Plans
7.3.5.9	PG&E will continue to use and build upon the CEMA second patrol program that utilizes two forms of inspections, ground and aerial, to patrol the distribution lines. Ground patrols involve a contract pre-inspector (PI) walking along the distribution lines inspecting for any issue that meets the scope of mid-cycle patrol. Ground patrols are the main method of inspection for the second patrol program. Aerial patrols involve a PI flying in a helicopter over the distribution lines inspecting any issue that meets the scope of the second patrol. To improve upon CEMA inspections, PG&E will begin updating our contracts with the intent of diversifying the PI vendors we use, continue to assess areas appropriate for aerial patrols, and evaluate the frequency of patrols in Wildland Urban Interface and non-HFTD areas. PG&E has not determined a long-term plan yet for this initiative. We will be assessing potential future CEMA improvements and second patrol procedure enhancements to boost focus on HFTD areas for inspectors to ensure efforts are concentrated on wildfire risk reduction. Long-term plan milestones are still under development with VMs Leadership team. These steps seek to drive toward decision-making based upon current second inspection in many parts of our service territory, namely HFTDs, and SRA that are at higher risk of tree mortality and/or wildfire risk, Federal Responsibility Areas, and Fire Hazard Severity Zones.	The improvement and development of the PG&E mid-cycle tracking metrics over the next 5 years will ensure that the mid-cycle patrols are completed within the specific time frame, as well as allow PG&E to track the percentage of mid-cycle patrols that are completed approximately 6 months before or after routine patrols. Additionally, to focus on HFTD areas, PG&E will improve mid-cycle procedures and tracking metrics to better concentrate on wildfire risk reductions.
7.3.5.10	As stated above, please reference Section 7.3.5.3 for more information on future improvements for this initiative.	Please refer to Section 7.3.5.3 for more information on future improvements for this initiative.
7.3.5.11	As stated above, please reference Section 7.3.5.2 for more information on future improvements for this initiative.	Please refer to Section 7.3.5.2 for more information on future improvements for this initiative.
7.3.5.12	As stated above, please reference Section 7.3.5.3 for more information on future improvements for this initiative.	Please refer to Section 7.3.5.3 for more information on future improvements for this initiative.

TABLE PG&E REMEDY-21-18-07:
LONG-TERM VISION AND RELEVANT TIMELINES FOR EACH VM INITIATIVE
(CONTINUED)

Initiative #	Revised 2021 WMP (Response to Section 5 and Action PG&E-25 [Class B])	Additional Information on Long-Term Plans
7.3.5.13	Quality Management Veg QA and Veg QV are beginning to use Survey123/Collector to perform audits/reviews. This is being done to align with how the line of business (LOB) performs its work, and to efficiently communicate findings and take advantage of a system (front end, database, dashboards) rather than a paper-based process. PG&E has not determined a long-term plan yet for this initiative. PG&E would like for all QC efforts to be completely paperless and utilize digital products only. Enhancing our QC efforts will take an internal coordinated team approach to successfully implement a process that is effective and efficient. Long-term plan milestones are still under development and will continue to be discussed well beyond 2021.	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.

TABLE PG&E REMEDY-21-18-07:
LONG-TERM VISION AND RELEVANT TIMELINES FOR EACH VM INITIATIVE
(CONTINUED)

Initiative #	Revised 2021 WMP (Response to Section 5 and Action PG&E-25 [Class B])	Additional Information on Long-Term Plans
7.3.5.14	Since 2020, PG&E has been supporting Butte College in developing and funding a 5-week tree worker training program intended to develop and support individuals looking to make a transition to the utility tree worker industry. This course allows individuals the ability to be certified and competitive when seeking a job as a utility tree worker. Not only does this support retraining and return to work for individuals, it also allows employers the ability to hire someone who can start work immediately. In 2021, PG&E will fund the digitization of course material to make material available online and to significantly reduce out of pocket cost for students currently purchasing hard copies of materials. Once Butte College is comfortable that the course is working successfully, PG&E will foster the expansion of this program to other community colleges throughout California. Recruiting and training of VM personnel is an effort that will expand well beyond 2030 as we continue the work started in 2020 that focuses on improving worker qualifications and supporting certification of employees and contractors. Long-term, PG&E plans to help improve the availability of tree workers not only in PG&E's service territory, but in the territories of other California IOUs. PG&E will continue to seek educational partnerships and explore other opportunities for employees and contractors to seek certification and advanced worker qualification.	PG&E will be implementing knowledge assessments. With the planned implementation of the knowledge assessments, it will place an enforcement of 3 attempts to pass the required PG&E training courses before the employee or contractor will be placed in a cooling off period before being allowed to retake the training course. The knowledge assessments will provide PG&E better metrics in tracking their internal and external employees progress and will also allow PG&E to continue to develop and improve on training areas through 2026, while continuing to expand and grow VM personnel through 2030.

TABLE PG&E REMEDY-21-18-07:
LONG-TERM VISION AND RELEVANT TIMELINES FOR EACH VM INITIATIVE
(CONTINUED)

Initiative #	Revised 2021 WMP (Response to Section 5 and Action PG&E-25 [Class B])	Additional Information on Long-Term Plans
7.3.5.15	In the future, PG&E will study post-EVM treatment outage and ignition data for opportunities to improve TAT effectiveness as part of our ongoing effort to improve our VM program. We anticipate that the results of this study will impact our VM practices beyond 2021. For further details on the Targeted Tree Species study, see Section 4.4.1. In the short-term, PG&E will continue the ongoing work of identifying and mitigating trees at elevated risk of failure. In the long-term, PG&E will study post-EVM treatment outage and ignition data for opportunities to improve TAT effectiveness. This study (which will be concluded in 2022), in conjunction with lessons learned, will be used to work toward a proactive analysis instead of reactive. The EVM program will continue to address approximately 1,800 miles per year as we continue to work through all HFTD Tier 2 and Tier 3 areas in a prioritized, risk-informed manner.	The Targeted Tree Species study to reduce potential wildfire ignitions by identifying species that pose an elevated risk of failure near PG&E facilities is expected to be completed in March 2022. (For further details on the Targeted Tree Study, see Section 4.4.1). In addition, PG&E is currently evaluating feedback from users for opportunities of improvement and will be using this to develop a list of enhancements to improve the TAT. Long-term, the results of this study in conjunction with user feedback, will be utilized in an effort to improve TAT effectiveness. As part of the TAT improvement initiative, PG&E is developing plans to make the TAT applicable to Routine. The EVM program will continue to address approximately 1,800 miles per year as we continue to work through all HFTD Tier 2 and Tier 3 areas in a prioritized, risk-informed manner.
7.3.5.16	As stated above, please reference Sections 7.3.5.2, 7.3.5.3, and 7.3.5.15 for more information on future improvements for this initiative.	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	For 2021, PG&E will inspect 263 Electric Distribution Substations not within a Tier 2 or 3 HFTD for purposes of achieving defensible space and fuel reduction beyond Tier 2 and Tier 3 HFTD. In addition, during routine defensible space inspections of Distribution 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. This program is funded through 2024. The work is ongoing and focuses on assessing the area around Electric Distribution Substations in Tier 2 and Tier 3 HFTDs to identify flammable fuels and vegetation for removal. In addition, during routine, defensible space inspections of Distribution 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. PG&E will continue inspections and prescription of vegetation work for defensible space maintenance and continued adherence to CAL FIRE recommendations.	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.

