Joint IOU Grid Hardening Working Group Report:

Update for 2026-2028 Wildfire Mitigation Plan

[3/19/2025]
Submitted on behalf of the following:

Southern California Edison Company (SCE)
San Diego Gas & Electric Company (SDG&E)
Pacific Gas and Electric Company (PG&E)

Introduction

In the final decisions for 2025 Wildfire Mitigation Plan (WMP) Updates for the Joint Investor-Owned Utilities (IOUs), the Office of Energy Infrastructure Safety (Energy Safety) issued an Area for Continuing Improvement (ACI) requiring the continuation of joint grid hardening studies from the 2023-2025 Base WMP. The ACI was identified as follows in the decisions for each utility:

- SCE-25U-03
- SDGE-25U-04
- PG&E-25U-03

This report serves as the Joint Utility response to the ACI. The language from the ACI is presented in italics, with the Joint Utility response presented in non-italics.

In many sections of this report, the Joint Utilities have presented a unified response to provide Energy Safety and other stakeholders with a combined narrative. The Joint Utilities note that each utility's individual practices may vary, both in the present day and in the future. As such, statements in this report about how the Joint Utilities approach specific issues or situations should be taken with the understanding that variations at each utility may exist.

ACI Description

Continuation of Grid Hardening Joint Studies

As directed in the 2023-2025 WMP Decisions, the IOUs have made progress on the areas for continued improvement related to the continued joint IOU grid hardening working group efforts. Energy Safety expects the IOUs to continue these efforts and meet the requirements of this ongoing area for continued improvement.

ACI Required Progress

In its 2026-2028 Base WMP, [each utility] must continue to collaborate with the other IOUs to evaluate various aspects of grid hardening and provide an updated Joint IOU Grid Hardening Working Group Report. This report must include continued analysis for the following:

(continued on following page)

Topic #1: Covered Conductor

1.1 The IOUs' continued joint evaluation of the effectiveness of CC for reducing ignition risk, PSPS risk, and outage risk associated with protective equipment and device settings. This evaluation must include analysis of risk reduction observed in-field as well as research on CC degradation over time and its associated lifetime risk mitigation effectiveness.

The Joint Utilities conduct a California Utility Wildfire Risk Reduction meeting on a monthly basis. Covered conductor (CC) is discussed as part of this meeting. This section details the evaluation of CC for reducing risks associated with protective equipment and device settings.

1.1.1 Ignition risk

SCE

As outlined in earlier WMPs, each utility's CC program varies due to factors such as location, terrain, and existing overhead facilities. Additionally, each utility has unique ignition frequencies, risk drivers, and deployment volumes. These characteristics, among others, lead to variations in data, calculations, and methods for estimating effectiveness. At SCE, CC is the primary mitigation implemented for Overhead Hardening, except in cases in which the level of risk is sufficiently high to merit undergrounding the lines (please see SCE's Integrated Wildfire Mitigation Strategy as described in its WMP Section 5).

SCE's mitigation effectiveness for its Wildfire Covered Conductor Program (WCCP) program is estimated to be 60 percent (see discussion in SCE's 2026-2028 WMP, Chapter 5). This value is based on testing, ignition data, experience, benchmarking, and Subject Matter Expert (SME) judgement. SCE completed extensive third-party CC testing in 2022, as provided in the 2023-2025 Joint IOU Covered Conductor Working Group report.

PG&E

PG&E's overhead hardening program consists of primary and secondary CC replacement along with pole replacements, replacement of non-exempt equipment, replacement of overhead distribution line transformers, framing and animal protection upgrades, and vegetation clearing. Although the focus of this request is CC, PG&E's efforts to estimate effectiveness include all elements of our Overhead Hardening program, which is more complete than CC alone.

As detailed in Section 8.2.1 of PG&E's 2026-2028 WMP, based on historical analysis of ignitions, PG&E estimates the effectiveness of CC at reducing ignition risk in the PG&E service territory to be 67 percent. When combined with Enhanced Power Line Safety Settings (EPSS) and Downed Conductor Detection (DCD), PG&E estimates the ignition risk reduction effectiveness increases to 79 percent.

SDG&E

In 2025, SDG&E calculated CC effectiveness using ignitions and evidence of heat data from 2019 to 2024. Outputs of CC testing and benchmarking with the Joint Utilities were also utilized to update the effectiveness of CC at preventing ignitions from risk drivers. The effectiveness of CC varies based on the wildfire risk driver. When combined with other mitigations such as falling conductor protection and early fault detection, overall ignition reduction for all risk drivers is 56.7 percent. By applying these findings to actual ignition counts, SDG&E estimates that the use of covered conductors is 44 percent effective at reducing wildfire risk.

1.1.2 PSPS risk

Due to CC's ability to reduce the risk of contact from foreign objects, wind speed de-energization thresholds on fully covered circuit segments can be raised from National Service Wind Advisory levels (31 mph sustained wind speed and 46 mph gust wind speed) to National Weather Service High Wind Warning levels (40 mph sustained wind speed and 58 mph gust wind speed). However, wind speed thresholds for de-energization of covered conductor segments vary due to each utility's risk tolerance and the unique circumstances impacting each PSPS event.

As part of their processes, the Joint Utilities analyze circuits impacted by PSPS. If the analysis shows that future de-energizations can be mitigated by CC, then CC will be considered. Additionally, analysis is now proactively performed on circuits that are at risk for PSPS but have not yet been impacted. CC will be considered for deployment on these circuits as necessary pending the results of the analysis.

1.1.3 Outage risk associated with protective equipment and device settings

The Joint Utilities deploy protective equipment and device settings in conjunction with CC, such as EPSS for PG&E, fast curve for SCE, or Sensitive Relay Profiles (SRP) for SDG&E.

CC may not have a direct impact on the outage risk associated with protective equipment and device settings. For example, even though CC may decrease the likelihood of transient level faults experienced by the utility, it could also increase the likelihood of a downed wire that would not be de-energized by standard device setting practices. Therefore, the utilities are continuing to develop and implement new devices and methodologies for clearing what would be experienced as open-wire scenarios.

PG&E

See Sections 5.1.1 and 8.7.1.1 of PG&E's 2026-2028 WMP for discussion of outage risk and protective equipment.

SDG&E

See Section 4.1.2 and 4.1.4 for SDG&E's utilization of protective equipment and section 5.1 for analysis on mitigations deployed in combination with CC.

SCE

See Section 8.2.8, 8.7.1, 8.7.2, and 10.3.1. for SCE's discussion of sectionalizing and protection devices and settings.

1.1.4 *Risk reduction observed in-field*

The Joint Utilities have continued to refine their data and methods to measure the effectiveness of CC in the field. Factors such as outage data, scored by SMEs and based on qualitative criteria (e.g. Equipment Type, Basic Cause, Outage Driver, etc.), are used to measure the effectiveness of CC in the field. Promising studies are underway with major California universities to monitor and produce meaningful observed effectiveness results, including the use of Bayesian inferences; however, data availability is a constraint given the relative novelty of CC installation programs. Ideally, SME-based assessment of effectiveness will not be relied on long term, but limited real-world observations of CC will support the assumptions used. For example, PG&E has experienced two ignitions involving CC. Both incidents experienced large vegetation failures that broke through the CC, resulting in wire down incidents that ignited ground fuels. Although both incidents occurred in locations where CC was installed, the vegetation failures were so large that the hardened circuit was not able to withstand the contact. These events reinforce PG&E's methodology of "medium" effectiveness for tree fall-in associated with wire on object and wire on ground ignitions.

PG&E

PG&E's overhead hardening program consists of primary and secondary CC replacement along with pole replacements, replacement of non-exempt equipment, replacement of overhead distribution line transformers, framing and animal protection upgrades, and vegetation clearing. Although the focus of this request is CC, PG&E's efforts to estimate effectiveness include all elements of our Overhead Hardening program, which is more complete than CC alone.

Determining whether a specific event could result in an ignition depends upon a wide variety of factors, including the nature of the event itself and prevailing environmental conditions (e.g., weather, ground moisture level, time of year). As PG&E does not have complete information to make this determination for each event, estimating overhead hardening effectiveness relies upon several assumptions. Most distribution outages (momentary and sustained) typically involve a fault condition. Thus, for purposes of estimating overhead hardening effectiveness, it is assumed that all distribution outages could potentially result in an ignition, regardless of other prevailing conditions. This approach aligns with what has been previously stated in PG&E's 2023 WMP and 2024 RAMP filing.

In 2023, PG&E re-evaluated the SME effectiveness designations and adjusted the estimated ignition effectiveness of CC in a few key areas based on an assessment of the Joint IOU grid hardening testing results. While this is expected to be an ongoing process, effectiveness values have been refreshed based on updated designations and the data as follows:

- Tree fall-in associated with wire on object and wire on ground changed from “none” (not effective) to “medium” (some effectiveness). While other IOUs considered a higher effectiveness than PG&E, as discussed above, there are trees in our service territory large enough to damage CC and as such, CC does not have as substantial an increase in effectiveness.

- Contact from Object Vehicle changed from “none” (not effective) to “medium” (some effectiveness). PG&E agrees with other IOUs that CC has some limited benefit. Given that PG&E is installing larger poles to support CCs, the larger poles have the potential to sustain more impact from vehicle than existing infrastructure.

