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Michael Backstrom
Vice President
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November 1, 2021

Caroline Thomas Jacobs, Director
Office of Electrical Infrastructure Safety
California Natural Resources Agency
715 P Street 20th Floor
Sacramento, CA 95814

SUBJECT: Southern California Edison Company's Wildfire Mitigation Plan Progress Report Pursuant to Resolution WSD-020

Director Thomas Jacobs,

Pursuant to Ordering Paragraph 3 of Resolution WSD-020 (Resolution Ratifying Action of the Office of Energy Infrastructure Safety on Southern California Edison Company's 2021 Wildfire Mitigation Plan Update Pursuant to Public Utilities Code Section 8386), SCE submits the attached report that details its progress on the remedies associated with the 14 areas of improvement identified in Resolution WSD-20 and the associated Action Statement. In addition, SCE's progress report includes its current plans to address the identified remedies in its 2022 Wildfire Mitigation Plan Update.

If you have any questions, or require additional information, please contact me at michael.backstrom@sce.com.

Sincerely,

//s//
Michael Backstrom
Vice President, Regulatory Policy
Southern California Edison

CC: Service List R.18-10-007
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Southern California Edison
2021 WMP Update
Progress Report

November 1, 2021

Issues Identified in the Final Action Statement on SCE's 2021 WMP Update
SCE-21-01, RSE estimates not provided for all PSPS-related mitigation initiatives

Issue:
SCE justifies its lack of RSE estimates for PSPS-related initiatives by quoting Resolution WSD-002, "… electrical corporations shall not use RSE as a means of justifying or evaluating the efficacy of PSPS as a mitigation measure." However, the WSD guidance is clear that the prohibition of RSE calculation is directed at PSPS as a mitigation activity only and does not extend to PSPS-related activities. RSE estimates enable the quantitative comparison of cost-effectiveness between various mitigation initiatives and brings rigor to the decision-making process.

Remedies:
SCE must provide RSE estimates for PSPS-related activities[1],[2] and include a clear description to explain how these were developed and what assumptions were used. If the RSE estimates are zero or unattainable, SCE must explain why and provide qualitative and quantitative information to demonstrate how the PSPS-related activities inform PSPS decision-making.

SCE Response:

SCE has begun its assessment of PSPS-related activities with the objective of developing RSE estimates for as many of these activities as feasible in its 2022 WMP Update. SCE's initial approach is to develop an RSE for each PSPS-related activity using one of the following methodologies:

1. PSPS consequence reduction – develop a unique RSE based on an activity's ability to directly reduce PSPS consequence in terms of safety, financial, and/or reliability impacts
2. Enabling activity – develop an RSE for an activity based on its ability to better enable other activities to reduce PSPS consequence and potentially probability of ignition
    a. SCE is still assessing the best means to develop RSE estimates for enabling (or foundational) activities, which is also a subject for consideration in the Risk OIR and SCE's forthcoming RAMP filing. One potential method would be to map an enabling activity to its enabled activities and then develop an RSE for the enabling activity based on the enabled activities' aggregate risk reduction and the aggregate costs of the enabled and enabling activities. An additional step would entail modifying the RSE methodologies of the enabled activities to ensure they reflect their pro rata cost share of the enabling activity.
3. No RSE – certain PSPS-related activities, primarily pilots in more nascent stages of development, still may not have enough quantifiable information available to inform a meaningful RSE estimate. For these activities, SCE will provide as much information as possible to explain why RSE estimates cannot be calculated, while also clearly articulating the potential benefits of these activities in terms of PSPS decision-making in its 2022 WMP Update.

[1] Here, PSPS-related activities are defined as mitigation initiatives that "supports the analysis and decision-making process that informs whether or not to call a PSPS event." SCE's 2021 WMP Update Revision – Redlined, p. 574.
[2] A comprehensive list of PSPS-related activities can be found in SCE's 2021 Wildfire Mitigation Plan Update Revision - Redlined, June 3, 2021, Table 9.8-1, Category B, p. 570.

SCE has taken a renewed inventory of the PSPS-related activities in its 2021 WMP Update Revision. This includes the 2021 WMP Update activities that were referenced as "Enabling / PSPS" in SCE's 2021 WMP Update Revision (Table SCE 9.8-2), as well as other 2021 WMP Update activities that are PSPS-enabling for which SCE did not previously provide an RSE estimate. For those that did not have an RSE methodology in place, SCE has begun evaluating each in the context of the methodologies mentioned above. SCE presents its initial RSE methodologies for all of these activities below, while noting that work is still ongoing and subject to further revision as part of development efforts for the 2022 WMP Update and beyond. SCE also welcomes input from OEIS on how to better align RSE methodologies across utilities and proceedings via the forthcoming OEIS-led workshops as outlined in SCE-21-02. Given that there are several proceedings and efforts at the CPUC (e.g., Risk OIR, RAMP, PSPS OIR) whose future guidance may influence how utilities calculate RSEs, SCE looks forward to working with OEIS and other involved parties to drive greater alignment, consistency, and understanding.

2021 WMP Mitigation Activity[3]	2021 WMP Identifier	RSE Calculated in 2021?	Initial RSE Methodology
CRCs and CCVs	PSPS-2	Yes	PSPS Consequence Reduction
Critical Care Back-up Battery		Yes	PSPS Consequence Reduction
Resiliency Zones		No	PSPS Consequence Reduction
Microgrid Islanding (CREI)		No	PSPS Consequence Reduction
Well Water and Residential Battery Enrollment		No	PSPS Consequence Reduction
Community Meetings	DEP-1.2	No	Enabling Activity for PSPS-2
PSPS Marketing Campaign	DEP-1.3	No	Enabling Activity for PSPS-2
Customer Research and Education	DEP-4	No	Enabling Activity for PSPS-2
High-Performing Computer Cluster (HPCC) Weather Modeling System	SA-3	No	PSPS Consequence Reduction
Fire Spread Modeling	SA-4	No	PSPS Consequence Reduction
Fuel Sampling Program	SA-5	No	PSPS Consequence Reduction
Remote Sensing/Satellite Fuel Moisture	SA-7	No	No RSE (Pilot)
Fire Science Enhancements	SA-8	No	PSPS Consequence Reduction
Fire Potential Index (FPI) Phase II	SA-2	No	No RSE (Pilot)
Weather Stations	SA-1	Yes	PSPS Consequence Reduction
PSPS IMT Training	DEP-2	No	PSPS Consequence Reduction
Unmanned Aircraft Systems (UAS) Operators Training		No	PSPS Consequence Reduction
Microgrid Assessment	SH-12	No	PSPS Consequence Reduction
Circuit Evaluation for PSPS Driven Grid Hardening Work	SH-7	No	Enabling Activity for SH-5

[3] Certain activities as presented in the 2021 WMP Update Revision may receive multiple RSEs if separate benefit streams can be quantified within those activities (e.g., for PSPS-2, SCE has already developed distinct RSEs for CRCs/CCVs and Critical Care Back-Up Battery, and may develop additional distinct RSEs for Resiliency Zones, Microgrid Islanding, and/or Well Water and Residential Battery Enrollment).

Issues Identified in the Final Action Statement on SCE's 2021 WMP Update
SCE-21-02, RSE values vary across utilities

Issue:
Energy Safety is concerned by the stark variances in RSE estimates, sometimes on several orders of magnitude, for the same initiatives calculated by different utilities. For example, PGE's RSE for covered conductor installation was 4.08,[4] SDGE's RSE was 76.73,[5] and SCE's RSE was 4,192.[6] 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:
The utilities[7] must collaborate through a working group facilitated by Energy Safety[8] 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 inputs and assumptions used by the utilities for their RSE calculations, which will allow for: 1. Collaboration among utilities; 2. Stakeholder and academic expert input; and 3. Increased transparency.

Response:

The utilities have prepared a joint response to this Issue/Remedy.

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

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[4] 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/natural- disaster/wildfires/wildfire-mitigation-plan/2021-Wildfire-Safety-Plan-Errata.pdf.

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

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

[7] Here "utilities" refers to SDG&E, Pacific Gas and Electric Company (PG&E), and Southern California Edison Company (SCE); although this may not be the case every time "utilities" is used through the document.

[8] The WSD is transitioning to the Office of Energy Infrastructure Safety (Energy Safety) on July 1, 2021.

Issues Identified in the Final Action Statement on SCE's 2021 WMP Update
SCE-21-03, Lack of consistency in approach to wildfire risk modeling across utilities

Issue:
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.

Remedies:
The utilities[9] must collaborate through a working group facilitated by Energy Safety[10] 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:
The utilities have prepared a joint response to this Issue/Remedy.

On October 5-6, 2021, Energy Safety hosted a two-day workshop on risk modeling. Each of the utilities made presentations on their risk modeling approaches and participated in the Q&A 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 an initial schedule of bi-weekly working group meetings, starting October 20, 2021 and running through January 19, 2022,[11] on various risk-modeling related topics such as modeling components, algorithms, data and impacts of other issues on modeling such as climate change and ingress/egress. Energy Safety initially scheduled the following meetings and topics:

- 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

[9] Here "utilities" refers to SDG&E and PG&E, 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.
[10] The WSD is transitioning to the Office of Energy Infrastructure Safety (Energy Safety) on July 1, 2021
[11] The October 20 meeting was subsequently rescheduled to October 27.

- December 15, 2021 Asset and vegetation data
- January 5, 2022 Initiative implementation impact, and PSPSP 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.

Issues Identified in the Final Action Statement on SCE's 2021 WMP Update
SCE-21-04, Limited evidence to support the effectiveness of covered conductor

Issue:
The rationale to support the selection of covered conductor as a preferred initiative to mitigate wildfire risk lacks consistency among the utilities, leading some utilities to potentially expedite covered conductor deployment without first demonstrating a full understanding of its long-term risk reduction and cost-effectiveness. The utilities' current covered conductor pilot efforts are limited in scope[12] 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:
The utilities[13] must coordinate to develop a consistent approach to evaluating the long-term risk reduction and cost-effectiveness of covered conductor deployment, including: 1. The effectiveness of covered conductor in the field in comparison to alternative initiatives. 2. How covered conductor installation compares to other initiatives in its potential to reduce PSPS risk.

Response:

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 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:

[12] Limited in terms of mileage installed, time elapsed since initial installation, or both. For example, SDG&E's pilot consisted of installing 1.9 miles of covered conductor, which has only been in place for one year

[13] 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 throughout this progress report.

- 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.

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.[14] 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.[15] 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 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

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[14] *See* Covered Conductor Compendium in Appendix A.

[15] *See* Covered Conductor Compendium in Appendix A.

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.

Issues Identified in the Final Action Statement on SCE's 2021 WMP Update
SCE-21-05, Out-dated risk assessment used to justify the selection and scope of covered conductor as a mitigation initiative

Issue:
SCE provides a risk buydown curve based on its old modeling efforts to justify the need for covered conductor. SCE acknowledges that its current models provide different and more accurate results but does not provide an updated risk buydown curve. SCE should not use outdated information to justify its covered conductor program scope. Additionally, if an updated risk buydown curve shows historic catastrophic ignitions on the low end of the curve, it raises doubts regarding the accuracy of SCE's wildfire risk models.

Remedies:
SCE must:

1. Provide an updated Figure 9.01-1 based on SCE's latest risk modeling assessment, including the ignitions shown.

2. Provide the cause of the nine ignitions shown in Figure 9.01-1.

3. For each of the nine ignitions shown, provide an assessment of the likelihood that covered conductor installation would have prevented the ignition.

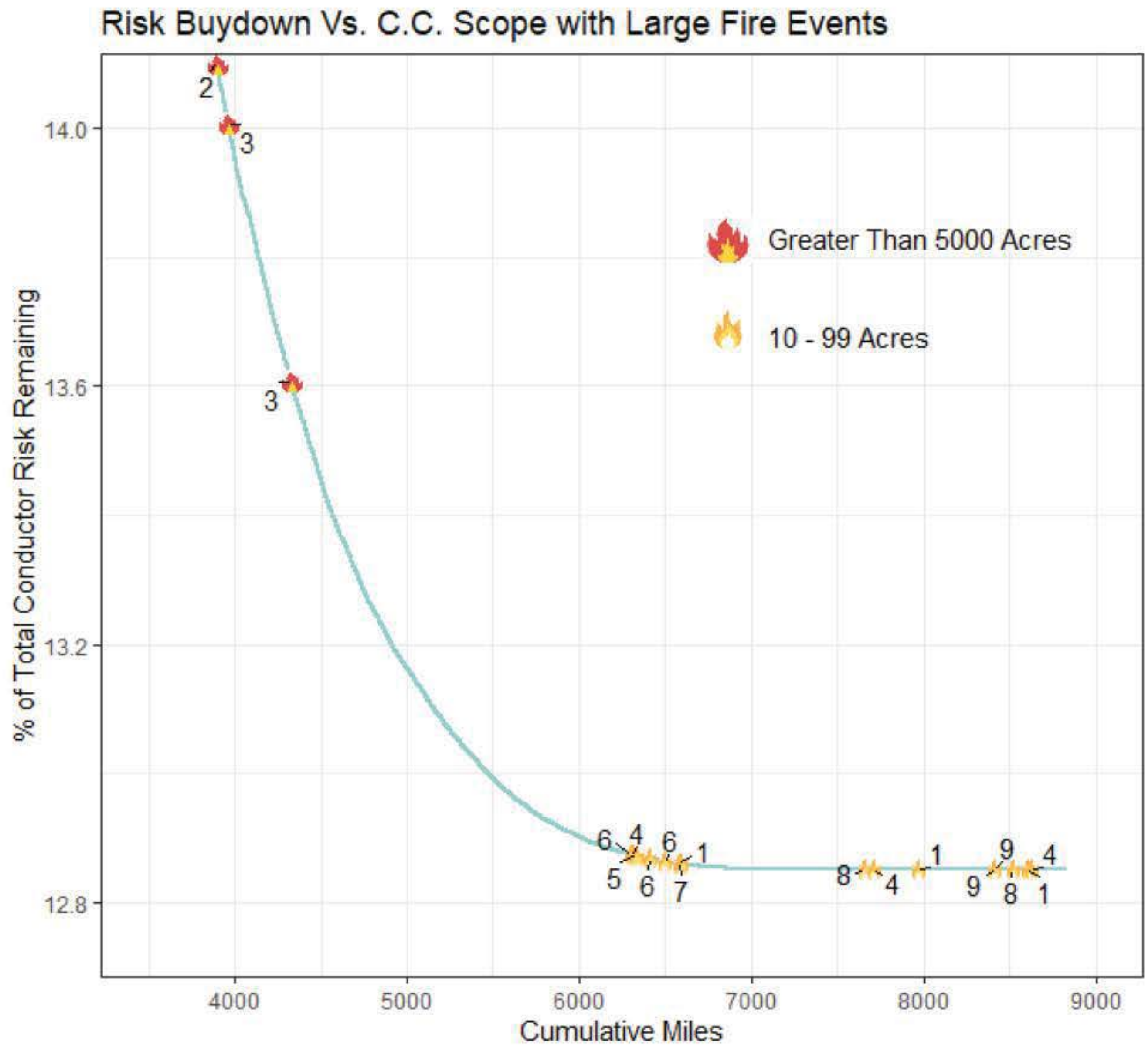
4. Provide a similar risk buydown curve for all cumulative circuit miles, including historic ignitions and ignition size.

5. If the updated risk buydown curves provided in response to the above continue to show historic catastrophic ignitions on the low end of the risk buy down curve, then provide the calculated accuracy of SCE's current risk model.

SCE Response:

1. Provide an updated Figure 9.10-1 based on SCE's latest risk modeling assessment, including the ignitions shown.

SCE has updated Figure 9.10-1 with its latest risk modeling assessment, which utilizes updated probability of ignition (POI) models and the latest Technosylva data. SCE calibrated its POI models to updated ignition forecasts and Technosylva's data now includes: 444 weather scenarios (as opposed to 41 in the previous version); updated fuel data that includes full 2020 burn scars and ten years of vegetation growth (as opposed to partial 2020 burn scars and five years of vegetation growth in the previous version); and enhancement of fire spread encroachment algorithms using calibrated loss data from the 2020 fire season.



In the graph above, SCE plotted the previously shown nine ignitions along the covered conductor risk buydown curve. The y-axis has been re-labeled from "Percent Remaining Risk" to "% of Total Conductor Risk Remaining," to reflect the wildfire risk that covered conductor is mitigating, specifically conductor-related risk as opposed to total risk (e.g., risk from a transformer failure).

Applying the current risk model may also cause the historical fires to shift locations from the previous model. Improvements to the model, including reliance on more recent conditions (i.e., infrastructure deployment and recent fire activity), may affect each segment's POI and or consequence score, thereby altering each segment's risk score. The changes in each segment's risk score will thus cause an associated fire to shift locations.

In this graph, as in the previous version of figure 9.10-1, some of the fires are represented by multiple points. That is because the estimated location of the point of ignition of those fires was in close proximity to multiple circuit segments.

2. Provide the cause of the nine ignitions shown in Figure 9.10-1.

See response to question 3 below.

3. For each of the nine ignitions shown, provide an assessment of the likelihood that covered conductor installation would have prevented the ignition.

The table below includes each of the nine ignitions previously shown in Figure 9.10.1, as well as five additional ignitions which are part of the revised cumulative circuit mile graph shown in response to Question 4. The table includes the equipment involved with the ignition, the suspected initiating event, and sub-driver (if known).

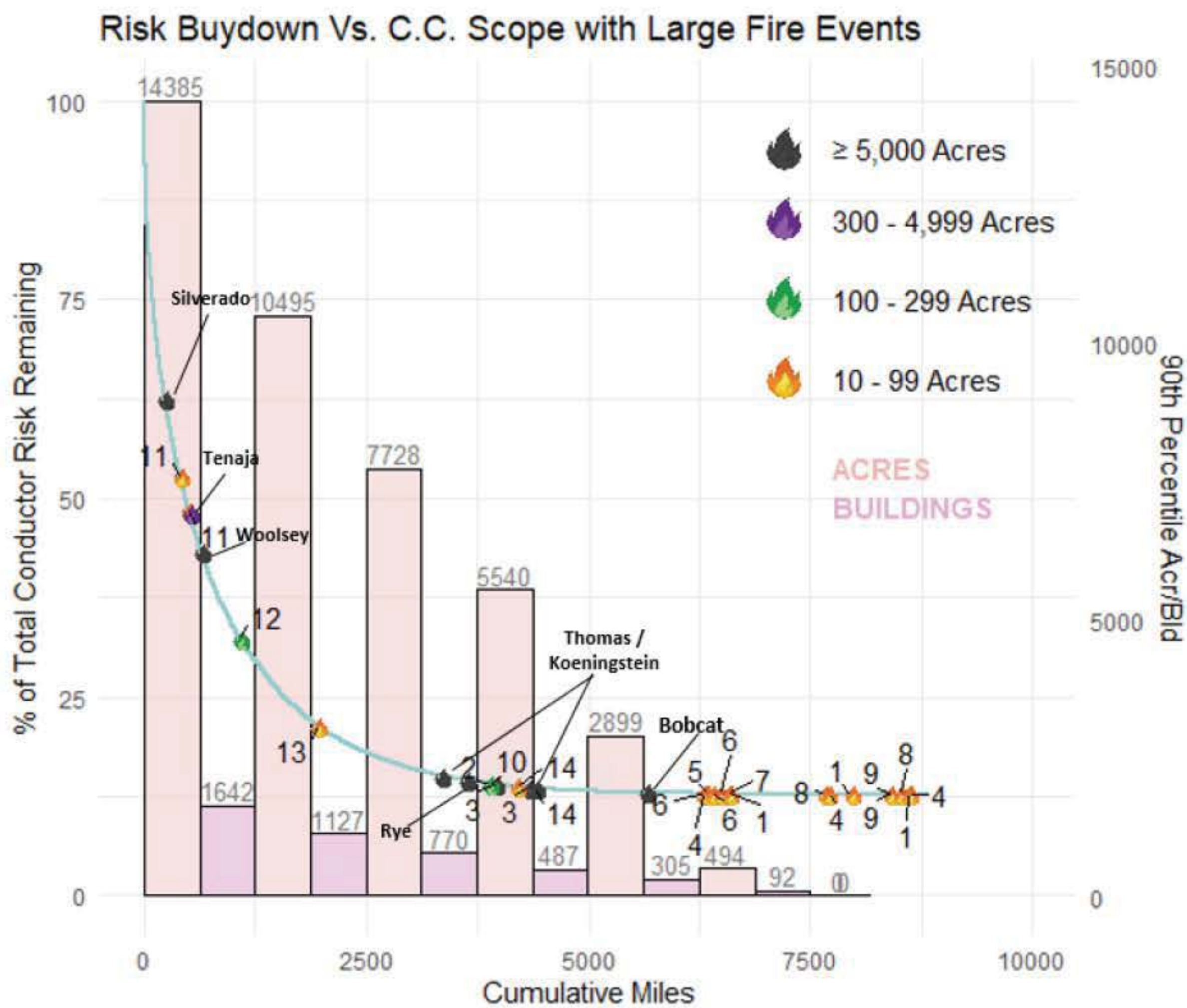
In the "Mitigated by CC" column, SCE has indicated whether covered conductor could have prevented the fire. This determination is based on information known about each of the ignitions, which may differ in terms of granularity. While the determinations may not be definitive, they represent SCE's best assessment based on available information. SCE continues to make efforts to improve its ignition documentation and reporting. Accordingly, more recent ignitions may have more documentation identifying details. Three possible answers are provided:

- Yes: Covered conductor is effective at mitigating fires associated with the equipment involved, suspected initiating event, and sub-driver. The mitigation effectiveness percentage is provided in these cases.
- Unknown: Not enough information is known about either the equipment involved, suspected initiating event, and/or the sub-driver, and thus a reasonable determination cannot be made. No mitigation effectiveness is provided in these cases.
- No: Covered conductor is not effective at mitigating fires associated with either the equipment involved (e.g., secondary conductor, fuse), suspected initiating event, and/or the sub-driver (e.g., vandalism/theft). The mitigation effectiveness provided is 0% in these cases.

Fire ID	YEAR	SIZE	Equipment Involved with Ignition	Suspected Initiating Event	Sub Driver	Mitigated by CC	CC Mitigation Effectiveness
1	2016	10 - 99 Acres	Conductor	Equipment/Facility Failure	Other	Unknown	Unknown
2	2015	≥ 5000 Acres	Conductor	Contact From Object	Vegetation	Yes	60%
3	2016	≥ 5000 Acres	Conductor	Contact From Object	Vegetation	Yes	60%
4	2016	10 - 99 Acres	Conductor	Vandalism/Theft	Vandalism/Theft	No	0%
5	2018	10 - 99 Acres	Conductor	Contact From Object	Balloons	Yes	99%
6	2015	10 - 99 Acres	Fuse	Equipment/Facility Failure	Fuse Damage/Failure	No	0%
7	2016	10 - 99 Acres	Conductor	Contact From Object	Balloons	Yes	99%
8	2015	10 - 99 Acres	Conductor	Contact From Object	Vegetation	Yes	60%
9	2014	10 - 99 Acres	Conductor	Contact From Object	Vegetation	Yes	60%
10	2015	100 - 299 Acres	Conductor	Unknown	Unknown	Unknown	Unknown
11	2015	10 - 99 Acres	Unknown	Unknown	Unknown	Unknown	Unknown
12	2017	100 - 299 Acres	Secondary Conductor	Equipment/Facility Failure	Conductor	No	0%
13	2020	10 - 99 Acres	Secondary Conductor	Vandalism/Theft	Vandalism/Theft	No	0%
14	2020	10 - 99 Acres	Primary Conductor	Contact From Object	Balloons	Yes	99%

4. Provide a similar risk buydown curve for all cumulative circuit miles, including historic ignitions and ignition size.

Below, SCE provides the same updated risk buydown curve for all cumulative circuit miles. Five additional fires have been added as a result of expanding the curve's x-axis and incorporating more recent fires. This version of the chart also includes bar graphs to illustrate the absolute risk in terms of buildings impacted and acres burned within eight hours of ignition at the 90th percentile of consequence for each 1,250-mile tranche along the curve. For further consideration, SCE has also plotted larger, more significant historical fires in SCE's service territory along the risk buydown curve using the closest segment to the suspected point of origin for each fire. Providing this information should not be construed as an admission of any imprudence, wrongdoing or liability by SCE. In many instances, the causes of these wildfires are still under investigation and even where an Authority Having Jurisdiction has issued a report on the cause, SCE may challenge or dispute the conclusions of such report. Nonetheless, these significant historical fires help to illustrate the accuracy of SCE's modeling.



5. If the updated risk buydown curves provided in response to the above continue to show historic catastrophic ignitions on the low end of the risk buy down curve, then provide the calculated accuracy of SCE's current risk model.