TABLE PG&E REMEDY-21-18-07:
LONG-TERM VISION AND RELEVANT TIMELINES FOR EACH VM INITIATIVE
(CONTINUED)

Initiative #	Revised 2021 WMP (Response to Section 5 and Action PG&E-25 [Class B])	Additional Information on Long-Term Plans
7.3.5.17.2	In 2021, PG&E will inspect 41 ET Substations not within a Tier 2 or 3 HFTD 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. This program is funded through 2024. The work is ongoing and focuses on assessing the area around ET Substations and Hydro Facilities in Tier 2 and Tier 3 HFTDs to identify flammable fuels and vegetation for removal. 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. PG&E will continue inspections and prescription of vegetation work for defensible space maintenance and continued adherence to CAL FIRE recommendations.	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	In 2021, PG&E will improve the defensible space program with herbicide treatment plans within defensible space zones for improved long-term control and abatement of noxious weeds and reoccurring/regenerating brush species, where permitted. Also, PG&E will perform additional vegetation thinning and/or removal work beyond CAL FIRE recommended zones for defensible space. This program is funded through 2024. The work is ongoing and in accordance with CAL FIRE defensible space recommendations (PRC 4291), it focuses on the removal of flammable fuels and the removal or trim of vegetation in and around Electric Distribution Substations within or adjacent to Tier 2 and Tier 3 HFTDs. PG&E will also look to improve the defensible space program with herbicide treatment plans, where permitted. PG&E will perform additional vegetation thinning and/or removal work beyond CAL FIRE recommended zones for defensible space, where permitted. Electric Distribution Substations will receive maintenance operations while additional CAL FIRE recommended tree, brush and debris compliance work will be prioritized from highest (Tier 3) to lowest (Tier 2) HFTD area.	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.

TABLE PG&E REMEDY-21-18-07:
LONG-TERM VISION AND RELEVANT TIMELINES FOR EACH VM INITIATIVE (CONTINUED)

Initiative #	Revised 2021 WMP (Response to Section 5 and Action PG&E-25 [Class B])	Additional Information on Long-Term Plans
7.3.5.18.2	In 2021, PG&E also looks to improve the defensible space program with herbicide treatment plans within defensible space zones for improved long-term control and abatement of noxious weeds and reoccurring/regenerating brush species, where permitted. In addition, PG&E will perform additional vegetation thinning and/or removal work beyond CAL FIRE recommended zones for defensible space, where permitted. This program is funded through 2024. The work is ongoing and in accordance with CAL FIRE defensible space recommendations (PRC 4291), it focuses on the removal of flammable fuels and the removal or trim of vegetation in and around ET Substations and Hydro facilities within or adjacent to Tier 2 and Tier 3 HFTDs. PG&E will also look to improve the defensible space program with herbicide treatment plans, where permitted. PG&E will perform additional vegetation thinning and/or removal work beyond CAL FIRE recommended zones for defensible space, where permitted. ET Substations and Hydro facilities will receive maintenance operations while additional CAL FIRE recommended tree, brush and debris compliance work will be prioritized from highest (Tier 3) to lowest (Tier 2) HFTD area.	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.

TABLE PG&E REMEDY-21-18-07:
LONG-TERM VISION AND RELEVANT TIMELINES FOR EACH VM INITIATIVE
(CONTINUED)

Initiative #	Revised 2021 WMP (Response to Section 5 and Action PG&E-25 [Class B])	Additional Information on Long-Term Plans
7.3.5.19	PG&E will continue to work on a project plan in 2021. This project plan will be utilized as a working document to move this initiative forward. As with all projects plans, we will expect changes to this document as new requirements are identified. PG&E is drafting a project plan that will be used as a working document to move toward the long-term goal of having one vegetation inventory system. PG&E will continue to document processes in support of this process as well as to review and test work management platforms. Long-term plan milestones are still under development.	The VM Program Management team has created a long-term plan for the One VM platform. The objective will be to complete the build and implementation of a virtual tool that can be used to increase visibility of vegetation work being performed at different times in different locations. In 2021 the One VM Platform will be tested to ensure system readiness and by January of 2022 it will be deployed to Routine Maintenance (Distribution) and CEMA. The release date will allow us to pilot the platform and work with our vendors to ensure it is functioning as intended before proceeding with future roll outs to other teams. In 2022 and 2023, using data from the initial pilot programs of the platform, we will continue to work with PG&E's internal IT team to increase roll out to 7 additional teams each of the respective years further enhancing visibility of work being performed and data being collected while increasing PG&E's ability to prevent wildfires. A total of 16 teams in various programs within PG&E will be able to share data on the same platform at the same time upon full completion and rollout of the One VM platform. The long-term plan for the One VM platform includes the following program release schedule. This schedule is subject to change. Internal targets and IT development will require schedule shifts:

TABLE PG&E REMEDY-21-18-07:
LONG-TERM VISION AND RELEVANT TIMELINES FOR EACH VM INITIATIVE
(CONTINUED)

Initiative #	Revised 2021 WMP (Response to Section 5 and Action PG&E-25 [Class B])	Additional Information on Long-Term Plans
		2021: • Routine Maintenance* (Distribution) • CEMA* 2022: • EVM • WV • Wood Management • LiDAR • Vegetation Control (Pole Clearing) • Wildfire Response • Utility Defensible Space 2023: • Routine Maintenance (Transmission) • Transmission Programs (Orchards, Integrated Vegetation Management (IVM), ROWX) • System Hardening VM Work/Estimating Arborist • Reliability • Enterprise Public Works Coordination • Vegetation Management Inspections (VMI) • Gas Transmission VM *Deployment for Routine and CEMA by January 2022.
7.3.5.20	As stated above, please reference Section 7.3.5.2, and Section 7.3.5.3 for more information on future improvements for this initiative.	Please refer to Section 7.3.5.2, and Section 7.3.5.3 for more information on future improvements for this initiative.

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.*[38] *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:

PG&E has made progress over the last few years on establishing programmatic permits/agreements with many of our critical agency partners and continues to focus on expanding these efforts due to the success we have seen from our current agreements. These agreements have allowed both parties to understand one another's needs and align on a standardized process for work being performed by PG&E (e.g., how work is to be submitted for authorization, expected turnaround times for authorization/approval, expectations on how the work activity is to be performed). This standardization has helped streamline the process and created a much more collaborative relationship between PG&E and our agency partners as the process is much more transparent and there are clear expectation and understanding by both parties involved.

An updated list of completed and executed Programmatic Permits and in-progress permits can be found in Attachment 2021WMP_OEISRemedy_PGE-21-19_Atch01.

Below, we provide a list of permits that have either been completed or are in progress, as well as some lessons learned.

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38 PG&E Revised 2021 WMP Update p. 691.