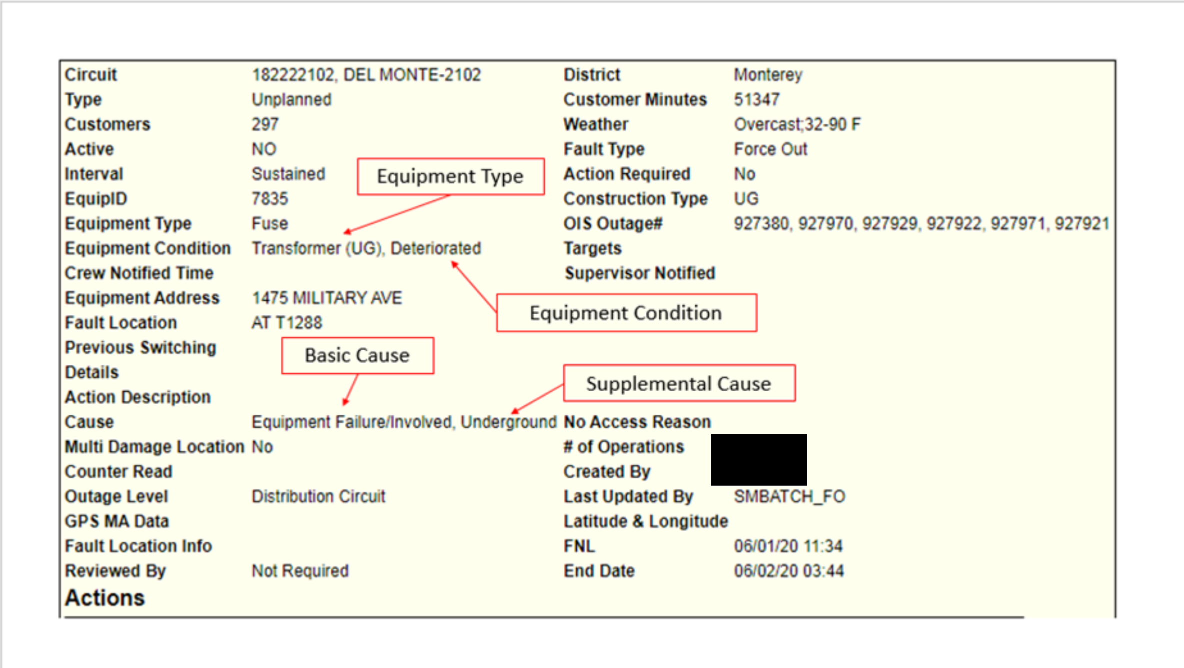
- Animal caused outages associated with conductor contact changed from “none” (not effective) to “All” (very high effectiveness). Testing on the covering material of CCs showed a high resiliency to damage. Also, PG&E found that the insulating properties of the covering did not diminish significantly when damaged. Therefore, PG&E has increased CC effectiveness for mitigating damage caused by animals such as squirrels and birds.

In the 2024 update, the analysis was updated to be more granular, and additional mitigation alternatives, including undergrounding, were added as a consideration. Given the many combinations of outage types seen on PG&E’s system, SMEs highlighted the need to differentiate effectiveness in a more granular level for some of the outage conditions. Therefore, qualitative categorization levels used in the analysis were increased from five (All, High, Medium, Low, None) to seven (All, Very High, High, Medium High, Medium, Low, None).

PG&E’s approach to calculating estimated effectiveness of CC is detailed below:

1. SMEs identified approximately 100,000 distinct outages between 2015 and 2024 by using all known combinations of basic cause, supplemental cause, equipment type, and equipment condition from the distribution outage database, shown in Figure 1. Whenever an outage is reported, an operator enters the required information about the outage. Through SME evaluation, it was decided that a combination of the four aforementioned combination fields provide an appropriate distinction of different outage types.

FIGURE 1: PG&E DISTRIBUTION OUTAGE DATABASE RECORD



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

2. SMEs identified whether the presence of CC would eliminate or reduce the potential of an ignition from each outage combination based on the qualitative categorizations below:
    - **All** = Eliminates the likelihood of ignition from a certain type of outage
    - **Very High** = Addresses most outage concerns, but OH construction still has the potential for outage events resulting in an ignition
    - **High** = Significant outage reduction, however still chance that contact failure would result in an ignition
    - **Medium High**= Better than average likelihood of reducing ignitions from a certain type of outage
    - **Medium =** Moderately reduces the likelihood of a certain type of outage occurring resulting in an ignition
    - **Low** = Minimally reduces the likelihood of a certain type of outage occurring resulting in an ignition
    - **None** = Will not affect the likelihood of ignition from a certain type of outage
3. Each qualitative category was assigned a quantitative value, which measured the likelihood of outage reduction:
    - All = 100 percent
    - Very High = 90 percent
    - High = 70 percent
    - Medium High = 60 percent
    - Medium = 40 percent

- Low = 20 percent
- None = 0 percent

4. The above criteria were applied to historical outages, which resulted in the likelihood of outage reduction for each outage.
5. Outages were classified by drivers in alignment with PG&E's current Wildfire Distribution Risk Model (WDRM v4). The outage drivers identified are:
    - Animal (Bird)
    - Animal (other)
    - Animal (Squirrel)
    - Equipment (Capacitor)
    - Equipment (DPD)
    - Equipment (Fuse)
    - Equipment (other)
    - Equipment (Support Structure)
    - Equipment (Switch)
    - Equipment (Transformer)
    - Equipment (Voltage Control)
    - Primary Conductor - Line Slap
    - Primary Conductor - Other
    - Primary Conductor - Wire Down
    - Secondary Conductor
    - Third Party (Balloon)
    - Third Party (other)
    - Third Party (Vehicle)
    - Vegetation (Branch)
    - Vegetation (other)
    - Vegetation (Trunk)

    One additional "Company Initiated" driver was created, but outages associated with this driver are excluded from results of the analysis. This category includes outages such as PSPS events.

6. A Pivot table was then created to aggregate outages in the HFTD. The aggregation was done at the outage driver level and the results are shown in Table 1.

TABLE 1: PG&E COVERED CONDUCTOR MITIGATION EFFECTIVENESS ESTIMATE

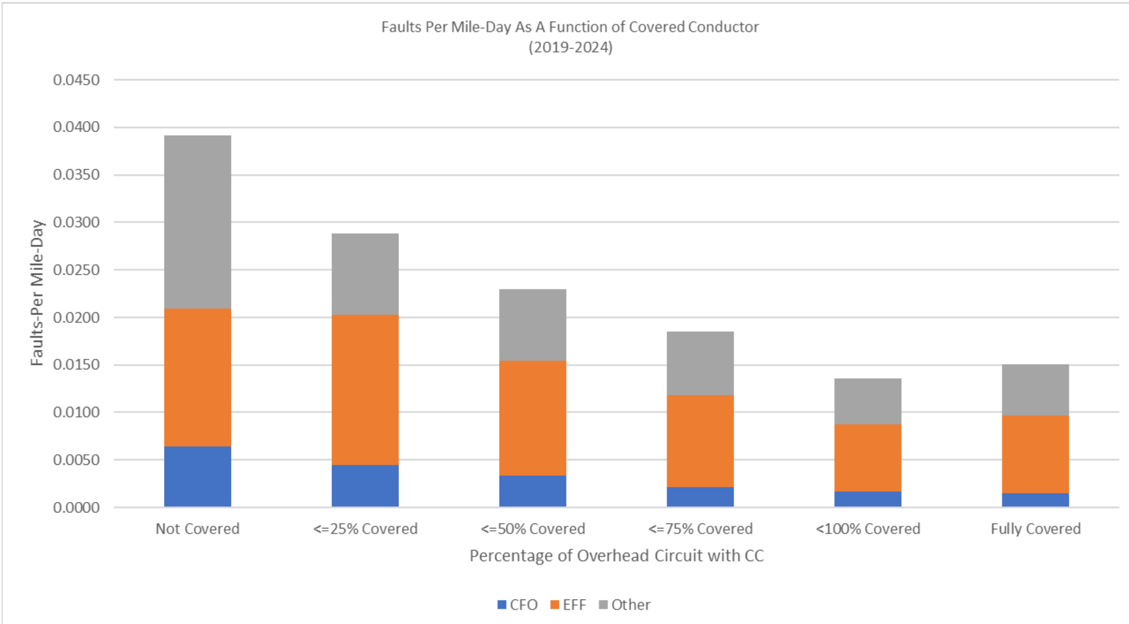
WDRM V4 Driver	Overhead Hardening	UG Primary and OH Secondary	UG Primary and UG Secondary
Vegetation (Branch)	76%	98%	100%
Vegetation (Trunk)	58%	98%	100%
Vegetation (other)	83%	97%	100%

WDRM V4 Driver	Overhead	UG Primary and	UG Primary and
Animal (Bird)	79%	100%	100%
Animal (Squirrel)	74%	100%	100%
Animal (other)	78%	99%	100%
Third Party (Balloon)	88%	100%	100%
Third Party (Vehicle)	64%	99%	100%
Third Party (other)	52%	71%	73%
Primary Conductor - Line Slap	85%	99%	99%
Primary Conductor - Wire Down	47%	100%	100%
Primary Conductor - Other	74%	100%	100%
Secondary Conductor	50%	50%	99%
Equipment (Support Structure)	73%	100%	100%
Equipment (Transformer)	70%	100%	100%
Equipment (Voltage Control)	32%	96%	98%
Equipment (other)	76%	94%	94%
Equipment (Capacitor)	41%	91%	91%
Equipment (DPD)	40%	97%	98%
Equipment (Fuse)	73%	100%	100%
Equipment (Switch)	81%	99%	99%
Grand Total	67%	98%	99%

SCE

SCE tracks fault rates on overhead distribution circuits with 100 percent CC installed, circuits that are partially covered, and circuits with no CC installed (bare wire). The data can be broken down by fault sub-drivers such as Contact from Object, Equipment/Facility Failure, and Other. The data is based on all circuits that traverse the HFTD and includes a breakdown of how many miles there are in the fully covered, partially covered, and not covered categories. Because it is difficult to determine if faults on partially covered circuits occurred on the covered or bare portion, SCE further delineated this data into the following partially covered groups: less than 25, 25 to 49, 50 to 74, 75 percent, and less than 100 percent. Furthermore, SCE is now using a faults-per-mile-per-day method that factors in how long the circuit was fully or partially covered. Faults-per-mile-per-day data from 2019 to 2024 are shown in Figure 2.