SCE's distribution conductor risk model displayed above is intended to prioritize the relative order in which covered conductor is deployed. In other words, while segments to the left of the curve may be riskier than segments to the right, that does not mean that the segments to the right do not have the risk of catastrophic wildfire. There still exists significant absolute risk in terms of buildings impacted and acres burned throughout the right side of the curve. Additionally, all but one of the historical fires over 5,000 acres occurred within the first 5,000 miles of the risk curve. The fire (Bobcat) which occurred to the right of 5,000 miles was a non-wind-driven fire which did most of its damage after the first eight hours and required approximately six weeks to contain.

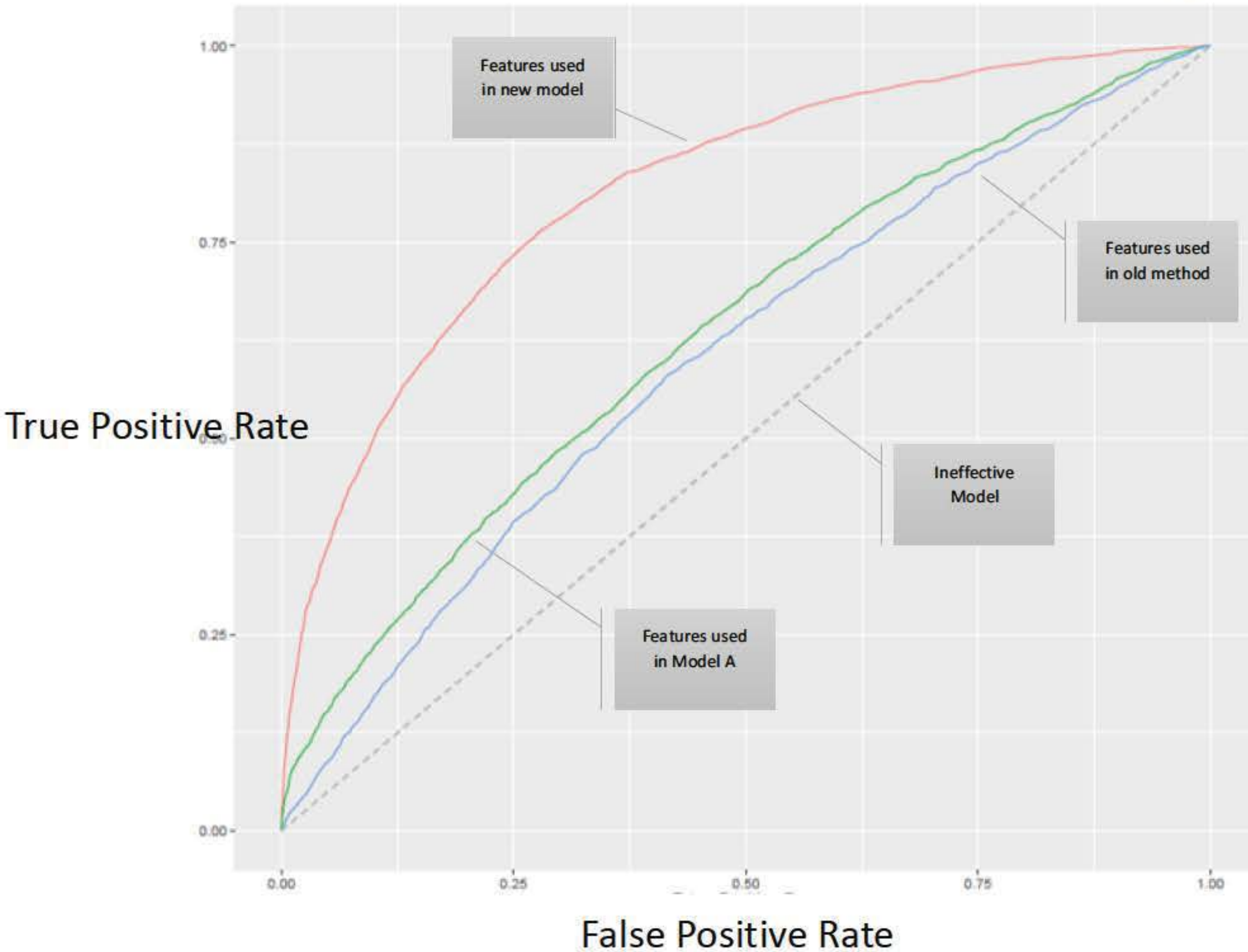
Further, SCE's models are also subject to many of the same limitations that are applicable to others, including those utilized by CAL FIRE. Namely, the models "rely on historical data from past fire seasons, not fully accounting for the extreme dryness of the fuels amid drought conditions that have rarely been so severe" which are "causing new fires, in areas that had never previously been fire-prone" and driving "once-improbable fire behavior."[16] SCE's current Technosylva modeling uses historical fire weather days, which have been typically wind-driven events. However, recent record-setting drought conditions have been contributing to dry-fuel fires in addition to the wind-driven ones.

SCE's current Technosylva modeling utilizes an eight-hour burn duration. Although fires can burn considerably longer than this, relying on an eight-hour duration appears to be appropriate at this time because it prioritizes resources toward areas where rapid consequences are deemed more likely. Moreover, modeling potential fire behavior past eight hours results in dramatic increases in the degree of uncertainty. Historical fires which resulted in significant destructive consequences past the eight-hour mark may have lower consequence scores (and thus, lower risk scores) than their ultimate acres burned and/or structures destroyed would suggest, given that a large portion of those consequences occurred well beyond the initial point of ignition being modeled, both temporally and spatially.

Lastly, the accuracy of SCE's modeling should be understood independently along its POI and consequence components. Where POI is concerned, it is helpful to measure modeling accuracy in terms of a receiver operating characteristic (ROC) curve which compares a model's true positive rate and false positive rate. The area under the curve (AUC) on the ROC curve provides an indication of the model's accuracy. A perfect model would have an AUC of 1.0, while a flawed model would have an AUC of less than 0.5 (less accurate than a coin toss). By comparison, the lowest AUC for SCE's POI models for conductor EFF and CFO is 0.86. The figure below serves to further illustrate this concept.

[16] From "'Moneyball' Analytics Help Fight Wildfires. This Year's Blazes Are Testing Their Limits.," Jim Carlton and Dan Frosch, Wall Street Journal, September 9, 2021.

SCE's POI Conductor Model: Area Under the Curve of the ROC plot



Where the wildfire consequence module is concerned, SCE uses Technosylva to simulate the potential progression of ignitions in terms of acres, buildings, and population impacted within an eight-hour burn period across approximately 440 weather and wind scenarios. Technosylva calibrates its fire propagation algorithms to historical fires. Additionally, SCE personnel reviews significant changes between each update of Technosylva's data and compares it to previous Technosylva versions and to its predecessor (from Reax Engineering) to help ensure a thorough understanding of, and agreement with, each new version.

Issues Identified in the Final Action Statement on SCE's 2021 WMP Update
SCE-21-06, Inadequate justification for scope and pace of its covered conductor program

Issue:
As described in Sections 1.1, 5.1, and 5.8, SCE does not provide adequate justification for the scope and pace of its covered conductor program. This is a recurring issue that was discussed in the WSD Action Statement for SCE's 2020 WMP and in the WSD Revision Notice for SCE's 2021 WMP Update. SCE's justification is not based on up-to-date circuit segment prioritization and risk calculations. Additionally, in SCE's justification for its covered conductor program, it does not discuss evaluating individual circuit segments to determine the most appropriate mitigation measure for that segment. Instead, SCE proposes to deploy covered conductor regardless of the location, circumstances, and risk of catastrophic wildfire for that circuit segment.

Remedies:
SCE must:
1. Re-evaluate the scope, and pace of its future covered conductor program using the outputs of its updated Wildfire Risk Models with an emphasis on:

i) The explicit consideration of all possible alternative mitigation initiatives along with a justification for why the preferred mitigation initiative was selected over and above the alternatives considered;
ii) Reduction of catastrophic wildfire risk;
iii) Reduction of PSPS events;
iv) Selecting mitigation initiatives for individual circuit segments based on the specific location, circumstances, and risk of catastrophic wildfire.

2. Re-evaluate the scope of SCE's covered conductor program based on the re-evaluation in part (1) as well as following remedies for other key issues identified within the Action Statement to specifically and effectively target risk of catastrophic wildfire and PSPS.

SCE Response:

SCE is developing an analysis that considers the ignition risk drivers of each overhead distribution circuit segment, PSPS risk, and which mitigation initiatives, or combination of mitigation initiatives, cost effectively address the drivers. This analysis will be coordinated with other considerations including time to deploy and operational feasibility.

At a high level, the analysis has the following steps:

1. <u>**Prioritization of circuit segments where there is the potential for significant fires:**</u> The analysis considers the potential consequence of an ignition at each segment using Technosylva, which estimates the potential number of acres burned or structures impacted within eight hours of an ignition. SCE will prioritize the segments where the potential consequences of an ignition are modelled to be significant.

2. **Determination of Mitigation(s) by Segment**: SCE will determine which initiatives and groups of initiatives are potential viable mitigations for a segment. Viable mitigations, at the very minimum, would adequately address all potential risk drivers at a segment.

3. **Prioritization of circuit segments where there is the potential for significant fires:** The analysis considers the potential consequence of an ignition at each segment using Technosylva, which estimates the potential number of acres burned or structures impacted within eight hours of an ignition. SCE will prioritize the segments where the potential consequences of an ignition are modelled to be significant.

4. **Consideration of Risk Drivers and Other Factors**: The analysis also utilizes SCE's probability of ignition models, which estimate the potential risk of ignition presented by each risk driver at each segment. SCE will consider these drivers, mitigation effectiveness and cost, and potential consequences, when determining which mitigation or combination of mitigations to deploy at a particular segment. Where undergrounding may be a preferred alternative, SCE will also consider ingress/egress routes, soil conditions, and other factors.

5. **Consideration of PSPS Risk**: In addition to risk of ignition, the analysis will take into account circuits that have been frequently impacted by PSPS events in the past and which mitigations could have potentially prevented those events given assumed static historical weather and fuel conditions. This may include, for example, prioritizing segments for covered conductor installation in order to completely cover isolatable segments to help reduce the need for PSPS.

A major challenge for developing and implementing this analysis is the sheer number of circuit-segments and associated data to process – SCE's high fire risk area (HFRA) has over 100,000 circuit segments. As such, analyzing this data from different perspectives is an extremely time-consuming and resource-intensive task.

SCE expects to have this analysis complete in time to include it in its 2022 WMP Update. As SCE makes further progress with this analysis, SCE will need to balance its risk-based circuit segment prioritization approach that is intended to reduce the risk of significant future fires with operational and practical installation considerations.

Issues Identified in the Final Action Statement on SCE's 2021 WMP Update
SCE-21-07, Inadequate joint plan to study the effectiveness of enhanced clearances

Issue:
RCP Action-SCE-18 (Class A)[17] required SCE, PG&E, and SDG&E to "submit a joint, unified plan" to begin a study of the effectiveness of extended vegetation clearances.[18] SCE, PG&E, and SDG&E presented the "joint, unified" plan to the WSD 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. Instead, SCE submitted its own plan to study the effectiveness of extended vegetation clearance as part of its February 26, 2021 Supplemental Filing. 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:
SCE, PG&E, 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[19] into the determination of outage and ignition risk caused by vegetation contact.

4. Assess the effectiveness of enhanced clearances.

In preparation for this study and the eventual analysis, SCE must collect the relevant data; the required data are currently defined by the WSD Geographic Information System (GIS Data Reporting Standard for California Electrical Corporations - V2). Table 2 outlines the feature classes which Energy Safety believes

[17] A note about the numbered conditions referenced in this document: "RCP Action-SCE-[#]" here refers to one of the actions required by the WSD in its evaluation of SCE's Remedial Compliance Plan of 2020, issued Dec. 30, 2020. The WSD issued 20 such orders (RCP Action-SCE-1 through RCP Action-SCE-20). There are two other related sets of references in this document: "SCE-[#]" refers to one of the actions required by the WSD in its evaluation of SCE's 2020 WMP issued June 11, 2020 (SCE-1 through SCE-22). "QR Action-SCE-[#]" refers to one of the actions required by the WSD in its evaluation of SCE's first quarterly report issued Jan. 8, 2021 (QR Action-SCE-1 through Action- SCE-28). Additionally, there are conditions that may be referenced by "Guidance-[#]", which refer to the requirements made of PG&E, SCE, SDG&E, Bear Valley Electric Service, Liberty Utilities, and PacifiCorp, addressing key areas of weakness across all six WMPs in Resolution WSD-002 "Guidance Resolution on 2020 Wildfire Mitigation Plans" issued June 19, 2020 (Guidance-1 through Guidance-12).

[18] Wildfire Safety Division Evaluation of Southern California Edison's Remedial Compliance Plan, December 30, 2020, p. 10.

[19] 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.

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:

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
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.

Issues Identified in the Final Action Statement on SCE's 2021 WMP Update
SCE-21-08, Incomplete identification of vegetation species and record keeping

Issue:
SCE needs to ensure proper identification of trees to the species level. In response to RCP Action-SCE-20, SCE submitted "Action SCE-20 SRVP.xlsx": a list of all remediations required from the 2020 Canyon Patrols and Summer Readiness inspections.[20] Under the column labeled "tree species," values include oak, pine, maple, etc. However, these are not tree species, but tree genera.

Remedies:
SCE must:

1. Use scientific names in its reporting (as opposed to common names). This change will be reflected in the upcoming updates to the WSD 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[21] or ignition[22] in the Quarterly Data Reports (QDRs) (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.).[23]

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

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

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[20] SCE's 2021 WMP Update Revision – Clean, p. 517

[21] 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

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

[23] Jenks, Matthew A. (undated, from 2012 archived copy), "Plant Nomenclature," Department of Horticulture and Landscape Architecture, Purdue University, accessed May 18, 2021:
https://archive.ph/20121211140110/http:/www.hort.purdue.edu/hort/courses/hort217/Nomenclature/description.htm

SCE Response:

SCE will implement all remedies for issue SCE 21-08. However, SCE will not be able to meet all of the new reporting requirements until 2023. Below, SCE provides a status update on meeting the six required remedies for Key Issue SCE-21-08.

1. SCE plans to use scientific names in its reporting (as opposed to common names) and will reflect these updates in future submissions to the OEIS' GIS Data Standard.[24] Implementation will likely take a full year of inspections to update those fields to reflect more specific information where that can be determined. Species updates will be made in SCE's Work Management System (WMS) throughout 2022, with significantly improved quarterly GIS data reports beginning in Q1 2023.
2. SCE Vegetation Management (VM) WMS updates, including genus and species designation, and training are planned for Q1 2022, using the tree species list that SCE developed in conjunction with the large IOUs in Q4 2021. Following training, SCE anticipates it will take one year for inspectors to update tree records with new information, where possible.
3. SCE is updating its Tree Caused Circuit Interruptions (TCCIs) Investigation Tool to include the enhanced list of species which is anticipated to be complete by Q4 2021. Once completed, investigators will begin to collect more definitive species data for future investigations (where the specific tree that caused the interruption can be identified).No retroactive updates are planned for species data.
4. SCE currently hosts over 100 common names in its species list, and the updated list will represent over 200 common names, accounting for the expanded species options. Even with an expanded list, some tree species may be impossible to identify even by an experienced arborist. In these cases, generic designations will have to be assigned to the record for both Outage Investigations and WMS data.
5. Inspectors will be given training on the enhanced list of common species names. The common name will be selected by the inspector, but the VM WMS data will be translated into the scientific naming convention for reporting purposes.
6. SCE will encourage all VM personnel to identify tree species more accurately in VM databases, where possible. SCE will accomplish this through training and communications by end of Q1 2022 from VM internal SMEs and Certified Arborists familiar with tree species commonly found in its service area.

[24] OEIS' latest GIS Data Standard (Version 2.1) was issued on September 7, 2021.

Issues Identified in the Final Action Statement on SCE's 2021 WMP Update
SCE-21-09, Need for quantified vegetation management (VM) compliance targets

Issue:
In Table 12, SCE only defines quantitative targets for eight of 20 VM initiatives. Energy Safety is statutorily required to audit SCE when a "substantial portion" of SCE's VM work is complete;[25] without quantifiable targets in the WMP and subsequent reporting on those targets in the Quarterly Data Report (QDR) and Quarterly Initiative Update (QIU), Energy Safety cannot fully realize its statutory obligations.

Remedies:
SCE must define quantitative targets for all VM initiatives in Table 12. If quantitative targets are not applicable to an initiative, SCE must fully justify this, define goals within that initiative, and include a timeline in which it expects to achieve those goals.

SCE Response:

7.3.5 Vegetation Management (VM) Compliance Targets Table

Below, SCE defines quantitative targets, where possible, for Vegetation Management efforts pursuant to the Section numbers and headings in the 2021 WMP.

Vegetation Management Initiative	Quantitative / Qualitative	Vegetation Management Compliance Target	Timeline
7.3.5.1 Additional efforts to manage community and environmental impacts	Qualitative	The Public Map Viewer will be available on the existing sce.com website and is anticipated to be published by year-end 2021. (Compliance evidence: Public Map Viewer completed/published)	Q4 2021
	Qualitative	Voice of the Customer (VOC) surveys commenced in March 2021 and will continue through the end of 2022. (Compliance evidence: Voice of the Customer (VOC) survey analysis)	YE 2022
7.3.5.2 Detailed inspections of vegetation around distribution electric lines and equipment associated quantitative goal	Quantitative	SCE's goal is to perform inspections of the entire tree inventory in HFRA in 2021 and 2022 in accordance with VM's annual work plans, barring access, permitting, or other constraints. (Compliance evidence: number of trees inspected/inspection records)	YE 2022
7.3.5.3 Detailed inspections of vegetation around	Quantitative	SCE's goal is to perform inspections of the entire tree inventory in HFRA in 2021 and 2022 in accordance with VM's annual work plans, barring access, permitting, or other constraints.	YE 2022

[25] Public Utilities Code Section 8386.3(c)(5)(A)

transmission electric lines and equipment		(Compliance evidence: number of trees inspected/inspection records)	
7.3.5.4 Emergency response vegetation management due to red flag warning or other urgent	Quantitative	SCE has identified "Areas of Concern," and, for 2021, prioritized non-exempt Pole Brushing work for these areas. Supplemental work will continually be evaluated in future years depending on risk profiles and other unforeseen circumstances. (Compliance evidence: number of non-exempt poles completed within AOCs)	YE 2022
7.3.5.5 Fuel management and reduction of "slash" from vegetation management activities- Expanded Pole Brushing (VM-2) & Expanded Clearances for Legacy Facilities	Quantitative	SCE's goal in 2020 was to perform pole brushing on approximately 200,000 to 300,000 distribution poles. SCE brushed approximately 230,000 poles as part of this goal. In 2021, SCE expects to exceed 200,000 distribution poles brushed in HFRA. (Compliance evidence: number of poles brushed in HFRA) Regarding Expanded Clearances for Legacy Facilities, as of Q3 2021, SCE has completed 47 of the remaining sites. The outstanding 48 locations are scheduled for treatment in Q4 2021 and 2022 during this 3-year plan. (Compliance evidence: records of completed expanded clearances for legacy facilities)	YE 2022
7.3.5.6 Improvement of inspections	Qualitative	"Add-on" tree rate training was/will be provided to all VM Inspection contractors. VM is also improving its oversight practices. (Compliance evidence: tree add-on rate analysis)	YE 2022
7.3.5.7 LiDAR inspections of vegetation around distribution electric lines and equipment	Qualitative	By the end of 2021, SCE will have analyzed a pilot of six circuits to compare field foot patrols to LiDAR data to determine the validity of the technology. (Compliance evidence: pilot analysis/pilot decision)	YE 2022
7.3.5.8 LiDAR inspections of vegetation around transmission electric lines and equipment	Quantitative	Approximately 45 LiDAR transmission circuit inspections were flown in 2020, accounting for approximately 1,700 miles. SCE will continue using LiDAR in 2021 and 2022 in accordance with SCE's LiDAR inspection plan. SCE expects approximately 80 transmission circuits to be flown in 2021. (Compliance evidence: miles planned/miles completed)	YE 2022
7.3.5.9 Other discretionary inspection of vegetation around distribution electric	Quantitative	Hazard Tree Management Program. Current plans are to perform between 120,000-130,000 HTMP assessments by year end 2021. (Compliance evidence: data showing completed assessments)	YE 2021

lines and equipment, beyond inspections mandated by rules and regulations			
7.3.5.10 Other discretionary inspection of vegetation around transmission electric lines and equipment, beyond inspections mandated by rules and regulations	Quantitative	Hazard Tree Management Program. Current plans are to perform between 120,000-130,000 HTMP assessments by year end 2021 (Compliance evidence: data showing completed assessments)	YE 2021
7.3.5.11 Patrol inspections of vegetation around distribution electric lines and equipment	Qualitative	Supplemental Patrols - Canyon patrols, Summer Readiness patrols, and Operation Santa Ana patrols. (Compliance evidence: inspections records for supplemental patrols)	YE 2021
7.3.5.12 Patrol inspections of vegetation around transmission electric lines and equipment	Qualitative	Supplemental Patrols - Canyon patrols, Summer Readiness patrols, and Operation Santa Ana patrols. (Compliance evidence: inspections records for supplemental patrols)	YE 2021
7.3.5.13 Quality assurance / quality control of inspections	Quantitative	SCE is on-track to perform over 6,000 risk-based HFRA circuit mile vegetation management QC inspections in 2021 and will target a similar volume for 2022. (Compliance evidence: evidence of circuit miles inspected)	YE 2022
7.3.5.14 Recruiting and training of vegetation management personnel	Quantitative	Contractor Guidance Activities – 40+ ISA certified SCE Senior Specialists (SSPs) HTMP – Currently has approximately 30+ ISA certified assessors Quality Control – QC contractor currently has 25+ ISA certified inspectors. The goal for 2022 is to maintain the current staffing levels of certified arborists performing work within SCEs service territory, relative to the work demands, across the programs mentioned above. (Compliance evidence: documentation showing the current staffing levels of certified arborists)	YE 2022
7.3.5.15 Remediation of at-risk species	Qualitative	Enhanced palm program - VM enhanced public outreach efforts through direct mailers and social media campaigns to increase customer awareness and reduce customer impacts, so as to increase the volume of palm tree removals from SCE's inventory. (Compliance evidence:	YE 2022

		public outreach documentation/palm removal data)	
7.3.5.16 Removal and remediation of trees with strike potential to electric lines and equipment-Hazard Tree Management Program (VM-1)	Quantitative	SCE plans to continue the Hazard Tree Management Program in 2021 and anticipates finishing this work in the HFRA by December 2024. Current plans are to perform between 120,000-130,000 HTMP assessments by year end 2021. (Compliance evidence: data showing completed assessments) In 2021 & 2022, SCE plans to continue targeting 90% active inventory removal for Dead & Dying Tree program efforts. (Compliance evidence: data showing completed mitigations)	YE 2021
7.3.5.17 Substation inspections	Quantitative	SCE Substation Operators perform substation inspections in accordance with CPUC GO 174 requirements. (Compliance evidence: substation inspection records-to be provided by substation operations)	YE 2022
7.3.5.18 Substation vegetation management	Quantitative	SCE will perform VM substation inspections for all substations in Tier 2 & Tier 3 totaling ~200. (Compliance evidence: substation inspection records)	YE 2022
7.3.5.19 Vegetation Inventory System (VM Work Management Tool – Arbora – VM-6	Qualitative	For 2021, SCE will continue to work towards a full rollout of Dead & Dying Tree Removal and Hazard Tree Management in Arbora, and conduct discovery and design architecture associated with Line Clearing. For 2022, SCE will continue with a phased rollout approach and development and releases will be implemented in accordance with the updated project plan. (Compliance Evidence: detailed project plans/timeline/status)	YE 2022
7.3.5.20 Vegetation management to achieve clearances around electric lines and equipment	Qualitative	SCE will continue cooperation with joint IOUs on the enhanced clearances effectiveness study. SCE expects it will take approximately two-to-three years of data to more definitively determine the effectiveness of enhanced clearances on reducing vegetation caused outages and ignition events. (Compliance evidence: documentation of joint IOU meetings/completed deliverables)	YE 2022

Below, SCE describes its efforts to define quantitative targets for Vegetation Management activities pursuant to the Section numbers and headings in the 2021 WMP.

7.3.5.1 Additional efforts to manage community and environmental impacts

To help eliminate barriers and enable information sharing of scheduled Vegetation Management (VM) work, SCE is publishing a Public Map Viewer (Viewer) which will provide visibility to local vegetation management work schedules. The Viewer will be able to be used by public agencies and private property owners to have a forecast of when vegetation work is being planned/performed in their area. The Viewer will be available on the existing sce.com website and is anticipated to be published by year-end 2021. A quantitative goal is not applicable to this initiative because the goal is to deliver a work product by a certain time (YE 2021).

Voice of the Customer (VOC) surveys commenced in March 2021 and will continue through the end of 2022. As of August 2021, approximately 1,500 surveys have been received. The Surveys provide feedback on customer experience with recent vegetation management activities, among other things. Results are categorized into positive, negative, and neutral responses. SCE plans to evaluate the results of the surveys and make adjustments to help improve overall customer satisfaction. A quantitative goal is not applicable to this initiative because the results of the surveys are highly variable and depend on customer activity.