Completed:

1) Bay Area Habitat Conservation Plan (HCP) – U.S. Fish and Wildlife Service (USFW) -- This is a 30 year permit that provides federal endangered species coverage for O&M activities within the 9 counties of the Greater Bay Area.
2) San Joaquin Valley HCP – USFW/California Department of Fish and Wildlife (CDFW) – This is a 30 year permit that provides federal and state endangered species coverage for O&M activities covering 9 counties south of Stockton.
3) Multi-Region HCP – USFW – This is a 30 year permit that provides federal endangered species coverage for O&M activities covering 34 counties within; Central Coast, Sacramento Valley, North State, and North Coast.
4) USFS O&M Plan – This is a 30 year permit and general easement providing a streamline process to do electric work on the 11 forests within the PG&E's service territory.
5) State Parks O&M plan – This agreement provides for a streamlined process to complete O&M work across the 99 State Parks within PG&E's service territory.
6) National Park Service Short Term Use Permit – This permit allows for O&M activities across the 7 national parks in PG&E's service territory.
7) Bureau of Land Management (BLM) short term Instruction Memorandum (IM) – The IM letter allows to FastTrack system hardening and wildfire related work across the 8 BLM field offices. This letter was extended until 2025.

In Progress:

1) Bay Area Incidental Take Permit (ITP) – CDFW – Will provide State coverage of three endangered State species within the 9 counties of the Bay Area.
2) Coastal Commission Memorandum of Understanding (MOU) – Will create a streamline process to complete wildfire and system hardening work within the coastal zone of PG&E's service territory.
3) Department of Water Resources MOU – Creates a process to expediate review of projects on DWR owned lands.
4) State Water Board – GO – Creates a GO for all the IOUs in the State to complete dredge and fill activities in waters of the State.
5) SF Bay Army Corp Programmatic Permit – Provides a permit for 15 years to complete work in the SF bay that would impact waters of the US.

6) Local Cities and Counties – PG&E is currently engaging multiple jurisdictions on programmatic encroachment permits.

Lessons Learned:

We are continuing our work to obtain additional programmatic permits/agreements due to the success we have seen with our current agreements. This programmatic approach has provided a clear strategy for agencies, local and tribal governments and PG&E to process the substantial amount of work around wildfire and system hardening. Through the development of these agreements, we have created standardization around work notification packages and nomenclature to describe the work. These agreements have also allowed us to help address the resource shortfall with many of these agencies and governments, by creating reimbursable agreements. The reimbursable agreements allow for the agencies and governments to hire additional staff to address PG&E's workload. These agreements have also created a more constructive and collaborative relationship between our agency and government partners and PG&E as there is more engagement between PG&E and our agency and government partners' leadership, so we are able to work through challenges when they arise due to the stronger lines of communication that have been built in the development and rollout of these agreements.

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).*[39] *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;*[40] *and*
6) *PG&E should use such a tool during Phase 1 "Imminent Threat Inspection" as feasible.*

Response to PG&E-21-20:

1) PG&E currently uses its VM Wildfire Response Guidance document as the guideline or standard for assessing post-wildfire hazard trees (see Attachment 2021WMP_OEISRemedy_PGE-21-20_Atch01) and is in the process of developing a more detailed standard which is anticipated to be completed in Q4 2021. In addition, PIs use their own professional judgment and training to make assessments.
2) This standard includes specific post-fire factors such as crown damage, cambium damage, root damage, char, and duff. Specifically, the appendices to this guidance document, 'Assessing fire-damaged trees' and 'Marking

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39 *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.

40 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.

Guidelines for Fire-Injured Trees in California,' include this information. (see Attachment 2021WMP_OEISRemedy_PGE-21-20_Atch02).

3) This standard already exists.
4) PIs will follow the current guidance document (Attachment 2021WMP_OEISRemedy_PGE-21-20_Atch01) for wildfire response as well as for data collection described above. PG&E is continuing to develop training for post-fire tree assessments.
5) PIs will consult the guidance documentation and make use of professional judgment during Phase 2 inspections, which is the listing of non-imminent hazardous trees.
6) PIs will consult the guidance documentation and make use of professional judgment during Phase 1 inspections, which is to inspect and eliminate any tree that is actively failing and to list trees that will need to be removed by construction crews to support reconstruction work to restore power.

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).*[41] *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.*

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41 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.

Response to PG&E-21-21:

1) Attached as Attachment 2021WMP_OEISRemedy_PGE-21-21_Atch01, please find an outline and review of the LC95W Fire Retardant product along with reference links to the materials including; Forest Service Ecological Risk Assessment, the Forest Service Final Environmental Impact Statement for Nationwide Aerial Application for Fire Retardant on National Forest System lands and others.
2) The objective of the 2021 PFRP pilot is to establish and test the end-to-end process for a PFRP and determine the viability of preventative fire retardant applications as an appropriate wildfire mitigation tool into 2022 and beyond. The PFRP has established and is evaluating 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. The PFRP pilot initially identified approximately 80 miles of target potential circuit miles to apply its screening criteria and customer engagement process. After subjecting the target miles to the PFRP screening methodology and contacting customers to seek approval to perform applications, PG&E had approval to conduct applications on 9.62 miles across all identified CPZs. The PFRP program is currently subjecting another 53 target potential circuit miles within Shasta County to the screening and customer approval process. In parallel, the PFRP is coordinating with state government agencies to examine target potential circuit miles on state-owned land and state right-of-way for potential application. PG&E is currently conducting environmental screening and pre-planning work on this potential scope on State land and ROW. The objective would be to conduct applications on final, approved miles within both the private property and state land workstreams prior to the end of 2021.

3) As of October 6, 2021, PG&E had completed applications as follows:

- Deschutes 1104 (Shasta): 6.04 miles
- Girvan 1101 (Shasta): 0.68 miles
- Vaca Dixon 1105 (Solano): 2.14 miles
- Vacaville 1104 (Solano): 0.76 miles

Single applications were applied on approved parcels within all CPZs noted above between August 13 and October 1, 2021. PG&E crews applied Perimeter Solutions LC95W retardant at Coverage Level 2 (i.e., 2 gallons of retardant per 100 square feet) (https://www.nwcg.gov/term/glossary/coverage-level). There is no plan to repeat applications at any locations, as the scientific data does not currently exist to support repeated applications. Moving forward, PG&E will provide quarterly reports with the requested information to Energy Safety.

4) There is presently no RSE value for planned basis fire retardant applications because the current RSE score was developed prior to the implementation of fire retardant in field use. PG&E is evaluating updating the RSE score assumptions based on more recent information and expect to have a decision and plan by the finalization of the 2022 WMP.

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,*[42] *it may choose to do so in the future; in this case, accurate recordkeeping of the species designation is essential.*

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42 PG&E 2021 WMP Update p.667.

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 outage*[43] *or ignition*[44] *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.);*[45]
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.*

Response to PG&E-21-22:

1) Moving forward, PG&E will use the scientific names of trees when reporting to Energy Safety.
2) PG&E's VM Database already possesses this capability.
3) PG&E will identify the genus and species of a tree that has caused an outage or ignition in its QDR whenever it is possible to do so.
4) PG&E will instruct its PIs to designate unknown tree species as described. There is presently a deficiency in the system that allows field PIs to choose a

43 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.