FIGURE 2: FAULTS PER MILE PER DAY AS A FUNCTION OF CC



There are currently no changes to the near-term approach for evaluating effectiveness. SCE will continue to track and analyze ignition events and may leverage this data to refine current assumptions for estimated effectiveness.

1.1.5 Research on CC degradation over time and its associated lifetime risk mitigation effectiveness

Over the last few years, the Joint Utilities have conducted extensive testing on CC. These tests included third-party testing in 2022, which included contact-from-obvious testing, wire down, flammability, and water ingress. In addition, the Joint Utilities require manufacturers to perform ultraviolet resistance and track resistance testing (to prevent covering degradation caused by electrical charges on the outer portion of the CC covering).

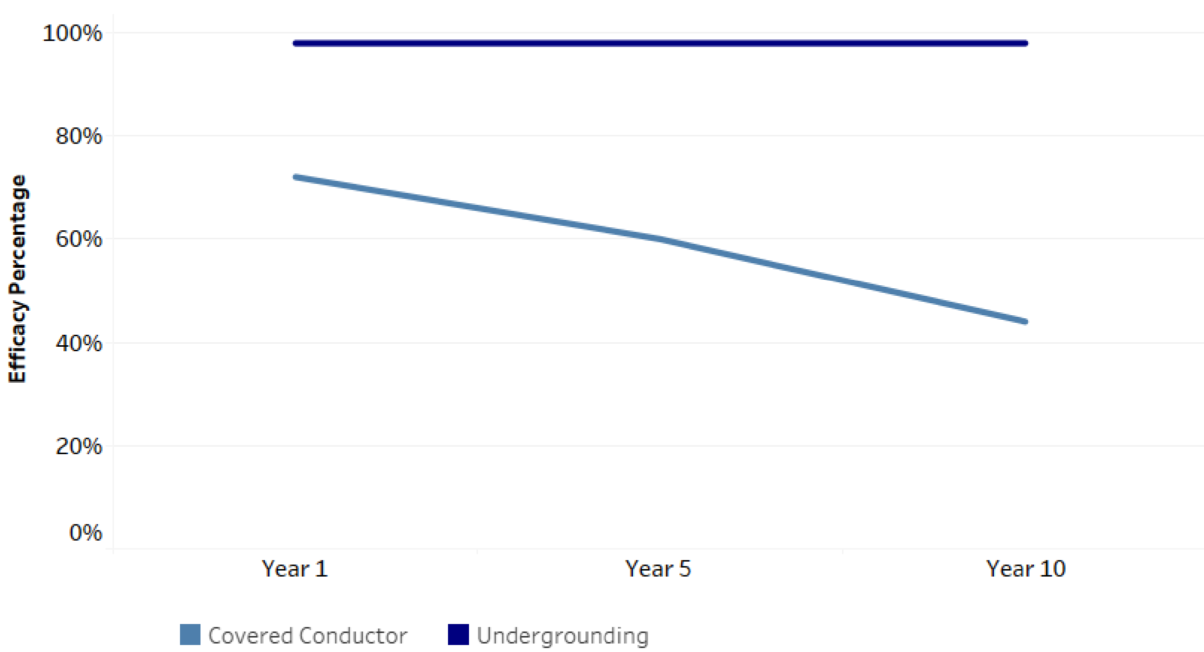
Based on tests, benchmarking information, and manufacturer feedback, SCE estimates the useful life of CC to be 45 years. SCE does not expect a reduction of mitigation effectiveness for CC within these 45 years.

PG&E utilizes 48 years as the estimated service life for CC, which aligns with industry information citing an expected service life in the range of 30 to 50 years. PG&E has a large service territory with varying environmental conditions that impact equipment aging and degradation in different ways. For example, testing results indicate that equipment degradation can be increased in damp locations, such as the coast where fog is more common. Therefore, PG&E does not have an estimated service life for CC. However, 30-50 years is the expected service life according to industry information.

SDG&E

The effectiveness of CC against various equipment failure risk drivers was reduced in 2025 for several reasons. Originally, the estimated effectiveness was derived using a year-over-year approach. Effectiveness was defined as the immediate protection gained from performing the CC installation, which replaces aging or damaged equipment with new equipment. However, because these effectiveness numbers are being utilized for long-term investment planning, it is more appropriate to utilize a long-term effectiveness number for risk drivers. While CC installation replaces aging equipment, covered conductors will also age and degrade, reducing the effectiveness of the original installation over time. To address this issue, previous studies on the effectiveness of traditional (bare conductor) hardening were used to estimate the effectiveness of CC on equipment failure risk drivers over time. As shown in Figure 3, traditional hardening had an estimated effectiveness of approximately 65 percent in the first year that decreased over the course of 10 years to 39 percent. Because of the similarities in equipment being replaced during covered conductor and traditional hardening initiatives, the 10-year recorded effectiveness of 39 percent for traditional hardening effectiveness against equipment failure risk events was also used to calculate CC effectiveness for the same equipment failure risk drivers, resulting in a decrease in covered conductor efficacy from 72 percent in the first year to 44 percent after 10 years.

FIGURE 3: HARDENING EFFICACY OVER TIME



Combined Mitigation Effectiveness Updated CC effectiveness values were utilized to study the combined effectiveness of CC with the Advanced Protection initiatives of FCP and EFD. Much like CC installations, FCP installations are new and therefore no recorded data is available for calculating effectiveness. Therefore, subject matter expertise from the System Protection and Controls Engineering (SPACE) team was utilized to estimate their effectiveness. EFD was calculated using data as described in ACI-SDGE-25–

05 (see SDG&E's 2026-2028 Wildfire Mitigation Plan, Appendix D). When combining mitigations, the following formula was used (in collaboration with the Joint Utilities):

$$Combined\ Effectiveness = 1 - [(1 - CC\ Efficacy) \times (1 - FCP\ Efficacy) \times (1 - EFD\ Efficacy)]$$

$$1 - [(1 - 44\%)] \times (1 - 8\%) \times (1 - 16\%) = 56.7\%$$

The overall efficacy of CC conductors is estimated to be 44 percent and the overall efficacy of CC combined with FCP and EFD is estimated to be 56.7 percent.

Topic #2: Undergrounding

2.1 The IOUs' joint evaluation of the effectiveness of undergrounding for reducing ignition risk, PSPS risk, and outage risk associated with protective equipment and device settings. This evaluation must account for any remaining risk from secondary or service lines and analysis of in-field observations from potential failure points of underground equipment.

The Joint Utilities continued to meet quarterly in 2023 and 2024 to share information and lessons learned regarding undergrounding within California and to participate in efforts to share and learn from utilities implementing underground programs outside California. In August 2023, PG&E and SDG&E participated in an Electric Power Resource Institute (EPRI)-sponsored 2-day in-person session with utilities from across the country to discuss topics such as undergrounding program motivations, operations, challenges, and efficiencies. In April 2024, PG&E published an undergrounding benchmarking report that discussed program approaches and trends for 11 electric utilities, including all three California IOUs. See Section 2.2 for details on this report.

Because every utility considers unique factors for selecting undergrounding, as well as environmental factors contributing to the feasibility and effectiveness of undergrounding, data and lessons learned from one utility are not always applicable to other utilities. However, the California utilities intend to continue meeting regularly to ensure communication and sharing of information and will apply lessons learned whenever applicable and participate in national undergrounding-related information-sharing opportunities.

2.1.1 Joint Evaluation of effectiveness of undergrounding for reducing Ignition risk:

Among the Joint Utilities, the estimated effectiveness of undergrounding at reducing ignition risk in a given location ranges from 94 to 99 percent. While the joint utilities' effectiveness rates are highly aligned and indicate that undergrounding is very effective in reducing ignition risk, the exact figures vary slightly due to differences in assumptions and methodologies used to calculate effectiveness values, differences in territory topography and weather, and differences in data, such as outage type and frequency, for past outages and ignitions.

PG&E estimates the ignition mitigation effectiveness of undergrounding primary powerlines to be approximately 98 percent and approximately 99 percent if both the primary and secondary services are undergrounded. Effectiveness is derived by using outages as a proxy for ignitions as well as subject matter expertise. PG&E provides additional information on calculating mitigation effectiveness in its 2026-2028 WMP, Section 8.2.1.

2.1.2 Joint Evaluation of effectiveness of undergrounding for reducing PSPS risk

PG&E

Beyond PG&E's projects targeted to reduce PSPS, lines that are undergrounded may be exempt from PSPS activity as the underground lines themselves do not pose an ignition risk during the extreme weather conditions that drive PSPS events. However, it is challenging for PG&E to provide a PSPS risk effectiveness value for undergrounding because the PSPS effectiveness of undergrounding in any particular location depends on whether, and how much of the upstream and downstream line sections have been undergrounded. For example, undergrounding may not eliminate PSPS risk for customers directly connected to an underground section of a circuit if the undergrounded section remains connected to an overhead line (either upstream or downstream) in a High Fire Risk Area (HFRA) that is subject to PSPS. While overhead hardening does not automatically exempt a location from a PSPS event, the hardened status of a line, and of any overhead upstream and downstream lines, is considered in the analysis that determines which lines are scoped into a PSPS event. As PG&E completes additional undergrounding and underground sections are connected, more PSPS risk will be mitigated.

