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SOUTHERN CALIFORNIA EDISON®

(U 338-E)

SCE-02: Direct Testimony in Support of GRC Track 4 Activity Forecast Request

Before the

Public Utilities Commission of the State of California

Rosemead, California
May 13, 2022

SCE-02: Direct Testimony in Support of GRC Track 4 Activity Forecast Request

Table Of Contents

SCE-02: Direct Testimony in Support of GRC Track 4 Activity Forecast Request

Table Of Contents (Continued)

SCE-02: Direct Testimony in Support of GRC Track 4 Activity Forecast Request

Table Of Contents (Continued)

SCE-02: Direct Testimony in Support of GRC Track 4 Activity Forecast Request

Table Of Contents (Continued)

SCE-02: Direct Testimony in Support of GRC Track 4 Activity Forecast Request

Table Of Contents (Continued)

SCE-02: Direct Testimony in Support of GRC Track 4 Activity Forecast Request

Table Of Contents (Continued)

SCE-02: Direct Testimony in Support of GRC Track 4 Activity Forecast Request

Table Of Contents (Continued)

SCE-02: Direct Testimony in Support of GRC Track 4 Activity Forecast Request

Table Of Contents (Continued)

SCE-02: Direct Testimony in Support of GRC Track 4 Activity Forecast Request

Table Of Contents (Continued)

SCE-02: Direct Testimony in Support of GRC Track 4 Activity Forecast Request

Table Of Contents (Continued)

SCE-02: Direct Testimony in Support of GRC Track 4 Activity Forecast Request

Table Of Contents (Continued)

SCE-02: Direct Testimony in Support of GRC Track 4 Activity Forecast Request

Table Of Contents (Continued)

SCE-02: Direct Testimony in Support of GRC Track 4 Activity Forecast Request

Table Of Contents (Continued)

V.

GRID HARDENING

A. Content and Organization of Chapter

In this chapter, SCE presents its updated 2024 forecasts of capital expenditures and Operations and Maintenance (O&M) expenses for Wildfire Management grid hardening activities. The decision from Track 1 authorized a budget-based post-test year mechanism for 2022-2023 wildfire mitigation capital additions, which SCE is updating for 2024 (with the addition of vegetation management capital expenditures, which is a sub-activity created after Track 1 and are also in large part driven by wildfire mitigation activities).[1] Concurrent with this filing, SCE is submitting its 2022 Risk Assessment and Mitigation Phase (RAMP) report, which includes the 2022-2024 period for the baseline risk calculation and the 2025-2028 period for future mitigated risk calculation. In the subsequent sections, SCE summarizes the proposed scope of work, key drivers for the work, and any regulatory requirements that impact the level of capital and O&M requested for grid hardening activities. The funding request presented in this chapter is necessary for SCE to continue its efforts to enhance the safety of the electrical system and to minimize the risk of significant wildfires associated with SCE equipment, consistent with state policy.

The chapter also includes analysis of (1) capital and O&M funding authorized in the 2021 GRC Track 1 Final Decision compared to recorded amounts in 2021, and (2) SCE's 2024 capital expenditure and O&M expense forecasts for grid hardening activities. This chapter is organized by activity as follows:

- Section C summarizes SCE's capital and O&M requests for grid hardening activities, which aim to reduce the probability of ignitions;
- Sections D-J describe SCE's Integrated Grid Hardening Strategy that was outlined in our 2022 Wildfire Mitigation Plan (WMP) Update, and the corresponding sub-activities contained within grid hardening. For instance, Section E includes SCE's Wildfire

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[1] *See* 2021 GRC Track 1 Final Decision, p. 547.

Covered Conductor Program (WCCP), which includes the installation of covered conductor and fire-resistant poles, retrofit of covered conductor lines with vibration dampers, and removal of tree attachments;

- Section F describes the Targeted Undergrounding (TUG) program, specifically targeting areas with egress constraints, high consequence ignition risks, and those areas that may experience extremely high winds and dry fuels where overhead hardening may not sufficiently reduce the impact of Public Safety Power Shutoff (PSPS) events;
- Section G describes Rapid Earth Fault Current Limiters (REFCL), which collectively constitute a family of technologies that detect ground faults and rapidly reduce the fault current in the line experiencing the fault event;
- Section H describes Early Fault Detection (EFD) technology, which uses radio frequency sensors to detect and locate degraded electrical facilities;
- Section I describes Distribution Fault Anticipation (DFA), which is a system that uses predictive algorithms based on electrical system measurements to recognize current and voltage signatures indicative of potential pending equipment failures; and
- Section J describes HFRA Sectionalizing Devices, which are deployed to mitigate fault-related ignition risks and isolate circuit segments to reduce the scope of PSPS events.

B. Background and Overview

In 2021, California experienced another year of extreme wildfire activity, exacerbated by intensifying drought. The California Department of Forestry and Fire Protection's (CAL FIRE) data showed that almost half of the top 20 largest wildfires, dating back to 1932, occurred in the past two years.[2] In October 2021, Governor Newsom declared a drought emergency across California, stating that August 2021 was the driest and hottest August on record since the state began reporting data.[3] The increasing temperatures, drought conditions and other aspects of accelerating climate change make

[2] https://www.fire.ca.gov/media/4jandlhh/top20_acres.pdf. Five of the 20 largest wildfires occurred in 2020, and four of those 20 occurred in 2021.

[3] https://www.gov.ca.gov/2021/10/19/governor-newsom-expands-drought-emergency-statewide-urges-californians-to-redouble-water-conservation-efforts/.

certain portions of SCE's service area much more vulnerable to wildfire risk. Approximately 27% of SCE's service area are defined by the Commission's High Fire Threat District (HFTD) map to be inherently subject to "extreme" or "elevated" wildfire risk. As outlined in our 2022 Wildfire Mitigation Plan (WMP) Update, SCE continues to prudently harden the electric grid in a risk-informed manner to help ensure safety, grid resiliency, and system readiness for these growing climate change-driven impacts.

Wildfire mitigation measures have been part of SCE's operational practices for years, as high fire risk areas (HFRA)[4] account for a significant portion of SCE's service area. However, due to increasing risk factors in part driven by accelerating climate change, beginning in 2018 SCE significantly expanded its wildfire mitigation programs as first set forth in its Grid Resiliency & Safety Program (GSRP) Application in late 2018. The GSRP proceeding proposed wildfire mitigation measures for the 2018-2020 period (incremental to amounts authorized in the 2018 GRC). In Track 1 of SCE's 2021 GRC, the Commission authorized wildfire mitigation programs (and their associated revenue requirements) for Test Year 2021 and attrition years 2022 and 2023. Additionally, Track 2 of the 2021 GRC addressed non-GSRP-related incremental wildfire mitigation costs for 2018-2019, and Track 3 addressed non-GSRP-related incremental wildfire mitigation costs for 2020, as well as GSRP costs for the 2018-2020 period above the amounts authorized in the GSRP Settlement Agreement (D.20-04-013). Due to the Commission's transition to a four-year GRC cycle, SCE is filing Track 4 requesting wildfire mitigation costs SCE expects to incur in 2024. SCE's Track 4 proposal generally aligns with the type of work and scope set forth in the Track 1 Final Decision.

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[4] SCE's HFRA is based on a combination of historical map boundaries (based on past fire management and response experiences), California Department of Forestry and Fire Protection's (CALFIRE) Fire Hazard Severity Zone maps, and the California Public Utility Commission's approved statewide fire High Fire Threat District (HFTD) maps. Collectively, SCE has considered Zone 1, Tier 2, and Tier 3 (collectively, the HFTD) and non-CPUC historical high fire risk areas to collectively be the HFRA. Zone 1 consists of Tier 1 High Hazard Zones (HHZ) on the map of Tree Mortality HHZs prepared jointly by the United States Forest Service and the CALFIRE. Tier 1 HHZs are in direct proximity to communities, roads, and utility lines, and represent a direct threat to public safety. Tier 2 consists of areas on the CPUC's Fire-Threat Map where there is an "elevated" risk for destructive utility-associated wildfires. Tier 3 consists of areas on the CPUC's Fire-Threat Map where there is an "extreme" risk for destructive utility-associated wildfires.

At the inception of its wildfire mitigation program, SCE utilized portfolio level risk-spend efficiencies and operational considerations to determine the appropriate scope of the program. From there, SCE used several iterations of risk-prioritization models for covered conductor deployment to inform prioritization of work from 2018 through 2023. SCE's risk-prioritization models are just that: models that determine the appropriate order of work to be performed (when operationally feasible and efficient), and the not the total amount or scope of work that should be done. Risk prioritization models estimate both the probability of ignition (POI) and their likely consequences, such as acres and structures burned. The outputs of those risk-prioritization models appropriately guided SCE's wildfire mitigation efforts in where to begin grid hardening deployment (*i.e.*, how to address the highest relatively risky areas first (when operationally feasible and efficient)). But SCE's total scope of work – including in this Track 4 – is appropriately determined by the objective of reducing the appropriate amount of absolute wildfire risk in specific locations to protect customers and communities.