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

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

generic tree genus without requiring a species and we are working on a solution to remove this generic choice from our data collection tools. Field arborists have a picklist in data collection tools in the field. This picklist will be modified to remove the generic choice of 'oak,' for example, and instead the choice will be 'oak, unknown.' These updates will be communicated to users via a Five Minute Meeting in the short term, and training materials will be updated as a long-term solution.

5) PG&E requires its VM vendors to provide accurate tree species information. To check compliance with this, including correct species identification, PG&E incorporates tree species into its QV audit process to ensure that our contractors are implementing species identification effectively. In addition, species identification training will be added to the Community College training PG&E is supporting as well as to future PG&E trainings. These trainings will be for both internal PG&E employees and our contract partners.
6) PG&E will encourage all VM personnel to identify trees down to the species level, where possible, in all VM activities and reporting.

Utility #: PG&E-21-23

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

Issue description: *RCP Action-PGE-35*[46] *(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." PG&E, SCE, and SDG&E presented the "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."*

46 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.

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: *PG&E, SCE, and SDG&E will participate in a multi-year vegetation clearance study. Energy Safety will confirm the details of this study in due course. 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 factors*[47] *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.

Response to PG&E-21-23:

This is a joint response prepared by the utilities.

SDG&E, PG&E, and SCE (jointly investor-owned utilities or IOUs) have begun collaboration on a vegetation clearance study. In benchmarking vegetation management practices and data collection methodologies across IOUs, it has been determined to be a multi-year effort concurrent with the terms of the study and are expecting the development of uniform standards following the timeline of the study. Bi-weekly meetings began on September 9th and three meetings were held with attendance by IOUs and Energy Safety at each meeting. Early meetings have focused on addressing the first two items listed in the remedies required for this issue:

1) Establish uniform data collection standards

47 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.

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

Meeting topics have consisted of the IOUs discussing their current data collection standards including:

- The amount (years) of historical data each IOU has collected
- Outage cause codes employed for tree-caused risk events
- Tree-caused risk event data collection across the primary and secondary voltages
- Definition of an inventory tree
- Post trim clearance data

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 was reviewed, including recommendation from Energy Safety that a database can be as simple as a spreadsheet. 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.

At the most recent meetings, the IOUs demonstrated their current analysis around the effectiveness of enhanced clearances. SDG&E and SCE presented their analysis with PG&E expected to present at the next meeting. SDGE’s initial analysis of expanded clearances demonstrates a reduction in vegetation related risk events as clearances are increased. SCE’s initial analysis demonstrates reduced tree-caused circuit interruptions since implementation of enhanced clearances in 2018-2019. The IOUs used the existing analyses to discuss the various methods of analyses that can be performed to assess the effectiveness of enhanced clearance. Over the course of this extended study the IOUs will 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. IOUs believe that biotic and abiotic factors can be extracted from existing data sets.

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

Utility #: PG&E-21-24

Issue title: *Need for quantified VM compliance targets.*

Issue description: *In Table 12, PG&E only defines quantitative targets for six of 20 VM initiatives. Energy Safety is statutorily required to audit PG&E when a "substantial portion" of PG&E's VM work is complete;[48] without quantifiable targets in the WMP and subsequent reporting on those targets in the QDR and QIU, Energy Safety cannot fully realize its statutory obligations.*

Remedies required and alternative timeline if applicable: *PG&E must define quantitative targets for all VM initiatives. If quantitative targets are not applicable to an initiative, PG&E must fully justify this, define goals within that initiative, and include a timeline in which it expects to achieve those goals.*

Response to PG&E-21-24:

TABLE PG&E-REMEDY-21-24-01:
QUANTITATIVE TARGETS OR GOALS FOR VM INITIATIVES

Initiative #	2021 WMP Quantitative Targets	Quantitative Targets or Goals
7.3.5.1	PG&E did not provide quantitative targets for this initiative in the 2021 WMP.	In 2021, PG&E did not have quantitative targets for this initiative, but our current goal is to apply the use of customer touchpoints (through postcards, door hangers, automated calls, etc.) prior to performing critical VM work. These touchpoints will be applied to customers within the CPZs being actively worked by EVM, Routine, and CEMA programs. We plan to define targets for this initiative by the end of 2021 and will continue to refine these targets as well as expand into other electric VM programs by the end of 2022.
7.3.5.2	PG&E's VM program inspects approximately 100,000 miles of overhead electric facilities on a recurring cycle.	In 2021, PG&E will complete inspections of the entire distribution system by December 31st of each year (inspection periods start on November 15th of the year prior). Additionally, PG&E will follow a fully implemented Vegetation Clearing/ Pole Clearing schedule where we will identify and complete all unconstrained clearing on all of poles by April 30th annually and maintenance from May 1st to September 30th (inspection period starts October 1st of the prior year).

48 Public Utilities Code § 8386.3(c)(5)(A).

TABLE PG&E-REMEDY-21-24-01:
QUANTITATIVE TARGETS OR GOALS FOR VM INITIATIVES
(CONTINUED)

Initiative #	2021 WMP Quantitative Targets	Quantitative Targets or Goals
7.3.5.3	In addition to compliance inspections, in 2021, approximately 200 miles of Transmission ROW expansion work are planned within HFTD areas. PG&E will also continue to perform IVM Maintenance based on aging of work cycles and evaluation of vegetation re-growth and will conduct LiDAR mid-cycle inspections on 80 percent-100 percent of HFTD Tier 2 and Tier 3 Transmission lines.	In 2021, PG&E will complete approximately 200 line miles of Transmission ROW Expansion. ROW Expansion is a measure taken to further reduce vegetation around PG&E energized conductors and other equipment. This program addresses approximately 200-line miles during recurring patrol cycles within Tier 2 and Tier 3 HFTD areas. IVM maintenance is a process that is ongoing and designed to maintain cleared ROW in a sustainable and compatible condition and thus quantitative targets are not applicable. PG&E will continue to conduct LiDAR inspections on 100 percent of Routine NERC and Routine Non-NERC Transmission miles. LiDAR mid-cycle inspections will be conducted on 80 percent-100 percent of HFTD Tier 2 and Tier 3 transmission lines.
7.3.5.4	PG&E did not provide quantitative targets for this initiative in the 2021 WMP.	Red Flag Warning patrols are reactive to extreme fire weather conditions that are determined by the National Oceanic and Atmospheric Administration. Thus, PG&E is unable to set goals or targets for this type of reactive and highly unpredictable work.
7.3.5.5	PG&E did not provide quantitative targets for this initiative in the 2021 WMP.	Starting in 2021, PG&E's UDS/fuel reduction program will prioritize work on 5 CPZs (approximately 4,100 poles). This work will be focused on clearing vegetation and modifying ladder fuels around these 4,100 distribution poles in HFTD areas.
7.3.5.6	PG&E did not provide quantitative targets for this initiative in the 2021 WMP.	Quantitative targets for inspections for distribution are provided in Section 7.3.5.2 and for transmission in Section 7.3.5.3. Quantitative targets for QA/QC inspections are provided in Section 7.3.5.13.