SCE

SCE has not quantified the effectiveness of Targeted Undergrounding (TUG) on PSPS risk. However, SCE would no longer have PSPS as the line is now underground, but someone on a UG circuit could potentially be subject to PSPS if they are downstream of a segment that is de-energized and SCE can’t otherwise section them off.

SDG&E

SDG&E subject matter experts from Meteorology, Fire Science, Engineering, and Risk Analytics groups are currently assessing the effectiveness of existing underground infrastructure considering the most recent fire weather conditions experienced in SDG&E's service territory from November 2024 to January 2025. This evaluation aims to determine the frequency and duration of SDG&E’s most recent PSPS de-energizations on underground segments and identify any necessary improvements to SDG&E’s risk models.

In addition, subject matter experts are evaluating the criteria for selecting future undergrounding projects based on the hardening status of upstream and downstream feeder segments. With this new approach, SDG&E aims to maximize PSPS risk reduction while balancing ignition risk reduction in the most cost-effective manner.

2.1.3 Joint Evaluation of effectiveness of undergrounding for reducing outage risk associated with protective equipment and device settings

PG&E analyzed the reliability performance of circuit sections where System Hardening Undergrounding work was performed in 2022 and 2023 to quantify overall improvements to service reliability. The analysis included approximately 750 outages between 2021 and 2024 and showed an approximate 90 percent reduction in faults that resulted in sustained outages.

2.1.4 How the effectiveness evaluation accounts for remaining risk from secondary or service lines

SDG&E

SDG&E's undergrounding program is inclusive of primary, secondary and service lines, thus limiting risk from secondary or service lines remaining overhead.

PG&E

While PG&E's distribution undergrounding program currently includes primary powerlines and secondary lines that run parallel to the primaries, PG&E expects that when the undergrounding program is transitioned to the EUP it will include some secondary and service lines in addition to primary lines in the HFTD. PG&E provides mitigation effectiveness values for Undergrounding All, which includes primary distribution lines, secondary lines, and services in PG&E's 2026-2028 Base WMP, Table PG&E 8.2.1-3, Section 8.2.1.

SCE

SCE's program currently focuses on undergrounding primary conductor and does not underground lateral secondary lines and service conductors. As such, SCE has not developed effectiveness values for secondary/service risk. For SCE's TUG program, secondaries will be included as part of the scope when possible and services are not part of the TUG scope.

2.1.5 How the effectiveness evaluation accounts for in-field observations from potential failure points of underground equipment

PG&E tracks data from ignition events and other failures by underground distribution infrastructure equipment. Data is analyzed and used to make updates to equipment and process standards. If relevant to wildfire mitigation effectiveness, updated standards may be leveraged to refine assumptions for estimated effectiveness of undergrounding in preventing wildfire ignitions. However, this data does not directly impact effectiveness values because failure modes of underground equipment are not typically affected by factors that are associated with wildfire risk. For example, extreme high wind conditions, which can be associated with higher ignition risk, do not trigger failures in underground lines because the lines are underground and thus not impacted by wind.

2.2 The IOUs' joint evaluation of lessons learned on undergrounding applications. These lessons learned must include use of resources (including labor and materials) to accommodate undergrounding programs, any new technologies being applied to undergrounding, and cost and associated cost effectiveness efforts for deployment.

Lessons learned regarding undergrounding have been discussed among the Joint Utilities during quarterly meetings held throughout 2024. The following lessons learned were noted in those discussions:

1. Managing resources requires a clear understanding of the scope of work and overall workplan to ensure the appropriate allocation of internal resources versus contractors. Ensuring the right resource balance between the two can optimize cost and efficiency.

2. Continuing to test and deploy new technologies is an effective way to improve productivity and reduce unit costs, particularly when paired with innovative construction approaches.
3. Proactive planning was identified as important, particularly in identifying potential challenges, such as encountering hard rock, that can significantly impede construction progress and contribute to cost overruns.

Each of these lessons learned could lead to revised practices that will minimize delays, cost overruns, and resource inefficiencies. To reinforce the need to improve upon these areas, the Joint Utilities continue to discuss these topics regularly.

In late 2023, PG&E and SDG&E participated in a 2-day EPRI workshop with over 10 utilities from across the United States to discuss electrical undergrounding programs and lessons learned. The workshop covered key challenges as well as solutions and best practices on a variety of undergrounding topics. Key challenges identified by workshop participants included:

- Obtaining easements and permits
- Geological challenges, such as granite and sand hills
- Paving requirements and coordination with local governments
- Material supply chain delays
- Managing project cost

Workshop participants explored solutions and lessons learned, including:

- Less invasive trenching (including shallow trenching and micro-trenching)
- Comprehensive contract bidding
- Best practice collaboration and communication with local government and permitting agencies
- Standardizing material components to simplify design, purchasing and installation

In April 2024, PG&E published its benchmarking study that evaluated 11 electric utility strategic undergrounding programs[1]. Strategic undergrounding programs are defined as those in which the utility chooses electric assets to underground with a goal of mitigating safety, reliability, or other risks. The participating utilities represent geographic regions across the United States and have strategic undergrounding programs in various stages of development. Collectively, these utilities serve more than 60 million customers.

[1] The 11 participants include PG&E and two other California electric utilities.

The purpose of this undergrounding benchmarking study was to learn how different utilities across the United States are approaching strategic undergrounding in their service areas and to identify trends and lessons learned. Overhead system hardening programs were not addressed in the study. Participating utilities responded to an online survey and participated in follow-up phone interviews. The study focused on the following issues: (1) the scale and scope of undergrounding; (2) utilities' motivation to underground and site selection approach; (3) costs and cost containment; (4) customer engagement; and (5) technical standards and operations.

Key takeaways and lessons learned included

- Scale and scope of undergrounding programs
    - Participating utilities' programs vary in scale, from established programs that have converted more than 1,500 overhead miles to underground to small pilots
    - Most utilities are undergrounding primary distribution lines, secondary distribution lines, and service lines, although some are pursuing alternative strategies such as installing more resilient poles and equipment, vegetation management, and operational mitigations, including power shutoffs.
- Motivation and site selection
    - Utilities in the South and Midwest cited reliability and/or resilience to weather events as their main motivations for strategic undergrounding. Utilities in the West primarily use their undergrounding programs to reduce wildfire risk.
    - Utilities selected sites based on metrics related to their motivation for pursuing strategic undergrounding: reliability metrics in the South and Midwest and wildfire risk in the West.
- Cost and cost containment
    - Unit costs are highly variable and are affected by factors such as terrain and population density. On the whole, Southern and Midwestern utilities see lower costs than Western utilities.
    - Several utilities noted negative impacts resulting from a constrained supply of pad mount transformers in the second half of 2023.
    - Utilities noted that economies of scale (e.g., contracting, design, and workforce considerations) have helped contain costs.
- Customer engagement
    - Utilities noted that obtaining easements can be challenging, but customer outreach and education can help.
- Technical standards and operations
    - Depth and method of cover above the undergrounded lines were fairly standard across utilities surveyed, at 30 to 36 inches, and most utilities pull cable through conduit rather than direct burying electric cables.

The report is publicly available here: https://www.pge.com/assets/pge/docs/outages-and-safety/safety/undergrounding-benchmarking-report.pdf

Use of resources (including labor and materials) to accommodate undergrounding programs

Materials supply chain issues were identified as key challenges by a number of the utilities in the PG&E's benchmarking study. Limits on the availability of key materials can stop or slow construction work and delays can increase project costs. For example, three utilities with established strategic undergrounding programs commented that a limited supply of pad mount transformers presented challenges and/or caused delays in their undergrounding programs during the second half of 2023; two of those utilities highlighted supply chain issues as the top challenge facing their programs. In addition, two utilities with undergrounding programs in the pilot stage reported that supply chain issues challenged their programs.

Effective management of labor resourcing has been a topic discussed in quarterly meetings. Utilities have shared lessons learned regarding how unproductive time can create cost challenges for a program and how schedule management and use of labor resources can help alleviate this issue. For example, utilities discussed the importance of managing contract resources to align with the timing and scale of planned work and to be able to offboard contract labor when scheduled work is decreased or delayed due to weather or other conditions.

2.3 New technologies being applied to undergrounding

The Joint Utilities are evaluating Ground Level Distribution Systems (GLDS), which may provide an alternative to traditional underground systems. This technology involves installing facilities at the ground level, removing the need to bury the cable in areas where difficult terrain that makes traditional undergrounding infeasible.

PG&E's Undergrounding Innovation team identifies new undergrounding technologies to understand their potential effectiveness and value to the program. Examples of new technologies PG&E is applying to its undergrounding program include:

- **Fluid Free Boring Technologies**: While horizontal directional drilling (HDD) is a valuable installation method, disposal of the resulting large quantities of mud presents cost and logistical challenges in remote areas. PG&E is pursuing multiple technologies that reduce or eliminate the production of mud as a result of drilling.

- **Automated Utility Design**: New smart design tools can be used to calculate characteristics such as voltage drop, cost, and parts needed on the fly as a design is created. By using this software to calculate these characteristics, cycle times and errors that would require design rework can be reduced.