7.3.5.2 Detailed inspections of vegetation around distribution electric lines and equipment

SCE inspected approximately 470,000 trees adjacent to distribution lines within its HFRA in 2020. SCE's goal is to perform inspections of the entire tree inventory in HFRA in 2021 and 2022 in accordance with VM's annual work plans, barring exceptions detailed in SCE's VM manuals such as access, permitting or environmental constraints. The inventory for 2021 and 2022 is estimated to be slightly higher than 2020.

7.3.5.3 Detailed inspections of vegetation around transmission electric lines and equipment -This activity has an associated quantitative goal

In its HFRA, SCE inspected approximately 180,000 trees adjacent to transmission lines in 2020. SCE's goal is to perform inspections of the entire tree inventory in HFRA in 2021 and 2022 in accordance with VM's annual work plans, barring exceptions detailed in SCE's VM manuals such as access, permitting or environmental constraints. The inventory for 2021 and 2022 is estimated to be slightly higher than 2020.

7.3.5.4 Emergency response vegetation management due to red flag warning or other urgent conditions

SCE does not have a VM standalone emergency response related to Red Flag Warning conditions. However, SCE's VM group supports other operating units as requested, such as during PSPS patrols and other emergency conditions. SCE has identified "Areas of Concern," and, for 2021, prioritized Pole Brushing work for these areas. Supplemental work will continually be evaluated in future years depending on risk profiles and other unforeseen circumstances. In 2022, SCE does anticipate supplemental inspections to be completed by year end. SCE expects a reduced number of supplemental inspection and mitigation findings because of refined annual planning and will describe these in the 2022 WMP.

7.3.5.5 Fuel management and reduction of "slash" from vegetation management activities

SCE's goal in 2020 was to perform pole brushing on approximately 200,000 to 300,000 distribution poles. SCE brushed approximately 230,000 poles as part of this goal. In 2021, SCE expects to brush

~200,000 distribution poles in HFRA which includes the poles required to be brushed in PRC 4292. In 2022, SCE will continue to brush all distribution poles required by PRC 4292, subject to access, permitting or environmental constraints, and will evaluate future expanded pole brushing within SCEs highest risk areas.

Additionally, SCE is working on implementing expanded clearances for legacy facilities. In 2020, all 156 Legacy Facilities in scope were assessed and SCE completed treatment of 61 of the highest risk locations, based on HFRA tier and assessment findings. As of Q3 2021, SCE has completed 47 of the remaining sites. The outstanding 48 locations are scheduled for treatment in Q4 2021 and 2022 during this 3-year plan.

Focusing on continuous improvement, SCE will leverage information identified in an on-going study to enhance fuel management practices expected to be completed by year-end 2022.

7.3.5.6 Improvement of inspections

SCE tree inspection contractors initially identify the trees needing mitigation; however, SCE tree trimming contractors have the ability to "add on" trees to the scope identified by the inspector if the trimming contractor observes additional trees needing mitigation. SCE will trend the "add-on" tree rate and establish a baseline for the appropriate level of add-ons. An initial analysis identified approximately 20% of inspected trees that had not been prescribed for work were later added by tree trimming contractors as needing work. While some discrepancy between trained professionals viewing from different vantage points is to be expected, the size of the discrepancy indicates that the quality of the prescriptions could be improved. Accordingly, training was provided to all VM inspection contractors on 8/31/2021 which included accurate prescription writing and inspection practices. Training guidance will be provided to contractors throughout 2022. VM is also improving its oversight practices to help identify lower quality inspection results and improve contractor performance. This goal cannot be quantified until the baseline for acceptable add-on levels is established.

7.3.5.7 LiDAR inspections of vegetation around distribution electric lines and equipment

Because the LiDAR was prioritized and collected for non-vegetation purposes, SCE used the sample data from the LiDAR flown around Distribution electric lines and equipment to determine the validity/usefulness of the resulting data and the feasibility of implementing LiDAR in the broader distribution population of equipment. By the end of 2021, SCE will have analyzed a pilot of six circuits to compare field foot patrols to LiDAR data to determine the validity of the technology. In 2022, SCE will prepare an analysis on the efficacy of LiDAR usage, specifically for distribution vegetation management, and document its decision. A quantitative goal cannot be established until SCE first determines whether LiDAR is effective for inspection within its service territory.

7.3.5.8 LiDAR inspections of vegetation around transmission electric lines and equipment

Approximately 45 LiDAR transmission circuit inspections were flown in 2020, accounting for approximately 1,700 miles. SCE expects approximately 80 transmission circuits to be flown in 2021. SCE will continue using LiDAR in 2022 in accordance with SCE's LiDAR inspection plan.

7.3.5.9 Other discretionary inspection of vegetation around distribution electric lines and equipment, beyond inspections mandated by rules and regulations

Please see Section 7.3.5.16.1 Hazard Tree Management Program

7.3.5.10 Other discretionary inspection of vegetation around transmission electric lines and equipment, beyond inspections mandated by rules and regulations

Please see Section 7.3.5.16.1 Hazard Tree Management Program

7.3.5.11 Patrol inspections of vegetation around distribution electric lines and equipment

Canyon patrols, Summer Readiness patrols, and Operation Santa Ana patrols for 2020 have been completed and continue to be planned for subsequent years. In 2021, supplemental patrols commenced in May will be completed by December. In 2022, SCE anticipates continued supplemental patrols to be completed by year end. SCE expects a reduced number of supplemental patrols and mitigation findings because of refined annual planning and will document all completed patrols in 2022. A quantitative goal is not applicable to this initiative because the need for patrols fluctuates year-over-year and mitigation findings are highly variable based local conditions.

7.3.5.12 Patrol inspections of vegetation around transmission electric lines and equipment

This activity for patrol inspections of vegetation around transmission lines is the same as those performed for vegetation around distribution lines. Please see Section 7.3.5.11 above for additional details.

7.3.5.13 Quality assurance / quality control of inspections

In 2020, SCE had a goal to perform 3,000 risk-based HFRA circuit mile vegetation management QC inspections (per VM-5 in SCE's 2020 WMP). SCE exceeded the goal by achieving over 6,000 HFRA circuit mile inspections, based on better than expected production rates and the ability to onboard qualified resources to perform the QC work. SCE is on-track to perform over 6,000 risk-based HFRA circuit mile vegetation management QC inspections in 2021 and will target a similar volume for 2022.

7.3.5.14 Recruiting and training of vegetation management personnel

Contractor Guidance Activities – SCE uses internal Senior Specialists (SSPs), who are ISA-certified arborists, to provide oversight and general guidance to contractors for SCE's compliance activities. SSPs are responsible for coaching and performing work verification on a sample of completed vegetation work performed in their respective work districts to verify contractors are meeting SCE's performance expectations. SCE currently has approximately 40 SSPs across its service area. To address future needs and potential industry-wide shortages of ISA-certified arborists, SCE created a pipeline for future development of ISA-certified arborists with sufficient skills, knowledge, and experience needed to support all SCE VM activities. SCE started hiring experienced but non-certified personnel as Specialists (SPs), with the intent that SPs will be mentored by SSPs in arboriculture and SCE program standards. After acquiring sufficient experience, the SPs will be prepared to take the required examinations to become ISA-certified. SCE continues to evaluate the effectiveness of the reorganization and adjusts as needed. SCE sees advantages to increasing the skillset of its large contract workforce developing more ISA-certified arborists while being mindful that the rapid expansion of vegetation management work, in

California and across the country, can constrain resource availability (anticipating continued resource constraints for 2022).

HTMP – Currently as of October 1, 2021, SCE performed approximately 115,000 HTMP assessments performed by approximately 30 ISA certified assessors, which is an increase from an average of 18 average assessors in 2020. There have been challenges related to procuring additional assessors due to statewide resource competition and availability. In April 2021, SCE onboarded an additional contractor to provide needed assessors to perform HTMP work. Although the total count of assessments is below target, SCE has completed the planned circuit miles. The reduced assessment count is largely attributed to the lower than expected volume of subject trees along the completed circuit miles.

Quality Control – SCE's QC inspections are performed by an independent contractor which uses ISA Certified Arborists to perform the inspections and complete published QC production goals. SCE is on track to complete the targeted circuit mileage inspections. SCE's QC contractor currently has 40 inspectors, 25 of which are ISA certified. The remaining 15 are in the process of completing certification but may require additional time for qualification before testing.

The goal for 2021 and 2022 is to maintain the current staffing levels of certified arborists performing work within SCEs service territory, across the programs mentioned above.

7.3.5.15 Remediation of at-risk species

In 2021, SCE launched an enhanced palm tree removal program to help mitigate the risk of vegetation-related ignitions and faults caused by palms.

SCE currently has an inventory of approximately 80,000 palms that can pose significant operational challenges, which include: (1) the palm is a major driver of emergent work and outages (e.g., palm fronds drop onto primary wire); (2) the palm represents a wildfire threat, as dead palm fronds are highly flammable and are easily blown long distances by winds; and (3) the palm is fast-growing (upwards) and may require multiple trims per year to maintain compliance. Furthermore, trimming a palm poses worker safety risks. Approximately 40% of palm inventory requires climbing the tree to trim it. To further remediate public and worker safety risks associated with trimming palm trees, palms near lines should eventually be removed. However, customers have proven to be very resistant to removals, and SCE often does not have the legal right to remove palm trees without the customers' express permission.

SCE's goal is to develop an integrated approach across stakeholder groups to address palm challenges, with strategies to make improvements immediately, over the next year, and longer-term. Near-term improvements in 2021 will involve prioritizing a subset of palm inventory for removal based on multiple factors: (1) their simultaneous location in HFRA and threat to worker safety due to the need for climbing; and (2) contact events. In 2022 and beyond, SCE will adjust its overall strategy with stakeholders to ensure SCE has support and the required resources to address palm inventory. SCE enhanced its public outreach efforts through direct mailers and social media campaigns in an attempt to raise customer awareness and increase of the number of palm trees removed from SCE's inventory. By addressing palm trees specifically, SCE is addressing the top cause of tree-related circuit interruptions.

This goal cannot be quantified until SCE establishes an acceptable baseline for annual palm removals. The baseline has not been established yet because SCEs inventory growth has not stabilized since implementing enhanced clearances. Additionally, SCE is still evaluating best methods to increase customer awareness so as to increase permission for palm removals.

7.3.5.16 Removal and remediation of trees with strike potential to electric lines and equipment

SCE plans to continue HTMP in 2021 and anticipates completing the initial first sweep of assessments in the HFRA by December 2024. Current plans are to perform between 120,000 to 130,000 HTMP assessments by year end 2021. This amount is a conservative estimate based on approximately 30 ISA-certified assessors currently on property, each performing 14 assessments/day. In 2022, SCEs HTMP inspections will continue to be performed according to the risk profiles and will continue to inspect remaining high priority risk circuits.

In 2020, SCE completed its planned Dead & Dying Tree Removal assessments in accordance with the schedule and at year end had mitigated 95% of active inventory. SCE performs all inspections in accordance with Dead & Dying Tree Removal program requirements. In 2021, SCE targets to remove 90% of active inventory within six months of assessment. Active inventory reflects trees for which SCE has both access and authorization to perform the removal. In 2021 & 2022, SCE plans to continue targeting 90% active inventory removal for Dead & Dying Tree program efforts.

7.3.5.17 Substation inspections

SCE Substation Operators perform substation inspections in accordance with CPUC GO 174 requirements. Although not specifically referenced in GO 174, SCE monitors substations for vegetation management and conducts inspections of substation perimeter fencing for encroachment. All SCE Substations will be inspected in 2021 & 2022 by substation operators.

7.3.5.18 Substation vegetation management

In 2020 and 2021, SCE completed its planned substation inspections. In 2022, SCE will perform VM substation inspections for all substations in Tier 2 & Tier 3 HFTDs totaling approximately 200. These inspections supplement the GO 174 substation inspections referenced in Section 7.3.5.17.

7.3.5.19 Vegetation Inventory System (VM Work Management Tool – Arbora) – VM-6

SCE plans to consolidate various digital tools into an integrated vegetation management platform, Arbora, in order to enhance efficiency, risk modeling, communication, reporting, planning and scheduling. For 2021, SCE will continue to work towards a full rollout of Dead & Dying Tree Removal and Hazard Tree Management in Arbora, and conduct discovery and design architecture associated with Line Clearing. For 2022, SCE will continue with a phased rollout approach and development and releases will be implemented in accordance with the updated project plan. The output of this activity is not quantifiable.

7.3.5.20 Vegetation management to achieve clearances around electric lines and equipment

In 2021, SCE continued to expand areas within its HFRA where enhanced clearances were achieved. SCE is currently observing achievement of those enhanced clearances on approximately 65% of all trimmed trees in HFRA based on the sampling results from its QC inspections. The level of achievement of enhanced clearances is affected by agency permitting constraints, crew equipment constraints, customer denials, PRC exemption trees, environmental constraints, tree health or condition constraints, and exception trees. SCE expects to achieve similar or greater enhanced clearance results in 2022. For the remainder of 2021, and continuing through 2022, SCE will continue cooperation with other IOUs on the study of the effectiveness of enhanced clearances. SCE expects it will take approximately two to three years of data to more definitively determine the effectiveness of enhanced clearances on reducing vegetation caused outages and ignition events. The results and methodology used in the initial analysis will be used to refine SCE's approach as appropriate. A quantitative goal is not applicable to this initiative because the achievement of enhanced clearances is highly variable and dependent on customer activity.

Issues Identified in the Final Action Statement on SCE's 2021 WMP Update
SCE-21-10, Inadequate transparency in accounting for ignition sources in risk modeling and mitigation selection

Issue:

SCE's justification for high levels of covered conductor deployment is partially due to the high number of ignitions due to contact. However, many of such ignitions are from third-party contact, and do not necessarily occur in the High Fire-Threat District (HFTD) and/or during wildfire season. Additionally, SCE does not provide sufficient detail as to how it accounts for third-party ignition sources in its risk models.

Remedies:

SCE must fully explain:

1. How third-party ignition sources feed into SCE's risk models;

2. How ignition sources impact SCE's mitigation selection process, including:

   a. How SCE prioritizes ignition sources;

   b. If SCE treats third-party ignition sources that are not under SCE's direct control differently than other ignition sources, and if so, how;

   c. How SCE targets its mitigations efforts to reduce ignitions that are more likely to result in catastrophic wildfire conditions.

SCE Response:

Below, SCE explains how third-party ignition sources feed into SCE's risk models and how ignition sources are considered in SCE's mitigation selection process. SCE's response completes the two required remedies for Key Issue SCE-21-10.

1. How third-party ignition sources feed into SCE's risk models

Preliminary fire incident data (including incidents associated with third-party[26] drivers) is gathered from SCE Watch Office notifications, repair orders, potential claims forms, and damage reports. SCE's Failure Analysis Team then investigates further to gather any necessary additional data on the event. This can involve collaborating with SCE Troublemen, Field Supervisors, and local Fire Departments. Completed investigation and ignition data is then incorporated into SCE's risk models.

SCE's Wildfire Risk Reduction Model (WRRM) models the probability of ignition (POI) caused by different ignition drivers, which is updated using the latest fire investigation data.[27] This includes drivers caused

[26] In the context of this Key Issue, OEIS defines third-party ignition data as vehicle, balloon and animal; Final Action Statement on 2021 Wildfire Mitigation Plan Update – Southern California Edison, p. 53.

[27] In 2021, SCE has been able to advance its risk modeling capability by transitioning from the REAX consequence model to the Technosylva consequence model. The Technosylva model represented an industry-recognized model

by equipment and facility failures (EFF) and contact with foreign objects (CFO). SCE's POI modeling incorporates inputs from across its service territory (both HFRA and non-HFRA) and relies on year-round historical data including third-party caused ignition data.

As OEIS has noted, these third-party drivers accounted for the majority of historical CFO ignitions across SCE's service territory at the distribution level from 2015 to 2020.[28] SCE agrees that vehicle, balloon, and animal driven ignitions are notable drivers and has thus incorporated these historical ignitions into its CFO modeling, along with historical vegetation and other/unknown contacts. The machine learning model takes the input from these historical data sets and applies a multiple class classification algorithm to predict the POI caused by all the CFO drivers listed above, as well as EFF drivers.

2. How ignition sources impact SCE's mitigation selection process, including:

a. How SCE prioritizes ignition sources

SCE performs preliminary reviews of ignition events on a weekly basis. SCE teams analyze investigation data, such as frequency of ignition driver and type of equipment involved in the failure to identify potential failure trends and mitigations. Monthly review meetings are held with engineers and data scientists to communicate and discuss identified failures, potential mitigations that would help to prevent failures, and the effectiveness of those mitigations. This investigation data is then aggregated, and data scientists rely on the historical ignition data, which is categorized by ignition driver, to predict POI with machine learning models.

SCE also quantifies each initiative's effectiveness at mitigating those same ignition drivers. Initiatives that are more effective against historical ignition drivers result in greater risk reduction in SCE's modeling. As noted in SCE's response to Critical Issue SCE-02, risk reduction is a key consideration in the evaluation and selection of mitigations.[29] Absent other considerations, then, ignition drivers responsible for higher historical ignition counts will effectively be prioritized via the deployment of initiatives which are most effective at mitigating those drivers.

It is also important to note that the machine learning models use location-specific POI driver information in their input features. Thus, the amount of calculated risk reduction for an initiative at a particular location is dependent on that location's specific POI drivers, and thus, ignition drivers in one location (e.g., non-HFRA) do not factor into POI estimates for equipment at a second location (e.g., HFRA).

b. If SCE treats third-party ignition sources that are not under SCE's direct control differently than other ignition sources, and if so, how;

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that uses recent weather data, fuels, census data, and fire propagation modeling techniques, among other enhancements. SCE's current probability of ignition model, paired with the Technolsylva consequence model, is known as SCE's Wildfire Risk Reduction Model (WRRM). SCE is utilizing these more advanced capabilities to plan its covered conductor installation scoping through 2022.

[28] Final Action Statement on 2021 Wildfire Mitigation Plan Update – Southern California Edison, p. 53.

[29] SCE 2021 WMP Revision – CLEAN, p. 583.

SCE does not treat third-party ignition sources (i.e., CFO-balloon, CFO-animal, and CFO-vehicle) differently than other ignition sources, because although "they are independent of how SCE maintains and operates its system,"[30] they are significant sources of ignition that may result in catastrophic wildfires and thus SCE must guard against them. It is helpful here to again refer to historical distribution contact ignitions in SCE's service territory from 2015 to 2020. Although there were fewer third-party ignitions by count in HFTD (81) than in non-HFTD (148), the frequency of those ignitions per line mile was 1.6 times higher in HFTD.[31] They also represented nearly the same majority percentage of distribution contact ignitions. Third-party ignitions represented 68% of distribution contact ignitions across the service territory, compared to 68% in HFTD and 69% in non-HFTD.

As described above, SCE's machine learning models take location-specific POI into account. Accordingly, all causes of ignitions, third-party and otherwise, are categorized by driver and sub-cause, assessed for historical frequency and location, and used as inputs into SCE's POI models. This data is used to help identify and track risks. SCE's engineers develop and implement mitigations and will engage other experts such as data scientists to help prioritize these risks. This process of tracking and prioritizing risks and their mitigations allows SCE to select from the suite of mitigations to reduce the risk of potential ignitions.

c. How SCE targets its mitigations efforts to reduce ignitions that are more likely to result in catastrophic wildfire conditions.

SCE prioritizes its deployment of initiatives to mitigate against ignitions that appear to be the most likely to result in catastrophic wildfire conditions. For example, SCE uses wildfire risk scores – the product of POI and consequence – to prioritize its deployment of covered conductor. In other words, SCE prioritizes deploying covered conductor on the circuit miles where it appears that replacing bare conductor with covered conductor would, in relative terms, result in the greatest wildfire risk reduction. The consequence component relies on Technosylva modeling and is itself a product of acres burned and structures destroyed. Thus, the greater the potential for damage from a particular part of its system, the higher SCE prioritizes it for mitigation with covered conductor. Similarly, SCE also deploys its high fire risk informed (HFRI) inspections utilizing Technosylva. SCE includes in its annual HFRI scope the parts of its system that have the greatest potential for damage in the event of a wildfire. Accordingly, using consequence models allows SCE to target its mitigation efforts to reduce ignitions that are more likely to result in catastrophic wildfire conditions.

[30] Final Action Statement on 2021 Wildfire Mitigation Plan – Southern California Edison WSD-020, p. 40.

[31] SCE 2021 WMP Revision – CLEAN, Table 7.2, p. 549.

Issues Identified in the Final Action Statement on SCE's 2021 WMP Update
SCE-21-11, Unclear how SCE's ignition models account for correlations in wind speeds, ignitions, and consequence

Issue:
Despite an observed correlation between some ignition causes and high wind speed, SCE states 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."[32] It is unclear how SCE accounts for this correlation between wind speed and ignitions in its probability of ignition models.

Remedies:
SCE must:

1. Fully demonstrate that its probability of ignition models accurately account for the correlation between wind speed, ignition, and consequence.

2. Explain:

a. Why SCE finds that is does not have enough "wind driven outage data at the circuit level,"

b. Specify the data required "to make determinations about correlations between wind speeds and outage rates," and

c. Explain how and when SCE plans to obtain such data moving forward.

SCE Response:

Below, SCE explains how its probability of ignition models accurately account for the correlation between wind speed, ignition, and consequence, why SCE does not have enough wind driven outage data at the circuit level, the data required to make determinations about correlations between wind speeds and outage rates, and how and when SCE plans to obtain such data moving forward. SCE's response completes the two required remedies for Key Issue SCE-21-11.

1. Fully demonstrate that its probability of ignition models accurately account for the correlation between wind speed, ignition, and consequence.

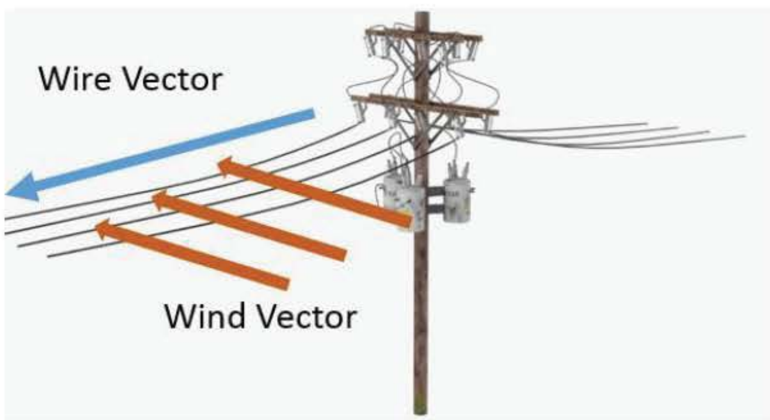
SCE's Wildfire Risk Reduction Model (WRRM) includes different components including the probability of ignition (POI) model and the consequence model for when a fire occurs. The POI model estimates the probability of an ignition that can be caused by SCE overhead lines and equipment. The consequence of fire is modeled separately using Technosylva fire simulations.

Wind speeds and wind directions are used as inputs to both POI and Technosylva fire consequence models. However, as described below, SCE's predictive POI model that is used for identifying and scoping wildfire mitigation work does not require individual correlation analysis done at the level of each individual circuit. Instead, it leverages big data and machine learning algorithms, which take into account wind speeds, wind directions, and wind-driven outages at the system level and identifies patterns that may lead to faults and ignitions at the segment/asset level.

[32] SCE Data Request Response MGRA-SCE-006-Q005.

SCE's POI model uses 20 years of historical weather data consisting of hourly Atmospheric Data Solutions (ADS) weather model data (e.g., wind speed, wind direction, temperature, dew point, etc.,) to capture the impacts from weather conditions on potential faults and ignitions. The variables used in the POI models include minimum/maximum/mean/standard deviation of the historical wind/gust speeds at each pole and segment level.

Furthermore, SCE leverages the same dataset in conjunction with SCE's pole-loading software program to calculate the cumulative downforce to SCE's lines including both wind speeds and wind directions as well as the relative wind direction to SCE's power lines. An example is illustrated in the figure below:



The downforce is calculated as:

$$Downforce = \|\vec{A}^{wire} \times \vec{w}^{wind}\|$$

where the magnitude and direction correspond to the wind speed and direction, and conductor length and direction, respectively. The cross product was chosen because it is maximal when the vectors are orthogonal[33] to each other and minimal when parallel.

By including these variables in the POI model, the machine learning model takes the contributions from wind speeds and wind directions, as well as downforces, into account and then correlates the spark-causing outages to these input variables.

For the consequence model, Technosylva uses selected worst weather days as an input to its fire simulation engine in which it leverages the same hourly ADS weather model data. The fire propagation engine uses the fuel type and condition in conjunction with weather conditions such as wind speed, wind direction, temperature, dew point, etc., to model fire behavior and potential propagation. For example, given the same fuel type, the wind speed and direction will impact the way the fire propagates and impacts final outcomes of the fire simulation in terms of acres burned, structures damaged, and population impacted.