SCE has further refined its grid hardening approach, based on guidance and requirements from the Office of Energy Infrastructure Safety (OEIS or Energy Safety) and the Commission in the 2021 WMP Update and the 2021 GRC, respectively. SCE's Integrated Grid Hardening Strategy (IGHS) is consistent with three regulatory directives from the Commission and Energy Safety regarding grid hardening. First, in the Track 1 Final Decision, the Commission "allow[ed] SCE to install additional covered conductor miles above the 4,500 circuit-mile level, including within this GRC period, subject to after-the-fact reasonableness review; however, SCE will have the burden to affirmatively establish further covered conductor deployment is justified based upon its most recent WMP and up-to-date circuit segment risk calculations."[5] Second, in the August 2021 Final Action Statement on SCE's 2021 WMP, OEIS required SCE to "[r]e-evaluate the scope and pace of its future covered conductor program," with an "explicit consideration of all possible alternative mitigation initiatives [including for the] [r]eduction of PSPS events," and to further evaluate the "[e]ffectiveness of covered conductor in the

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5 D.21-08-036 at p. 201.

field … ."[6] Third, in the Track 1 Final Decision, the Commission also directed "SCE to incorporate egress, and other conditional risks as appropriate, in future RAMP and GRC risk modeling."[7]

In response to this regulatory guidance and in the pursuit of continuous improvement, SCE continued benchmarking with other utilities[8] and performing updated risk analyses with more sophisticated tools and improved data sets acquired over the past few years. SCE also conducted a segment-by-segment assessment of all of its overhead distribution system in HFRA to identify where the consequences of an ignition to public safety are most significant that would require SCE to proactively mitigate as many significant risk drivers as reasonably possible and determine which mitigations to deploy in each of those locations to achieve that objective. Collectively, this led to IGHS, which drives our Track 4 wildfire mitigation forecast and plans. Specifically, through IGHS SCE proposes the continued deployment of covered conductor in 2024 through our WCCP, but adds the proposed increased deployment of TUG, as well as a suite of complementary mitigations measures for sections of our overhead distribution facilities where an ignition has the most potential of growing into a significant wildfire. These additional measures include deployment of other new technologies such REFCL, which are discussed in Sections E-J of this Chapter. As discussed in Section D below, SCE's proposed scope of work – and the mix of mitigations that make up that work – is driven by the necessity to reduce unacceptable amounts of public safety risk related to ignitions and population egress constraints in the event of a wildfire.

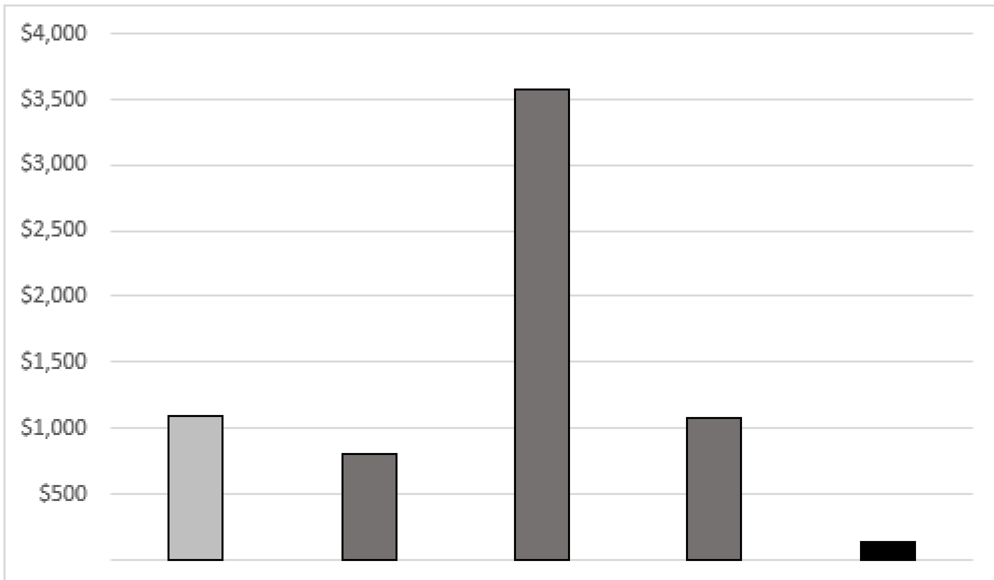
C. Summary of O&M and Capital Request

This Chapter V presents SCE's requests for $0.134 million (Constant 2018 dollars) in O&M expense and $866.769 million in capital expenditures (Nominal $) for the 2024 bridge-funding year to effectively implement its wildfire mitigation activities. SCE's total requests for Wildfire Management – Grid Hardening are presented below in Figure V-1 for 2024 O&M expense and Figure V-2 2024 for capital expenditures. This funding is crucial to implement effective wildfire mitigation programs and

6 August 18, 2021 Final Action Statement on the 2021 Wildfire Mitigation Plan (WMP) Update of Southern California Edison Company (SCE) at pp. 57-58.
7 D.21-08-036 at Finding of Fact (FoF) 567.
8 *See* Appendix B, Joint IOU CC Effectiveness Workstream.

activities designed to reduce the frequency and likelihood of ignitions and risk of significant wildfire associated with utility infrastructure.

Figure V-1
O&M Summary
Wildfire Management - Grid Hardening
O&M Authorized, Recorded, and Forecast[9]
(Constant 2018 $000)



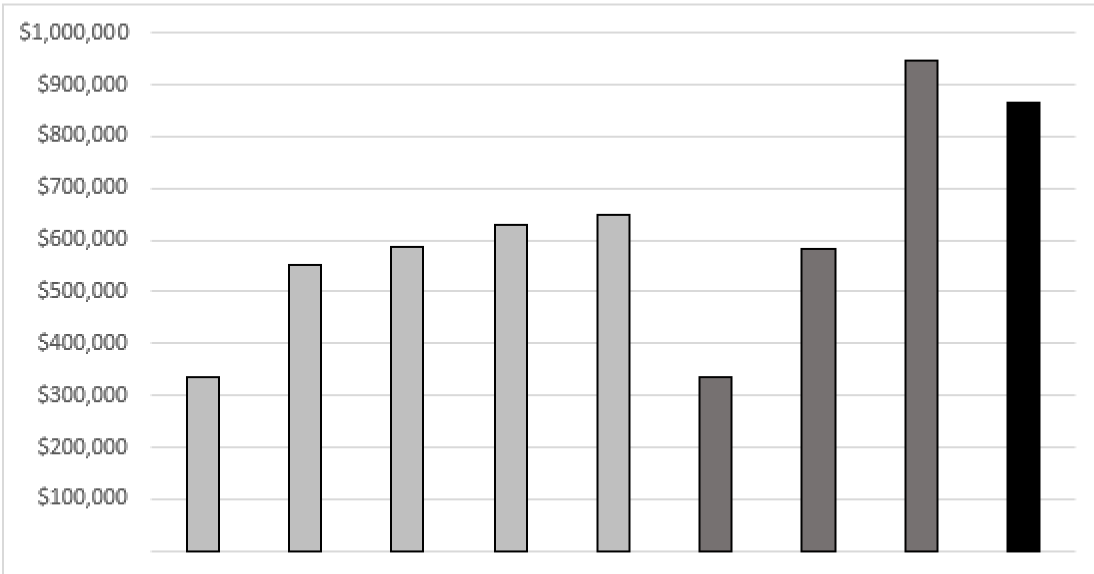
Track 1 Authorized*	Recorded			Track 4 Forecast
2021	**2019**	**2020**	**2021**	**2024**
$1,089	**$811**	**$3,575**	**$1,076**	**$134**

		Track 1 Authorized*	Recorded	Recorded	Recorded	Track 4 Forecast
	Subactivity	**2021**	**2019**	**2020**	**2021**	**2024**
1	Distribution Fault Anticipation	($0)	$150	$215	$134	$134
2	HFRA Sectionalizing Devices		$409	($13)	$13	
3	Fusing Mitigation	$1,089	$252	$3,255	$35	
4	Transmission Open Phase Detection			$118	$894	
	Total Expenses	**$1,089**	**$811**	**$3,575**	**$1,076**	**$134**

* Authorized 2022 and 2023 are equivalent to 2021 authorized (in constant 2018 dollars) after removing the impact of the Track 1

[9] Fusing Mitigation and Transmission Open Phase Detection are included in this figure to account for recorded costs, however as there are no 2024 forecasts, Track 4 does not contain any testimony on these two activities.

Figure V-2
Capital Summary
Wildfire Management - Grid Hardening
Capital Authorized, Recorded, and Forecast[10] [11]
(Nominal $000)



Track 1 Authorized					Recorded			Track 4 Forecast
2019	2020	2021	2022	2023	2019	2020	2021	2024
$334,982	$550,426	$585,876	$629,297	$650,016	$334,982	$581,556	$947,585	$866,769

		Track 1 Authorized					Recorded			Track 4 Forecast
	Subactivity	2019	2020	2021	2022	2023	2019	2020	2021	2024
1	Wildfire Covered Conductor Program	$249,288	$509,814	$557,495	$580,066	$604,826	$249,288	$553,802	$919,542	$796,024
2	Targeted Undergrounding			$23,047	$43,713	$45,190		$784	$6,586	$45,996
3	Rapid Earth Fault Current Limiter (REFCL)							$1,855	$3,668	$18,827
4	Early Fault Detection								$2,015	$5,922
5	Distribution Fault Anticipation	$3,445					$3,445	$260	$8,362	
6	HFRA Sectionalizing Devices	$11,951	$28,961	$5,334	$5,518		$11,951	$15,900	$7,891	
7	Fusing Mitigation	$70,298	$11,651				$70,298	$8,955	($479)	
	Total Capital	**$334,982**	**$550,426**	**$585,876**	**$629,297**	**$650,016**	**$334,982**	**$581,556**	**$947,585**	**$866,769**

D. Integrated Grid Hardening Strategy (IGHS)

1. Background

Since the devastating California wildfires that occurred in the last half of 2017, SCE has been enhancing and advancing its approach to reducing the risk of ignitions associated with utility

[10] SCE identified errors in the WCCP and REFCL capital forecasts. SCE's corrected unit cost forecast for covered conductor results in a capital forecast for WCCP is $25.6 million (nominal $) higher than what is currently reflected in the RO model and overall revenue requirement. Similarly, SCE's corrected forecast for the number of planned REFCL installations in 2024 is $18.957 million lower than what is in the RO model
(*Continued*)

equipment. Over the last several years, it has become apparent that the magnitude of wildfire risk associated with significant portions of SCE's service areas is unacceptable and continuing to grow. Accelerating climate change, with associated extreme weather events and pervasive drought, as well as the continued expansion and migration of Californians into the wildland-urban interface,[12] has made it imperative that SCE do everything within its reasonable control to mitigate the risk of catastrophic wildfires associated with its overhead lines; historically, these assets are linked to the majority of ignitions and ignition risk associated with SCE's utility equipment.