- **Spider Plow**: This installation method for rough terrain can install multiple conduits without the need for an excavated trench, even when an area can only be accessed by bulldozer. Spider plow can efficiently install reels of conduit in terrain that would be high cost for conventional means of construction.
- **Augmented Reality (AR) Tools**: These tools can create more transparency with customers by providing three-dimensional visuals of work that will take place on a customer's property. This transparency provides greater understanding of the undergrounding work and the end result, improving the customer experience and reducing the need for redesigns.

SDG&E

SDG&E is evaluating various technologies to enhance the efficiency of wildfire mitigation. These technologies aim to strengthen fire prevention efforts, improve situational awareness, and enhance response capabilities in high-risk areas. For example:

1. GLDS: SDG&E is exploring the use of GLDS, ideal for areas where underground conversions are difficult, such as rocky terrains, environmentally sensitive regions, or challenging field conditions. This technology features durable above-ground trays that hold distribution conductors and are then encased in epoxy resin concrete for added resilience. To evaluate the effectiveness of GLDS in various scenarios, SDG&E plans to construct a test setup and conduct a pilot project. SDG&E is partnering with the Electric Power Research Institute (EPRI) to further test this technology.
2. Mobile application for improved communications with property owners: SDG&E is exploring the use of mobile applications to enhance communication with property owners. Through the use of artificial intelligence and machine learning, property owners can view an augmented reality visual representation of how their property will look after the installation of electric equipment such as transformers or junction boxes. This technology will give property owners a better understanding of the impact of installed equipment during an underground conversion project, helping them make more informed decisions about granting easements to the utility.
3. Improved process for handhole installation in high altitude areas: When above surface land rights and/or geography limits the ability to install padmounted structures, sub surface handholes are installed. To prevent collisions between handhole covers and snowplowing vehicles in high-altitude areas, particularly on unpaved county roads, SDG&E has successfully implemented a new handhole installation method utilizing soil stabilization materials. This approach enhances the durability of handholes while protecting both the covers and snowplowing equipment.

4. Microgrids: SDG&E is evaluating microgrid solutions as an alternative to overhead power lines, particularly for circuits that serve minimal loads like well pumps or antennae. If a load analysis confirms that the microgrid can reliably support these applications, SDG&E considers removing the overhead lines, reducing wildfire risk and infrastructure maintenance needs.

For SCE, refer to the ground level duct system, referenced in Chapter 8 of the 2026-2028 Base WMP.

2.3.3 Cost and associated cost effectiveness efforts for deployment

A key finding from the PG&E benchmarking study was that unit costs are highly variable and are affected by factors such as terrain and population density. Unit cost information shared by seven utilities with established strategic undergrounding programs was analyzed. [2]Multiple utilities reported that undergrounding costs can vary widely from project to project, and ranges given for a “typical” project may not capture the full variability. The seven utilities reported typical undergrounding unit costs that varied from approximately $300,000 to more than $3 million per overhead mile removed (all costs are presented in 2023 USD). Costs may have limited comparability across and even within utilities because indirect costs may be allocated differently by different utilities, costs differ by the type of asset being undergrounded[3] and method of construction,[4] and smaller, more nascent programs may face higher costs than larger, more established programs.[5] Other themes that drive cost variation include:

- **Terrain**. Four utilities noted that terrain features including hard rock, flood plains, water crossings, or soil type can affect ease and cost of construction. One utility noted that encountering unanticipated hard rock can increase costs because the project cannot be executed as originally designed. When asked to rank the top challenges facing their strategic undergrounding programs, five[6,7] utilities ranked physical topography among the top two.

- **Population density and customer load base**. Two utilities noted that undergrounding costs are higher in more densely populated areas, and a third noted higher costs in areas where customer load base is higher. A fourth utility noted that the need to obtain more easements can drive project costs up and that the use of existing easements where possible can help contain costs.

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[2] Because smaller or pilot programs unit cost estimates are based on at most a few completed miles, they were not included in this analysis. In addition, one utility with an established program declined to share unit cost estimates.
[3] For example, one utility noted that the cost of undergrounding a single-phase line was approximately 40 percent lower than that of undergrounding a 3-phase line, and that a 3-phase, large conductor line cost approximately 30 percent more to underground than a standard 3-phase line.
[4] For example, as noted by one utility, directional boring had higher costs than trenching.
[5] Programs in the pilot phase are excluded from this analysis due to the potential for higher costs than established programs.
[6] The utility that did not report its unit costs is included in this analysis.
[7] Including PG&E.

- **Region**. Typical undergrounding unit costs varied between $300,000 to less to $1.7 million per overhead mile removed among Southern and Midwestern utilities. Western utilities[8] reported costs to date generally varied from $2.0 to $3.7 million per overhead mile removed, but one projected that future costs could rise to as much as $4.6 million per overhead mile removed.

The eight utilities with established strategic undergrounding programs[9] were asked about strategies they have used to contain costs. Common themes included:

- ***Building economies of scale.*** Three utilities[10] noted that they achieved cost efficiencies by undergrounding adjacent or nearby segments simultaneously or in sequence. They also discussed finding cost efficiencies through larger-scale purchases or longer-term contracts or providing contractors with a consistent level of work to enable them to maintain a steady workforce level.

- ***Unit pricing and other contract considerations.*** Five utilities described contracting approaches that have helped contain costs. Two reported signing turnkey, unit-priced contracts with vendors. A third reported it is moving toward fixed pricing and currently limits change orders. A fourth noted that it is negotiating construction allowance agreements to limit unanticipated costs. A fifth noted that competitive bidding has generally helped drive undergrounding costs down. One utility further noted that it tracks contractor performance metrics such as on-time completion of work.

- ***Design considerations.*** Six utilities[11] noted that efficient or careful system design, exploring alternative design options, and ensuring design-build alignment can help contain costs.

- ***Depth of cover and method of trenching.*** Two utilities noted that they have reduced depth of cover (also referred to as trench depth) where possible as a cost containment strategy; another noted that shallower trenches could work in some locations and was in the process of piloting this strategy.[12] A fourth utility reported that its use of directional boring, rather than trenching, may increase costs.

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[8] Including PG&E.
[9] Utilities included were those with large or moderately-sized programs, including the utility that did not share unit costs.
[10] Including PG&E.
[11] Including PG&E.
[12] While data on depth of cover was collected from the majority of participating utilities, due to small sample size and the number of other factors that vary between utilities, a clear pattern relating cost and depth of cover did not emerge across participants.

- ***Workforce.*** Two utilities noted the importance of maintaining a qualified skilled workforce to contain costs. Two utilities reported using a project management office to oversee the end-to-end undergrounding process and to identify process efficiencies.

Topic #3: Protective Equipment and Device Settings

3.1 The IOUs' joint evaluation of various approaches to implementation of protective equipment and device settings. This evaluation must include an analysis of the effectiveness of various settings, lessons learned on how to minimize reliability impacts and safety impacts (including use of downed conductor detection and partial voltage detection devices), variations on settings used by IOUs including thresholds of enablement, and equipment types in which such settings are being adjusted.

Beginning in 2019, the Joint Utilities met regularly to discuss various electrical protection and sensor-based methods to mitigate wildfire ignition risk and to exchange lessons learned. Topics of discussion included various protective equipment and device settings deployed by the Joint Utilities. The initial participants were PG&E, SCE, and SDG&E. Meetings have since expanded to include Liberty Utilities, and most recently, PacifiCorp.

The following sections provide a comparison of the various protective equipment and device settings the Joint Utilities have implemented to reduce the risk of wildfire ignitions from utility equipment and mitigate reliability impacts.

3.1.1 Effectiveness of various settings

PG&E

EPSS program effectiveness for the years 2021 to 2023 was calculated by comparing the reduction in ignitions when EPSS is enabled to a baseline timeframe before the Dixie Fire (2021) when EPSS would have been enabled in the same conditions.

Based on this analysis, PG&E found an ignition reduction effectiveness of 74.1 percent in 2021, 68.8 percent in 2022, and 72.7 percent in 2023. In 2024, PG&E adopted a Stratified Effectiveness methodology to understand EPSS effectiveness in reducing the rate of overall ignitions. The current calculated effectiveness based on the new FPI-stratified effectiveness formula is 65.2 percent.

This analysis is explained in greater detail in Section 8.7.1.1 of PG&E's 2026-2028 WMP.

SCE

SCE began using Fast Curve Settings (FCS) in 2018. In June 2022, SCE refined its FCS setting program for application to new and existing installations. FCS is applied in conjunction with recloser relay blocking, which prevents the automatic closing of circuit breakers and remote automatic reclosers following a relay/trip operation. The combined effectiveness of FCS and recloser relay blocking for the years 2021 to

2023 was estimated comparing ignition event frequencies of SCE circuits. Please see Sections 8.2.8 and 8.7.1 of SCE's 2026-2028 for information on setting effectiveness.

SDG&E

SDG&E completed a study to determine the impact of sensitive relay settings at reducing ignitions from risk events downstream of SRP enabled devices. SRP device enable history was examined against the risk events and ignition data from 2015 to 2024, and found zero ignitions by primary faults downstream of devices with sensitive relay settings enabled. This study was detailed in SDGE's 2020-2022 WMP and is updated on an annual basis.