In summary, SCE uses wind speeds and wind directions in both its POI models and fire consequence model. Wind speeds, wind directions, and other weather measurements such as temperature, dew point, etc. are all important inputs into SCE's wildfire modeling efforts.

[33] Of or involving right angles; at right angles.

2a. *Explain why SCE finds that is does not have enough "wind driven outage data at the circuit level,":*

SCE's response to MGRA's data request was intended to clarify that "*for most circuits*, SCE does not have enough wind-driven outage data at the circuit level to make determinations about correlations between wind speeds and outage rates"[34] (*emphasis added*). As SCE discusses in response to Question 2b below, this determination was based on a *statistically significant* correlation of the data, which requires a certain number of data points to exist at the location under evaluation. While sufficient data did not exist on *all* circuits, there was sufficient data on many circuits which has allowed SCE to observe statistically significant correlations for 10% of circuits for which there was available data."[35] This was determined based on a study SCE performed in late 2018, when SCE tested the circuit-level wind speeds and wind-driven outage correlations in order to perform circuit-by-circuit analysis. In some cases, for example for circuits located in non-windy areas, there were limited recorded wind-caused outages over the past five years. As described in response to question 2b, a lack of available data points can limit or remove our ability to perform a regression analysis to determine correlation. In other cases, historical cause data for certain outages may not have been known (e.g., cause of outage was not able to be determined at the time), which could limit wind-driven outage data points. As a result, SCE currently does not have the data necessary to build circuit-level wind speed and wind-driven outage correlations for all circuits. But as previously stated, circuit-level wind speed and wind-driven outage correlations are unnecessary to identify patterns that may lead to faults and ignitions at the segment/asset level.

Importantly, when looking at wind speeds and wind-driven outages at a higher level, e.g., fire climate zone level, which has multiple circuits in each zone, or system level, sufficient quantities of data exist such that SCE can draw correlations between wind speeds and wind-driven outages.

2b. Specify the data required "to make determinations about correlations between wind speeds and outage rates,":

In general, at least ten data points are needed to run a simple regression and establish a reasonable correlation. In this case, ten wind-driven outages at varying wind speeds would be required for each circuit to estimate a correlation at the circuit level.

2c. *Explain how and when SCE plans to obtain such data moving forward:*

To assess the correlation between wind speeds and outage rates for the circuits that have sufficient wind-driven outage data, SCE has focused on the past five years because the use of relatively recent data helps reflect current circuit configuration, changing weather conditions, and performance. If SCE were to utilize data from more than five years ago to incorporate more years of historical performance, doing so would present challenges from an accuracy standpoint due to the relatively recent work that has been performed on circuits for grid hardening, as well as circuit reconfigurations. Accordingly, SCE plans to continue to collect such data to help determine whether correlations can be determined in the remaining circuits for which sufficient data had not previously existed. However, SCE cannot guarantee

[34] MGRA-SCE-006 Question 5.

[35] MGRA-SCE-006 Question 5.

that the data will be sufficient to establish statistically significant conclusions as to the correlation between specific circuit level wind speeds and outage rates for all circuits.

Issues Identified in the Final Action Statement on SCE's 2021 WMP Update
SCE-21-12, Insufficient evidence of effective covered conductor maintenance program

Issue:
SCE does not have a separate covered conductor maintenance program. On-going covered conductor inspection and maintenance is included in HFRI inspections and remediations and follow the same approach, schedule, and prioritization. Given SCE's plan for rapid deployment of covered conductor, it is particularly important that SCE has a comprehensive and effective plan for maintaining its covered conductor once installed. Additionally, SCE did not initially include vibration dampeners in its covered conductor installations, and states that it is now retrofitting its existing covered conductor with vibration dampeners.

Remedies:
SCE must provide all supporting material to demonstrate that its maintenance programs effectively maintain its covered conductor, including the following information:

• Pace and quantity of scheduled maintenance;

• Pace and quantity of inspections; and

• Pace and quantity of vibration damper installations.

If SCE finds that its existing maintenance programs do not provide effective maintenance for covered conductor, SCE shall:

1. Enhance its current operations to provide such maintenance; and

2. Detail the enhancements to its existing programs;

3. Provide all supporting material for the enhancements to its existing program, including the information listed above.

SCE Response:

Pace and Quantity of Scheduled Maintenance:

The foundation of SCE's maintenance programs for its overhead structures and equipment including covered conductor is its inspection program (pace and quantities of inspections described below). Similar to bare wire, covered conductor does not require maintenance above and beyond what is discovered during inspections. Accordingly, SCE's covered conductor maintenance is similar to its maintenance of other assets in the field. Instead of scheduling maintenance at fixed intervals that may not be needed, SCE bases its maintenance on potential hazards identified through SCE's inspection program. SCE's inspection and maintenance program that includes covered conductor maintenance is sufficient. Implementing a separate program would incur unnecessary costs and further impact already constrained resources.

Maintenance items are prioritized in accordance with the timelines specified in GO 95, Rule 18. Priority 1 (P1) issues require remediation as soon as the issue is discovered, either by fully remediating the condition, or by temporarily repairing the equipment or structure to allow for follow-up corrective action. Priority 1 issues are typically made safe within 24 hours and remediated within 72 hours. Priority 2 (P2) issues are lower risk and therefore remediation work is scheduled to be completed within 6 or 12 months depending on the HFTD tier. Priority 3 (P3) issues do not require near-term remediation as they do not pose material safety, reliability, or fire risks, and require remediation within 60 months.

Pace and Quantity of Inspections:

As explained in SCE's comments on the Draft Resolution,[36] SCE has a comprehensive inspection program that effectively identifies potential hazards associated with its covered conductor. SCE's covered conductor inspections are included as part of its Distribution High Fire Risk Informed Inspections (HFRI, IN-1.1). Distribution HFRI inspections exceed GO 165 compliance requirements in terms of both frequency and inspection criteria. During these inspections, an Electric System Inspector (ESI) performs a thorough assessment of the structure, all components and equipment and associated conductors, identifies any potential hazards or GO 95 nonconformances, takes photographs and answers detailed survey questions. SCE's 2021 WMP Update describes how SCE uses risk modeling to identify the riskiest structures to be inspected each year.[37] In addition, any structures due for a compliance-based inspection in 2021 will be included in the 2021 scope of HFRI. In 2021, SCE will inspect between 163,000 and 198,000 structures and associated conductors, which represents a majority of its Distribution HFRA structures. As of September 30, 2021, SCE has inspected approximately 184,000 structures and associated conductors. Additionally, SCE performs aerial and infrared (IR) inspections of its overhead lines. Aerial inspections include questions on conductor condition and type and offer a view of SCE's equipment which is not visible from a ground-based perspective. IR inspections reduce the risk of conductor failure by identifying deteriorated connection points on equipment including conductor.

Moreover, as mentioned in Section 7.3.3.4 of SCE's 2021 WMP Update, "As covered conductor installation is relatively new, SCE will continue to analyze installation practices to identify any additional inspection and maintenance required."[38]

In late 2019, SCE engineers engaged in a focused effort to observe covered conductor installations completed in 2018 and 2019 to help ensure adherence to the then new construction standards. Lessons learned from that effort have helped inform the current inspection survey that ESIs use during inspections. The survey includes six questions specifically inquiring about covered conductor, which are included below in Appendix B. SCE and contract crews have remediated instances of standards non-conformance observed in those 2018 to 2019 installations and are in the process of remediating the remaining findings. The bulk of issues found were lack of wildlife covers at dead-ends, connectors, fuses, and other equipment.

Pace and Quantity of Vibration Dampers Installations

SCE's use of vibration dampers on lines with covered conductor illustrates SCE's evolving design and construction standards and should not be construed as a maintenance and inspection issue. SCE evaluated locations where covered conductor had been initially installed and determined that

[36] SCE Comments on Draft Resolution WSD-020, pp. 11-12
[37] SCE 2021 WMP Revision – CLEAN, pp. 241-245
[38] SCE 2021 WMP Update (Revision), p. 218

approximately 3,000 structures should be retrofitted with vibration dampers. This determination relied on analysis of span vibration susceptibility based on wind and terrain. Specifically, conductors in areas with a high frequency of winds within a range of 2 to 15 miles per hour, and areas with relatively flat terrain and no obstructions are more susceptible to Aeolian vibration. In other words, conductor spans that are exposed to slow steady crosswind are more susceptible to Aeolian vibration issues. SCE is currently working on prioritizing the structures designated for vibration damper retrofit work.

On a going forward basis, SCE's current standards[39] require that vibration dampers are installed on every span in light loading areas (areas with elevation of 3,000 feet and below); however, reduced tension spans are excluded from this requirement. Additionally, for 336 (30/7)[40] Aluminum Conductor Steel Reinforced (ACSR) covered conductor, vibration dampers will be installed in both light loading and heavy loading areas because design tensions for this conductor are high in both areas, which increases the likelihood of Aeolian vibration. Accordingly, the pace and quantity of vibration damper installation is subject to the scope of applicable covered conductor installation. For every 100 miles of applicable covered conductor that SCE installs, it is estimated that 5,200[41] dampers or damper pairs, depending on the covered conductor size, will be needed.

Potential for Changes in the Future

Due to the reasons mentioned above, SCE finds that its existing inspection and maintenance program provides effective maintenance for covered conductor. SCE appreciates Energy Safety's acknowledgement of the speed of changes and the need to respond to changing conditions as covered conductor deployment continues. SCE's existing inspection and maintenance program accomplishes this. Nonetheless, as mentioned in its 2021 WMP Update, given that covered conductor installation is relatively new to SCE, SCE will continue to analyze installation practices to identify any additional inspection and maintenance required. As suggested by Energy Safety, if SCE finds that its existing inspection and maintenance program does not provide effective maintenance for covered conductor, SCE will revise its inspection survey questions and/or alter its maintenance practices.

[39] SCE standards updated for vibration dampers on October 30, 2020

[40] "336" refers to the size of the conductor; "30/7" is the stranding configuration (30 aluminum strands with 7 steel strand core)

[41] Based on the assumption that 77.5% of SCE territory meets the light loading condition for vibration damper requirement, the average span length is 180ft between poles, and an average of 2.3 conductor phases on the system.

Issues Identified in the Final Action Statement on SCE's 2021 WMP Update
SCE-21-13, Lack of specificity regarding how increased grid hardening will change system operations, change PSPS thresholds, and reduce PSPS events

Issue:
SCE does not commit to changes in its PSPS thresholds for increased grid hardening, except for increasing wind speed thresholds specifically for circuits mitigated with covered conductor.[42] SCE provides a table showing how six of its mitigation alternatives may impact PSPS frequency, duration, and number of customers impacted,[44] but provides no quantitative analysis of impacts.

Remedies:
For each mitigation alternative, including pilot program initiatives, SCE 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.

SCE Response:

In the 2021 WMP Update Revision, SCE provided a list of six mitigation alternatives (listed below) that may impact PSPS scope, frequency, and duration. A quantitative analysis for changes in system operations, changes in PSPS thresholds, and estimated changes in frequency, duration, and number of customers impacted by PSPS events as a result of these mitigations is provided in the sections below. It should be noted that in the context of PSPS threshold changes, these mitigations are often dependent on each other. For example, switches are used to connect and/or disconnect the conducting path of power flowing through circuits. Where covered conductor is installed, a switch can be used to isolate that portion of the circuit for application of a higher wind threshold than other bare wire segments of the same circuit. Thus, the PSPS benefit of the switch is difficult to separately quantify from the PSPS benefit of the covered conductor; the mitigations work in concert to collectively reduce the scope, frequency, and duration of PSPS. The following mitigations are discussed in this response:

1. Covered conductor
2. Circuit segment exceptions
3. Automated switches
4. Updated switches and load rolling
5. Temporary generators
6. Undergrounding

As noted in the 2021 WMP Update Revision, SCE developed a quantitative forecast of the expected reduction in PSPS de-energizations in 2021 as compared to 2020, assuming the same weather and fuel conditions as 2020, but with the portfolio of PSPS mitigations now in place. These benefits reflect the expected aggregate impact of planned covered conductor, sectionalizing devices (switches) and load

[42] SCE's 2021 WMP Update Revision - Redlined, p. 644 Table SCE 9.10-6. See Appendix C.

rolling, circuit segment exceptions, and temporary generators. The results of this quantitative analysis are as follows:

Scope (Unique customers de-energized)	**Frequency** (Circuits de-energized)	**Duration** (Customer minutes of interruption)
↓ 30%+	↓ 25%+	↓ 50%+

It is also worth reiterating that "to assess the effectiveness of the WMP mitigations in reducing the frequency and scope of PSPS de-energizations, the total number of customers affected or the duration of outages during any period need to be normalized for the intensity of weather events, how widespread the weather events were, and the duration of the events, as these factors can influence the number of circuits or circuit segments that have to be de-energized. In addition to weather, these metrics must account for customer density on impacted circuits and other factors outside of SCE's control. SCE is currently evaluating how metrics such as windspeed, FPI, etc., can be used to appropriately normalize the number of impacted customers and duration of PSPS events."[43]

1. Covered Conductor

Covered conductor deployment continues to be one of SCE's most important wildfire mitigation initiatives. In 2021, SCE plans to install approximately 1,300 miles of covered conductor on its circuits. Of the 1,300 miles, approximately 710 miles (consisting of more than 100 isolatable circuit segments) will be installed on frequently impacted circuits that experienced four or more PSPS de-energizations from 2019 to 2021. Although wildfire risk reduction is the primary criterion for prioritizing where covered conductor is installed, covered conductor installation can also mitigate the need for PSPS de-energizations.

Where covered conductor and other grid hardening activities are deployed, wind speed de-energization thresholds can be raised, reducing the number of circuits and circuit segments that will need to be de-energized during extreme weather conditions.

a) **Changes in system operations**
Circuits with covered conductor installed may be de-energized less frequently than those without covered conductor, since the covered conductor allows for a change in PSPS threshold (see below). If an isolatable circuit segment is covered, but not the entire circuit, SCE can leverage automated switches and the situational awareness provided by weather stations to keep that isolatable segment energized while de-energizing the uncovered segment(s) of the circuit, depending on weather conditions.

b) **Changes in PSPS thresholds**
Where covered conductor is installed on a complete isolatable circuit segment, the wind speed threshold is increased from the National Weather Service's (NWS) wind advisory level (defined as 31 mph sustained wind speed or 46 mph gust wind speed) or the 99th percentile of historical wind speeds, and is then set to 40 mph sustained and 58 mph gusts, which aligns with the

[43] SCE 2021 WMP Revision – CLEAN, p. 154.

National Weather Service high wind warning level for windspeeds at which infrastructure damage may occur.

c) Estimated changes in the frequency, duration, and number of customers impacted by PSPS events

SCE determines the benefits of covered conductor installation on scope, frequency, and duration of PSPS by using the following steps:

(i) Selecting the circuit segment where installation and operationalization of covered conductor is complete
(ii) Identifying the number of customers and number of times the customers were de-energized on the circuit in 2020
(iii) Analyzing the scope, frequency, and duration of historical de-energization events
(iv) Calculating the total number of customer minutes of interruption (CMI) in 2020, which is the number of customers affected by an outage times the number of minutes de-energized
(v) Using back-casting methodology, and considering other PSPS mitigations also planned for the circuit, determine the estimated CMI for the same customers using the revised wind thresholds, assuming the same weather and fuel conditions as 2020

Construction issues (e.g., permits, environmental delays) make it difficult to predict the exact completion date for installation and operationalization of covered conductor. Accordingly, in predicting the 2021 PSPS benefits associated with covered conductor installation on the frequently impacted circuits, SCE applied a 90% confidence level for installation completion.

2. Circuit Segment Exceptions

SCE completed its analysis of circuit exceptions by identifying potential circuits or circuit segments where wildfire risk is temporarily abated or no longer exists. The considerations for an exception include fault history, fuel type and loading, visual evidence, proximity to other HFRA tiers, construction type, and local field knowledge. The circuit exception review allows SCE to 1) completely remove some circuits or circuit segments from PSPS scope or 2) increase the wind speed thresholds for de-energization.

a) Changes in system operations

For some circuits or circuit segments where an exception has been approved, the entire circuit or circuit segment is removed from scope of PSPS for the wildfire season.

b) Changes in PSPS thresholds

Review of some circuits allows SCE to change the wind speed threshold for de-energization. Based on the circuit exception review, the wind speed threshold is increased from the National Weather Service's (NWS) wind advisory level (defined as 31 mph sustained wind speed or 46 mph gust wind speed) or the 99th percentile of historical wind speeds, and is then set to 40 mph sustained and 58 mph gusts, which aligns with the National Weather Service high wind warning level for wind speeds at which infrastructure damage may occur.

c) <u>Estimated changes in the frequency, duration, and number of customers impacted by PSPS events</u>

SCE determines the benefits of circuit exceptions on PSPS scope, frequency, and duration by using the following steps:

(i) Selecting the circuit segment that was approved for exception
(ii) Identifying the number of customers and number of times the customers were de-energized on the circuit in 2020
(iii) Analyzing the scope, frequency, and duration of historical de-energization events
(iv) Calculating the total number of customer minutes of interruption (CMI) in 2020, which is the number of customers affected by an outage times the number of minutes de-energized
(v) Using back-casting methodology, and considering other PSPS mitigations also planned for the circuit, determine the resulting estimated CMI in light of the approved circuit segment exceptions assuming the same weather and fuel conditions as 2020

3. & 4. Automated Switches and Load Rolling

SCE installs automated switches to provide the ability to operate the switches remotely. These switches enable SCE to be more targeted during PSPS events and faster switching is also expected to help reduce the duration of PSPS events.

a) <u>Changes in system operations</u>

Automated switches allow SCE to sectionalize and minimize PSPS outage footprints wherever possible. SCE regularly isolates circuit segments to keep certain areas energized because of their raised thresholds due to covered conductor, or because adverse weather conditions are only affecting part of a circuit, for example. If an isolatable circuit segment is covered, but not the entire circuit, SCE can leverage automated switches and the situational awareness provided by weather stations to keep that isolatable segment energized while de-energizing the uncovered segment(s) of the circuit, depending on weather conditions. Even in the absence of covered conductor, automated switches and weather stations can be leveraged to keep an isolatable segment of a circuit energized, while de-energizing another segment on the same circuit which is experiencing more adverse weather conditions. SCE's switching plans, which are pre-planned and updated throughout the year as circuit configurations or conditions change, allow for these sorts of circuit isolation and segmentation to be carried out efficiently and safely during PSPS events. In conjunction with switching activity, SCE is also able in certain instances to roll load between systems, which can enable a downstream isolatable circuit segment that would otherwise be de-energized during a PSPS event to remain energized via a different part of the system which is not experiencing PSPS conditions.

b) <u>Changes in PSPS thresholds</u>

There are no changes in PSPS thresholds when automated switches are installed, but isolating segments of a circuit from others does allow SCE to maintain different thresholds for different portions of the same circuit.

c) **Estimated changes in the frequency, duration, and number of customers impacted by PSPS events**

Switches are used to connect and disconnect the conducting path of power flowing through circuits. Although automated switches are a mitigation for PSPS, switches work in concert with other mitigations to reduce the scope, frequency, and duration of PSPS. Therefore, the benefits of switches are analyzed as part of the benefits analysis for covered conductor and circuit segment exceptions described above.

5. Temporary Generators

SCE has the ability to install a temporary generator at selected facilities to assist in maintaining electric service on a case-by-case basis. SCE reviewed the most frequently impacted circuits and identified the unique circuits where temporary generators could be installed to isolatable, underground load blocks during a PSPS event. Identification of circuits where temporary generators could be installed was based on a prioritization approach that included factors such as frequency and duration of PSPS events in 2019 and 2020 on the circuits, number and types of customers residing on the circuit, etc.

a) **Changes in system operations**

By installing a temporary generator, SCE is able to reduce or eliminate the outage duration during PSPS events. Small portions of circuits are isolated and powered directly by the temporary generator, and power is no longer supplied through the normal circuit configuration.

b) **Changes in PSPS thresholds**

There are no changes in PSPS thresholds when temporary generators are utilized. Installing a temporary generator allows the underground portions supplied by the generator to stay energized irrespective of the wind speed conditions.

c) **Estimated changes in the frequency, duration, and number of customers impacted by PSPS events**

SCE determines the benefits of installing temporary generators on the scope, frequency, and duration of PSPS by using the following steps:

(i) Reviewing historic (2020) PSPS de-energizations on the circuits where temporary generators can be installed during a PSPS event
(ii) Identifying the circuits that were actually de-energized during this time period
(iii) Determining the number of customers that were impacted by the PSPS events that resided on these circuits
(iv) Determining the number of times each circuit had been de-energized in 2020.
(v) Analyzing the scope, frequency and duration of historical de-energization events
(vi) Using the total number of outages and the average duration of an outage to calculate the total number of CMI
(vii) Calculating the estimated reductions in CMI for 2021, assuming the same weather and fuel conditions as 2020.

6. Undergrounding

SCE undergrounds circuit segments based on several factors, including PSPS history, limited egress routes, terrain, and community feedback. Although the 2021 scope has been limited due to relatively high costs and long construction lead times, SCE is examining ways to make undergrounding a more widespread long-term wildfire mitigation solution.

Undergrounding overhead conductors reduces POI as well as probability of PSPS. For 2021, SCE will install 4 to 6 miles of undergrounded HFRA circuits subject to resource constraints and other execution risks, such as permitting, environmental risks, and issues around coordinating activities with other utility service providers.

Undergrounding can be a very effective mitigation for faults associated with overhead conductors, but it is not always cost-effective, easy to deploy, or easy to maintain and repair. SCE evaluated circuit segments based on multiple criteria including wildfire risk scoring, PSPS impacts (including circuits that have experienced multiple PSPS events), terrain, grid topography, construction complexity associated with undergrounding, and cost. SCE also consulted with local districts and reviewed egress in areas where poles and overhead facilities may make it challenging to evacuate should a fire occur. In addition, SCE worked with communities to assess areas where customers may require electric service to provide essential public health and safety services. In 2021 SCE will continue to refine its evaluation methodology and work with local communities to pursue undergrounding in HFRA.

Since SCE is still in the process of completing our target of 4 miles and will strive to complete up to 6 miles of undergrounding in 2021, SCE did not use any of the constructed miles in its calculations for reduction in scope, duration and frequency of PSPS events. However, after SCE has completed additional miles of undergrounding, SCE will count the number of customers on that circuit segment that were de-energized in the prior year, and use the same methodology as described above for covered conductor in estimating the reduction in scope, duration and frequency of PSPS events.

a) Changes in system operations

There are no changes to system operations related to undergrounded circuits.

b) Changes in PSPS thresholds

For circuits or circuit segments that have been completely undergrounded, the entire circuit or circuit segment is removed from PSPS scope.

c) Estimated changes in the frequency, duration, and number of customers impacted by PSPS events

Since isolatable circuit segments or even entire circuits will not be completely undergrounded in 2021, SCE did not use this mitigation to calculate changes in frequency, duration and number of customers impacted by PSPS events.

Pilot Projects and Programs

While SCE has pilot projects and programs underway which may help reduce the probability of ignition, they are still in the early stages and thus not enough data has been collected to be able to determine how these initiatives will be applied more broadly, including the benefit they may have on reducing the scope, frequency, or duration of a PSPS event. Several of these pilots are listed below for reference. However, other than Microgrids, none of these pilots in concept are likely to reduce PSPS risk. Given the nascent stage of the Microgrid pilot, even it is not yet in a position to provide more specific analysis of PSPS reduction benefits. As SCE matures its various pilot efforts, it will seek to articulate their potential benefits in terms of PSPS reduction, where applicable.

1. Meter Alarming for Down Energized Conductor (MADEC)
2. Vibration Dampers
3. Advanced Unmanned Aerial Systems Study
4. Rapid Earth Fault Current Limiter (REFCL) pilots including Isolation Transformers REFCL Scheme, Ground Fault Neutralizer (GFN), and Resonant Grounded Substation
5. Distribution Fault Anticipation (DFA)
6. Asset Defect Detection using Machine Learning Object Detection
7. Assessment of Partial Discharge for Transmission Facilities
8. Early Fault Detection (EFD) Evaluation
9. High Impedance Relay Evaluations
10. Microgrids / Customer Resiliency Equipment Incentive (CREI)

1. Meter Alarming for Down Energized Conductor (MADEC)

Meter Alarming for Down Energized Conductor is a machine learning algorithm utilizing smart meter data to detect a subset of energized wire-downs and other high impedance faults/hazards and is currently being used throughout SCE's service area. The MADEC system was originally developed for minimizing energized wire-down events with bare wire, but also works with covered conductor. The algorithm generates an alarm that allows an operator to act quickly and de-energize the circuit. While improvement to the MADEC system is on-going for bare and covered conductor, this activity was initiated to evaluate possible improvements to MADEC algorithm to be used for covered conductors as part of the large deployment on SCE HFRA circuits.