**TABLE PG&E-REMEDY-21-24-01:
QUANTITATIVE TARGETS OR GOALS FOR VM INITIATIVES
(CONTINUED)**

Initiative #	2021 WMP Quantitative Targets	Quantitative Targets or Goals
7.3.5.7	PG&E did not provide quantitative targets for this initiative in the 2021 WMP.	PG&E did not have targets for this initiative in 2021 because it was still in the pilot phase. However, starting in 2022, PG&E will perform a GBL scan of approximately 2,000 miles of Electric Distribution assets along roadside-available (i.e., road conditions that do not allow for high quality data collection would not be considered 'roadside available' as data collected would be of low quality due to limitations of the technology) ROWs in HFTD areas. In 2023, PG&E currently intends to perform a GBL scan of approximately 4,000 miles of Electric Distribution assets along roadside-available ROWs in HFTD areas. In 2024, PG&E currently intends to perform a GBL scan of approximately 6,000 miles of Electric Distribution assets along roadside-available ROWs in HFTD areas.
7.3.5.8	The PG&E Transmission VM Program conducts LiDAR inspections on 100 percent of PG&E's Transmission System (lines carrying 60 kV and above) as an integral first step of our routine program.	In 2021, PG&E's target for this initiative is 100 percent of LiDAR inspections of PG&E's transmission system. We currently plan for this target to continue in 2022 and beyond. However, this target may be subject to change as PG&E plans to use the LiDAR Risk Score Model as well as SME input to make determinations on scoping or descoping of transmission lines prior to PSPS events. Please refer to Section 7.3.5.3 regarding LiDAR Midcycle inspections.
7.3.5.9	PG&E did not provide quantitative targets for this initiative in the 2021 WMP.	In 2021, PG&E plans to track mid-cycle patrols within every circuit to ensure that they fall within a certain time frame. The mid-cycle patrol should take place in between the yearly routine patrols. PG&E will be tracking metrics to make sure the mid-cycle patrols are completed within approximately 6 months before or after Routine patrols, as well as track the percentage of mid-cycle patrols performed.
7.3.5.10	PG&E did not provide quantitative targets for this initiative in the 2021 WMP.	Quantitative targets for inspections for transmission are provided in Section 7.3.5.3.
7.3.5.11	PG&E did not provide quantitative targets for this initiative in the 2021 WMP.	Quantitative targets for inspections for distribution are provided in Section 7.3.5.2.
7.3.5.12	PG&E did not provide quantitative targets for this initiative in the 2021 WMP.	Quantitative targets for inspections for transmission are provided in Section 7.3.5.3.

**TABLE PG&E-REMEDY-21-24-01:
QUANTITATIVE TARGETS OR GOALS FOR VM INITIATIVES
(CONTINUED)**

<table>
<tr><th>Initiative #</th><th>2021 WMP Quantitative Targets</th><th>Quantitative Targets or Goals</th></tr>
<tr><td>7.3.5.13</td><td>The Quality Management Team has developed an annual audit plan based on Key Enterprise Risk. Key Enterprise Risk is compiled by Internal Audit and shared with Quality Management. Findings from the audits are shared with the LOB leadership for corrective action. In 2020, our QV goal was to complete approximately 2,000 audits. QV completed approximately 2,500 audits. QA completed 88 percent of its Distribution compliance audit goal for 2020. For 2021, the Veg QA and QV teams will conduct approximately 2,000 audits/reviews.</td><td>For 2021 our annual audit plan was developed in October 2020 as follows:

<u>QVVM:</u>
<table><tr><td>Reviews* planned</td><td>2,447</td></tr><tr><td>Reviews* completed 2021 YTD</td><td>1442 – plus 1 break-in audit</td></tr><tr><td colspan="2">* A review is location-based consisting of an address, a segment, a span, a source-side device or a pole.</td></tr></table>
<u>QAVM</u>
<table><tr><td>Planned</td><td>71</td></tr><tr><td>YTD Completions</td><td>33</td></tr></table>
QAVM will be removing one audit on the plan for 2021; this audit is focused on paperwork and maps and will be better suited for January 2022 so that all of 2021 paperwork can be sampled for the audit. This also frees up the QAVM team to perform Field Compliance Audits through the end of 2021.

All audit plans are developed in October for the upcoming year. The 2022 audit plan is currently being developed and is subject to change.</td></tr>
<tr><td>7.3.5.14</td><td>PG&E did not provide quantitative targets for this initiative in the 2021 WMP.</td><td>PG&E will gather quantitative measurements through the implementation of knowledge assessments. In the past, PG&E has utilized knowledge checks, which provide a Pass or Fail result, but do not take into account how many times an employee has taken the course. With the implementation of the knowledge assessment, it will enforce a limit of 3 attempts to pass the course. If an employee is unable to pass the course within 3 tries, they will be forced to enter into a 30 day cooling off period before being allowed to retake the course and in order to be reinstated, they must pass the exam.

With the implementation of knowledge assessment and other training programs described in our 2021 WMP, we will be able to establish quantitative targets for this initiative in 2022.</td></tr>
<tr><td>7.3.5.15</td><td>The EVM program will continue to address approximately 1,800 miles per year as we continue to work through all HFTD Tier 2 and Tier 3 areas in a prioritized, risk-informed manner.</td><td>The quantitative target for this initiative is the number of line miles completed and verified in HFTDs. In 2021, we have targeted performing EVM on approximately 1,800 circuit miles of distribution facilities in Tier 2 and Tier 3 HFTD areas.</td></tr>
</table>

TABLE PG&E-REMEDY-21-24-01:
QUANTITATIVE TARGETS OR GOALS FOR VM INITIATIVES
(CONTINUED)

Initiative #	2021 WMP Quantitative Targets	Quantitative Targets or Goals
7.3.5.16	PG&E did not provide quantitative targets for this initiative in the 2021 WMP.	Quantitative targets for this initiative are provided in Sections 7.3.5.2, 7.3.5.3, and 7.3.5.15.
7.3.5.17.1	In 2021, inspections of 178 Electric Distribution Substations within or adjacent to Tier 2, Tier 3 and Zone 1 HFTD will be performed.	The quantitative target for this initiative is substation inspections. In 2021, we have targeted performing inspections of 178 Electric Distribution Substations within or adjacent to Tier 2, Tier 3 and Zone 1 HFTDs.
7.3.5.17.2	In 2021, inspections of 72 Electric Transmission Substations and 61 Hydro facilities within or adjacent to Tier 2 and Tier 3 HFTDs will be performed.	The quantitative target for this initiative is substation inspections. In 2021, we have targeted performing inspections of 72 Electric Transmission Substations and 61 Hydro facilities within or adjacent to Tier 2 and Tier 3 HFTDs.
7.3.5.18.1	In 2021, 178 Electric Distribution Substations within or adjacent to Tier 2, Tier 3, and Zone 1 HFTDs will receive maintenance operations, and additional CAL FIRE recommended tree, brush and debris compliance work will be performed based on availability of required permits.	The quantitative target for this initiative is substation inspections. In 2021, we have targeted 178 Electric Distribution Substations within or adjacent to Tier 2, Tier 3, and Zone 1 HFTDs will receive maintenance operations, and additional CAL FIRE recommended tree, brush and debris compliance work will be performed based on availability of required permits.
7.3.5.18.2	In 2021, 72 Electric Transmission Substations and 61 Hydro facilities will receive maintenance operations while additional CAL FIRE recommended tree, brush and debris compliance work will be performed based on the availability of required permits.	The quantitative target for this initiative is substation inspections. In 2021, we have targeted 72 Electric Transmission Substations and 61 Hydro facilities to receive maintenance operations while additional CAL FIRE recommended tree, brush and debris compliance work will be performed based on the availability of required permits.
7.3.5.19	PG&E is reviewing work management platforms and is planning to perform proof-of-concepts with one or more vendors in 2021 to begin to test how platforms may perform with current data collected in VM programs as well as to collect additional data required by the WSD Guidance 10 Data standards. VM is also engaging with PG&E's internal IT department to define and plan database support.	At this time, quantitative data is being collected through our proof-of-concept release. Thus, no targets can be established With regard to goals, below is a High-Level Milestone schedule plan of release for the One VM tool. This schedule is subject to change, these are internal targets, and any IT development will require schedule shifts. **Task Name** / **Start** / **Finish** RELEASE 1 / 08/01/21 / 02/01/22 RELEASE 2 / 01/03/22 / 03/01/22 RELEASE 3 / 03/01/22 / 05/01/22
7.3.5.20	PG&E did not provide quantitative targets for this initiative in the 2021 WMP.	Quantitative targets for this initiative are provided in Sections 7.3.5.2 and 7.3.5.3.