3.1.2 Lessons learned on how to minimize reliability impacts and safety impacts (including use of downed conductor detection and partial voltage detection devices)

Downed Conductor Detection (DCD)

PG&E

DCD technology could improve the ability to detect and isolate high impedance faults before an ignition can occur. PG&E first deployed DCD in 2022 as a pilot that provided an additional protection element to address fault types not yet fully mitigated through the EPSS program. This additional protection is achieved by enhancing the ability to quickly detect and de-energize low and very low initial current (high-impedance) line-to-ground faults before an ignition can occur, which is the primary existing gap in EPSS protection on primary overhead distribution conductors.

During EPSS, DCD is enabled if the device is DCD capable. This feature is highly sensitive, which allows the detection of high-impedance ground faults. However, due to its sensitivity it cannot be coordinated between devices in series. In response to unintended false positive trips with DCD settings, PG&E upgraded the firmware on existing DCD devices to improve the high-impedance fault detection accuracy, which reduced nuisance outage frequency. By the end of 2024, over 500 devices have received updated firmware to improve performance. PG&E will continue to upgrade firmware on remaining DCD devices during the 2026-2028 WMP cycle.

SCE

SCE is refining the fast curve settings but generally is seeing this in a steady-state without major changes since the settings update around 2022-2023 time period.

SDG&E

As discussed in ACI SDGE-25U-05, SDG&E performed an efficacy study on EFD devices, which found that the initial settings of EFD detected many underground faults. Moving forward, EFD algorithms will be fine-tuned to further focus on the detection of overhead incipient faults. See SDG&E's 2026-2028 Base WMP Appendix D for details on ACE SDGE-25U-05.

Partial Voltage Detection Devices

PG&E

To support PG&E's identification and response to high-impedance faults, new data-driven capabilities leveraging the SmartMeter™ network have been implemented. Partial Voltage (PV) Alerts target the 3-wire distribution system with Line-to-Line connected transformers and indicate low SmartMeter Voltage (25 to 75 percent of nominal 240 V).

If partial voltage conditions are detected, Control Center Operators can force out, remotely or locally manually opening a switch or protective device to de-energize the line downstream, an upstream Supervisory Control and Data Acquisition (SCADA) device at the location where multiple partial voltage alarms are received. When a partial voltage alarm indicates low SmartMeter™ voltage on two or more SmartMeter™ devices at the fuse level, the Distribution Control Center Operator can open the next upstream 3-pole gang-operated SCADA device and dispatch response teams to the area of the alarm.

This technology helps PG&E detect and locate a downed wire within minutes, instead of relying on an employee assessment or customer alert. This can reduce the amount of time a downed line is energized, reducing the possibility of an ignition. If an ignition does occur, first responders are able to locate and extinguish it more quickly. A total of 86 partial voltage force outs occurred from 2022 to 2024. These were largely triggered by vegetation or animal contact, which are common fault types that trigger ignitions.

SCE

SCE uses its smart meter voltage alerts and other data sources to identify abnormal circuit conditions and acts to either de-energize circuitry or dispatch crews for further investigation. Meter Alarming for Downed Energized Conductors (MADEC) is a machine learning algorithm utilizing smart meter data to detect a subset of energized wire-downs and other high impedance faults/hazards and generates an alarm that allows an operator to act quickly and de-energize the circuit. MADEC is currently being used throughout SCE's service area. The MADEC system works for both bare wire and CC applications. The MADEC system can limit the total time a downed conductor stays energized after falling, providing potential reduction of ignition risk and public safety benefits.

SCE additionally applies algorithms using voltage data from smart meters can detect small voltage rises associated with shorted turns in the transformer. These algorithms can identify early signs of transformer degradation, to allow proactive equipment replacement prior to complete failure.

Smart meter voltage alarms are also used to dispatch SCE crews to investigate causes of abnormal conditions often helping improve response times to circuit events that may impact customer reliability.

Examples of these conditions are transformer or branch line fuse operations that create customer electric service interruptions.

SDG&E

To support the identification of high impedance faults not tripped by other protective devices, SDG&E has developed a partial voltage detection platform that uses AMI 1.0 voltage readings to determine if there is an active downed wire within minutes. The tool is currently being evaluated by the engineering group for correctness and adjustment to the algorithms. Upon operationalization, this tool will act as a last line of defense to reduce the amount of time a downed line is energized, which will reduce the safety risk to the public and reduce the possibility of the downed conductor causing an ignition. If an ignition does occur, the location will be easily identifiable, allowing first responders to extinguish it more quickly.

3.1.3 Variations on settings used by IOUs including thresholds of enablement and equipment types in which such settings are being adjusted

	PG&E	**SCE**	**SDG&E**
Settings Program Name	Enhanced Powerline Safety Settings (EPSS)	Fast Curve (FCS) Settings	Sensitive Relay Profile (SRP) and Sensitive Ground Fault (SGF)
First Deployed	2021	2018	2011
Scope	HFTD, HFRA, and non-HFTD Buffer Zones	HFRA	HFTD and non-HFTD
Equipment Types in Which Such Settings are Being Adjusted	Circuit breakers Line Reclosers Interrupters Fuse Savers	Distribution circuit breakers Remote controlled automatic reclosers	Some feeder circuit breakers starting in 2025 Line reclosers
Enablement Criteria	In the HFTD and HFRA EPSS is always enabled during peak season on days with a rating of R2 and above, and under certain R1 and R2 conditions during Non-Peak Season: During Peak Season: *R1*: EPSS is enabled if wind speed is >19 mph, relative humidity is <75%, and dead fuel moisture is <9%	FCS are enabled in conjunction with automatic recloser relay blocking. FCS are enabled by using EMS and DMS group controls during the following conditions: • Red Flag Warning issued by the National Weather Service	SRP and SGF are enabled when extreme fire weather conditions or PSPS de-energizations are forecasted.

	PG&E	SCE	SDG&E
	During Winter Posture (Non-Peak Season): *R1*: EPSS is enabled if wind speed is >25 mph, relative humidity is <20%, and dead fuel moisture is <9% *R2*: EPSS is enabled if wind speed is >22+ mph, relative humidity is <25%, and dead fuel moisture is <9% In EPSS Buffer Zones: EPSS enabled during FFW/RFW / mFPC / PSPS adjacent conditions	• Fire Weather Threat declaration made by SCE Weather Service • Fire Climate Zone declaration made by SCE Weather Service • Thunderstorm Threat declaration made by SCE Weather Service	
Note: RFW = Red Flag Warning, FWW = Fire Weather Watch, mFPC = Minimum Fire Potential Conditions			

Topic #4: New Technologies

4.1 The IOUs' continued efforts to evaluate new technologies being researched, piloted, and deployed by IOUs. These efforts must include, but not be limited to: REFCL, EFD, distribution fault anticipation (DFA), falling conductor protection, use of smart meter data, open phase detection, remote grids, and microgrids.

4.1.1 REFCL

The Joint Utilities evaluated the distribution network for applications of REFCL technology to aid with wildfire mitigation efforts.

SCE

See the main discussion on REFCL in chapter 8 of SCE's 2026-2028 WMP.

PG&E

PG&E continues to evaluate performance of REFCL as implemented at the Calistoga substation. In 2025, PG&E will be assessing an additional site for potential REFCL installation that is aligned with the broader underground and overhead hardening strategy for substations located in the HFRA.

SDG&E

SDG&E does not employ REFCL. SDG&E performed a REFCL study from 2020 to 2021. The purpose of the study was to identify the requirements, costs, and benefits of implementing a REFCL scheme at a single transmission-distribution substation feeding 3 distribution circuits in Tier 3. Results of the study showed that the cost to implement REFCL was too significant considering the need for distribution circuit and substation rebuilds. See SDG&E's 2022 WMP Update, Section 4.4.2.10 for details on the full study.

4.1.2 EFD

SDG&E

SDG&E's Early Fault Detection (EFD) Program utilizes two independent technologies to detect incipient faults on the system, with the goal of providing sufficient time to locate and potentially fix or replace equipment prior to it permanently failing. Incipient faults occur on aging and failing pieces of equipment typically long before they fail, sometimes violently, potentially causing damage to the surrounding area.

In 2024, the EFD program focused efforts on developing and optimizing processes and procedures to enable repeatable results and increase production capacity. Key milestones included:

- Revising and publishing overhead construction standard (OHCS) 743. This standard was also converted to a 3D model, allowing users to fully visualize installation best practices.
- Drafting construction standard (UG 7665), which is expected to be published in 2025. Design of ARFS on pad mounted transformers was paused until the standard is fully published.
- Developing a solar assembly for ARFS, enabling installation of sensors at locations where potential transformers did not already exist, and installation of new transformers would be too difficult or cost prohibitive.

In 2025 SDG&E will test a smaller and more cost effective ARFS solution that does not require a full engineering design cycle, rarely requires pole replacements, and is connected directly to the low voltage side of existing transformers using insulation penetrating connectors (IPC). If successful, the program has the potential to quickly increase sensor density and speed of deployment. Additional PQ meters will also be installed on distribution assets, which will increase incipient fault awareness.

PG&E

PG&E has installed EFD sensors on eight distribution circuits (203 locations) in Tier 2 and Tier 3 of the HFRA that are being used to proactively detect incipient equipment conditions. EFD uses the capture of partial discharge events (micro arcing) to detect and isolate early-stage equipment failures, including degrading/damaged conductor, cracked/damage/loose insulators, failing splices, and vegetation encroachment. PG&E is planning on installing approximately 180 sensor locations per year in the 2026-2028 WMP cycle.