2. Vibration Dampers

Vibration dampers are hardware attached to the conductors to inhibit conductor abrasion and fatigue from vibration. SCE undertook further assessment of vibration dampers for covered conductor application in 2020. The assessment involved working with manufacturers to develop vibration damper design for covered conductors and evaluating and testing the new vibration damper design. Upon completion of the assessment, SCE will publish construction standards for vibration damper application in covered conductor systems.

3. Advanced Unmanned Aerial Systems Study

SCE performed a study that analyzed if Beyond-Visual-Line-Of-Sight inspections can be used in high fire risk areas to accelerate power restorations. This study tested the use and capabilities of advanced drones for performing inspections. Once wildfire conditions have passed, SCE can inspect the poles and wires to ensure the conditions are safe to restore power. SCE noted that inspecting a 12-mile circuit could take the entire day, while the same effort can be completed within an hour with the use of drones. SCE is currently reviewing the findings from this study to determine if Beyond-Visual-Line-Of-Sight inspections can be used to restore power more quickly following a PSPS event.

4. Rapid Earth Fault Current Limiter (REFCL) pilots including Isolation Transformers REFCL Scheme, Ground Fault Neutralizer (GFN), and Resonant Grounded Substation

SCE is piloting the use of Rapid Earth Fault Current Limiters that can sense disturbances on the electric grid, like a downed power line, and instantly reduce the power flowing through the line, and therefore has the potential to significantly reduce ignition risk.

5. Distribution Fault Anticipation

SCE plans to complete installation of approximately 150 DFA units in 2021 in HFRA and continue evaluation of DFA technology. This pilot is aimed at evaluating the effectiveness of the DFA installed units to determine scale and remaining deployments. DFA technology incorporates electrical system measurements to alert on the potential for pending equipment failures by continually monitoring circuits to detect, assist with locating and categorizing electrical events such as incipient and traditional faults.

6. Asset Defect Detection using Machine Learning Object Detection

SCE has begun developing a company-wide Machine Learning strategy that creates alignment amongst all stakeholders by leveraging existing efforts in the space. SCE is investigating processing LiDAR images using Artificial Intelligence (AI) to process and identify vegetation encroachment on assets.

For training and testing the models from the tagged images, we learned that we could use a third-party tool to significantly improve the number of images we could process through our algorithms allowing us to run these models at scale. An analysis of the defect data between 2019 and 2020 shows how the defect types are changing and have provided good input to the priority of the models that need to be developed.

7. Assessment of Partial Discharge for Transmission Facilities

SCE is no longer performing further studies on this pilot program.

8. Early Fault Detection (EFD) Evaluation

SCE is evaluating Early Fault Detection technology to leverage radio frequency emitted from equipment to detect emerging issues. This type of technology provides complementary benefits to the DFA systems and could work in concert with the DFA to detect potential system anomalies and more accurately pinpoint the source of the potential defects and needed repairs.

9. High Impedance Relay Evaluations

SCE is piloting a high impedance (Hi-Z) element at 15 locations to assess the effectiveness of detecting Hi-Z conditions such as down conductor or arcing conditions. Pilot locations for the fifteen target installs have been identified. Protection settings for all fifteen locations have been issued and firmware upgrades have been completed.

10. Microgrids / Customer Resiliency Equipment Incentive (CREI)

Microgrids can potentially mitigate PSPS impacts by enabling some customers to remain energized when they otherwise would not be. SCE is pursuing microgrid opportunities in a variety of formats. SCE is working with customers interested in behind-the-meter (BTM) single-customer microgrids. SCE is also exploring opportunities for front-of-the-meter (FTM) microgrids that utilize utility distribution infrastructure to serve multiple customers. In 2019, SCE initiated a pilot to fund two sites with microgrid controllers. One site has existing solar generation and power storage capability (retrofit pilot); the second site has solar generation and is in the process of adding power storage capabilities to its existing solar system (new build pilot). Installation of the retrofit pilot at San Jacinto High School in the San Jacinto Unified School District was completed in August 2020, and SCE entered an agreement with Kordyak Elementary in the City of Fontana within the Rialto Unified School District for a microgrid targeted for 2021.

Issues Identified in the Final Action Statement on SCE's 2021 WMP Update
SCE-21-14, Equivocating language used to describe RSE calculation improvements

Issue:
SCE reports "[c]alculating RSE for all potential initiatives" as a potential future focus between 2023-2030, but does not provide any measurable, quantifiable, and verifiable commitments.

Remedies:
SCE must make measurable, quantifiable, and verifiable commitments to calculate RSE estimates for all potential initiatives in Non-HFTD, Zone 1, HFTD Tier 2, and HFTD Tier 3 territory.

SCE Response:

SCE is committed to developing RSEs whenever it is reasonable to do so. In some instances, such an approach may require making broader assumptions and including appropriate caveats. SCE will include additional RSEs, plans for more RSEs, and its progress and potential benefits of its pilot projects in its 2022 WMP Update. In the direct and specific context of its WMP reporting, SCE commits to providing RSEs for all WMP initiatives that directly reduce either wildfire or PSPS risk in its 2023-2025 WMP Update.

For the several WMP initiatives that do not directly reduce either wildfire or PSPS risks, SCE is committed to evaluating whether reasonable assumptions can made and/or new methods employed to construct additional RSEs. In doing so, SCE also commits to incorporating pertinent feedback and relevant guidance from the California Public Utilities Commission's *Order Instituting Rulemaking to Further Develop A Risk-Based Decision-Making Framework for Electric and Gas Utilities (R.20-07-013),* where available and applicable. Historically, SCE focused its RSE calculations on WMP activities where RSE calculations can be meaningfully and reliably developed using reasonable assumptions. For example, various situational awareness activities as well as certain customer outreach programs or technology projects do not reduce risks by themselves but enable effective deployment of other WMP activities. As such, and even though calculating reductions in probability or consequence of ignition or PSPS events for these activities is subjective, SCE is committed to developing meaningful RSEs for initiatives that do not directly reduce either wildfire or PSPS risk in its 2023-2025 WMP.

SCE does not believe that pilots should have calculated RSEs as they are being conducted to assess technologies that can potentially reduce risks to determine operational impacts, costs, risk reduction benefits, etc. As such, once the results of the pilots are available, RSEs will be calculated prior to broad scale deployment. SCE has and will continue to explain the potential benefits of its pilot projects and will report on their results.

Lastly, SCE also looks forward to Energy Safety's forthcoming working group with PG&E, SDG&E, and SCE on RSE development and will seek to incorporate feedback in future WMP efforts.

Appendix A
Covered Conductor Compendium

Covered Conductor - Everything You Need To Know (Compendium)

Prepared by Apparatus & Standards Engineering Group

T&D Engineering

October 8, 2018

Purpose

- There has been a vast amount of literature search, testing, calculation, benchmarking and standards development by T&D Engineering for the deployment of Covered Conductor
- As a result, multiple work documentation on various topics concerning Covered Conductor has been created for supporting the issuance of SCE specifications, design and construction standards for covered conductor
- These topics on Covered Conductor are summarized on the "Table of Contents" slide.
- The purpose of this slide deck is to consolidate and condense the key thoughts of these works into a single document, providing a comprehensive overview of covered conductor

Table of Contents

Chapter I
What is Covered Conductor?
Why Covered Conductor?

1. The Evolution of Covered Conductor Design

This section introduces the high-level understanding of Covered Conductor and how it has evolved from a simple model in the early 1970s to a robust design today that mitigates contact issues and achieves long service life

A Brief History

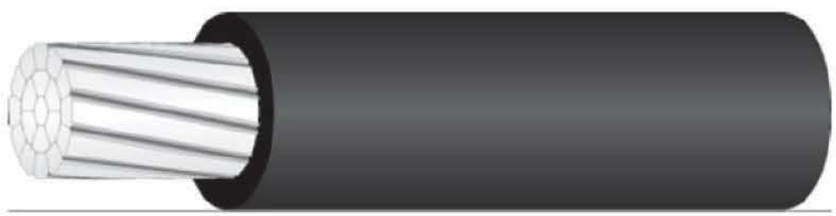
- Covered Conductor has been used by utilities since the 1970s in Europe and the U.S.
  - Key driver: reliability improvement in dense vegetation areas, such as forests in Scandinavia, the U.K., New England, etc.
- Other drivers expand the use of covered conductors:
  - Tokyo, Japan: public safety in dense population
  - Southeast Asia (Thailand, Malaysia): animal protection (snakes, monkeys, rodents), and dense vegetation, also public safety in downtown Bangkok
- Reduction of "bushfires" has become a key driver for replacing bare with covered conductor in Australia
- Over the years, significant development in the covered conductor design led to improved performance and extended life

Nomenclature of Covered Conductor

- Covered conductor is a widely accepted and used term for distinguished from bare conductor
- The term indicates a conductor being "covered" with insulating materials 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 parts in the world use the term "covered conductor", "insulated conductor", "coated conductor" interchangeably
- Covered conductor is a generic name for many sub-categories of conductor design and field construction arrangement
- Covered conductor in the U.S.:
  - Tree wire
    - Term was widely used in the U.S. in 1970's
    - Associated with simple one layer cover
    - Used to indicate cross-arm construction
  - Spacer cable
    - Associated with construction using trapezoidal insulated brackets for suspending covered conductor
  - Aerial bundled cable (ABC)
    - Installation of underground cable on poles with benefits of being grounded
- Covered Conductor in Europe:
  - SAX, PAS/BLX, BLX-T are some names for covered conductor used in Scandinavia for installations in forests
  - CC/CCT are covered conductor and covered conductor with extra thickness are used in Australia, the Far East
- Covered Conductor at SCE:
  - The term "Covered Conductor" was introduced to SCE standards in Q1, 2018, previously, the term "tree wire" was used
  - SCE is more familiar with "aerial cable" to indicate field-bundled underground cable (with or without jacket) prior to 2000's, and manufacturer "pre-bundled" underground cable on air (ABC) in the 2000's
  - Current SCE specified Covered Conductor is more robust than CCT with has better UV protection

Single Layer Covered Conductor

- Characteristics:
  - Single Layer
  - Typically, Low Density Polyethylene (insulating material)
  - Covering Thickness ranges from 0.091 to 0.130 inches
- Lower impulse strength than the two or three layer design
- Provides some resistance to outages caused by tree and wildlife contact



Two Layer Covered Conductor

- Characteristics:
  - Two Layers
    - Layer A: Polyethylene (PE)
      - Insulating material
      - 0.080 inches
    - Layer B: High Density Polyethylene (HDPE)
      - Insulating Material
      - Tougher than layer A
        - Abrasion Resistant
      - 0.080 inches
- Higher impulse strength than the single layer design

Three Layer Covered Conductor

- Characteristics
  - Three Layers
    - Layer A: Conductor Shield
      - Semiconducting layer
      - Reduces Voltage Stress
    - Layer B: Polyethylene Layer
      - Insulating Layer
      - Can be crosslinked (XLPE)
    - Layer C: Polyethylene Layer
      - Insulating Layer
      - Can be high density and/or crosslinked

- Higher impulse strength than the single layer design and two layer design

SCE's Evolution

Single Layer

- 150 mils HDPE

3 Layer 75°C Rated

- 15 mils conductor shield
- 75 mils LDPE Inner Layer
- 75 mils HDPE Outer Layer

3 Layer

90°C Rated

- 15 mils conductor shield
- 75 mils XL-LDPE Inner Layer
- 75 mils XL-HDPE Outer Layer

Covered Conductor Installation Options

- Cross-arm Construction
  - (aka Tree Wire)

Most of SCE installations on Cross-arm (SCE uses grey to reduce the impact of sun light heating effect, thus increase ampacity)

- Compact Construction
  - (aka Spacer Cable)

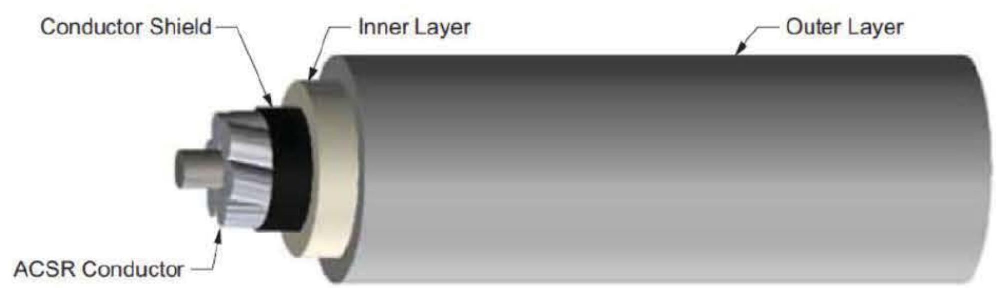
Some installations will be space cable (e.g. replacement of tree attachments)

2. SCE Covered Conductor Design

This section provides more insights of SCE Covered Conductor Design – layer by layer and the functions of each layer (sheath)

SCE Design

- Three Layer Covered Conductor
  - Conductor
    - Aluminum Conductor Steel-Reinforced (ACSR)
    - Hard Drawn Copper (HDCU)
  - Conductor Shield
    - Semiconducting Thermoset Polymer
  - Inner Layer
    - Crosslinked Low Density Polyethylene
  - Outer Layer
    - Crosslinked High Density Polyethylene

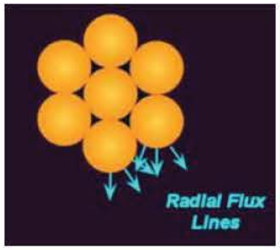


Conductor

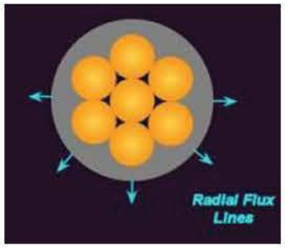
- Aluminum Conductor Steel-Reinforced (ACSR)
  - Sizes
    - 1/0 AWG (6/1 Strand)
    - 336.4 AWG (18/1 Strand)
    - 653 AWG (18/3 Strand)
- Hard Drawn Copper (HDCU)
  - For use in coastal areas (within 1 mile of the coast)
    - Copper is more resistant to corrosion than Aluminum
  - Sizes
    - #2 AWG (7 Strand)
    - 2/0 AWG (7 Strand)
    - 4/0 AWG (7 strand)

Conductor Shield

- Material: Semiconducting Thermoset Polymer
- Reduces stress concentrations caused by flux lines from individual conductor strands.
    - Transforms strands into a single uniform conducting cylinder



Flux lines without a conductor shield



Flux lines with a conductor shield

- The reduction of electrical stress, especially if the covered conductor is in contact with another object, will help preserve the integrity of the insulation and lengthen the useful service life of the covered conductor.

Inner Layer

- Material: Crosslinked Low Density Polyethylene (XL-LDPE)
- Insulating Layer
  - Contributes to the high impulse strength of the covering, which will protect the conductor from phase-to-phase and phase-to-ground contact
- Crosslinking will allow the material to retain its strength and shape even when heated

Outer Layer

- Material: Crosslinked High Density Polyethylene (XL-HDPE)
- Insulating Layer
  - Contributes to the high impulse strength of the covering, which will protect the conductor from phase-to-phase and phase-to-ground contact
- Abrasion and Impact Resistant
- Environmental Stress-Crack Resistant
- Track Resistant
- UV Resistant
- Crosslinking (XL) will allow the material to retain its strength and shape even when heated
- HDPE uses Titanium Dioxide as the most effective UV inhibitor, and providing the best track resistant

Temperature Rating

- Normal Operation: 90°C
- Emergency Operation: 130°C
- Short Circuit Operation: 250°C

Covered Conductor vs. Bare Comparison

- ACSR Covered Conductor

Conductor Size (AWG)	Conductor Type (Stranding)	Cover Type	Weight (lb/ft)	Overall Diameter (in)	Ampacity per Conductor/ (Amps)
1/0	ACSR (6x1)	XL-HDPE (165 mils)	0.277	0.728	271
336.4	ACSR (18x1)	XL-HDPE (165 mils)	0.564	1.014	550
653.9	ACSR (18x3)	XL-HDPE (180 mils)	0.973	1.313	835

- ACSR Bare

Conductor Size (AWG)	Conductor Type (Stranding)	Cover Type	Weight (lb/ft)	Overall Diameter (in)	Ampacity per Conductor/ (Amps)
1/0	ACSR (6x1)	N/A	0.146	0.398	280
336.4	ACSR (18x1)	N/A	0.365	0.684	605
653.9	ACSR (18x3)	N/A	0.677	0.953	920

Covered Conductor vs. Bare Comparison

- Copper Covered Conductor

Conductor Size (AWG)	Conductor Type (Stranding)	Cover Type	Weight (lb/ft)	Overall Diameter (in)	Ampacity per Conductor/ (Amps)
#2	HDCU (7)	XL-HDPE (165 mils)	0.316	0.622	240
2/0	HDCU (7)	XL-HDPE (165 mils)	0.569	0.744	367
4/0	HDCU (7)	XL-HDPE (165 mils)	0.845	0.852	488

- Copper Bare Conductor

Conductor Size (AWG)	Conductor Type (Stranding)	Cover Type	Weight (lb/ft)	Overall Diameter (in)	Ampacity per Conductor/ (Amps)
#2	HDCU (7)	N/A	0.205	0.292	260
2/0	HDCU (7)	N/A	0.411	0.414	405
4/0	HDCU (7)	N/A	0.653	0.522	540

3. Contact with Foreign Object

This section demonstrates how Covered Conduct reduces ignition risks during contact with foreign object or other conductor by performing a complex engineering analysis and testing impacts of contact on Covered Conductor

Contact with Foreign Object

- Covered conductors will prevent incidental contacts that cause phase-to-phase and phase-to-ground faults caused by:
  - Vegetation/Palm fronds
  - Conductor slapping
  - Wildlife
  - Metallic Balloons
- Analysis of computer modeled scenarios and field testing supports that covered conductor will prevent faults caused by incidental contact.

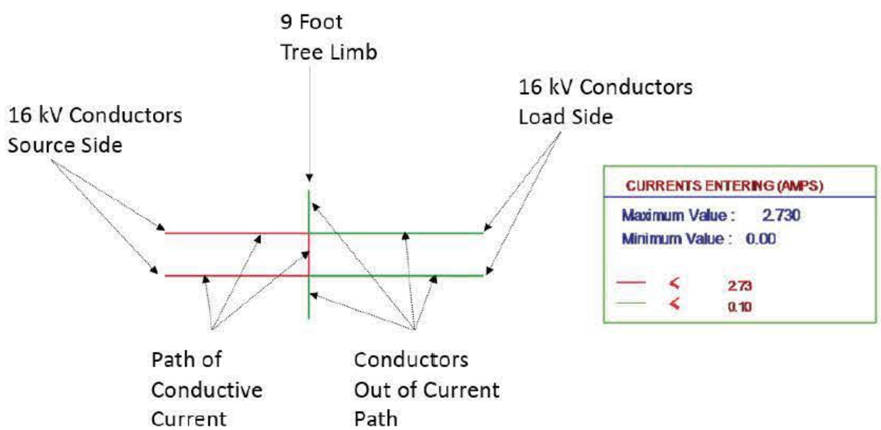
Contact with Foreign Object Using Computer Modeling & Simulation

- An SCE study analyzed the effectiveness of the covering in preventing phase-to-phase faults due to incidental contact
- The study also analyzed the energy absorbed by the foreign object when contact with two covered conductor is significant low and not sufficient to start a fire.
- Scenarios Modeled in computer models using two complex electric power engineering program tools (PSCAD and CDEGS):
  - Tree/Vegetation phase-to-phase contact
  - Conductor Slapping
  - Wildlife phase-to-phase contact
  - Metallic Balloon phase-to-phase contact

Example of Computer Modeling & Simulation Results for Tree Contact (CDEGS)

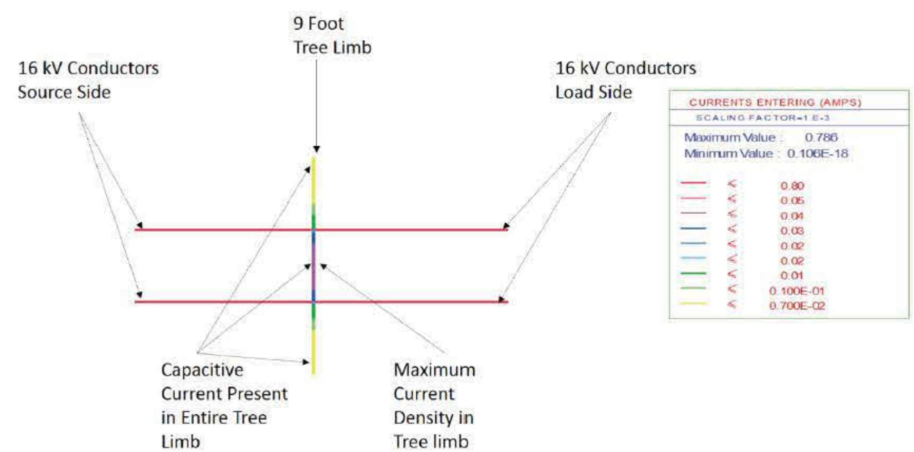
<u>Case 1: Tree on Two Bare Conductors</u>

Maximum Current through object: **2.7 A**



<u>Case 2: Tree on Two Covered Conductors</u>

Maximum Current through object **0.04 mA**



Study Conclusion

- The analysis concluded that a foreign object contact with covered conductors will not cause a fault
- The results showed that covered conductors reduce the energy from tens of thousands of watts to well under one milliwatt.
- This reduction is expected to be sufficient to prevent ignition

Simulation Method	Conductor Type	Current in Branch	Resistance of Branch	Power into Branch
PSCAD	Bare Conductor	2800 mA	5800 Ω	45,472 W
	Covered Conductor	0.18 mA	5800 Ω	0.00019 W
CDEGS	Bare Conductor	2730 mA	5800 Ω	43,227 W
	Covered Conductor	0.04 mA	5800 Ω	0.00001 W

Field Testing

- Field testing was performed at SCE' EDEF Test Facility in Westminster to validate the computer model study
- Tests performed for contact with covered conductors only
- No tests performed for contact with bare conductors, because this information is well studied by the industry
- Scenarios tested:
  - Tree/Vegetation phase-to-phase contact
  - Conductor Slapping
  - Wildlife phase-to-phase contact
  - Metallic Balloon phase-to-phase contact

Palm Frond Contact

- Energized at 12 kV
- Observations
  - No arcing
  - No damage to the covered conductor
  - No damage to the palm frond

Tree Branch contact

- Energized at 12 kV
- Observations
  - No arcing
  - No damage to the covered conductor
  - No damage to the tree branch

Conductor Slapping

- Energized at 12 kV
- Observations
  - No arcing
  - No damage to both covered conductors

Wildlife Contact

- 700 Ω resistor simulated animal contact
- Energized at 12 kV
- Observations
  - No arcing
  - No damage to the covered conductor
  - No damage to resistor

Metallic Balloon Contact

- Energized at 12 kV
- Observations
  - No arcing
  - No damage to the covered conductor
  - No damage to the metallic balloon

Field Test Conclusion

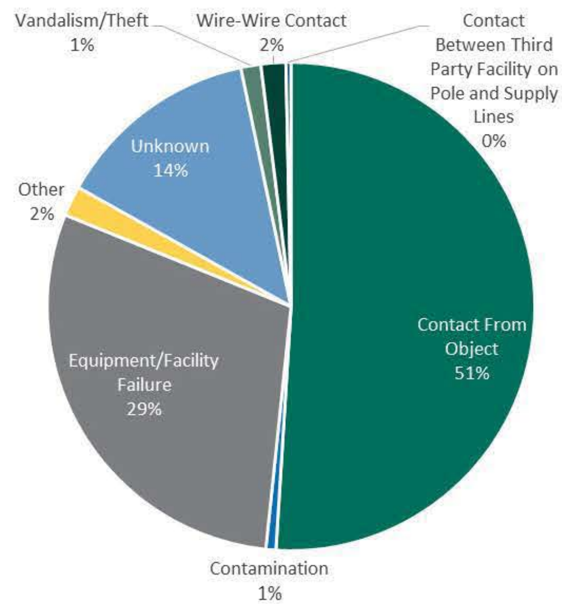
- Field testing validated that covered conductor will prevent faults and reduce the chance of ignition due to incidental contact

4. Wildfire Mitigation Effectiveness

This section illustrates the analysis of the fire mitigation effectiveness of covered conductors.