Grid Operations and Operating Protocols, Including PSPS (Section 5.6)

Utility #: PG&E-21-25

Issue title: *Lack of specificity regarding how increased grid hardening will change system operations, change PSPS thresholds, and reduce PSPS events.*

Issue description: *PG&E does not commit to changes in its PSPS thresholds for increased grid hardening. PG&E does not specify how increased grid hardening will change system operations.*

Remedies required and alternative timeline if applicable: *For each mitigation alternative, including pilot program initiatives, PG&E must provide quantitative analysis on:*

1) *Changes in system operations;*
2) *Changes in PSPS thresholds; and*
3) *Estimated changes in the frequency, duration, and number of customers impacted by PSPS events.*

Response to PG&E-21-25:

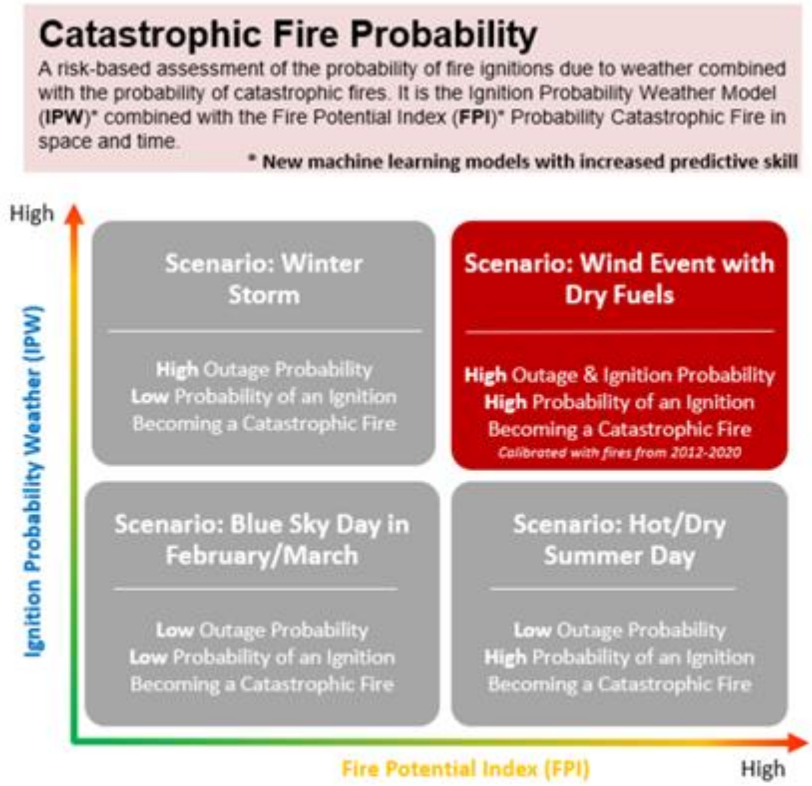
1) Changes in system operations and estimated changes in PSPS impacts due to grid hardening mitigation initiatives, are provided in Attachment "2021WMP_OEISRemedy_PGE-21-25_Atch01".
2) PG&E does not make specific changes in its PSPS protocols due to new improvements and mitigation initiatives, including 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 we improve the quality of some specific assets, we expect a reduction in the chance of that asset causing an ignition. However, we do 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 our models and gradually change our 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 (IPW) model, and the probability of catastrophic fires, called the Fire Potential Index (FPI). This combination is called the Catastrophic Fire Probability (CFP_D) and is given by the equation:

$$CFP_D = p(ignition) * p(catastrophic\ fire|ignition) = IPW * FPI$$

The guidance values PG&E utilizes when making a PSPS decision through the lens of this framework is a CFP_D (IPW*FPI) value > 9. This value was determined by running 70 PSPS sensitivity studies over the years of 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 CFP_D framework is presented below.

FIGURE PG&E-REMEDY-21-25-01:
CATASTOPHIC FIRE PROBABILTIY FRAMEWORK



$$CFP_D = P(\text{Ignition}) * P(\text{Catastrophic Fire} \mid \text{Ignition})$$

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. We do not use wind speed thresholds on a per-circuit basis as a proxy of outage or ignition probability and therefore do not simply increase our wind speed thresholds where hardening has been performed based on engineering estimates of efficacy.

Overhead system hardening is expected to reduce the probability of outages and ignitions. We believe 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 PG&E assets.

We have built a PSPS model framework that can account for changes overtime based on actual performance data. The machine learning IPW framework is flexible as we do not have to consider each individual program such as covered conductor and EVM to manually 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 we apply a time-weighted approach to weight more recent years of learned performance more heavily in the final model output. The model learns 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. This exponential weighting allows changes in local areas to be addressed (both negative - increased tree mortality, asset degradation, etc.; and positive – conductor and pole replacement, VM etc.).

Since the IPW model accounts for changes over time and we evaluate PSPS through a risk-based assessment, we do not propose adjusting the final CFP_D threshold manually for circuits. 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. Thus, instead of manually adjusting wind speed thresholds or CFP_D for multiple programs (e.g., system hardening, EVM, inspections) across hundreds of circuits or thousands of circuit segments, a single PSPS threshold is utilized across the entire territory based on the probability of an outage leading to an ignition (IPW) combined with the probability of catastrophic fires (FPI). We also need to consider that the probability of an outage and ignition changes across the length of each circuit as the weather, vegetation exposure, asset age, topography and other factors are not homogeneous across circuits. The IPW and probabilistic output better addresses these local factors than a single circuit wind speed threshold by using localized wind speeds, granular vegetation data, topography and local wind-versus outage response. In addition, if different CFP_D values or adjustments were made to some circuits, we could make the mistake of double counting the performance benefit achieved as any changes in performance are accounted for in the IPW model.