4.1.3 DFA

SCE

Between 2019 and 2021, SCE installed 215 DFA units for monitoring HFRA circuits. DFA is a standalone device that is intended to anticipate system failures, although the use of data from other systems can help diagnose or locate some of the alerts from the system. These other systems include Advance Metering Infrastructure (AMI) and Intelligent Electronic Device (IED). Early identification of pre-fault or pre-failure electrical signatures can allow maintenance to be conducted prior to a larger electric system event, helping to reduce ignition or other risks. SCE applied a product from Texas A&M for its DFA applications, however other types of fault recorders or power quality meters could potentially be configured to provide similar capabilities. This technology is presently using traditional voltage and current transformers for collecting measurements. In many cases existing voltage and current transformers at the substation can be configured to these data acquisition systems, helping limit total installation cost.

PG&E

PG&E installed DFA sensors at substations on 96 circuits in Tier 2 and Tier 3 of the HFRA. DFA sensors in combination with Line Sensors, Line Reclosers, SmartMeters, and an in-house Foundry based analytical platform are being used to preemptively detect and isolate latent sources of unknown caused outages to remove the risk of outage recurrence during high wildfire risk periods. PG&E is planning on installing 15 additional circuits each year in the 2026-2028 WMP cycle.

4.1.4 Falling conductor protection

PG&E

As discussed in ACI PG&E-23-07 in PG&E's 2025 WMP Update, falling conductor protection (FCP) is defined as a protective scheme that attempts to de-energize a broken wire before it contacts the ground (or shortly thereafter) to prevent an ignition. This scheme requires sensing devices and communication links, which can be difficult to implement at scale on a distribution system in highly forested terrain. Additionally, to be effective circuit-wide, every lateral branch of the circuit would need a sensing device at the end of the line to be able to detect broken wires before or shortly after they contact the ground, which would be cost prohibitive. Finally, the majority of CPUC-reportable ignitions within HFRA portions of PG&E's service territory occur because of vegetation contact or other external contact, which FCP cannot always mitigate.

However, in certain strategic and high-risk locations, it may be possible to implement a FCP scheme to provide coverage for a targeted section of distribution overhead circuitry. PG&E is currently in the early stages of a pilot initiative to attempt to provide FCP online reclosers over existing cellular connectivity to determine the overall feasibility of this type of solution. Lessons learned, such as cellular connectivity latency, device compatibility, and ignition mitigation effectiveness, will be evaluated as part of this effort.

In the meantime, PG&E will continue to leverage and expand the EPSS program to mitigate distribution falling conductor related ignitions. This program also includes an algorithmic based high impedance ground fault DCD capability and SmartMeter partial voltage detection to mitigate distribution wire down-related ignitions.

SDG&E

SDG&E's Advanced Protection Program (APP) develops and implements advanced protection technologies within electric substations and on the electric distribution system. The program aims to prevent and mitigate the risks of fire incidents, provide better distribution sectionalization, create higher visibility and situational awareness in fire-prone areas, and allow for the implementation of new relay and automation standards in locations where protection coordination is difficult due to lower fault currents attributed to high impedance faults.

The program upgrades and installs protection equipment and devices capable of supporting FCP technology, which trips one or more zones of protection on overhead distribution circuits before broken energized conductors can reach the ground. When an energized conductor fails due to normal aging, over-stressed conditions, or other reasons, the conductor may continue to be energized as it falls and when it reaches the ground. If the conductor makes physical contact with other objects as it falls, arcing may occur, which could result in sparks or embers being distributed across the adjacent area. If the conductor is energized when it reaches the ground, the same type of arcing and subsequent ignition may occur. The risk of falling CCs, while minimized by the insulation surrounding the length of the cable, may result in a high impedance fault at the failure point that could go undetected by protection equipment, creating a potential for ignition. FCP is compatible with traditional open and CC cable and provides the same risk mitigation benefits to both.

SDG&E implements FCP by using a combination of substation protective relays, distribution reclosers, and line monitoring equipment that are in constant communication via high-speed wireless data connections. All devices send readings at 30 samples per second to a centralized real-time automation controller (RTAC) located in the substation. The RTAC consolidates the data and uses multiple algorithms to determine whether a falling conductor condition exists, where it is located, and what section(s) of the circuit must be deenergized. A typical conductor takes approximately 1.4 seconds to reach the ground when it falls; the system is capable of detecting, reacting, and deenergizing a conductor in less than 700 milliseconds (0.7 seconds).

Cost of FCP deployments varies due to multiple factors. Substation circuit breakers, relays, and remote terminal units may require replacement to support FCP. Expulsion fuses may need to be replaced with reclosers, and line monitoring equipment must be installed at the end of each protected branch. High speed data communications must exist or be installed, and poles may need replacement to support the additional weight of reclosers and line monitor equipment. To reduce the total cost of construction, SDG&E is exploring emerging single-ended FCP detection technology, which may reduce the required number of devices. EFD ARFS coverage will also be included on circuits targeted for FCP to determine which technology provides the best risk reduction. FCP will typically cover the main feeder and branches of the circuit and EFD will typically cover remote branch sections too cost prohibitive to deploy FCP.

4.1.5 Smart meter data

SCE

Smart meters provide large quantities of data, and when coupled with other data can help alert SCE of inspection needs or other actions. Smart meter data is coupled with GIS system data and historical event data to help detect possible wire down situations where the conductor may remain energized. SCE calls this Meter Alarming for Downed Energized Conductor (MADEC). When a MADEC alarm is identified, SCE manually de-energizes the line to help reduce ignition and other public safety risks. SCE also uses smart meter data to help detect defects that lead to failures in distribution transformers. Winding shorts, partially turn-to-turn shorts, create small increases in voltage on a transformer secondary that can be detected by smart meters. By aggregating and comparing voltage data of surrounding transformers, SCE can create replacement maintenance actions for some transformers prior to failure. This helps reduce ignition risks due to equipment failure and also helps limit the effects of electric service outages to customers. SCE continues to explore other possibilities for the use of meter data to help manage operation and maintenance of the distribution electric system.

PG&E

Similar to SCE's MADEC, PG&E uses SmartMeter partial voltage detection alerts to inform operators of possible down conductor conditions. PG&E also uses SmartMeter interval voltage data and machine learning algorithms (IONA) to detect secondary and transformer high risk conditions including service transformer windings failures, overloaded transformer, and secondary service connection issues. Additionally, next generation SmartMeters are currently being piloted to see if high resolution edge computing sensor devices improve visibility and alerting of secondary voltage conductor conditions issues including, splice/connection issues, conductor insulation deterioration, vegetation contact, and transformer early-stage failures.

4.1.6 Open Phase Detection

SCE

Open phase detection/protection (OPD), sometimes referred to as falling conductor and broken conductor detection/protection, focuses on de-energizing powerlines when a separation is detected with sufficient speed to de-energize the line before it makes contact with the ground. Transmission and Distribution system topologies and relaying strategies have led to differences in how open phase detection can be applied.

Downed powerlines that remain energized create a risk of ignition when arcing proximate to fuels. Various conditions, such as car collisions with poles, falling vegetation, mechanical impacts, failure of conductor supports, and arcing associated with electrical faults can create open phases. Additionally, a conductor may remain intact in some situations but can still fall to the earth, for example when a car hits a pole, or a large tree and damages crossarms and/or poles without causing a wire separation.

Distribution systems schemes rely heavily on voltage measurements to determine the normal and operational conditions. Radio communication, which requires remote measurements at the end of the protection zone, is the preferred choice for voltage monitoring. Operating times of approximately one second are needed to sufficiently detect an open phase event and de-energize a line section. The demands for speed and bandwidth of the radio system are within present technology capabilities. Current common practice is to have 900 Megahertz (MhZ) radio networks to support traditional distribution automation schemes, which may not have the needed speed or bandwidth to reliably apply an OPD scheme.

SCE's mainline distribution OPD will typically focus on larger conductor sizes and can encompass multiple miles of conductor. The costs for monitor voltage at one end point compared to total conductor length will generally be lower than multiple voltage measurement points needed to monitor tapline locations. While it is generally expected that a smaller conductor is more prone to experiencing a downed wire event, both large and small conductors can experience separation or failure.

For transmission systems, OPD schemes have focused on current measurement quantities rather than voltage. Transmission systems may have more than one voltage source that can operate islanded, which traditional radial distribution systems usually do not do. The additional voltage source as well as lack of distributed loads allow current and changes in current to be integrated into protective relays.

PG&E

PG&E leverages SmartMeter Partial Voltage Detection as part of EPSS to mitigate some wire down incidents due to high impedance faults associated with broken conductors. This is not a "falling conductor" scheme in traditionally sense but does provide some level of open phase detection capability to force out a line after some time when the condition occurs. See Section 4.1.4 for more information on Falling Conductor Protection.

4.1.7 Remote Grids

The Joint Utilities continue to use Remote Grid Applications as they help to limit ignition risk exposure for some circuitry or costly upgrades by serving customer loads from a dedicated source rather than the grid. Remote grids must be capable of providing sufficient and reliable power for the customer load that would be islanded with the dedicated generation. In general, these customer loads are relatively small and are in areas where a distribution line may extend a substantial distance as this helps to limit the cost of remote generation grid facilities and helps with reasonability of the comparative risk of traditional electric system upgrades, such as CC or undergrounding of overhead lines.

4.1.8 Microgrids

The Joint Utilities design and build permanent and temporary microgrids that can be electrically isolated during a PSPS event, thereby maintaining electric service to customers within the microgrid boundary. While alternative hardening solutions, such as undergrounding electric lines, may be better at simultaneously mitigating wildfire risk, those options are not always technically feasible or cost-effective.