Fault to Fire Analysis

- Initial studies analyzed fault types associated with High Fire Risk Areas and fires produced
- Historical Ignition Source Distribution



System Level Risk Distribution

- A ignition risk percentage was tied to each fault type, based on historical data of fires produced by each fault

Fault Type	"Frequency of Fault" Annual TEF	"Likelihood it leads to a Fire" CP	"Fires Produced" Annual Fires	"Normalizing for Total Wildfire Risk"	Annual CRR
Contact From Object	895	2.6%	**23.3**	**53%**	**5,303,030**
Animal	250	2.0%	5.0	11%	1,136,364
Balloon	152	3.1%	4.7	11%	1,060,606
Other	48	6.9%	3.3	8%	757,576
Vegetation	238	3.1%	7.3	17%	1,666,667
Vehicle Hit	207	1.5%	3.0	7%	681,818
Equipment/Facility Failure	1,354	1.0%	**13.3**	**30%**	**3,030,303**
Capacitor Bank	8	8.0%	0.7	2%	151,515
Conductor/Wire	145	2.8%	4.0	9%	909,091
Crossarm	39	0.8%	0.3	1%	75,758
Fuse/BLF/Cutout	98	0.3%	0.3	1%	75,758
Insulator	24	7.0%	1.7	4%	378,788
Other	111	2.4%	2.7	6%	606,061
Splice/Connector/Tap	138	1.9%	2.7	6%	606,061
Transformer	791	0.1%	1.0	2%	227,273
Other	571	1.3%	**7.3**	**17%**	**1,666,667**
Total	2,819	1.6%	**44.0**	**100%**	**10,000,000**

Covered Conductor Ignition Risk Mitigation

- Covered Conductor was found to be effective against Contact from Object faults, such as:
  - Animal
  - Balloon
  - Vegetation
  - Other
- Covered Conductor was found to be effective against some overhead equipment faults due to:
  - Conductor/Wire
  - Splice/Connector/Tap
- Overall, mitigation effectiveness of covered conductor was found to be 60%

	Covered Conductor			
Fault Type	**Mitigated Events**	**Equivalent Fires**	**Mitigation Effectiveness**	**MRR**
Contact From Object	**677**	**19.5**	**84%**	**4,442,340**
Animal	250	5.0	100%	1,136,364
Balloon	152	4.7	100%	1,060,606
Other	37	2.5	76%	578,704
Vegetation	238	7.3	100%	1,666,667
Vehicle Hit	0	0.0	0%	0
Equipment/Facility Failure	**283**	**6.7**	**50%**	**1,515,152**
Capacitor Bank	0	0.0	0%	0
Conductor/Wire	145	4.0	100%	909,091
Crossarm	0	0.0	0%	0
Fuse/BLF/Cutout	0	0.0	0%	0
Insulator	0	0.0	0%	0
Other	0	0.0	0%	0
Splice/Connector/Tap	138	2.7	100%	606,061
Transformer	0	0.0	0%	0
Other	**0**	**0.0**	**0%**	**0**
Total	**960**	**26.2**	**60%**	**5,957,492**

5. Alternatives Comparison

This section describes the alternatives considered and provides a comparison on their fire mitigation effectiveness and cost.

Alternatives Considered

- Wildfire Mitigation Options
  - Covered Conductor
    - Replace existing conductor with new, appropriately sized, covered conductor
  - Bare Conductor
    - Replace existing conductor with new, appropriately sized, bare conductor
  - Underground Relocation
    - Relocate existing overhead primary voltages to underground

Alternatives Mitigation Effectiveness Analysis

- **Based on input from Distribution / Apparatus Engineering, a mitigation is assumed to have either 0% (i.e. none) or 100% (i.e. complete) effectiveness against a particular subset of faults within ODRM**

	ODRM Cause Code	Covered Conductor Effective?	Bare Conductor Effective?	Undergrounding Effective?[1]
Contact From Object	Animal	**Yes**	No	**Yes**
	Balloon	**Yes**	No	**Yes**
	Foreign Material; Ice/Snow	**Partial (Yes for 'Foreign Material')**	No	**Yes**
	Vegetation Blown; Vegetation Overgrown	**Yes**	No	**Yes**
	Vehicle Hit	No	No	**Yes**
Equipment / Facility Failure	Transformer	No	No	**Yes**
	Conductor / Wire	**Yes**	**Yes**	**Yes**
	Splice / Connector / Tap	**Yes**	**Yes**	**Yes**
	Fuse / BLF / Cutout	No	No	**Yes**
	Lightning Arrestor	No	No	**Yes**
	Crossarm	No	No	**Yes**
	Pothead	No	No	**Yes**
	Insulator	No	No	**Yes**
	Switch / Disconnect AR	No	No	**Yes**

1. Undergrounding Effectiveness shown only include the mitigation of CFO faults and OH Equipment/Facility Failures, and does not include the additional risk of undergrounding (vault-lid ejection, UG cable and equipment failures, etc.)

Mitigation Effectiveness Comparison

- The following mitigation effectiveness values were assigned to each alternative:

Alternative	**Mitigation Effectiveness**
Covered Conductor	60%
Bare Wire	15%
Underground	100%

Cost Comparison

- The following Unit Cost values were assigned to each alternative:

Mitigation Option	Relative Mitigation Effectiveness Factor	Cost per Mile ($ million)	Mitigation-Cost Ratio
Re-conductor - Bare	0.15	0.30	0.50
Re-conductor - Covered	0.60	0.43	1.40
Underground Conversion	1.00	3.00	0.33

Conclusion

- While re-conductoring with bare conductor would have lower cost, and underground conversion would have greater benefit, re-conductoring with covered conductor has greater overall value.
- A dollar spent re-conductoring with covered conductor provides nearly three times as much value in wildfire risk mitigation as dollar spent re-conductoring with bare conductor
- A dollar spent re-conductoring with covered conductor provides over four times as much value in wildfire risk mitigation as dollar spent on underground conversion.

6. Safety Advantages

Safety

- In the case of a downed conductor, covered conductors will provide a safety advantage over bare wire.
- The covering on the covered conductor will reduce the charging current enough to result in, at most, a slight shock during human contact while contact with bare wire will result in electrocution.
- While evidence of a reduced charging current is available in multiple industry papers, SCE has sponsored a test with NEETRAC on covered conductor touch current to verify this data

Effects of Electrical Current

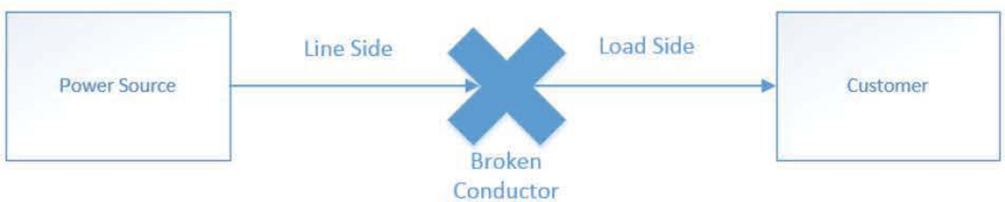
- Effects of Electrical Current on the Human Body

Current	Effect
Below 1 mA	Generally not Perceptible
1 mA	Faint Tingle
5 mA	Slight Shock; Not painful but disturbing. Average individual can let go
6-25 mA (women) **9-30 mA (men)**	Painful shock, loss of muscular control. The freezing current or "let-go" range. Individual cannot let go, but can be thrown away from the circuit if extensor muscles are stimulated
50-150 mA	Extreme pain, respiratory arrest (breathing stops), severe muscular contractions. Death is possible

NEETRAC Testing – Energized Downed Conductor

- The following are test cases of energized wire down scenarios that were simulated and empirically tested by NEETRAC
  - Person holding broken **covered conductor** on **line side**
  - Person holding broken **covered conductor** on **load side**
  - Person holding broken **bare conductor** on **line side**
  - Person holding broken **bare conductor** on **load side**

*Note that bare conductor test cases were not performed in the laboratory.



NEETRAC Testing

- Test Information:
  - Conductor: 1/0 Covered Conductor
  - Source: 12.447 kV
  - Test Results: Human contact current measured

	Covered Conductor		Bare Conductor
	Simulation Results (Theoretical Value)	Lab Test Results (Actual Values)	Simulation Results (Theoretical Value)
Line Side	0.220 mA	0.227 mA	5,300 mA
Load Side	0.218 mA	0.227 mA	34.2 mA

- Conclusion:
  - Covered Conductor Touch Current: Generally Not Perceptible
  - Bare Conductor Touch Current: Electrocution
  - Overall, covered conductors can potentially provide public safety benefits during wire down events

Chapter II
Life Expectancy

1. Expected Service Life

This section describes the life expectancy of covered conductors, the basis for the projection, and factors that influence service life.

Service Life

- SCE expects covered conductors to have a service life of **45 years**
- Conclusion of 45 years is based on
  - Manufacturer response
  - Historical Records
  - SCE experience with similar products

Manufacturer Survey

- Manufacturer consensus is that the covered conductor service life is expected to be 40 years minimum

Surveyed Questions	Supplier 1	Supplier 2	Supplier 3
1. What is the expected service life of the covering?	Minimum of 40 years, and probably 60 plus years	40 years	40 years
2. What is the expected service life of the conductor?	Useful service life in excess of 80 years	40 years	40 years
3. What is the expected service life of the covered conductor as a whole?	Excess of 67 years	40 years	40 years

Basis for Expected Service Life

- Advancement of compound technology and the upgrade of manufacturing equipment
- Known service life of XLPE is 40 years minimum
- Conformance to and successful passing of qualification tests ensures life expectancy
- Historical records with systems installed since 1951 are still in operation and performing as designed 67 years ago

Factors that Influence Service Life

- Conductor Temperature
  - Operating at extreme temperature is known to damage the conductor and/or covering
- Extreme contamination
- Severe UV exposure
- Installation methods and condition
- Type and Quality of Accessories

Qualification Testing

- SCE requires the following tests to ensure the longevity of the conductor
  - UV Testing
  - Environmental Stress Cracking
  - Track Resistance
  - Maximum Dielectric Constant
- Passing qualification tests ensures that the covered conductor deployed in SCE facilities meet industry standard and are high quality
- Passing ensures that the covering can perform as intended for a 45 year operating life

2. UV Resistance

This section describes the requirements of the UV resistance testing.

Sunlight (UV) Resistance Testing

- SCE requires conformance to ICEA S-121-733-2016 Sunlight Resistance (UV) Testing
- Testing will accurately predict, on an accelerated basis, the effect of sunlight
- UV testing will involve inducing property changes associated with the end use conditions, including the effects of sunlight, moisture, and heat. Testing requires specimens to be exposed to xenon-arc radiation and water-spray exposure.
- The exposure time is 720 hours with a radiation level of 0.35 Watt/meter. This radiation level was chosen based on the most extreme summer weather similar to the state of Florida, which is always equal to or greater in UV intensity than in Southern California.
- The covering is considered sunlight resistant if the original to aged tensile and elongation ratio 80% or greater after the 720 hours of exposure. Additionally, because the covering is grey, the amount of UV absorption will be limited.

Significance

- Testing ensures that the strength of the covering is still at least 80% of the original strength before accelerated UV exposure
- Overall, UV testing requirement ensures the longevity of the covering

3. Environmental Stress-Cracking

This section describes the requirements of Environmental Stress-Cracking Testing.

Definitions

- Stress-Crack – An external or internal rupture in a plastic caused by tensile stresses less than its short-time mechanical strength

Environmental Stress-Cracking Testing

- ICEA S-121-733-2016 does not require Environmental Stress-Cracking Resistance for 90°C rated covered conductor because the covering material is inherently resistant to Environmental Stress-Cracking
- Environmental Stress-Cracking is the development of cracks in the material due to low tensile stress and environmental conditions. Under certain conditions of stress with the presence of contaminants like soaps, wetting agents, oils, and detergents, ethylene material may exhibit mechanical failure by cracking.

Significance

- Having a 90°C Rated covered conductor means that the covering will be inherently resistant to cracking under conditions of stress and in the presence of contaminants

4. Track Resistance

This section describes the requirements of the track resistance testing.

Definitions

- Electrical Erosion – The progressive wearing away of electrical insulation by the action of electrical discharges
- Track – A partially conducting path of localized deterioration on the surface of an insulating material
- Tracking – The process that produces tracks as a result of the action of electrical discharges on or close to the insulation surface
- Tracking Resistance – A quantitative expression of the voltage and the time required to develop a track under specified conditions

Track Resistance Testing

- SCE requires conformance to ICEA S-121-733-2016 Track Resistant Testing
- Track resistance testing will evaluate the tracking and erosion resistance of the covering and its effects upon the insulation.
- During this test, the covering is exposed to a conducting liquid contaminant at an optimum rate, in a manner that allows continuous electrical discharge to be maintained.
- The effects are similar to those that may occur in service under the influence of dirt combined with moisture condensed from the atmosphere.
- Producing continuous surface discharge with controlled energy will mimic long-term exposure in the field in an accelerated time frame.
- For the sample to pass, the time to track one inch at 2.5 kV must be a minimum of 1000 minutes.

Significance

- Testing ensures that the covering is track resistance
- Track resistance properties will ensure insulation that electrical charges will not erode the insulation over time
- Overall, testing requirement ensures the longevity of the covering

5. Maximum Dielectric Constant

This section describes the maximum dielectric constant requirements

Definitions

- Dielectric Constant: a quantity measuring the ability of a substance to store electrical energy in an electric field
- Dielectric Strength: the maximum electric field that a pure material can withstand under ideal conditions without breaking down

Maximum Dielectric Constant

- The maximum dielectric constant must be 3.5, per ICEA standards
- The lower the dielectric constant, the higher the dielectric strength.

Significance

- Ensuring that the dielectric constant meets the requirements certifies that the insulation strength of the covering is acceptable and the covered conductor will perform as designed.

6. Production Testing

This section describes production testing requirements.

Production Testing

- SCE requires manufacturers to perform routine production testing
  - DC Resistance
    - The DC resistance on the conductor must not exceed 102% of the maximum allowable value
  - Unaged and Aged Tensile and Elongation
    - Tensile elongation is the stretching that a material undergoes. The point of rupture must be greater than 1800 psi for unaged samples. Samples are aged at 121°C for 168 hours. Aged samples must rupture at a minimum of 75% of the unaged value. This test validates the mechanical properties of the covering
  - Hot Creep
    - Hot creep tests validates that the covering is crosslinked, making it a thermoset. Thermosets can withstand higher temperatures and are less likely to deform at high temperatures.
  - Spark Test
    - Spark tests validates the integrity of the insulation. An electrical cloud is generated around the cable. Any pinholes or faults in the insulation will cause a grounding of the electrical field and this flow of current will register a defect in the insulation.
- Passing routine production tests ensures that the covered conductor deployed in SCE facilities meet industry standard and are high quality
- Passing ensures that the covering can perform as intended for a 45 year operating life

7. Covered Conductor Failure Mode

This section articulates the possible failure modes and provides a high-level analysis how the these impact on Covered Conductor at SCE, and finally what SCE has done to address these failure modes

Known Failure Modes

- Covered conductor could have burn down if not adequately designed or installed
- The following known issues are addressed either by design criteria or installation guideline
  - Electrical tracking on surface of covers
  - Arc generated from lightning strikes
  - Aeolian (Wind-Induced) Vibration
  - Premature Insulation Breakdown

Mitigating Against Electrical Tracking on Surface of Covers

- Electrical tracking occurs when carbon pathways (tracks) form on the surface of an insulating material, which could lead to breakdown
- SCE will only procure CC that has completed extensive qualification testing to industry standards (UV Resistance, Environmental Cracking, and Track Resistance)
- Early material that suffer from tracking issues are crosslinked polyethylene with high carbon content for UV inhibiting purposes
  - SCE specified material using cross-linked high density polyethylene with little carbon black. Titanium Dioxide is used as a UV inhibitor.
- Early design of CC specify thin layers of insulation (less than 100 mils)
  - Covered conductor SCE will used has 150 mils of insulation

Arc Generated During Lightning Strikes

- During lightning strikes, an arc could form on the transition from covered to bare conductor, or where there are stripped or open point in the covered conductor
- Direct lightning strike on covered conductor would be more damaging than bare conductor because lightning moves more freely on bare conductors (to look for a path to earth)
- However, SCE is well prepared to mitigate this known issue for several reasons:
  1. SCE service territory is considered low lightning area
  2. Covered conductor is generally less "attractive" to lightning than bare conductor (insulating materials reduces electric field on the surface of covered conductor)
  3. SCE uses the most effective mitigation tool for lightning strikes
- Mitigating Lightning Failure
  1. Industry uses Arc Protection devices (APD's), Power Arc Devices (PAD's) and Lightning Arrestors (LA's) for mitigating lightning strike failures
  2. Lightning Arrestor is the most well-built and effective device of all three
  3. SCE uses Lightning Arrestors and bolster the standards for covered conductor systems to be treated as high lightning area
  4. SCE's high lightning standards require Lightning Arrestors to be installed in all equipment poles (all transformer sizes, capacitor, RAR, switch, voltage regulator, etc.)
  5. SCE standards requires Lightning Arrestors to be installed in covered conductor to underground transitions
  6. SCE will minimize stripping and removal of the covering
  7. SCE standards require stripped or uncovered portions will be covered (i.e. splice)

CONCLUSION: SCE is well positioned for protecting covered conductors from lightning because direct strikes on covered conductors are less likely at SCE's territory, but if it happens, damage due to lightning may be mitigated by Lightning Arrestors, i.e. direct to ground instead of stuck on one covered location, or covered to bare transition or flash over to other phases.

Aeolian (Wind Induced) Vibration

- Wind induced vibration of conductors could lead to fatigue failure of the conductor (similar to bending a piece of wire back and forward until it break) High conductor tensions lead to Aeolian vibration issues
- Mitigating Aeolian Vibration
  - SCE developed proper sag and tension values for covered conductor
  - SCE's tension limits are in line with Northeast Utilities that have an 80% covered conductor system.
  - The Northeast utilities indicated that they have not experienced problems due to Aeolian vibration

Premature Insulation Breakdown

- Wear and tear could lead to premature insulation breakdown
  - Insulation breakdown will equate effectiveness of covered conductor to bare
  - Result from improper installation or constant abrasion from vegetation
- Mitigating premature insulation breakdown
  - Outer covering is a high density material, and is resistant to incidental abrasion
  - Discussion with other utilities indicated that older covered conductor design performed as intended even after 50 years
  - Construction standard requires care during installation and handling of the covered conductor

Learning from Past Experience

- SCE has performed literature research, talked to industry experts, visited utilities and suppliers, and employed consultants to inform the design and installation of covered conductor to withstand early known issues
- Based on past performance in various utilities and the robustness of the current covered conductor design, Engineering fully expect the covered conductor to perform for at least 45 years without issues

Chapter III
Industry Benchmarking and Research

Energy for What's Ahead℠

SOUTHERN CALIFORNIA EDISON®

1. Benchmarking

Utility Benchmark Questionnaire

- Sent out survey questionnaire to utilities to learn about covered conductor standards, application and performance:
  - Seattle City Light (Washington)
  - Puget Sound Energy (Washington)
  - Con Edison (New York)
  - Orange and Rockland Utilities (New York)
- Learned about downed wires with covered conductor
  - In Early 1980s, Con Ed experienced plenty of burn downs
    - Failures were at dead ends and equipment leads
    - Failures were at bare to covered transitions
  - Orange and Rockland found that protective relays will trip during a burn down
- Failure modes of covered conductor
  - Nicked conductor during stripping
  - Prolonged incidental contact (months)
- Cable type and Size
  - Seattle City Light and Puget Sound: 125 mils HDPE
  - Con Edison: 175 mils EPR
  - Orange and Rockland: 40-80 mils XLPE
- Voltage
  - Seattle City Light: 7.2 kV
  - Con Edison:
    - 27 kV – Mostly CC
    - 4-14 kV – CC

Round Table Benchmark with Northeast Utilities

- Conducted an in-person discussion on covered conductor experience with the Northeast utilities:
    - Hendrix (manufacturer), Liberty Utilities (New Hampshire), Groveland Light (Massachusetts), Holyoke (Massachusetts), Middleton (Massachusetts).
    - Past standards engineer of Eversource attended as well
- Covered Conductor Systems
    - New England overall is approximately 80% Covered Conductor and 20% Bare
- End of life
    - Covered conductor still looks and performs the same after 50+ years of service
- Issues
    - Manufacturing problems due to ring cuts was experienced in the late 70s before cleanrooms
    - Corona is main failure mode (phase to ground through tree), but it takes years to fail
    - None has experienced Aeolian vibration issues
    - None has encountered water ingress
- Lightning
    - Burn down happens at stripped portion
    - Add lightning arrestors at equipment, transitions to bare, and dead-ends
    - Had enough incidents to decide to install lightning arresters at end of line
    - All advise not to install lightning arresters at every 1000 ft. Avoid stripping as much as possible.

Global Research

- Global information was gathered from covered conductor research literature as well as government and utility publications.
- Future Benchmarking Plans:
  - SCE will contact Australian utilities directly to gather more information about their Bushfire Mitigation Plans
  - SCE will conduct a round table discussion with South Korea's utility Korean Electric Power Corporation (KEPCO) to learn more about construction best practices and understand the reasoning behind their deployment of covered conductor.

Global Research – Australia (Historical Installations)

- Covered Conductor has been used in Australia for over 50 years
- Early installations experienced the following problems:
  - Initial coverings of PVS, HDPE, and nylon gave very limited lifetimes and suffered surface degradation.
  - Initial installations were subject to failure due to lightning damage
- In the late 1980s, Australia reconsidered Covered Conductor for safety considerations (human and wildlife), conductor clashing, tree problems, and bushfire mitigation.
  - However, within 2 years of installation, it was found that the covered conductor was incapable of handling anything more than momentary contact
  - Other problems include severe RF emissions and tracking
- In the mid 2000s research for the Australian Strategic Technology Program illustrated that technological advancements and solutions to historical issues regarding covered conductors exist, which may allow for a widespread adoption of covered conductors in Australia

Global Research - Australia

- In 2009, the Victorian Bushfires Royal Commission (VBRC), which was established in 2009 by the government after the devastating Black Saturday bushfires, recommended the following:
  - The progressive replacement of all SWER (single-wire earth return) power lines in Victoria with aerial bundled cable, underground cabling or other technology that delivers greatly reduced bushfire risk. The replacement program should be completed in the areas of highest bushfire risk within 10 years and should continue in areas of lower bushfire risk as the lines reach the end of their engineering lives
  - The progressive replacement of all 22-kilovolt distribution feeders with aerial bundled cable, underground cabling or other technology that delivers greatly reduced bushfire risk as the feeders reach the end of their engineering lives. Priority should be given to distribution feeders in the areas of highest bushfire risk.
- Progress of VBRC recommendation implementation:
  - 2010 – Established a Bushfire Powerline Safety Taskforce (BPST) to recommend to the Victorian Government how to maximize the value to Victorians from the VBRC recommendations.
  - 2011 – The Bushfire Powerline Safety Taskforce recommended the following:
    - The BPST recommended to target SWER and 22kV powerlines in the next 10 years
    - The BPST recommended that any new powerlines built in areas targeted for replacement should also be built with underground or covered conductor
    - Estimated a 90% reduction in the likelihood of a bushfire starting by installing covered conductors
    - Recommendations were accepted by the Minster for Energy and Resources on December 29, 2011
    - AUS $750 million Powerline Bushfire Safety program was announced by the Victorian Government
  - 2012 – Areas of highest bushfire risk for purposes of asset installation were identified and a detailed forward works program was developed
  - 2013 – A brief focusing on the first five years of the program, described in more detail the complexities of delivering the substantial set of reforms and provided concise project planning, management, and delivery structure.
  - 2014 – Installation of first replacement powerline in high bushfire risk areas
  - **2016 – Amendments were made to the Electricity Safety (Bushfire Mitigation) Regulations which specify the use of covered conductors or undergrounding for any new or rebuilt circuits in high bushfire risk areas**
    - **The Victorian Government's Powerline Replacement Fund makes available up to $200 million to electrical distribution businesses and private land owners to replace bare wire powerlines**

Global Research – Australia

- Utility Implementations of VBRC Recommendations
  - Ausnet
    - Victorian utilities to use either insulated or covered conductor for any planned conductor replacement of more than 4 spans of 1kV-22kV line (within codified areas)
    - For AusNet, the codified areas included approximately 1,000 miles of bare wire, medium voltage powerlines. **They began replacing line in this area in 2014 relying on an established $200M Powerline Replacement Fund (PRF)**
    - AusNet is progressively replacing the remaining bare wire in codified areas outside of PRF activities because of the cost associated with insulated/covered conductors
    - **Construction of any new medium voltage electric line that is part of the supply network must use insulated cable or covered conductor**
  - Powercor
    - Per their 2016 Bushfire Mitigation Plan, Powercor is implementing underground cable/overhead covered conductor when construction either 22kV, single wire earth return (SWER) or low voltage assets for all new construction and the same Electrical Safety (Bushfire Mitigation) Regulations listed for AusNet reconductoring activities
- Utilities outside of Victoria
  - Energy Queensland
    - 2017 Summer Preparedness Plans target installation of covered conductor in bushfire risk areas.
  - Essential Energy
    - Bushfire Risk Management Plan (Issue 13, 2017) was provided to meet the objectives and requirements of the NSW Electricity Supply (Safety and Network) Regulation 2014, which includes a provision for the review of equipment types or construction methods known in their operation or design to have bush fire ignition potential and a mitigation strategy in relation to their use
    - Plan calls for use of underground cable and covered conductor on overhead primary, promoting underground or insulated low voltage lines in rural areas, and identifying at-risk private low voltage lines on customer properties and undergrounding or replacing with CCT

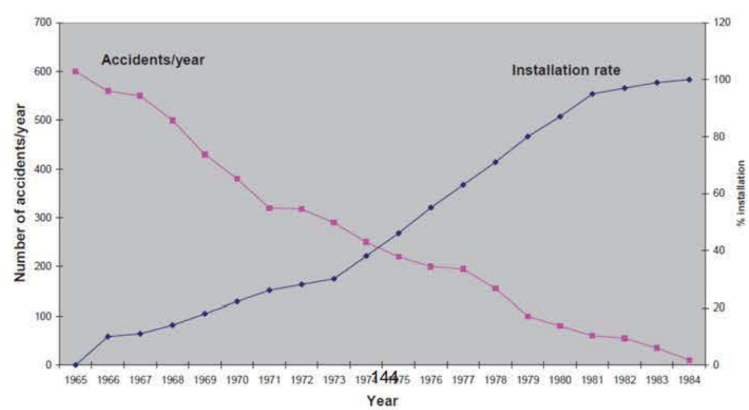
Global Research - Europe

- United Kingdom
  - The UK started installing covered conductors in 1994
  - The typical close spacing and compact construction prompted the first use of covered conductors in the UK
  - As of 2005, UK has installed 9,300 circuit miles of covered conductor
- Finland
  - Finland installed the first installations of covered conductors in Europe.
  - Main impetus for research into covered conductors in the 1970s was the reduction of forest fires caused by trees falling on bare overhead lines.
  - As of 2005, Finland installed approximately 3,100 miles of covered conductor.
  - 60% of new construction and refurbishment schemes use covered conductor
- Sweden
  - Covered Conductor was first introduced in Sweden in 1984.
  - First installation was in a snowy and high wind area to reduce faults due to snow-laden branches resting on the line and wire slapping
  - As of 2005, Sweden installed approximately 2,500 miles of covered conductor
  - 60% of new construction and refurbishment schemes use covered conductor

Global Research - Asia

- South Korea
  - Extensive CC use by Korea Electric Power Corporation (KEPCO) for 23 years
  - Covered Conductors make up 96% of South Korea's low voltage and medium voltage distribution line
  - Use CC Tested to 25 kV
- Japan
  - Started using covered conductors in 1965
  - Driving force behind CC installation is to reduce the number of accidents and fatalities due to bare OH lines and improve reliability

Reduction in electrical accidents against CC installation rate



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2. Industry Surveys

Background

- SCE requested members of the following groups to participate in a survey about covered conductors
  - Edison Electrical Institute (EEI)
  - Western Underground Committee (WUC)
  - The Association of Edison Illuminating Companies (AEIC)
- A total of 36 utilities participated.