To date, PG&E has hardened approximately 600 miles out of approximately 25,500 miles of overhead line miles in the HFRA. We have identified two circuits where grid hardening has been performed across the entire circuit in the HFRA. These circuits are the Oakland K 1102 and Rossmoor 1102. The other areas hardened are more localized spans on circuits based the highest risk scores from the 2021 WDRM; however, other line segments on these circuits have not been hardened and exist in a HFRA.

We conducted a comparison analysis on the expected number of PSPS events for these two circuits. The historical PSPS lookback that utilizes the current 2021 PSPS guidance shows that these circuits would only come into scope for the largest and strongest PSPS event in the record from 2008 through 2020, which is the October 26 to October 27, 2019 PSPS event. Thus, locations where we have performed hardening across entire circuits in the HFRA come into scope only once across the 13 year look back analysis. Note that a similar look back was conducted on the 2020 PSPS guidance and showed that the Oakland K 1102 would have met PSPS guidance twice, and the Rossmoor 1102 once.

3) Changes in system operations and estimated changes in PSPS impacts due to grid hardening mitigation initiatives, are provided in Attachment "2021WMP_OEISRemedy_PGE-21-25_Atch01".

Resource Allocation Methodology (Section 5.8)

Utility #: PG&E-21-26

Issue title: *Inadequate discussion on impact of Risk Spend Efficiencies (RSE) in initiative selection.*

Issue description: *PG&E does not clearly explain how RSE estimates impact the initiative selection process. RSE estimates provide a pathway to assess the relative benefit provided by the mitigation initiatives and must play an integral role in the selection process. Energy Safety understands the dynamic nature of initiative selection due to work management efficiencies, operational realities, resource constraints, and other factors. However, a clear description of how RSE estimates impact the selection process must be provided to ensure consistency across initiatives.*

Remedies required and alternative timeline if applicable: *PG&E must provide an overview of its decision-making framework to include a clear explanation of how RSE estimates impact decision making for initiative selection. The overview must show the rankings of the relative decision-making factors (e.g., planning and execution lead times, resource constraints, etc.) and pinpoint where quantifiable risk reductions and RSE estimates are considered in the initiative selection process. Energy Safety recommends a cascading, dynamic "if-then" style flowchart to effectively demonstrate this prioritization process and satisfy this requirement.*

Response to PG&E-21-26:

PG&E continues to evaluate how RSE estimates can most effectively be used in its decision-making process. We continue to expand the development and reporting of RSEs to help inform our decision-making. RSEs can be used in one of two ways. First, RSEs can be used to compare between initiatives to select the right initiative for wildfire mitigation in a specific area. Second, RSEs can be used within a specific initiative to select between various options within that initiative. For example, RSEs could be used to select between line removal, overhead covered conductor, and undergrounding as options within the System Hardening Program initiative.

There are challenges to using RSE estimates in decision-making. For example, the specific risk reduction benefits at the project level are not currently factored into our RSE analysis, nor are the execution constraints and knowledge directly from field and public safety specialists. As such, currently RSEs are only used at the overall program level, to identify where one program can be seen as more beneficial than another for high-level planning purposes.

Although we have made substantial progress on developing RSEs for our WMP initiatives, at this point RSEs cannot be used as the sole criteria for decision making on projects within a specific initiative or for decision making between various alternatives. However, as we explain below, we are beginning to incorporate RSEs into our initiative programs, such as system hardening, and will be doing the same when comparing various initiative options.

The System Hardening decision tree is one example in which the RSE estimates are used for prioritization within a program. Consistent with the RSE results, PG&E shares the various initiative considerations based on its risk reduction and cost effectiveness. Seen as the first step when going into a project, the highest risk reduction for the lowest cost is to consider line removals, buy outs, and remote grid. Those solutions are generally less expensive actions to reduce wildfire risk when compared to traditional overhead or underground hardening. If these less expensive options are not possible, more traditional system hardening solutions are considered. If the location also has a PSPS impact, it is accordingly higher priority, as it mitigates both wildfire and PSPS. When considering between overhead hardening and underground hardening, RSEs indicate that based on current unit costs, underground hardening still has a lower RSE than overhead hardening. However, this is very specific to each project and its benefits. In addition, PG&E continues to review the lifetime O&M costs of undergrounding versus overhead, representing potential savings of undergrounding over the course of lifetime of the asset when compared to overhead.

Changes in costs impacted by program expansion or technological development will also impact RSEs. For example, as more undergrounding is executed, along with accelerated technology and unit cost reductions, the RSEs are expected to move in favor of undergrounding rather than other system hardening alternatives, allowing PG&E to capture both higher risk reduction as well as higher RSE. As part of that development, planning and execution lead times are anticipated to drive the prioritization of the locations of projects being scoped. For example, PG&E identifies as a set of tranches as highest risk, considering various factors like high ranked risk model circuit segments, fuel and terrain, critical customers, and stakeholder feedback. A location that historically has quicker permitting and execution would be under consideration for earlier scoping to allow for earlier construction. This would allow PG&E to reduce risk on the system as quickly as possible. In parallel, for the other locations that would have slower permitting due to various jurisdiction constraints, PG&E would undertake early stakeholder engagement on opportunities to accelerate buy-in, through for example, demonstrating the undergrounding efforts on other parts of the PG&E system.

Figure PG&E-Remedy-21-26-01 below provides a visual depiction of the prioritization process.