Wildfires over the last five year-period, have demonstrated that the level of absolute risk across California and the West may require actions beyond the utilities' short- and medium-term risk mitigation plans which is the focus of Track 4. For example, burning for months in 2021, the Dixie Fire became the largest single wildfire in California history, burning almost a million acres – an area larger than the state of Rhode Island – and across the crest of the Sierra Nevada mountains. On December 30, 2021, an unprecedented wildfire broke out in suburban Boulder, Colorado, spreading with devastating speed and destroying more than 1,000 structures. Both of these events demonstrate that the level of absolute wildfire risk on the system – including potentially in areas that may not currently be designated as HFTD – is beyond what can be mitigated and addressed in a single GRC cycle (and certainly in a single attrition year). Given finite resources and other constraints, SCE uses a risk-prioritization methodology to sequence the deployment of mitigations in the riskiest parts of its service area, as defined by the Commission's HFTD maps. Our risk prioritization methodology helps us determine the relative ranking of locations from a risk perspective, to help prioritize work in the very riskiest areas using the most effective and expeditious mitigations.

To address the unacceptable level of absolute risk facing our customers and communities associated with wildfires, beginning in 2018 SCE initiated an ambitious plan to significantly and

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and overall revenue requirement. While the amount shown in this table is correct, SCE will submit errata in the future to update the RO model and overall revenue requirement.

[11] Fusing Mitigation is included in this figure to account for recorded costs, however as there is no 2024 forecast, Track 4 does not contain any testimony on this activity.

[12] Wildland-urban interface is dense housing adjacent to vegetation that can burn in a wildfire. https://frap.fire.ca.gov/media/10300/wui_19_ada.pdf.

materially harden our overhead electrical infrastructure to reduce ignitions associated with that infrastructure. Those efforts – effectuated through SCE's WCCP – focused on replacing existing overhead bare wires with wires covered by insulating materials, also known as "covered conductor." In Track 1 of this GRC, the Commission approved a substantial portion of SCE's request for covered conductor: 4,500 circuit miles over the 2019-2023 period. SCE has effectively executed on that authorized work, and SCE's covered conductor installations to date have materially reduced ignition risk across the HFRA.[13] But more needs to be done to protect customers. Accordingly, in this Track 4 SCE is proposing an additional scope of 1,200 miles of covered conductor for completion in 2024 (which constitute miles ~5,000-6,200 under WCCP). SCE recognizes that the Track 1 Final Decision requires SCE to justify the reasonableness of installing miles beyond the initial 4,500-mile tranche authorized therein. SCE has done so in this testimony. The circuit-by-circuit analysis that led to SCE's IGHS demonstrates that substantial and unacceptable ignition risk remains on portions of the HFRA that will not have been hardened within the first 4,500 miles of WCCP installation.

In addition, and as discussed in detail below, recently it has become clear to SCE that for certain selected portions of our service area, there is either a lack of available road capacity that could prevent people from effectively evacuating in the event of an approaching wildfire (this is known as "egress constraint"); have an exceptionally high consequence in acres burned at eight (8) hours; or there is the likelihood of continuing PSPS events even if covered conductor is installed. Accordingly, for those selected areas (and for areas adjacent to them from which a wildfire could propagate), the risk of ignitions or the likelihood of continued PSPS events occurring is simply too high to rely on covered conductor alone. While covered conductor is extremely effective at reducing ignitions by addressing several of the most significant risk drivers that lead to ignitions, it is more appropriate to maximize the risk reduction in these select areas with targeted undergrounding to the extent feasible. Accordingly, SCE's IGHS proposal includes undergrounding the unhardened overhead equipment in these

[13] *See* Section V.E for details.

extraordinarily risky areas.[14] Undergrounding eliminates almost all ignition risks associated with electrical equipment, which is necessary for those limited areas that face egress constraints, and in which a wildfire occurring could lead to catastrophic consequences. Undergrounding also virtually eliminates the need for PSPS on circuits that have been undergrounded. Accordingly, in this Track 4 SCE proposes to underground approximately 20 miles of overhead wire through TUG.[15]

a) Evolving Risk Analysis

SCE's latest risk analysis enhanced methodology considers not only the public safety risk associated with simulated ignition probabilities, but also the public safety-related egress risk during wildfires, as well as reliability risk due to PSPS. SCE's updated egress risk analysis methodology is used in this filing, as well as the 2022 RAMP (being submitted concurrently with this Track 4). As more sophisticated tools and improved data sets became available, SCE further refined its mitigation strategy by identifying locations where the consequences of an ignition to public safety are most significant and deploying a suite of mitigations that can reduce as many significant risk drivers as reasonably possible. The Commission has already defined all areas in HFTD as inherently being at elevated or extreme risk of wildfire. Within those HFTD areas, SCE has also determined subsets of areas that are considered "Severe Risk Areas," as they have attributes that further elevate the risk levels to populations residing, working in, or visiting these locations. In addition, within the HFTD, SCE has defined certain areas as "High Consequence Segments," which are areas where a wildfire can propagate over large areas in a relatively short period of time and/or have the potential to be impacted by PSPS. Finally, the remaining risk areas in the HFTD are included in the "other HFRA" category.

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[14] Because of the uncertainties associated with accelerating climate change and changing risk profiles, in certain cases, in the future SCE may need to underground specific circuit segments that were already hardened with covered conductor to further reduce risk and protect SCE's customers. At this time, SCE expects such occurrences to be the exception and not the rule.

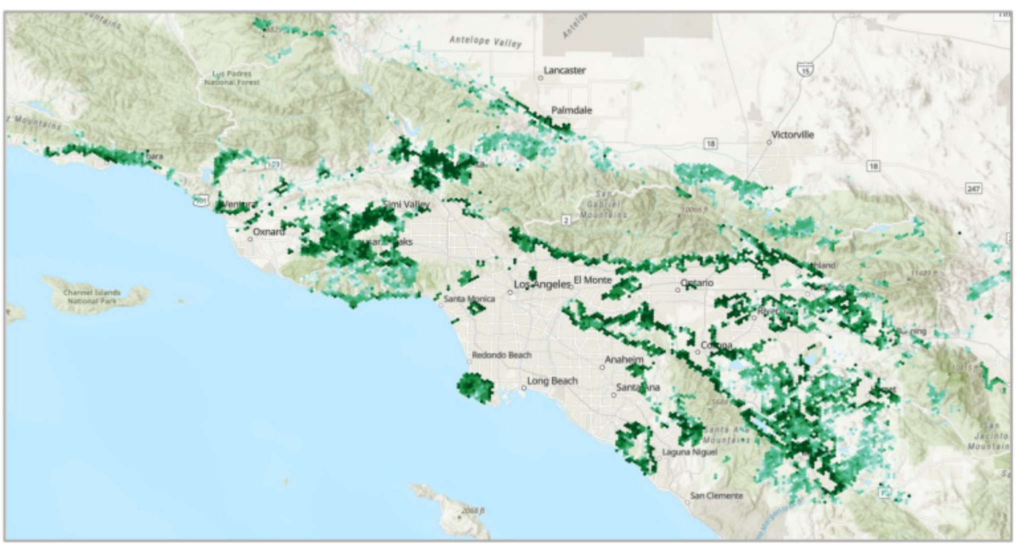
[15] In certain situations, as discussed below, undergrounding is infeasible. For example, certain existing overhead infrastructure is located directly above rocky mountains or other substantially challenging terrain, or where there is not enough room to meet required clearances for an underground replacement.

(1) <u>Severe Risk Areas</u>

SCE divided its HFRA into equally-sized polygons or hexagons.[16] From these hexagons, SCE categorizes Severe Risk Areas as locations with egress challenges, areas that fires have historically propagated towards (burn-in buffer), areas with extremely high winds, and areas with extreme Technosylva[17] consequence scores (*i.e.*, greater than 10,000 acres burned within 8 hours in simulated wildfire ignition consequence).

SCE first defined the egress constrained areas as those with substantial road availability concerns, using a ratio of roads to the population in each hexagon. A lower score indicated fewer miles of roads available per person in a given hexagon, meaning a potential egress concern should everyone in the polygon need to evacuate the area simultaneously. Figure V-3 shows areas with egress concerns in green hexagons. The darker green indicates less road availability for egress.