Summary

- Bare wire is the standard.
  - On average bare wire makes up 88% of a utility's distribution system
- 28% of participants indicated that they use covered conductors on primary distribution lines.
- 33% of participants indicated that they historically used covered conductors, but no longer use them on new installations
- Most utilities indicated that covered conductor is used to prevent vegetation contact
- Most utilities indicated that the benefit of using covered conductor is less contact related faults

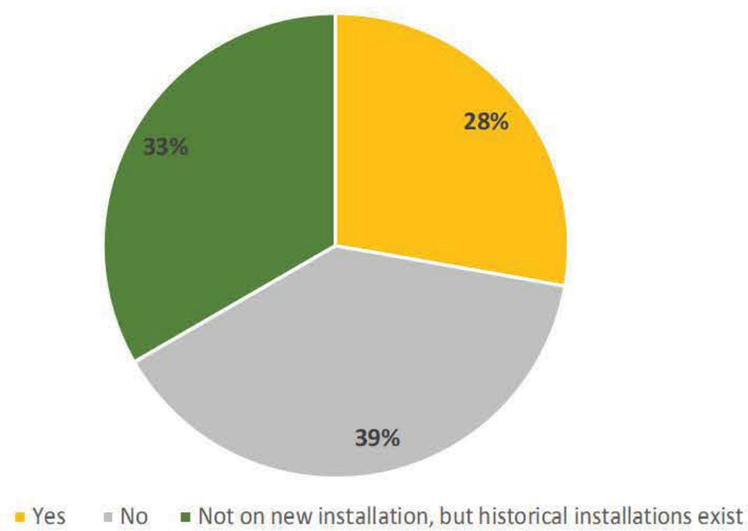
List of Participants

1	AES
2	Alliant Energy
3	Ameren
4	American Electric Power
5	Anonymous Participant
6	CenterPoint Energy
7	City of Banning
8	City of Lodi
9	City of Mesa Energy Resources
10	City of Richland, WA
11	City of Roseville
12	Con Edison
13	Dominion Energy
14	DTE Energy
15	Duke
16	FirstEnergy
17	Florida Power & Light
18	Idaho Power
19	Kansas City Power and Light

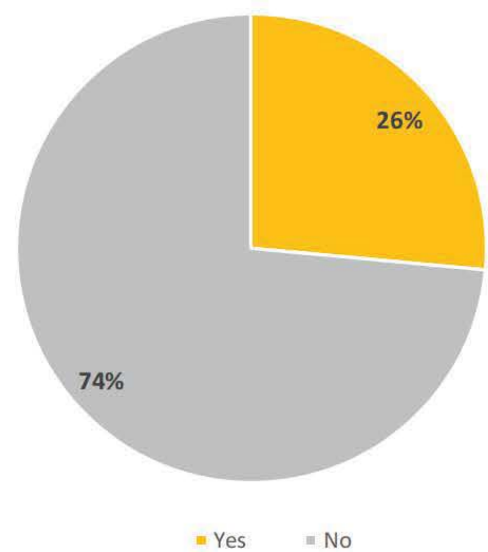
20	LADWP
21	LG&E and KU Energy
22	Midwest Energy, Inc.
23	National Grid
24	Northern Indiana Public Service Co.
25	Northwestern Energy
26	Oklahoma Gas & Electric
27	Oncor Electric Delivery
28	Orange & Rockland
29	Puget Sound Energy
30	Sacramento Municipality Utility Distrct
31	Salt River Project
32	Snohomish PUD
33	Southern Company
34	Tampa Electric
35	Tucson Electric Power
36	Westar Energy

Covered Conductor Usage

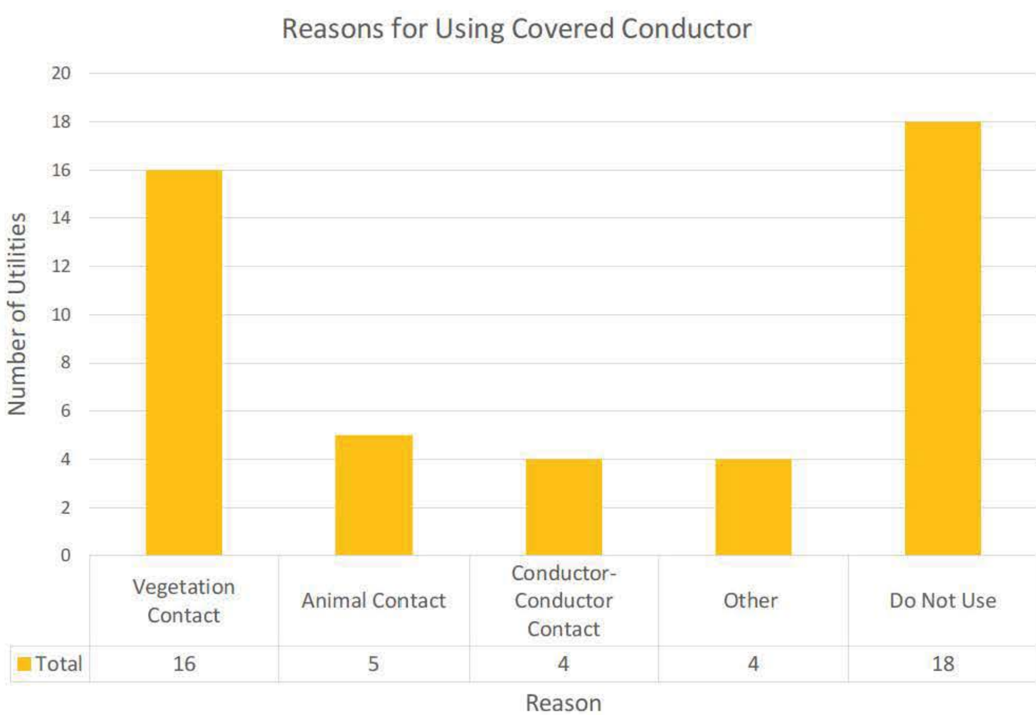
- Do you install covered conductor (Tree wire) for your primary (4 kV or higher) distribution lines?



- Do you install covered conductor (tree wire) for your branch line primary distribution wire? (fused, radial, two phases or less)



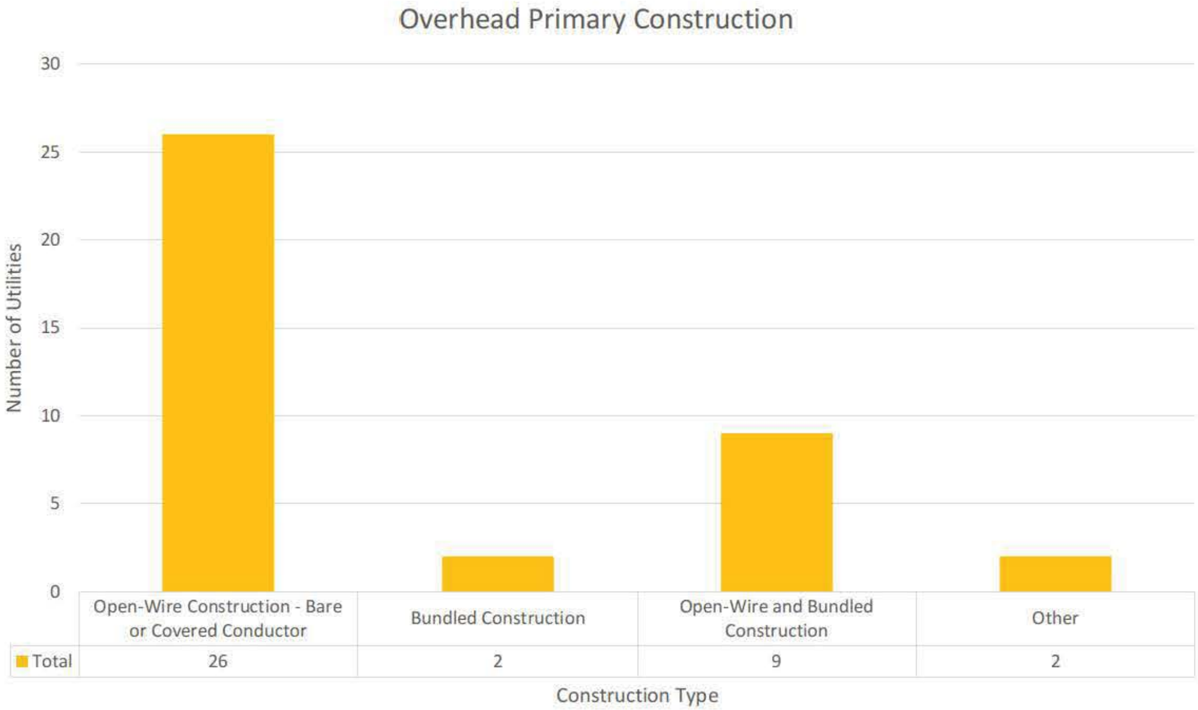
Reasons for Using Covered Conductor



Other

- Clearance and space management
- Higher density of circuit routing on a single pole

Types of Overhead Primary Construction Used

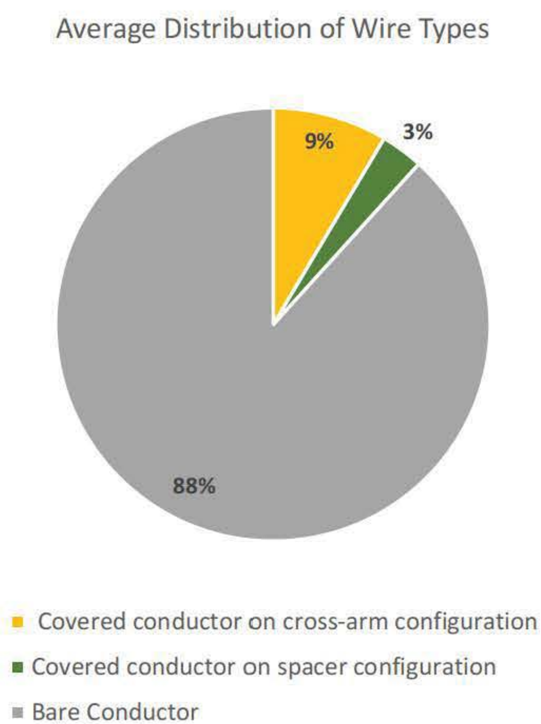


- Other
  - Armless Construction
- Open-wire can mean vertical or horizontal construction

Construction Criteria

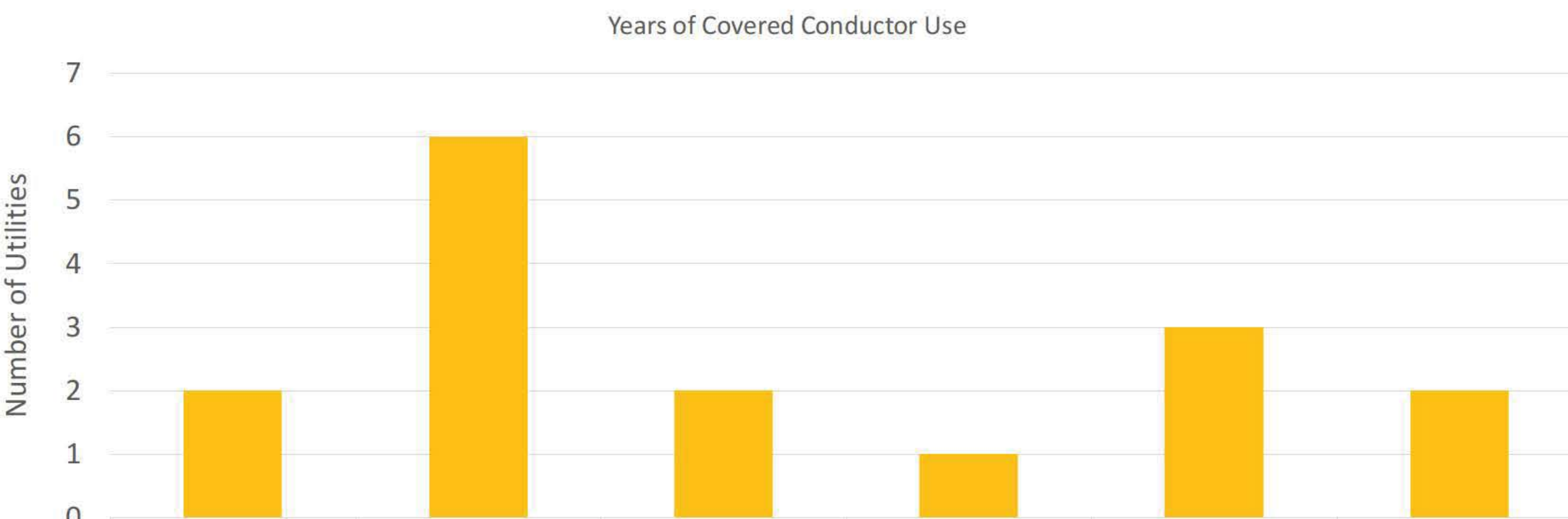
- Utilities typically use bundled construction in limited scenarios, which can include the following:
  - Use in areas in lieu of underground due to difficult trenching conditions
  - Express or dedicated feeders with limited or no taps
  - Limited right of way space
  - Heavily treed areas with tight clearances
  - Multiple circuits on a single pole
  - Storm hardening

Distribution of Various Wire Types



- On average, a utility's distribution system is made up of
  - 88% Bare Wire
  - 9% Covered Conductor on cross-arm configuration
  - 3% Covered Conductor on spacer configuration

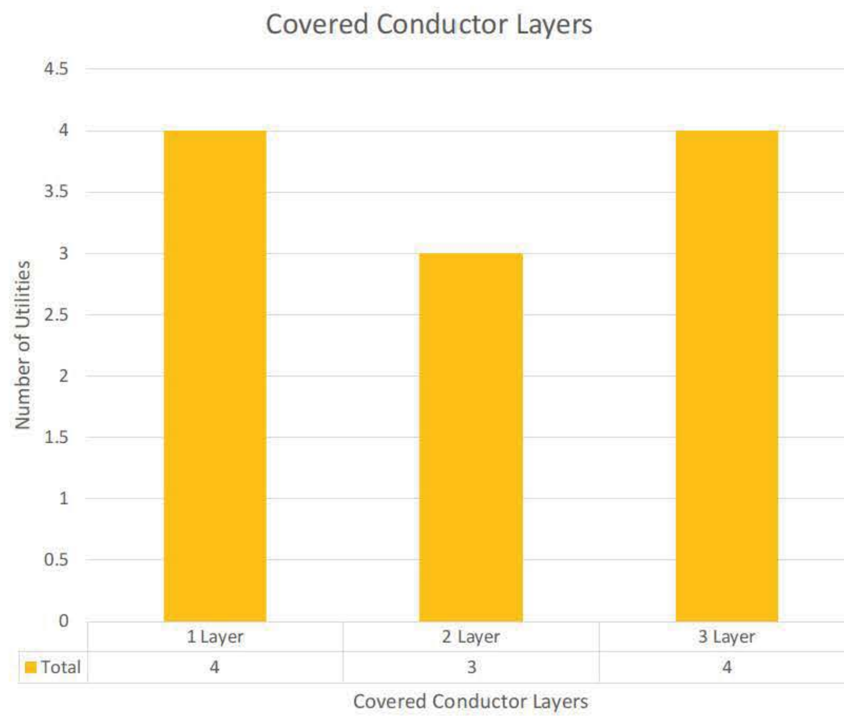
Years of Covered Conductor Use



	10	20	30	40	50 or greater	Unknown (Old)
Total	2	6	2	1	3	2

Years

Covered Conductor Wire Sizes and Layers



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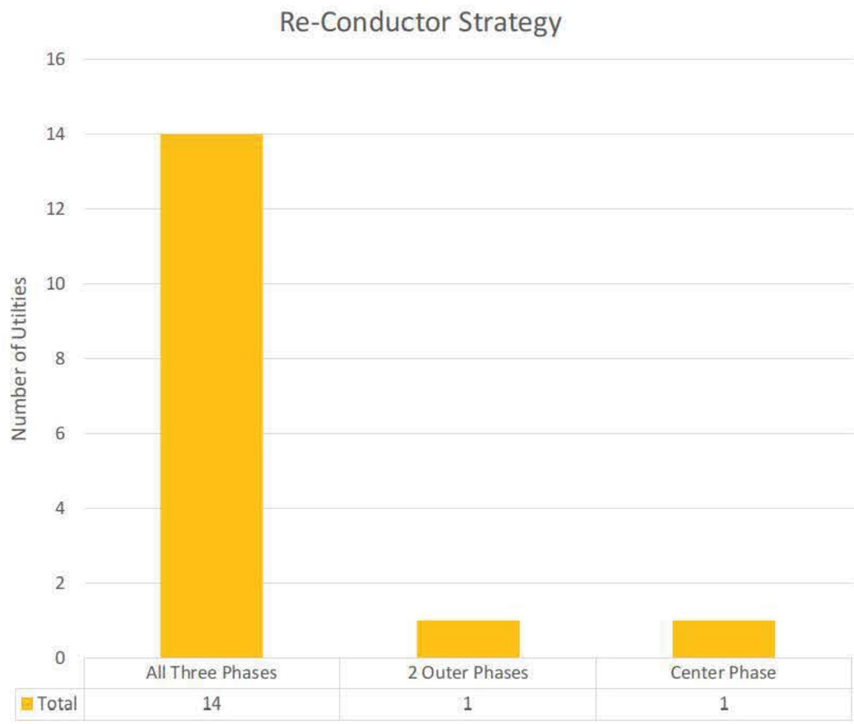
Re-conductoring Main Line



- All utilities indicated that they re-conductor all three phases when moving from bare wire to covered conductor
- One utility indicated that a standard does not exist and therefore performs all three options when re-conductoring to covered conductor:
  - All Three Phases
  - Two Outer Phases Only
  - Center Phase Only

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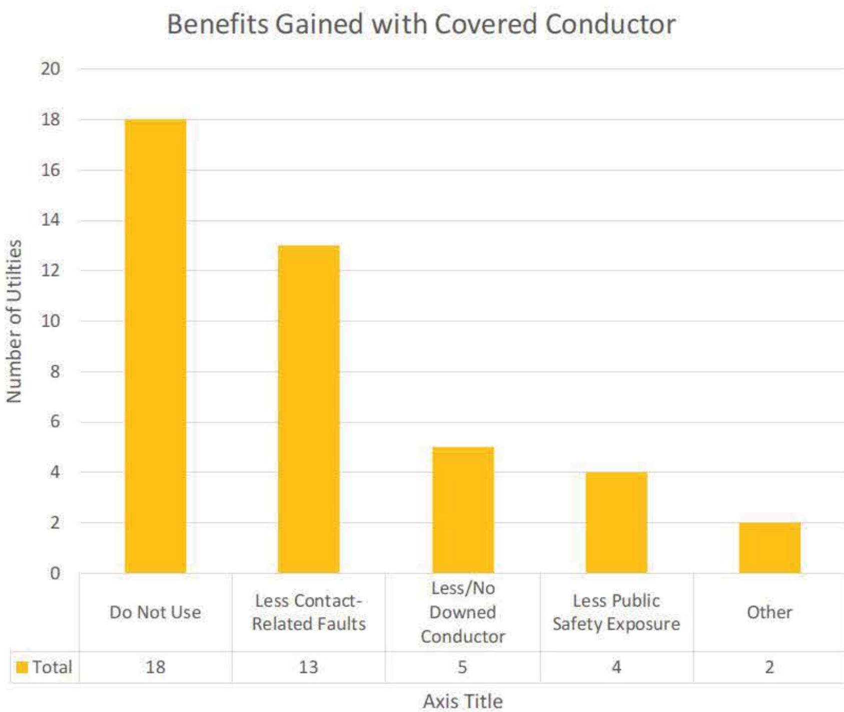
Benefits Gained with Covered Conductor



- Other:
  - Utilities that answered "Other" indicated covered conductor caused more problems such as more downed conductor however, this experience is based on historical covered conductor systems (from 20 years ago or more).

3. Incorporating Lessons Learned

Known Challenges

The following challenges associated with covered conductor have been identified via research and benchmarking:

1. Aeolian Vibration
2. Abrasion
3. Electrical Withstand
4. Lightning Protection
5. Corrosion
6. Tracking
7. Burn Down
8. Wire Down Detection
9. Radio Frequency

Incorporating Lessons Learned

1. **Aeolian Vibration Limits**
   - Sag and Tensions for the covered conductor will take into account the terrain. There will be two separate tables for light and heavy loading. The loading limits account for wind and ice.
2. **Abrasion**
   - SCE's Covered Conductor design uses a Crosslinked High Density Polyethylene layer to help resist abrasion. Additionally, covered conductor must be handled with care in order to prevent damage to the covering.
3. **Electrical Withstand**
   - SCE uses a triple sheathed covered conductor design, which has been found to be the best choice for long term electrical withstand for trees and with adjacent phases. BIL of SCE's CC is 200 kV.
4. **Lightning Protection**
   - Surge arresters will be installed at all overhead equipment locations and at UG Dips.

Incorporating Lessons Learned

5. **Corrosion**
   - SCE will be using copper covered conductors in coastal applications.
6. **Tracking**
   - SCE's covered conductor design will include a track resistant XLPE outer layer. Additionally, SCE will mitigate tracking by using polymeric insulators, using crimped connectors, and using a low carbon content sheath.
7. **Burn Down of CC**
   - SCE will incorporate the following to prevent burn downs.
     - Suitable lightning protection (installation of surge arresters)
     - Reducing electrical stresses and carbon content on sheath material (polymeric insulator, low carbon XLPE, etc.)
     - Correct installation and tensioning (Sag and Tension will take into account terrain such as wind loading and ice)
     - Tree Trimming (SCE will maintain tree trimming requirements)
8. **Detection of Downed CC**
   - SCE will use SEF method of protection for covered conductors, which is the same protection scheme for bare wire.
9. **Radio Frequency Concerns**
   - SCE will use low carbon black content sheaths and polymeric insulators to significantly reduced tracking, thus reducing RF problem in coastal area.