FIGURE PG&E-REMEDY-21-26-01:
MITIGATION DECISION TREE FOR SYSTEM HARDENING

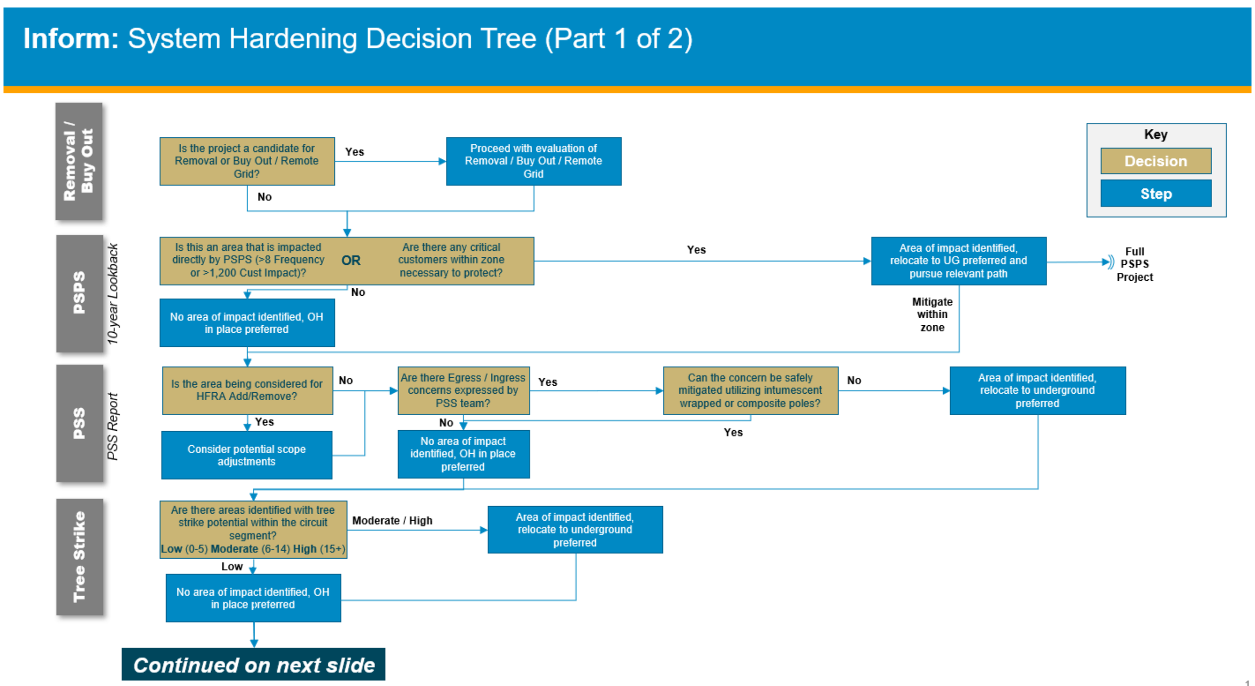
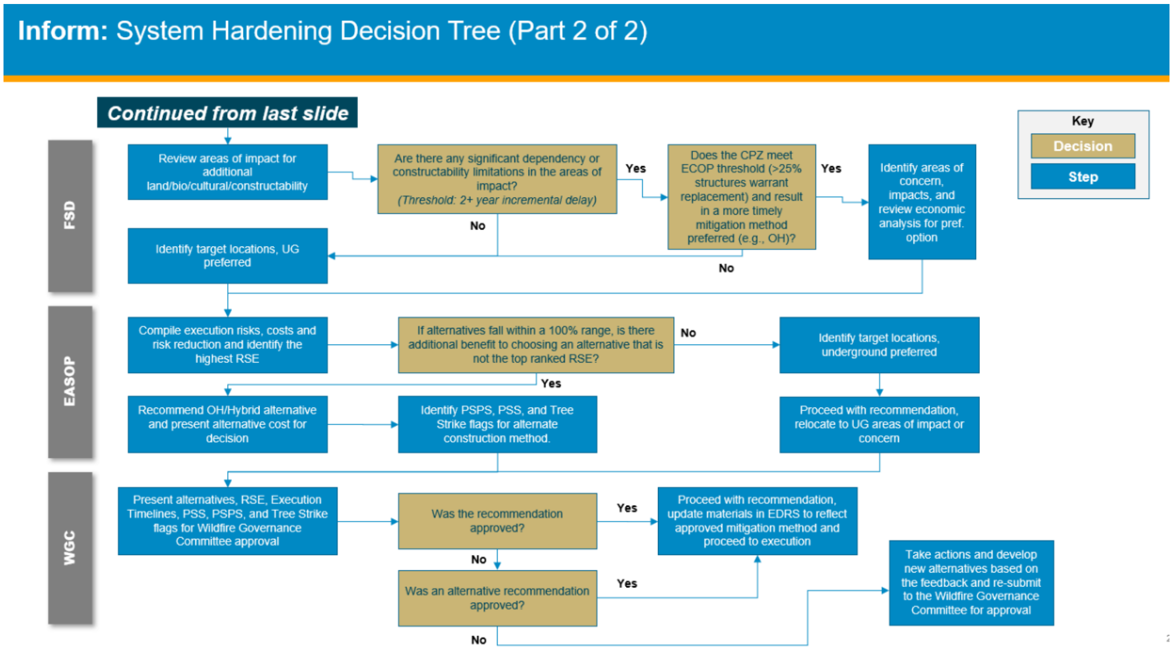


FIGURE PG&E-REMEDY-21-26-01:
MITIGATION DECISION TREE FOR SYSTEM HARDENING
(CONTINUED)



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:

We have been and plan to undertake a number of steps to validate our RSE methodologies and data inputs, as well as the resulting scores. First, we are currently investigating the actual effectiveness of our two major wildfire mitigation programs, system hardening and EVM, through the use of actual performance data from the locations where system hardening and EVM work has been performed. This analysis is not a one-time effort, but instead is intended to be a monitoring of effectiveness that can be refreshed on a recurring basis as more system hardening or EVM work is completed on the system. Results of this analysis has been shared at our WRGSC and with other utilities in order to ensure the results are benchmarkable and reasonable as compared to other utility results. It is expected that the actual effectiveness results will help inform the calculation of RSE scores provided in the 2022 WMP.

Second, PG&E has engaged a third-party technical advising group that will perform an assessment of RSE methodologies used in 2021 and provide recommendations for the methodologies used for the 2022 WMP. The individuals in the technical advising group each have over 15 years of operational and engineering experience working for gas and electric agencies, including specific experience working on risk mitigation issues for California utilities. The assessment will review both the RSE approach used for the 2021 WMP, as well as the updated RSE approach used for the 2023 GRC. We expect the work from this advising group to be completed in advance of the 2022 WMP.

Third, as a mid-term action for RSE verification, we will continue to regularly participate in joint utility meetings and utilize benchmarking with other utilities. One avenue for joint utility collaboration and benchmarking will be the Energy Safety facilitating working group described in Remedy PG&E-21-28 below. We have a number of issues that we believe would benefit from discussion and benchmarking. For example, there are differences in the utilities' respective MAVF calculations.[49] As a result, the utilities developed their own set of consequence factors, weightings, scaling and bounds, in its development of the MAVF risk scores. Because the utilities' MAVF risk scores are different, risk reduction and RSE calculations produce different results, not allowing for cross-utility comparison. Another example is the difference in the inputs to the RSE calculations, such as the effectiveness measures. Because each utility has different datasets relating to ignition drivers and observed frequency, and subject matter expertise based on the unique territory the utilities operate in, differences in the inputs of an RSE calculation could lead to difference in results. We look forward to using the working group as a forum for closer collaboration with the utilities and stakeholders to address these kinds of issues. We expect the RSE work group facilitated by Energy Safety will be initiated in November or December 2021 and will continue its work through 2022. Depending on the timing and outcome of the RSE working group., the utilities may be able to make revisions as needed to their RSE methodologies for their respective 2022 WMPs.

Finally, as a longer-term organizational alignment, PG&E has created the Operational Risk Validation organization to begin assessment and validation of risk reduction performance and efficacy in support of the overall verification needs. Because this organization was initiated in Q3 of 2021, staffing is still underway and we currently expect the Operational Risk Validation organization to start performing assessment and validation of RSE calculations in 2022.

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[49] MAVF calculations are prepared by the utilities in accordance with the Safety Model and Assessment Proceeding (SMAP) settlement agreement approved in D.20-12-014.

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,[50] SDG&E's RSE was 76.73,[51] and SCE's RSE was 4,192.[52] 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[53] must collaborate through a working group facilitated by Energy Safety[54] 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.*

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50 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.

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

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

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

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

Response to PG&E-21-28:

The utilities have prepared a joint response to this Remedy.

Energy Safety has not yet initiated the RSE working group. The utilities look forward to working with Energy Safety and other stakeholders on RSE approaches and issues.