Figure V-3
Egress Constrained Areas



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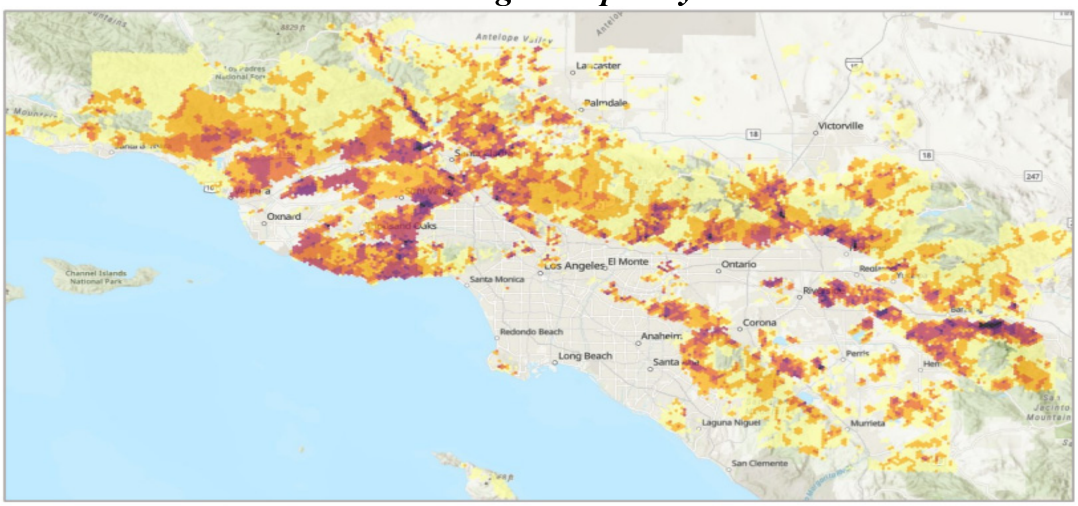
[16] SCE used hexagons because the distance from the center of a hexagon to all adjacent hexagons is the same distance and it enabled SCE to compare variables across similar-sized polygons.

[17] In 2020 SCE adopted a GIS-enabled software platform known as Technosylva to enhance SCE's ability to model wildfire risk. One of the tools provided by Technosylva is the Wildfire Risk Reduction Model (WRRM), which integrates wildfire ignition probability.

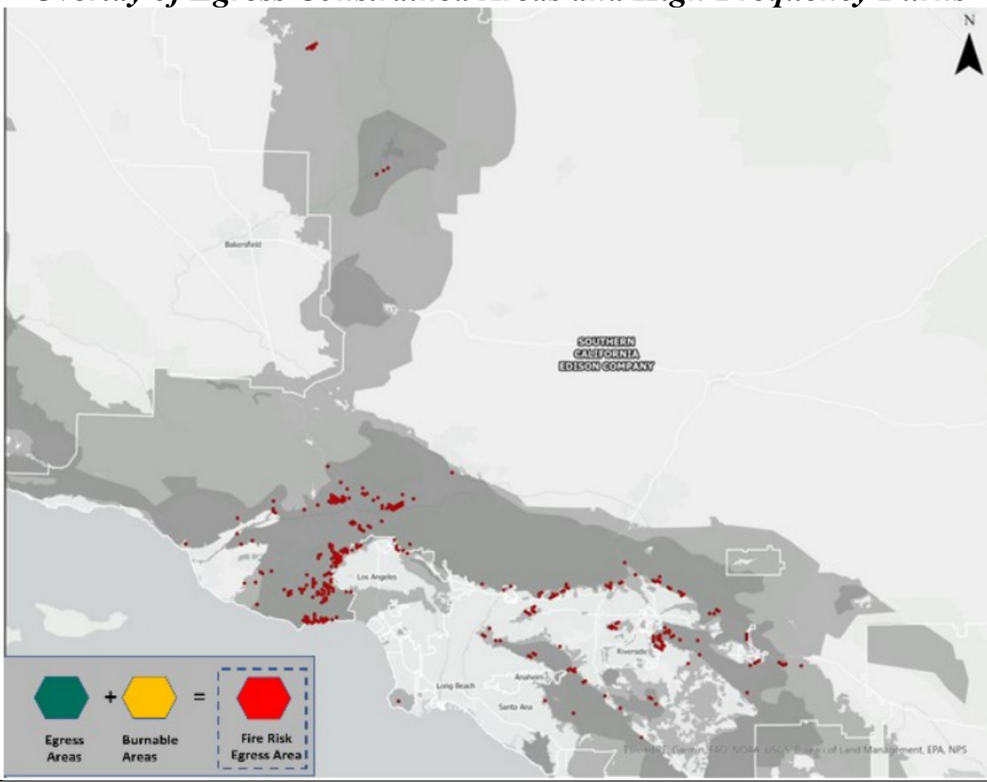
SCE then overlaid the egress-constrained areas with regions that have a high historical fire frequency using fire scars from 1970 to 2020. A higher score indicated a higher likelihood that a given hexagon will burn, meaning fires either originated from or travel into these hexagons (see Figure V-4).

Figure V-4
Areas with High Frequency Fires



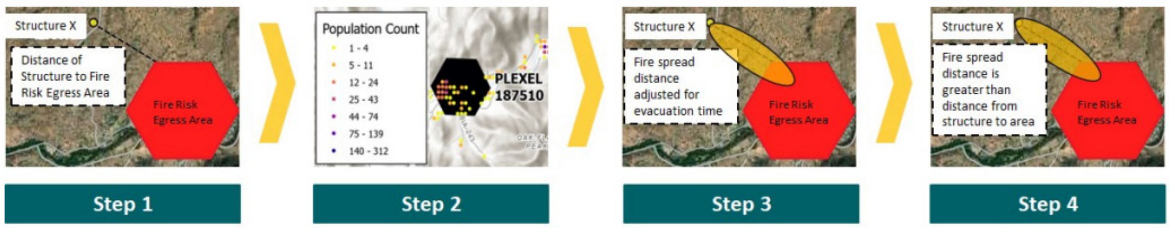
SCE flagged hexagons with both limited road availability and a high burn frequency as potential Fire Risk Egress Constrained Areas shown in Figure V-5 below.

Figure V-5
Overlay of Egress Constrained Areas and High Frequency Burns



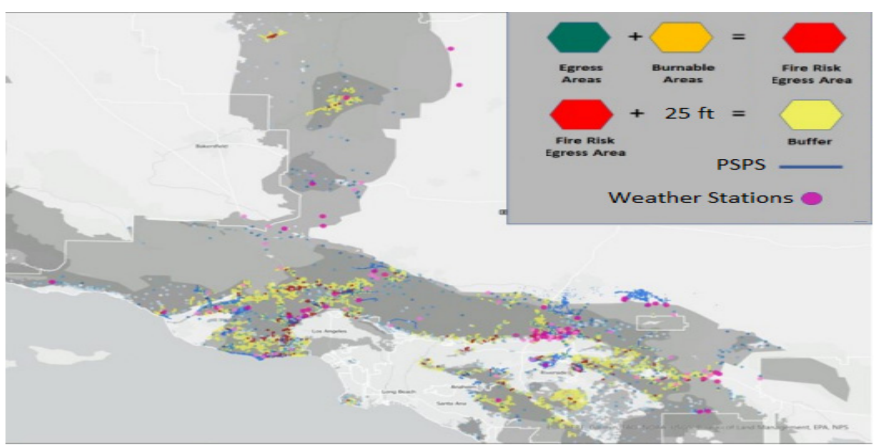
Utilizing Technosylva simulated wildfire ignition consequence data, SCE determined locations where SCE infrastructure could be associated with an ignition that would potentially result in fires burning into Fire Risk Egress Constrained Areas (within 8 hours), potentially trapping members of the public. Figure V-6 below shows the steps taken to determine this area, which SCE refers to as the Burn-in Buffer. In step 1, SCE identified all structures within 25 miles of a Fire Risk Egress Constrained Area. In step 2, SCE calculated the time needed for the population to exit the polygon using population size, travel speed, and distance to safety. Taking into account terrain and other factors, in step 3 SCE calculated the distance the fire could travel from each SCE distribution overhead structure within 25 miles, in the time needed to evacuate the Fire Risk Egress Constrained Area. In step 4, SCE flagged the structure as a potential burn in buffer structure if a fire originating there could enter the Fire Risk Egress Constrained Area, accounting for wind direction, topography, and physical barriers (*e.g.*, lakes).