Chapter IV
Covered Conductor Construction

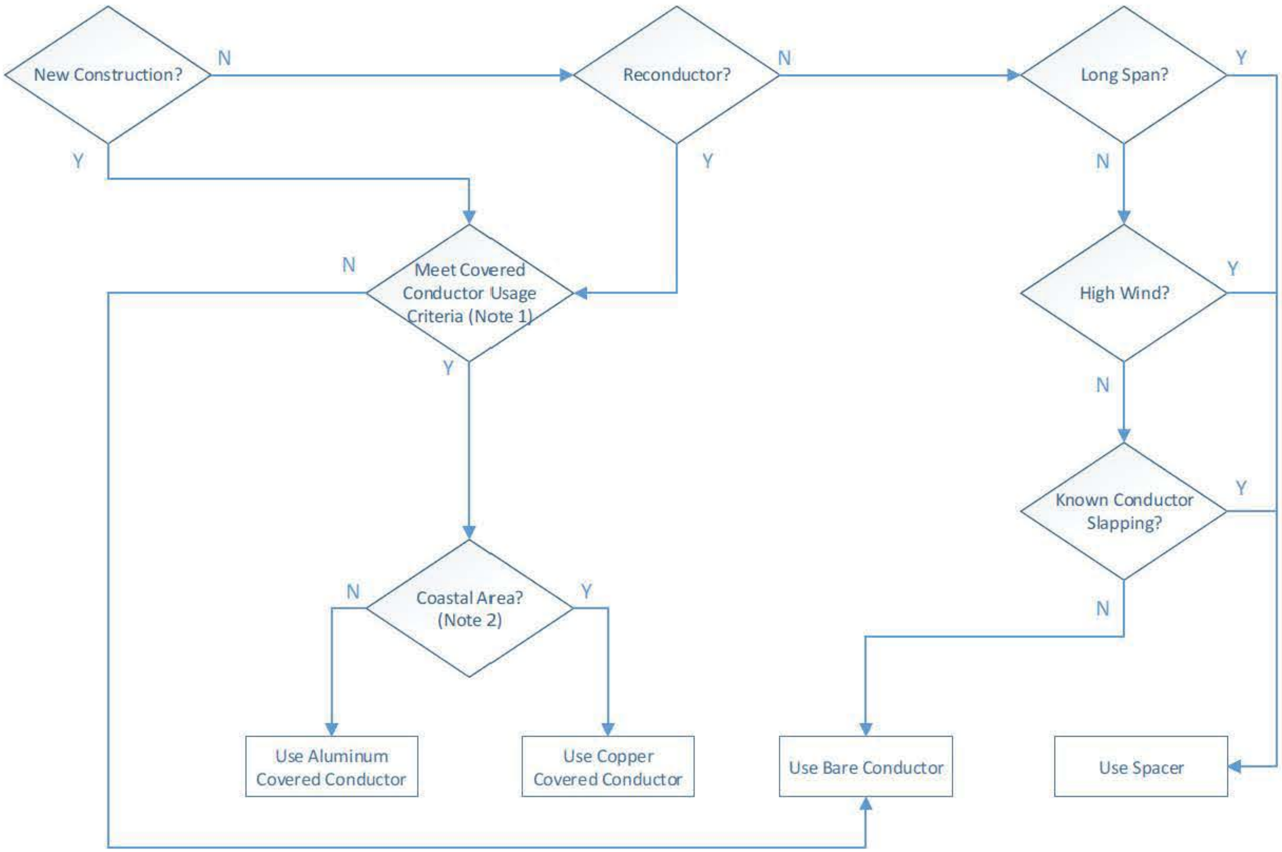
Energy for What's Ahead℠

SOUTHERN CALIFORNIA EDISON®

1. Covered Conductor Installation Guideline

This section discusses the covered conductor installation criteria

Installation Guideline



- New Construction and reconstruction in High Fire Areas will require covered conductor
- Reconductor will be triggered by other programs, such as OCP

- Note 1: See Next Slide for Usage Criteria
- Note 2: Coastal Area is defined as area within one mile of the coast

Covered Conductor Usage Criteria

1. System Operating Bulletin 322 Areas (HFRA)
2. Heavy vegetation with potential tree and palm frond contact
3. Known metallic balloon contact causing circuit outages
4. Any area with outages due to known intermittent contact
5. Coastal areas within one mile of the ocean
6. Any specific area that experiences accelerated corrosion

2. Covered Conductor on Three Phases and Neutral

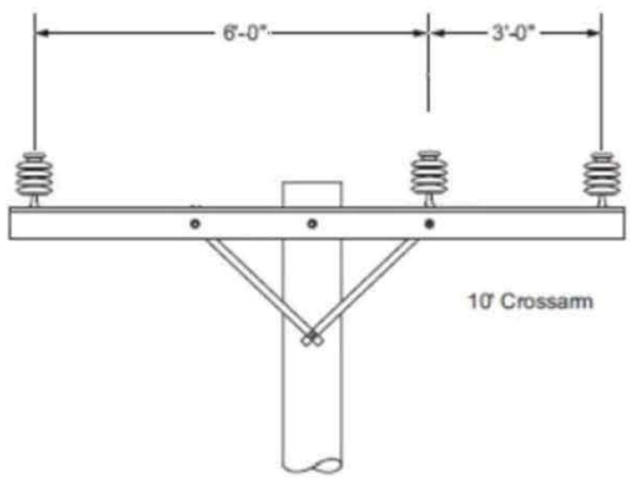
This section discusses the key factors considered to select covering all phases in SCE Standards

SCE Standards: Covered Conductor on Three Phases and Neutral

- Covered conductor will be used on all three phases in three-wire overhead system (mostly mainline)
- Covered conductor will be used on all two phases in overhead branch lines
- Covered conductor will be used on the neutral wire in four-wire overhead system (20% of SCE system has a neutral wire)

Analysis Factors

- Phase Spacing is key for the covered conductor
- This analysis will assume a three phase system. Refer to the figure below for phase spacing distances on a composite crossarm.



Evaluation of 1 Phase Covered

- In this configuration, it is assumed that only Phase B will be covered. Phase A and C will be bare wire.
- Analysis of effectiveness for mitigating phase to ground contact
  - This configuration will not be effective in preventing phase to ground contact. Phase A or Phase C will be susceptible to incidental contact with trees, therefore not eliminating the risk of a phase to ground fault.
- Analysis of effectiveness for mitigating phase to phase contact
  - This configuration will not be effective for phase to phase contact. There is 9 inches between the bare Phase A and Phase C. A foreign object or wildlife that is long enough could cause phase to phase contact. Palm fronds can be up to 13 feet long and California Condors have wingspans that are up to 10 ft long, which is enough to cause a phase to phase fault.
- Analysis of fire mitigation effectiveness
  - Covered conductor is considered effective for fire mitigation due to its ability to prevent incidental contact. However, its ability to prevent incidental contact will be compromised if the only one phase is covered.
  - Additionally, downed conductor is still possible due to mechanical failures or other equipment failure. The probability of a bare wire igniting a fire is higher than if it was covered.

2 Phase Covered

- In this configuration, it is assumed that Phase A and Phase C will be covered. Phase B will be bare wire.
- Analysis of effectiveness for mitigating phase to ground contact
  - This configuration will not be effective in preventing phase to ground contact. While the probability of a phase to ground contact is lower because Phase A and Phase C will be covered, Phase B will still be susceptible to incidental contact with trees, which will lead to a phase to ground fault.
  - Additionally, some equipment, such as transformers may be within 6 feet from the phases. Phase to ground faults may be possible due to incidental contact between the equipment and the center phase.
- Analysis of effectiveness for mitigating phase to phase contact
  - Because Phase A and Phase C are covered, the probability of phase to phase contact is reduced.
  - Internal SCE studies have shown that current through an object, such as a tree limb, connecting two phases of covered conductor is about 0.2 mA. This value doubles to 0.4 mA if the object is connecting a bare wire and covered conductor.
  - Insulation degradation on the covered conductor will happen at a faster rate, leading to failure happening at a faster rate.
- Analysis of fire mitigation effectiveness
  - The fire mitigation effectiveness is still less than if the system was fully covered. Phase to ground incidental contact is still possible even with two phases covered, leading to arcing that could cause ignition.
  - Furthermore, downed conductor is still possible due to mechanical failure or other equipment failure. The probability of a bare wire igniting a fire is higher than if it was covered.

Evaluation of 3 Phases Covered

- In this configuration, it is assumed that Phase A, Phase B, and Phase C will be covered.
- Analysis of effectiveness for mitigating phase to ground contact
  - Because the system is fully covered, there is a very low probability of incidental contact causing phase to ground faults.
- Analysis of effectiveness for mitigating phase to phase contact
  - Because the system is fully covered, there is a very low likelihood of incidental contact causing phase to phase faults.
- Analysis of fire mitigation effectiveness
  - Covered conductor is considered effective for fire mitigation due to its ability to prevent incidental contact. By fully covering all three phases, the possibility of faults due to incidental contact is greatly reduced.
  - If a downed wire scenario were to happen, covered conductors are less likely to cause a spark that bare wire. Therefore, the chance of ignition has been greatly reduced.

Neutral Covered

- In this configuration, it is assumed that Phase A, Phase B, Phase C and the Neutral will be covered.
- Analysis of effectiveness for mitigating phase to neutral contact
  - Because the system is fully covered, there is a very minute likelihood of incidental contact causing phase to phase faults.
- Analysis of fire mitigation effectiveness
  - In a downed wire scenario, a covered neutral will be less likely to cause a spark than a bare neutral.
  - Chance of ignition is reduced

Other Factors to consider

- Sagging
  - Covered conductor and bare wire are sagged at different tensions
  - If covered conductors were to be sagged like bare wire, it may cause vibration problems
  - Covered conductors have more sag than bare
  - Mixing bare and covered conductor in one crossarm will cause uneven sags
  - Uneven sags may increase the risk of conductor slapping, leading to an increased chance of insulation degradation, arcing, and ignition.
- Benchmark
  - Other utilities use a 3 phase covered system

Conclusion

- Partially covering the system (1 phase covered, 2 phase covered, bare neutral) will dilute the effectiveness of covered conductor.
- Using covered conductor for all three phases and the neutral promotes SCE's grid resiliency and the elimination of an ignition source.

3. SCE Covered Conductor Construction

This section illustrates how Covered Conductor and Wildlife Covers being used in SCE Standards to achieve maximum protection from incidental contacts

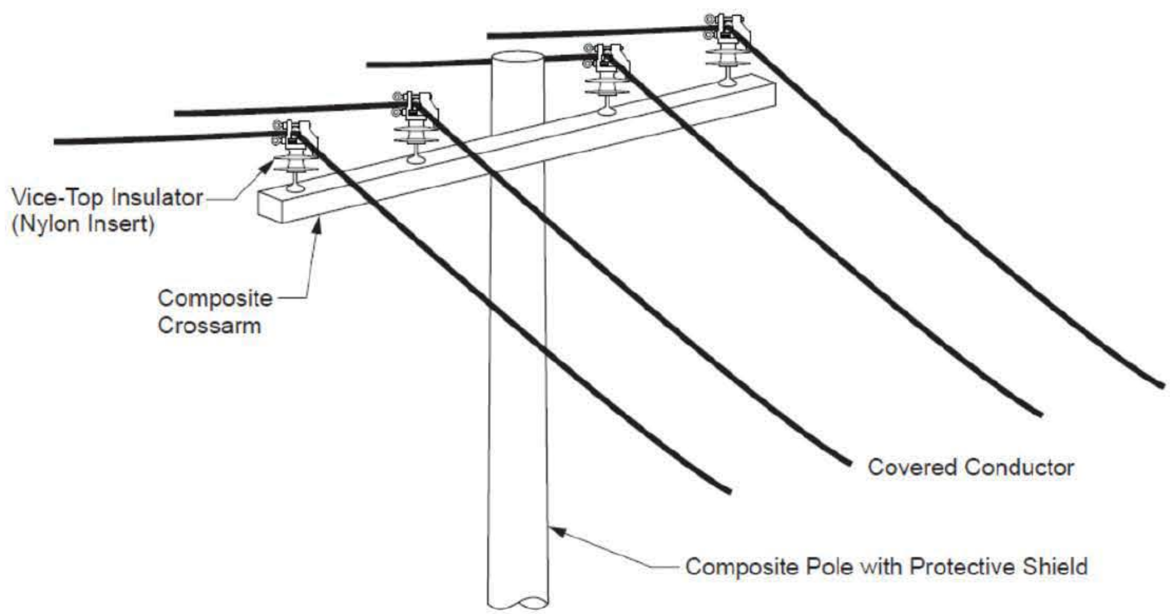
SCE Construction Diagrams

- SCE's covered conductor systems will be all covered
- This includes wildlife covers on dead-ends, terminations, and equipment bushings, jumper wires
- Also illustrated are other Wildfire resilient equipment/hardware, such as composite pole, composite cross-arm, polymer insulator for covered conductor
- These illustrations depict the four common pole configurations:
  - Tangent pole: means covered conductor pass thru insulators
  - Dead-end pole: covered conductor will stripped off to connect to dead-end insulator
  - Transformer pole: stripping cover required for connecting to transformer (or equipment)
  - Riser pole: stripping cover required to connecting to underground cable

Tangent 4 Wire Construction

Tangent pole does not need other covering hardware

3 Phase, 4 Wire Tangent (Straight-Line) Construction

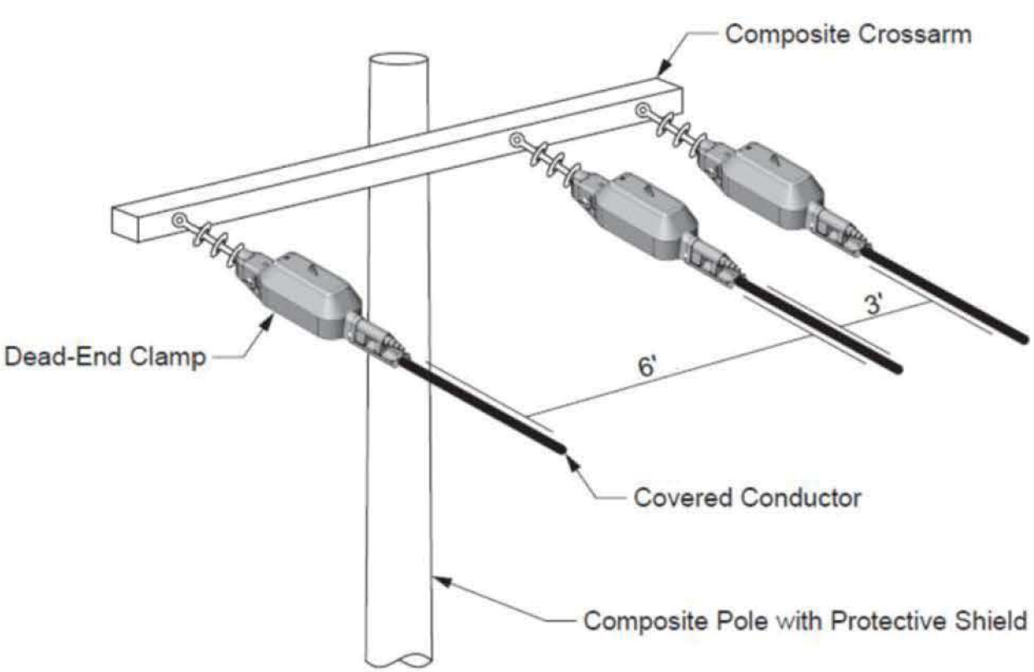


Same concept for three-wire and two-wire constructions

Three-wire Dead-end Construction

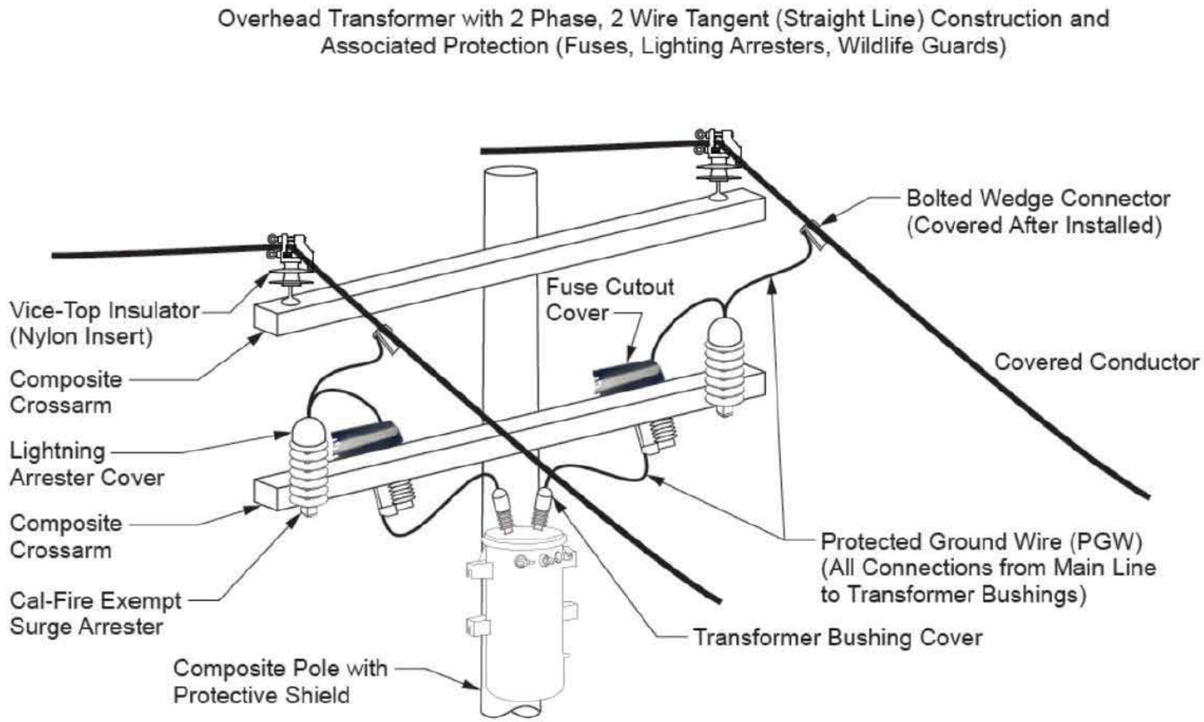
Introduce new standards for dead-end cover, composite pole and cross-arm

Single Dead-End (3 Phase, 3 Wire) Construction



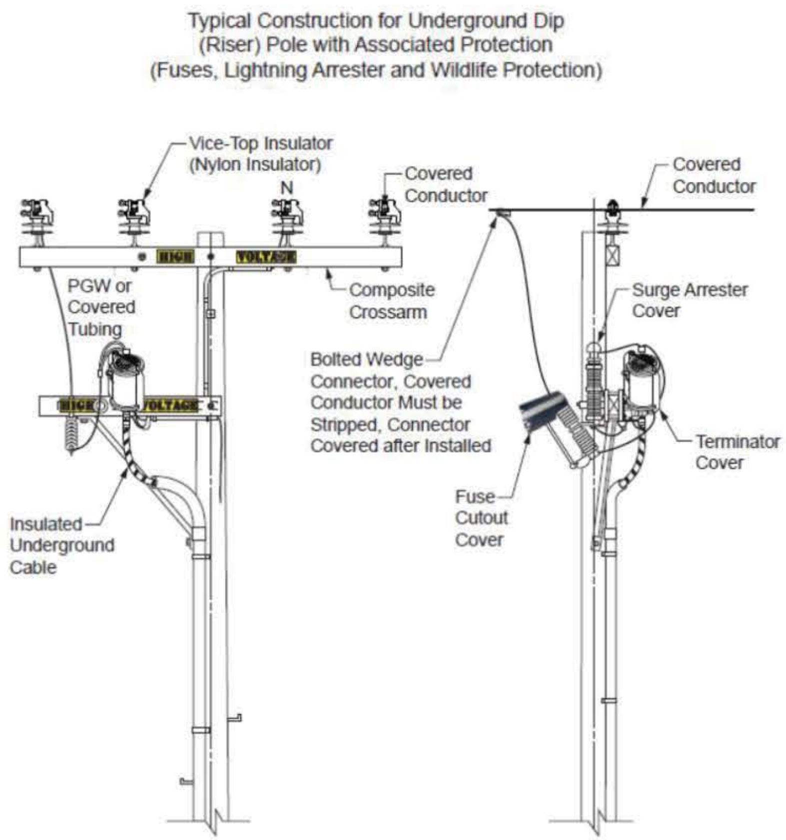
Same concept for four-wire and two-wire constructions

Tangent 2 Wire with Transformer Construction



Same concept for connecting to other equipment: capacitor, switch, remote automatic recloser, etc.

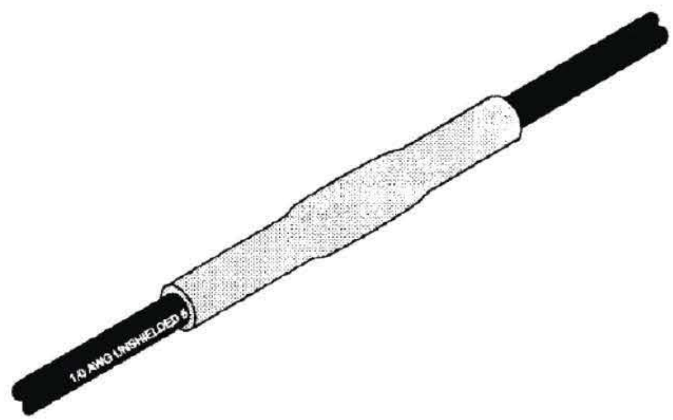
Riser Pole Construction



Same concept for three-wire and two-wire constructions

Splices

- Splices will be covered
- Splices for adjacent conductors shall not be installed next to each other and should be staggered 18 inches end to end.



Appendix B
Covered Conductor Related Questions from the Distribution Ground Inspection Survey

What type(s) of primary conductors are installed? Select all that apply.
NOTE: Only select primary conductor sizes and NOT taps/jumpers. Covered is tree wire. Aerial cable is bundled cable.

- Covered/insulated
- Copper
- Aluminum
- Aerial cable

For covered conductor – select all applicable directions covered conductor is installed? Select all that apply or select "No primary covered conductors installed".

- North
- South
- East
- West
- No primary covered conductor installed

For covered conductor – indicate if any of the following covered conductor covers are missing. Select all that apply or select "No missing covered conductor covers" or select "No primary covered conductor installed".

- Dead-end cover (Notification Required)
- Bare Tap (Notification Required)
- Connector cover (Notification Required)
- Fuse cover (Notification Required)
- Lightning arrestor cover (Notification Required)
- Equipment bushing cover (Notification Required)
- Pothead cover (Notification Required)
- No primary covered conductor installed
- No missing covered conductor cover

If covered conductor is installed, are there visible signs of tracking or damage on the outer jacket?

- Yes (Notification Required)
- No
- No primary covered conductor installed

For covered conductor – Are lightning arresters installed on structures containing the following equipment: RAR, RSR, Capacitors, Voltage Regulators, PTs associated with RSCs and PE equipment, Transformers, BLFs, and UG Dips?

- No (Notification Required)
- Yes
- No primary covered conductor installed

- No primary equipment present

For covered conductor – For line connections (excludes connections to equipment), what jumper is used?

- PGW (Notification Required)
- Bare wire (If bare, will need to be covered with split tube) (Notification Required)
- Covered Conductor
- Wire with split tube
- No covered conductor installed

Appendix C
Comparison of Expedited Grid Hardening Mitigations

Table 9.10-6: Expedited Grid Hardening Mitigations

Table SCE 9.10-6
Comparison of Expedited Grid Hardening Mitigation Measures

Mitigation	Reduce PSPS event frequency?	Reduce number of customers impacted by PSPS events?	Reduce PSPS event duration?	Notes
Covered Conductor	**Yes** When wind does not exceed covered conductor thresholds, events may be avoided	**Yes** When events are avoided, fewer customers may be impacted	**Yes** When wind still does exceed covered conductor thresholds, events may be shorter in duration	These benefits are achieved when a PSPS isolatable segment is fully addressed via covered conductor, exception, or a combination of both
Circuit Segment Exceptions	**Yes** When weather and environmental factors are consistent with the conditions for identified exception, events may be avoided	**Yes** When events are avoided, fewer customers may be impacted	**Yes** When weather and environmental factors are inconsistent with the conditions for identified exception, events may be shorter in duration	
Automated switches	**No** Automation does not inherently eliminate PSPS events (but may reduce the resulting impacts)	**Yes** With greater ability for circuit segmentation, fewer customers may be impacted	**Yes** With ability for remote operation, faster switching may reduce the duration of some events	These benefits are further enabled by installation of weather stations
Updated switching and load rolling plans	**No** Switching and load rolling does not inherently eliminate PSPS events (but may reduce the resulting impacts)	**Yes** With switching and load rolling plans updated to reflect most recent circuit conditions, fewer customers may be impacted	**No** Switching and load rolling does not inherently make PSPS events shorter in duration	
Temporary Generators	**No** Use of temporary generators does not inherently eliminate PSPS events (but may reduce their impacts)	**No** Customers served by temporary generators will still experience brief outages during PSPS events (associated with generator startup and switching)	**Yes** Customers served by temporary generators may see significantly shorter PSPS event durations	Temporary generators are not allowed to operate "in parallel" with the existing system prior to PSPS events for safety reasons
Undergrounding	**Yes** When circuits are fully underground, events will be avoided	**Yes** When events are avoided, fewer customers may be impacted	**Yes** When circuits are fully underground, events will be avoided	Underground segments may still be subject to PSPS depending on the presence of overhead circuitry elsewhere on the same circuit