A combination of data including the risk of wildfire from overhead infrastructure, feasibility of traditional overhead hardening solutions, alternative solutions such as undergrounding distribution infrastructure, and historical PSPS impact data is used to guide the installation of microgrids.

This mitigation focuses on reducing electric service interruptions for customers who would otherwise be affected during PSPS events. The operation of microgrids complements the reduction risk of ignitions caused by electric service lines that are de-energized during PSPS events.

4.1.9 Other-All

SCE

Radio Frequency Defect Detection System (RFDDS) equipment, also called Early Fault Detection (EFD), is applied on SCE's network. SCE has applied sensors to its distribution and sub-transmission networks up to 115 kV. These systems attempt to both detect and provide a location of a defect or undesirable condition on the network. SCE's findings include failing insulators, vegetation contact, broken conductor strands, poor connections, and damaged bond wires. Locating and repairing these types of issues prior to failure can help avoid potential ignition events and improve the integrity of the electric system.

Distribution Waveform Analysis (DWA) equipment, also referred to as Distribution Fault Anticipation (DFA), is applied on SCE's distribution system. SCE applies DFA to distribution circuits to monitor performance of the system to better understand the technology functionality and requirements on the SCE workforce to utilize the technology. The alerts from DFA have helped locate faults, particularly for phase-to-phase conductor contact faults. These types of faults can repeat over time and identifying the location and making remediations to the line, like insulated line spacers, can help avoid future outages or ignition events. As part of SCE's trial, SCE also learned about the ability for DFA to help detect failing underground connections or components among other detection conditions. SCE continues to monitor alerts from the existing DFA system and work with the DFA supplier to better understand where DFA can supplement other monitoring systems such as smart meters or RFDDS.

Topic #5: Overall Effectiveness of Mitigation

5.1 The IOUs' joint evaluation of the overall effectiveness of mitigations in combination with one another, including, but not limited to overhead system hardening, maintenance and replacement, and situational awareness mitigations. This must also include analysis of in-field observed effectiveness, interim risk exposure during implementation, and how those impact effectiveness for ignition risk, PSPS risk, and outage risk associated with protective equipment and device settings.

Each utility implements the wildfire mitigations and combinations of mitigations that are most suited to that utility's territory and risk factors. The Joint Utilities do not have a single joint evaluation of mitigation effectiveness. However, they meet regularly to benchmark mitigation efforts. Each utility implements the mitigations and combinations of mitigations that are most effective in its own service territory, which can have different effectiveness values depending on the service territory (fuels, topography, weather, etc.) and methodologies used. Each utility describes its mitigation combinations and available mitigation data and effectiveness values in their WMP.

5.1.1 Overall effectiveness of mitigations <u>in combination with one another</u>, including, but not limited to overhead system hardening, maintenance and replacement, and situational awareness mitigations

The Joint Utilities measure the overall results of wildfire mitigation efforts through a combination of evaluation, measurement, and verification practices. For overhead system hardening, the Joint Utilities track the completion of hardening projects, such as replacing wooden poles with steel ones, installation of CC, and undergrounding power lines.

The Joint Utilities track and collect ignition outage and equipment failure data and outage data. Combining system hardening with regular maintenance and timely replacement of aging or damaged equipment is crucial for preventing failures that could spark wildfires. The Joint Utilities maintain detailed records of inspection and maintenance activities and equipment replacements. Assets are evaluated for effectiveness by analyzing the frequency and severity of equipment-related incidents or by observing equipment damage during regularly scheduled inspection activities. The Joint Utilities continue to measure the collective effectiveness of these mitigations by monitoring the number of incidents and risk event data. Finally, each Joint Utility employs risk modeling to monitor how risk changes with different combination of mitigations.

SDG&E partnered with a third-party to validate individual mitigation effectiveness values and methodologies and explore the impact of combined mitigation strategies, which will help identify the most cost-effective and impactful mitigation approaches. The study's findings indicate that undergrounding of electric lines is the most effective mitigation measure, surpassing other combinations, including CC, FCP, and EFD. SDG&E is currently reviewing the methodology, assumptions, and results of this analysis. This evaluation will help determine whether an update to the existing methodology is necessary.

5.1.2 In-field observed effectiveness

Field crews conduct routine diagnostic testing, as appropriate, and perform regular visual ground inspections and manned and unmanned aerial inspections of power lines, poles, and other infrastructure to identify potential hazards such as damaged equipment, vegetation encroachment, and other risk factors. These inspections help the utilities assess the condition of assets and the effectiveness of maintenance and hardening efforts. The utilities also install monitoring devices such as weather stations, high-definition cameras, and remote sensing technology on electric infrastructure. These devices provide real-time data on environmental conditions, equipment performance, and potential ignition sources. By analyzing this data, the utilities can evaluate the effectiveness of technologies and make informed decisions about necessary interventions. In addition, the utilities regularly gather feedback from field crews who are directly involved in implementing and observing mitigation measures. This feedback helps identify practical strategies to improve mitigation efforts and areas for improvement.

5.1.3 Interim risk exposure during implementation

The Joint Utilities deploy a variety of interim mitigations to reduce system risk until more permanent, long-term mitigations can be fully deployed. The Joint Utilities perform vegetation management throughout their service territories by trimming and removing vegetation around power lines and equipment to help prevent contact that could cause an ignition event. This includes creating defensible spaces (pole clearing). The Joint Utilities proactively utilize PSPS during extreme weather conditions to prevent electrical equipment from igniting wildfires. This measure is used as a last resort when the risk of wildfire is exceptionally high. In addition, the Joint Utilities adjust protective equipment and device settings to reduce the risk for a potential ignition event.

5.1.4 How [in-field observed effectiveness and interim risk exposure during implementation] impact effectiveness for ignition risk, PSPS risk, and outage risk associated with protective equipment and device settings

In-field observed effectiveness and interim risk exposure data is analyzed on a regular basis through various methods, such as modeling and trend analysis, and reevaluated on a regular basis through quarterly and annual updates to each Joint Utility's WMP.

Based on the results of the analyses, modifications are implemented to each Joint Utility's WMP and combinations of mitigations.

More details regarding the results of the analysis and mitigation strategy changes are discussed in each Joint Utility's WMP.

Topic #6: Applications in the WMP

6.1 Additionally, PG&E must report on all lessons learned PG&E has applied or expects to apply to its WMP, including a list of applicable changes and a timeline for expected implementation as applicable.

Utility	**Lessons Learned**	**Changes in the Utility's WMP**
PGE	Topic 1: CC	Reference Section 8.2.1 in PG&E's 2026-2028 WMP
PGE	Topic 2: Undergrounding	Reference Section 8.2.2 in PG&E's 2026-2028 WMP
PGE	Topic 3: Protective Equipment and Device Settings	Reference Section 8.7.1.1 in PG&E's 2026-2028 WMP
PGE	Topic 4: New Technologies	Reference the following Sections in PG&E's 2026-2028 WMP: REFCL–8.7.1.3.1 DFA/EFD–10.3 FCP/SmartMeter Data/ OPD–8.7.1.1 Remote Grids–8.2.7.1 Microgrids–8.2.7
PGE	Topic 5: Overall Effectiveness of Mitigations	Reference Section 5 and Section 6 in PG&E's 2026-2028 WMP
SCE	Topic 1: CC	Reference Sections 5.2.1.2 and 8.2.1 in SCE's 2026-2028 WMP
SCE	Topic 2: Undergrounding	Reference Sections 5.2.1.2 and 8.2.2 in SCE's 2026-2028 WMP
SCE	Topic 3: Protective Equipment and Device Settings	Reference Sections 8.2.8, 8.7, and 10.3.1.5 in SCE's 2026-2028 WMP
SCE	Topic 4: New Technologies	**For REFCL, r**eference Sections 8.2.6.1 and 10.3.1.8 and Table 8-1 Targets in SCE's 2026-2028 WMP **For EFD,** reference Section 10.3.1.1 and Table 10-1 Target in SCE's 2026-2028 WMP **For MADEC,** reference Section 10.3.1.6 in SCE's 2026-2028 WMP **For DOPD/TOPD, r**eference section 10.3.1.2 and 10.3.1.3 in SCE's 2026-2028 WMP **For Microgrids,** reference Section 8.2.7 in SCE's 2026-2028 WMP **For Remote Grids,** reference Section 8.2.9 in SCE's 2026-2028 WMP
SCE	Topic 5: Overall Effectiveness of Mitigations	Reference Section 6.1.3 Table SCE 6-01 and Section 6.2.1 Table 6-3 in SCE's 2026-2028 WMP

Utility	Lessons Learned	Changes in the Utility's WMP
SDGE	Topic 1: CC	Lessons learned include the importance of capturing complete lifecycle costs for CC. See Section 6.1.3 of the 2026-2028 Base WMP
SDGE	Topic 2: Undergrounding	Lessons learned from the grid hardening working group are included in Table 13-1 of the 2026-2028 Base WMP
SDGE	Topic 3: Protective Equipment and Device Settings	Lessons learned include an efficacy study that showed sensitive relay settings eliminate the occurrence of ignitions in the event of a fault on electric lines. See the efficacy study in Section 8.7.1.1 of the 2026-2028 Base WMP
SDGE	Topic 4: New Technologies	For EFD lessons learned, see ACI SDGE-25U-05 in Appendix D of the 2026-2028 Base WMP
SDGE	Topic 5: Overall Effectiveness of Mitigations	SDG&E partnered with a third-party to validate individual mitigation effectiveness values and methodologies while also exploring the impact of combined mitigation strategies. See Section 6.1.3.3.5 of the 2026-2028 Base WMP for lessons learned.