Figure V-6
Burn in Buffer



With the benefit of available data from SCE's weather stations that SCE has installed over the last several years since the initiation of our enhanced wildfire mitigation efforts, SCE was able to examine historical wind data since 2017 and determine which areas have experienced high sustained wind speeds above 40 mph and wind gusts above 58 mph (i.e., SCE's current PSPS de-energization thresholds for fully covered isolatable conductor segments) (see Figure V-7 below).[18]

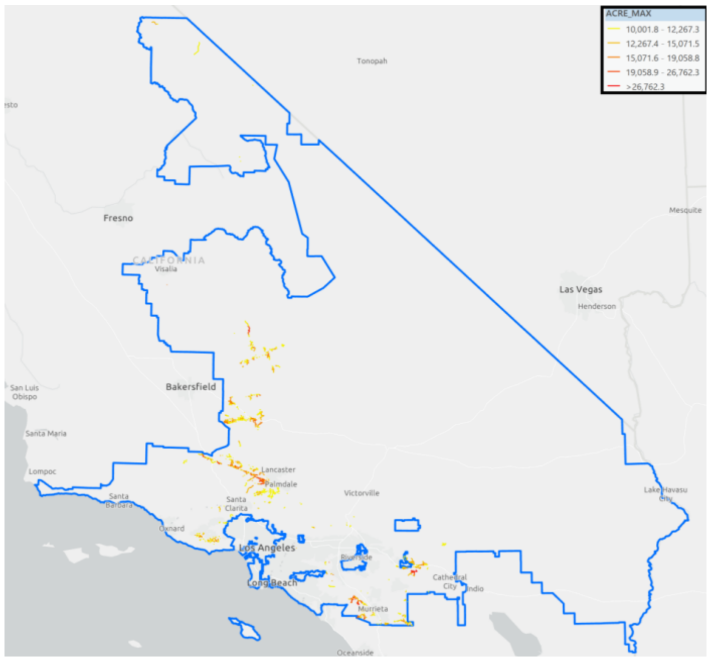
Figure V-7
Areas with Extremely High Wind Speeds



[18] The blue line in the figure shows PSPS circuits that are likely to exceed Fire Potential Index (FPI) criteria (wind/fuel moisture) even if fully covered. The purple dots in the figure shows SCE's weather stations in which gusts have been recorded in excess of threshold.

Finally, SCE determined segments in its HFRA that have an exceptionally high Technosylva consequence in acres burned at eight hours.[19] SCE used the threshold of 10,000 simulated acres burned in the first 8 hours. Historical data shows that some fires that burn over 10,000 acres in the first 8 hours ultimately burn over 100,000 acres.

Figure V-8
Areas with Exceptionally High Technosylva Consequence Scores



SCE aggregated the analyses on egress, burn-in buffer, extreme high winds, and extreme Technosylva consequence to determine the Severe Risk Areas.[20] Of the 9,700 total distribution circuit segment miles within its HFRA, SCE identified approximately 2,275 miles that are in this category of risk. From these 2,275 miles, SCE removed miles that already have been hardened with covered conductor installation and that are now in pre-construction and in-construction for covered conductor hardening. This resulted in approximately 700 miles of unhardened Severe Risk Areas scope, which SCE needs to mitigate over time (*i.e.*, approximately 600 miles of undergrounding and 100 miles

[19] Eight hours was used due to the current modeling capability of SCE's Technosylva model.
[20] SCE conducted further review of the segment designations (*i.e.*, severe, high consequence) in its HFRA after filing its WMP and updated some of the designations based upon the additional review.

of covered conductor due to infeasibility of undergrounding or urbanized areas)[21] (see Table V-2 below). Once the scope of 700 miles was established, SCE then engaged in a second, more detailed review of this more discrete scope to determine feasibility of undergrounding. This second and more in-depth review was conducted with the regional planners and resulted in the conclusion that within the 700 miles, 100 of those miles were not feasible to be mitigated by undergrounding.

(2) High Consequence Segments

For miles that are not included in Severe Risk Areas but are categorized as a High Consequence Segment, SCE proposes to deploy the full suite of CC++ measures as the preferred mitigation option on all remaining High Consequence Segments. Although these miles do not have the risk profiles that would qualify them as Severe Risk Areas (and that would therefore lead SCE to underground them), they are still sufficiently risky so that covered conductor standing alone would be insufficient from a risk mitigation standpoint. HFRA overhead conductor segments in which associated simulated wildfire ignitions resulted in a wildfire consequence of 300-acres-or-greater after 8 hours,[22] as well as those circuits which have the potential to be frequently impacted by PSPS events and not captured in Severe Risk Areas were categorized as High Consequence Segments. Technosylva fire-spread projections rely on an assumed eight-hour burn duration after ignition.

The real-world implications of a fire of that spreads to 300 acres or more within eight hours can be far more dire. Analysis of more recent fires in California between 2018 and 2020 shows that one out of four (25%) fires that were only 300-999 acres after approximately eight hours post ignition ultimately grew to 10,000 acres or more (Figure V-9).[23] SCE's analysis of California fires between 2015 to 2019 indicated that number of acres burned was a reasonable and reliable

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21 For locations that meet the Severe Risk Area criteria, but where undergrounding would not be practically feasible, SCE will deploy covered conductor (CC) supplemented with other vegetation and asset management activities. These activities include the Hazard Tree Mitigation Program (HTMP), pole brushing, line clearance, and enhanced inspection practices where appropriate. Collectively, deploying covered conductor in combination with these other activities is known as CC++. These are discussed in the sections below.

22 CAL FIRE uses the 300-acre threshold for large fires in its annual fire report. The National Wildland Coordinating Group defines a "large fire" as any wildland fire in timber 100 acres or greater and any grassland/rangeland fire 300 acres or greater.

23 Data from SimTable https://www.simtable.com/.

correlated proxy for buildings destroyed. For example, as shown in Table V-1, a fire of 10,000 to 50,000 acres or more results in the destruction, on average, of approximately 200 buildings.

Figure V-9
Fire Size at 8-Hours Relative to Final Fire Size

Table V-1
High Correlation between Final Fire Size and Average Buildings Destroyed

Final Fire Size (Acres)	Average Buildings Destroyed
300-1k	~2
1k-5k	~7
5k-10k	~15
10k-50k	~200
50k+	~1250

In addition, SCE conducted an analysis that identified circuits that have experienced or are expected to experience high customer minutes of interruption (CMI) from PSPS de-energizations absent appropriate grid hardening.[24] The analyses on fire propagation and PSPS impacts collectively informed the determination of High Consequence Segments. Of the 9,700 total distribution circuit segment miles within its HFRA, SCE identified approximately 4,675 circuit miles that fall into

[24] Circuits outside of those already hardened, scoped, or within Severe Risk Areas.

this category of risk. From these 4,675 miles, SCE removed already hardened and, in-construction miles. This resulted in approximately 2,100 miles of unhardened High Consequence Segments scope, which SCE needs to mitigate over time (*i.e.*, all 2,100 miles with covered conductor hardening) (see Table V-2 below).

(3) Other HFRA

For its overhead distribution lines that are neither High Consequence Segments nor Severe Risk Areas, SCE will replace retired or damaged bare wires with covered conductor pursuant to its standards in HFRA (*i.e.*, we are not currently planning on proactive replacement). SCE will continue wildfire mitigation initiatives such as asset inspections, Fast Curve (FC) settings, and vegetation management work that have relatively low incremental costs or are dictated by compliance requirements or local conditions. Although SCE is not currently targeting proactive hardening of these lines (with the exception of where it may be operationally efficient to do so),[25] SCE will regularly re-evaluate risks in these locations based on climate change impacts, refined risk methodologies and modeling, and/or more accurate information. Of the 9,700 total distribution circuit segment miles within its HFRA, SCE identified approximately 2,750 circuit miles that fall into this category of risk. From these 2,750 miles, SCE removed already hardened[26] and in-construction miles through a high-level scoping review. This resulted in approximately 1,650 miles of unhardened "Other HFRA" scope. For these miles, SCE plans to mitigate them via 1,250 miles of hardening of non-WCCP miles reactively hardened over time pursuant to SCE's current engineering standards and 400[27]

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[25] During the course of installing covered conductor under the WCCP, operational realities must also be considered in determining the actual amount of deployment scope (20% additional circuit miles for spans adjacent to those determined to be high risk).

[26] In some cases, SCE has previously hardened miles in areas that SCE would not currently designate as High Consequence Segments or Severe Risk Areas. That is due both to previous work being completed pursuant to scoping conducted under previous iterations of SCE's risk-prioritization methodologies and/or "buffer" miles, which are additional miles installed immediately adjacent to risk-prioritized circuit segments, for operational reasons. Regarding previous risk-prioritization methodology scoping installations, please refer to SCE's Track 3 Briefs. Regarding the operational buffer, please refer to the Track 1 Final Decision at p. 204 and Conclusion of Law (CoL) 74, specifically authorizing such work.

[27] There are a total of 2,050 miles of covered conductor SCE plans to complete in the 2024-2028 period (*i.e.*, 100 in Severe Risk Areas plus 1,950 in High Consequence Segments). The 20% buffer of these 2,050 is approximately 400 miles in "Other HFRA."

miles of WCCP installation due to the Commission-authorized operational "buffer" described above (see Table V-2 below).

Table V-2
Number of Miles SCE Plans to Proactively Harden in 2024-2028

Category of Risk	Total Miles In HFRA	Unhardened Miles by End of 2023	Miles SCE Plans To Proactively Harden in 2024-2028
Severe Risk Area Miles	2,275	700	700
High Consequence Segments Miles	4,675	2,100	1,950
Other HFRA Miles	2,750	1,650	400
Total	**9,700**	**4,450**	**3,050**

b) Mitigation Selection

SCE utilized the decision tree in Figure V-10 below to determine the appropriate mitigation strategy for each circuit segment location, which informed this Track 4's proposed scope. Per the decision tree, if the circuit segments are located in a Severe Risk Area and are not already hardened, then SCE determines whether it is feasible to underground. If feasible, SCE will underground those segments.[28] Similar to the operational buffer adopted for WCCP in SCE's 2021 GRC Track 1 Final Decision, the final scope for undergrounding will also include any miles necessary to account for operational realities.[29] If not, SCE will harden with covered conductor and perform additional mitigations, such as asset and vegetation management (*e.g.*, CC++).[30] For segments already hardened that are in Severe Risk Areas, SCE will add additional mitigations. If the circuit segments are not in Severe Risk Areas but are in High Consequence Segments, and are also not already hardened, SCE will install covered conductor. All segments in this case will also receive additional mitigations (*e.g.*, CC++). If circuit segments are not located in a Severe Risk Area or do not meet the High Consequence criteria, then they are considered as "Other HFRA" and will be hardened over time through other replacement programs (including storm rebuilding work as necessary) since the standard in HFRA is covered

[28] The final selection of underground scope is determined through a feasibility analysis to determine the level of difficulty, which is discussed in Chapter V.F.1.c)(1)(a) below.

[29] Undergrounding lines often requires re-routing that results in more circuit miles constructed than if the structures were left overhead.

[30] Please see page 23 for a definition of CC++.

conductor. Under this integrated grid hardening strategy, SCE proposes to harden a total of approximately 3,050 circuit miles of riskiest areas in the 2024-2028 period for the reasons stated above. Specifically, for 2024 (*i.e.*, this Track 4), SCE proposes to install 1,200 circuit miles of covered conductor, 20 circuit miles of undergrounding, and various other grid hardening activities that would address risks in the Severe Risk Areas and High Consequence Segments. Given the ignition risk associated with secondary conductor and service drops, the scope of TUG has been expanded to include not only the primary conductor but also secondaries and services.[31] This will remove all overhead electrical conductor and wires to eliminate the risk of overhead equipment failure and contact-from-object-related faults/ignitions.[32]

It is important to note that although this Track 4 addresses only calendar year 2024, SCE anticipates that some of the IGHS scope described above will not be completed by 2024 and will be installing more undergrounded miles in the 2025-2028 GRC cycle (and in some of those years, substantially fewer covered conductor miles). SCE's final forecasts for the 2025-2028 GRC cycle will be set forth in SCE's Test Year 2025 GRC, filing in May of 2023.

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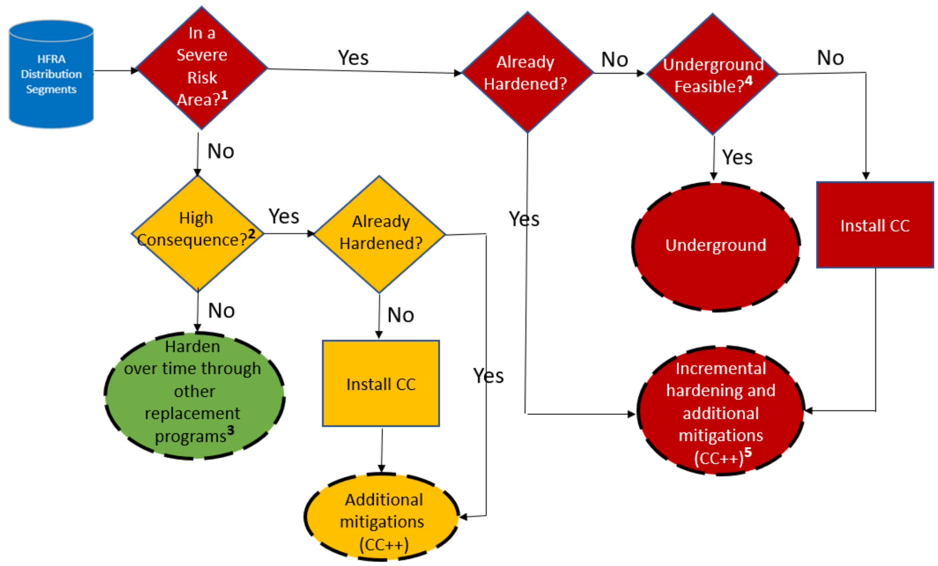
[31] The undergrounding miles completed in 2021 were performed on the primary conductor only. Due to the secondary and service wire ignition incidents experienced in 2020 and 2021, SCE is expanding undergrounding scope from only primary conductors to primary and secondary conductors and service wires. In 2020 and 2021, SCE experienced an increase in CPUC-reportable ignitions due to secondaries and services compared to prior years and re-evaluated its undergrounding strategy concerning lower-voltage conductors. Specifically, in 2020 and 2021, system-wide, SCE experienced 38 and 53 CPUC-reportable fires connected to secondary conductors and service wires, and this represents an increase of 72% and 140% over 2019 secondary and service wires ignitions. Furthermore, covered conductor projects only replace bare secondary conductors and service wires with multiplex conductors, which increase safety benefits but are still at risk from heavy vegetation fall-ins, overloading due to energy theft and grow houses, and wildlife contact by way of animal chewing through the wires. In some cases, services may be left on the overhead system due to various reasons such as customer refusal to underground.

[32] Underground electric services will still have some above-ground equipment, such as pad-mount transformers. As such, some residual risks still remain with undergrounding, but it significantly reduces the risk for these Severe Risk Areas.

Figure V-10
Decision Tree for Evaluating Undergrounding and other Mitigations



[1] Segment in areas that are Fire Risk Egress Constrained Area, Extreme High Wind Area, etc.
[2] Segment that meets 300-acre consequence threshold or at risk of PSPS but not in Severe Risk Area
[3] Segment that is not in a Severe Risk Area or does not meet High Consequence criteria; will replace retired or damaged bare wires with covered conductor pursuant to its standards in HFRA
[4] Undergrounding feasibility will be based upon factors such as terrain, cost, and customer constraints
[5] Because of the uncertainties associated with accelerating climate change and changing risk profiles, in certain cases SCE may need to underground specific circuit segments that were already hardened with covered conductor to further reduce risk and protect SCE's customers. At this time, SCE expects such occurrences to be the exception and not the rule.

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c) Mitigations Identification

SCE identified the suite of mitigation options that could effectively mitigate risk for the Severe Risk Areas and High Consequence Segments. Because of the significant risk associated with these locations, SCE is seeking to substantially reduce the risk. Undergrounding overhead lines is likely the most effective option to reduce this risk, and because of the extraordinary consequences associated the Severe Risk Areas (i.e., egress constraint, extremely high fire damage, or potential for extreme wind events that may exceed the covered conductor windspeed threshold), SCE chose undergrounding to be the primary mitigation in this area.

For High Consequence Segments, SCE used the mitigation effectiveness of undergrounding as a benchmark against which to build alternative mitigation options against. Each option includes a set of individual mitigations that collectively seeks to increase risk reduction effectiveness beyond what covered conductor installation would achieve by itself, although it would not achieve as much ignition risk mitigation as undergrounding. Importantly each mitigation option presents different feasibility, cost, execution, and resource considerations that help to inform our decision of which option to select for each location. These options include applying multiple complementary mitigations to a location (e.g., covered conductor, inspections, vegetation management), and applying new technologies in concert with complementary mitigations (REFCL, inspections, vegetation management), or applying new technologies with alongside traditional overhead hardening solutions (e.g., REFCL, covered conductor). More specifically, these options include:

- CC++:[33] Installing covered conductor combined with fire-resistant poles installation, asset inspections, fast curve settings for circuit breaker relays, along with activities (as necessary) including the Hazard Tree Management Program (HTMP), pole brushing, and line clearing. In some circumstances, covered conductor may be substituted with spacer cable or aerial bundled cable.
- REFCL++:[34] Installing REFCL, which is a series of related technologies that reduce fault current in automatic response to anomalies detected on the distribution system, combined with asset management. REFCL++ includes fast curve settings for circuit breaker relays, along with vegetation management activities (as necessary) including HTMP, pole brushing, and line clearing.
- CC&REFCL++: Installing covered conductor and REFCL combined with fire-resistant poles installation, asset inspections, fast curve settings for circuit breaker relays, along with vegetation management activities (as necessary) including HTMP, pole brushing, and line clearing.

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33 Note that CC++ is not a mitigation in and of itself. "CC" denotes covered conductor and "++" denotes additional mitigations, *e.g.*, asset inspections. CC++ is a suite of mitigations that has CC as a grid hardening activity plus other activities.

34 Note that REFCL++ is not is not a mitigation in and of itself. The ++ denotes additional mitigations, such as asset inspections. REFCL++ is a suite of mitigations that has REFCL as a grid hardening activity plus other activities.

In selecting a mitigation or suite of mitigations, SCE considers their expected efficacy in addressing ignition risk drivers associated with overhead conductors, operational considerations such as how quickly the mitigations can be deployed, and mitigation deployment feasibility based on terrain, etc. Table V-3 below summarizes these considerations for the various options.

Table V-3
Efficacy of Mitigation Suites

Attribute	CC[1]	CC++	Undergrounding	REFCL++[2]	CC&REFCL++
Mitigation Effectiveness	66%	78%	99%	73%	90%
Deployment speed[3]	16-24+ months	16-24+ months	25-48+ months	18-36+ months	18-36+ months
Phase-to-phase incandescent particle ignition[4] mitigation	High	High	High	Low	High
Phase-to-ground incandescent particle ignition[5] mitigation	High	High	High	High	High
Distribution wire-down ignition mitigation	Medium	High	High	Medium	High
Equipment failure mitigation	Low	Medium	High	High	High

[1] CC by itself is not among the mitigation options SCE considers but initial capital deployment cost is included here for reference.

[2] Preliminary determination of effectiveness, subject to change pending further experience.

[3] Typical deployment timelines based on historical installations and projections. Actual timelines can vary further due to local conditions.

[4] Examples include conductor to conductor contact, balloon coming between two phase wires.

[5] Examples include tree to conductor contact, animal contact between phase wires and pole.

The basis for which SCE selects these mitigation options for particular locations is detailed below as well as the scope and costs SCE is requesting to performing the work.

E. <u>Wildfire Covered Conductor Program (WCCP)</u>

This section of testimony describes SCE's WCCP, which includes the installation of covered conductor, fire-resistant poles (FRPs), Tree Attachment Remediation, as well as a new supplemental activity called Vibration Damper Retrofit. WCCP has been SCE's flagship wildfire mitigation grid hardening program since late 2018, as discussed at length in SCE's WMPs, the GSRP, and Tracks 1 and 3 of this GRC. The risk models in late 2018 only had the ability to analyze mitigations at the portfolio level and thus WCCP was the fastest way to cost-effectively reduce risk in the shortest amount of time. these risk models did not capture additional risks such as egress and PSPS nor did it have the granular wildfire risk analysis that our current IGHS employs.

The funding requests for capital expenditures for each sub-activity are presented in Table V-4 below. The WCCP capital expenditure amount of $796.024 million includes the Vibration Damper Retrofit cost of $0.608 million.[35]

Table V-4
Summary of WCCP Capital Expenditures
(Nominal $000)

		Track 1 Authorized					Recorded			Track 4 Forecast
	Subactivity	**2019**	**2020**	**2021**	**2022**	**2023**	**2019**	**2020**	**2021**	**2024**
1	Covered Conductor	$249,240	$494,359	$535,036	$553,513	$572,228	$239,911	$544,093	$897,602	$779,205
2	Tree Attachment Remediation	$49	$15,454	$22,458	$26,553	$32,598	$9,378	$9,708	$21,940	$16,819
	Total Capital	**$249,288**	**$509,814**	**$557,495**	**$580,066**	**$604,826**	**$249,288**	**$553,802**	**$919,542**	**$796,024**

1. Covered Conductor and Fire-Resistant Poles

a) Work Description and Need

While IGHS shows that TUG is the primary choice of mitigation for Severe Risk Areas since it reduces all ignition risk drivers to a greater extent than any other single mitigation or suite of mitigations, in many locations within High Consequence Segments (and where TUG is infeasible in Severe Risk Areas) covered conductor along with fire resistant poles (FRP) is the primary choice of mitigation because it reduces CFO, equipment failure and wire-to-wire faults cost-effectively and expeditiously. On an annual basis, these drivers account for 86% of historical ignitions experienced by SCE between 2016-2021. Covered conductor refers to an overhead conductor being "covered" with insulating materials to provide incidental contact protection. The installation of covered conductor sometimes necessitates pole replacements because of the heavier weight of the conductor, and, in those cases, SCE's construction standard in HFRA is FRP. FRPs protect against ignition risks associated with equipment failure drivers and are effective at helping to prevent pole damage when a wildfire occurs, which helps to add resiliency to SCE's system. These two activities are performed in tandem, where applicable, to maximize the risk buydown.

[35] As noted in Exhibit SCE-01, SCE forecasts the completion of 1,250 miles of WCCP installation in each of 2022 and 2023 (*i.e.*, approximately 5,000 total miles installed through YE 2023). The 2024 proposed scope of 1,200 miles would be incremental to those previously installed miles (*i.e.*, they represent miles ~5,000-6,200).

SCE performed benchmarking, testing, and developed standards for the deployment of covered conductor. SCE 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. These efforts helped inform SCE's WCCP, the pre-2024 scope of which was authorized by the GSRP Final Decision (D.20-04-013) and Track 1 of this GRC (D.21-08-036). More recently, pursuant to the direction of OEIS, SCE and other California utilities including PG&E, SDG&E, Liberty, PacifiCorp, and Bear Valley, collaborated through a working group to evaluate the effectiveness, long-term risk reduction and cost-effectiveness of covered conductor deployment, among other things. The joint working group developed a survey consisting of 24 questions that focused on covered conductor usage, performance metrics, conductor applications, and system protection. The survey was sent to approximately 150 to 200 utilities in the U.S. and abroad. To date, 19 utilities have participated in the benchmarking survey.[36] The majority of utilities base covered conductor's effectiveness in its ability to reduce faults and ignitions from CFOs. Utility respondents also noted the effectiveness of covered conductor in reducing reliability impacts, wildfire risk, wire downs events, and public safety incidents. The information and assessments continue to indicate covered conductor effectiveness being approximately 60 to 70 percent effective[37] in reducing the drivers of wildfire ignition risk drivers, which is consistent with past benchmarking, testing and utility estimates, and which is consistent with SCE's internal risk analyses as set forth in various WMPs, the GSRP, and Track 1 of this GRC.

Additionally, SCE performed extensive testing to determine the effectiveness of covered conductor. Testing has shown that covered conductor dramatically reduces or eliminates faults (and potential resulting ignitions) from incidental contacts that cause phase-to-phase and phase-to-ground faults caused by vegetation, conductor slapping, wildlife, and metallic balloons. To further

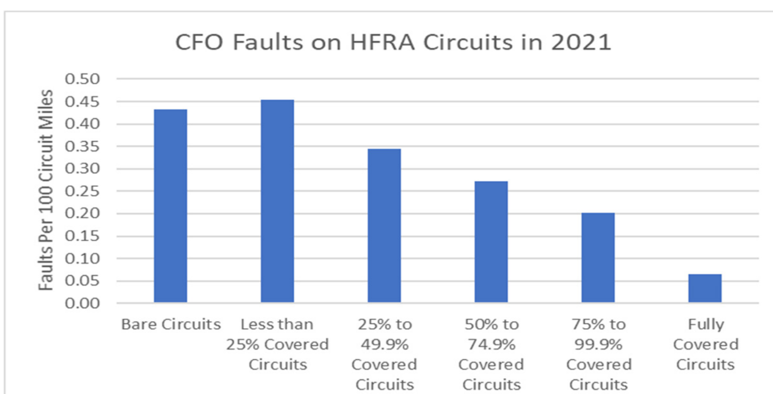
[36] The 19 utilities are: American Electric Power, Ausnet Services, Bear Valley Electric Service, Inc, Duke Energy, Essential Energy, Eversource Energy (CT), Korean Electric Power Corporation, Liberty, National Grid, Pacific Gas and Electric Company, PacifiCorp, Portland General, Powercor, Puget Sound Energy, San Diego Gas & Electric Company, Southern California Edison, TasNetworks, Tokyo Electric Power Company, and Xcel Energy.

[37] The overall effectiveness for CC is 60%-70% and for some drivers it is 90%+.

validate the effectiveness of covered conductor, in 2022, and in collaboration with PG&E and SDG&E, the utilities hired an independent third-party to perform lab testing of covered conductor effectiveness which is still ongoing. Recent initial results from this third-party testing validated the effectiveness of covered conductor at preventing phase-to-phase and phase-to-ground faults. SCE has also measured the overall effectiveness of covered conductor by comparing events (primary wire downs, primary conductor-caused ignitions and faults) on fully covered circuits to bare circuits in its HFRA on a per-mile basis in current years.[38]

Covered conductor also has a secondary benefit: increasing reliability. This intuitive benefit results from covered conductor's primary purpose; *i.e.*, to prevent faults. SCE's fault data shows that circuits fully covered experience approximately 85% less faults caused by CFO than circuits with bare conductor (see Figure V-11 below).[39] Because of its effectiveness in reducing faults and ensuing ignition risk, for the last several years covered conductor has been SCE's HFRA construction standard (*i.e.*, all new overhead installations in HFRA are constructed using covered conductor).

Figure V-11
Faults per Mile on HFRA Circuits in 2021



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[38] Installation of covered conductor also results in a secondary public safety benefit. In addition to reducing ignition risk, covered conductor reduces wire-down incidents and risks from contact with energized downed wire.

[39] The data was not adjusted for weather variations so it may either under- or over-represent the fault-reduction benefits of covered conductor.

Figure V-12 below shows an example of the effectiveness of covered conductor in. When a vehicle hit a pole severely damaging it, the energized covered conductor made contact with vegetation, but no fault or ignition occurred.

Figure V-12
Car-hit-pole with Covered Conductor – No Fault Occurred
Ojai, California – July 24, 2020

As discussed above, poles that require replacement as part of WCCP are replaced with FRPs. SCE utilizes a combination of both fire-resistant wrapped poles and composite poles in HFRA. A fire-resistant wrap is capable of withstanding temperatures exceeding 2,100 degrees Fahrenheit.[40] Applying a protective layer to new wood poles has proven to be an effective measure to protect from the typical conditions a wood pole may be subjected to during a passing wildfire (after an ignition has occurred). Installing fire-resistant wrapped poles is not always appropriate, however. For example, at locations with pole-top electrical equipment, risers, or where there are known woodpecker problems, SCE will continue to deploy composite poles. Installing FRPs also has reliability benefits after a fire. For instance, burned and/or fallen poles can cause other equipment on the pole to fail, making service restoration after a fire more difficult. Figure V-13 below shows an example of a composite pole and fire-resistant wrapped pole.

[40] *See* SCE Advice 4120-E, p. 17 and SCE's 2020-2022 Wildfire Mitigation Plan.

Figure V-13
Composite Pole (left), FRP Close-up (center), and FRP Full Length (right)

(1) GSRP, GRC Track 1 and Track 3 Findings

Given the increased risks of wildfire occurring in SCE's service areas, during the time between SCE's 2018 and 2021 GRCs, SCE filed its GSRP application, requesting funding for a portfolio of mitigation activities, including the installation of 592 circuit miles of covered conductor in HFRA over the 2018-2020 period (or GSRP Period). That scope was based on an initial set of risk criteria falling in two main categories: (1) spans with vintage small conductor at risk of damage during fault conditions and (2) spans with elevated risks of vegetation-related contact from object faults. A year later in September 2019, in Track 1 of the 2021 GRC, SCE's forecast was based on an updated risk analysis and requested funding for approximately 6,200 circuit miles of covered conductor over the 2019-2023 period. In April 2020, as part of the GSRP Settlement Agreement, the Commission approved SCE's request of 592 circuit miles of covered conductor. Miles in addition to that soft cap, and any expenditures by which the average recorded costs exceed the average unit costs in excess of 115% for the GSRP Period, were subject to reasonableness review in a later proceeding. As such, SCE filed its 2021 GRC Track 3 Request in March 2021, requesting reasonableness review of the 1,132 circuit miles that were installed in the GSRP Period. In August of 2021, the Commission issued the 2021 GRC Track 1 Final Decision, which approved $2,404 million in capital expenditures for 3,750 circuit miles plus a 20% buffer for operational considerations (*i.e.*, 4,500 circuit miles over the 2019-2023 period).[41] The Track 1 Final Decision also

[41] The miles completed within the GSRP Period are within the Track 1-approved 4,500 miles.

provides for a subsequent reasonableness review for costs in excess of 110% of the authorized expenditures associated with miles above the 4,500 authorized for that time period, as those costs are tracked in the approved Wildfire Risk Mitigation Balancing Account (WRMBA).

(2) Historical Variance Analysis

This section provides a year-over-year comparison of the number of completed covered conductor circuit miles and associated capital expenditures (see Table V-5 below).[42]

Table V-5
WCCP Circuit Miles and CapEx Recorded
(Nominal $000)

$000 Nominal						
Covered Conductor	2019	2020	2021	2022	2023	Total
Recorded Completed Circuit Miles	277	797	1,426	N/A	N/A	2,500
Recorded Capital Expenditures	$ 239,911	$ 544,093	$ 897,602	N/A	N/A	1,681,606

By the end of 2019, soon after SCE filed its 2021 GRC Track 1 application, SCE had completed 277 circuit miles with an attendant $240 million in capital expenditures. In 2020, SCE completed 797 circuit miles and spent approximately $544 million. In 2021, SCE ramped up its wildfire mitigation activities and almost doubled the circuit miles compared to the prior year, completing 1,426 circuit miles with an associated spend of approximately $898 million, which included both completed and construction work-in-progress projects. Because incurred costs for covered conductor projects often span multiple years, it is not accurate to simply divide the calendar year total costs by the calendar year total circuit miles to calculate an average unit cost.[43]

(3) 2021 Authorized v. Recorded

The 2021 GRC Track 1 Final Decision authorized a total revenue requirement amount for 2019-2023 for WCCP. Therefore, to the extent that SCE's cumulative final costs and scope for that time period exceed 110% the initially authorized amounts, SCE will demonstrate the reasonableness of those costs in a subsequent application, pursuant to the requirements in D.21-08-036.

[42] Note that SCE completed a total of 3,000 circuit miles of covered conductor by the end of 2021, and 2,500 of those were under the WCCP.

[43] Costs and scope for both completely closed work orders and work orders where the assets are in service should be used instead to calculate unit costs.

(4) Capital Expenditure Forecast

(a) Basis for Capital Forecast

(i) Scope Forecast

By the end of 2023, approximately 2,200 Severe Risk Areas and High Consequence Segments circuit miles will remain unhardened in HFRA, which, based on the IGHS analysis, SCE plans to harden through WCCP to reduce wildfire risks. SCE proposes to install 1,200 of those circuit miles in 2024, balancing resources across SCE's portfolio of work, including the work associated with targeted undergrounding and infrastructure replacement programs. This amount also includes the 20% buffer authorized by the Commission in Track 1 to account for operational realities/efficiencies, which are additional circuit miles for spans adjacent to the segments that SCE's risk-prioritization model selects based on relative-risk criteria.[44] This grid hardening work will help to address a considerable amount of the residual risk that will remain on SCE's unhardened overhead distribution system in its HFRA after 2023. Historical wildfires have demonstrated the potential of ignitions ultimately leading to significant and destructive fires. These large fires could, in turn, lead to urban conflagration (a large fire that spreads beyond a natural or artificial barrier, *e.g.*, a city block). There are over a million people[45] living in the WUI within SCE's HFTD Tier 2 and Tier 3 as shown in Figure V-14 below. SCE believes it is prudent to continue its grid hardening efforts in such areas as these to protect SCE's customers and communities.

[44] In the field, when SCE installs covered conductor, it necessarily does not solely cover the particular circuit segment explicitly identified by the wildfire risk analysis. Instead, SCE's standard practice is to prudently extend that covered conductor installation to the next contiguous structure with equipment or the next structure that is a dead-end, even if those structures are outside of the range of the initial scoping selected by the risk model. In the 2021 GRC Track 1 Final Decision (p. 204), the Commission approved an additional 20 percent of circuit miles to account for operational design considerations and found it "reasonable to expect some additional operational miles to be installed during actual design and deployment."

[45] There are over 500,000 customer accounts (1.5 million customers living) in HFTD Tier 2 and Tier 3 WUI as of 2021. *See* SCE's 2022 WMP Update, Table 8. AFN is Access and Functional Needs.

Figure V-14
Type and Proportions of Customers Living in the WUI within
SCE's HFTD Tier 2 and Tier 3

(ii) Unit Cost Forecast

SCE estimates the average unit cost for covered conductor including FRPs to be $649k per circuit mile (nominal $).[46] When this average unit cost is applied to the scope of 1,200 circuit miles proposed for 2024, SCE's Track 4 2024 request for covered conductor and FRPs is $778.596 million (nominal $).[47] This average unit cost was estimated by using work orders for the WCCP from 2018 to Q1 2022. The recorded data showed that SCE installed a 71%/29% ratio of fire-resistant wrap/composite poles. In 2021, there was a shortage of FR composite poles, and as a result SCE prioritized composite pole allocation for the most critical locations. As the shortage has been alleviated, SCE continues to work with crews to return to previously prescribed processes, which should lead to the installation of FR poles at the approximate ratio SCE originally proposed in Track 1.

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[46] *See* WP SCE Tr. 4-02 Covered Conductor Unit Cost, p. 2.

[47] The WCCP unit cost is based on both completely closed work orders and work orders where the assets are in service, but the work order has not yet completely closed. For the first category (*i.e.*, closed work orders) these include essentially all recorded costs, though a small of amount of costs may still be charged to the work order. For the second category (*i.e.*, not-yet-closed work orders for in-service assets), these do not include all expected recorded costs (and SCE has not included a forecast of expected future recorded costs).

The 2021 unit costs have increased compared to historical unit costs due to various reasons outside of SCE's control. First, due to a projected increase in critical work execution through 2021, SCE prudently decided in 2019 to extend its existing Distribution Electrical Contractor workforce contracts through December 31, 2021. Doing so enabled SCE to obtain crucial stability and certainty for necessary contract personnel resources needed to complete vital wildfire mitigation work.[48] The negotiations for the contract extensions resulted in an aggregate increase of approximately 20% over then-current costs due to increased costs for unionized labor.

Another factor that increased the costs was COVID-19 impacts. Starting in March 2020 and lasting through the summer of 2020, SCE received stop work order directives from multiple cities and local authorities (*e.g.*, Los Angeles County), not allowing planned outages during day-time hours due to the potential impacts on customers during safer-at-home orders. This meant SCE had to shift work to night-time hours, and crews accordingly incurred premium time expenses. Crews were also reconfigured differently such as using five-man crews (instead of four)[49] and keeping crews isolated to avoid swapping personnel between crews (i.e., creating crew pods where members could not mix with other crews as SCE does under normal circumstances). In addition, crew starting times were staggered to lower the number of personnel in the district location at one time. As a result of the changing conditions due to COVID-19, SCE required additional scheduling effort and changes in the way work was executed, which increased the support activities costs. In addition to the city permitting restrictions, crews incurred premium time charges to expeditiously complete covered conductor work on circuits that were scoped under the Frequently Impacted Circuits (FICs)[50] list that

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[48] As part of SCE's Line Construction Category Strategy, a request for information (RFI) was issued in December 2018 to the existing Line Construction Sourced Contractors. The objective was to explore an amend and extend option through the RFI. The purpose of the RFI was to 1) provide stability in work execution, 2) to address commercial and technical pain points with input provided by SCE's Transmission & Distribution and the Contractors, 3) create contract efficiencies and sustainability through unit rate and time & equipment (T&E) recalibration efforts, 4) enable recalibration of original 2016 bid assumptions and 5) evaluate responses to determine if the RFI approach is viable. The RFI approach was considered successful as the outcomes of the RFI were achieved and contract extensions were issued through December 31, 2021.

[49] 5-man intact crews were implemented to enable safe continuity of work in the event the crew was shorthanded due to illness or otherwise. This was necessary based on use of crew pods.

[50] FICs are circuits that experienced at least four PSPS events in the past since the inception of PSPS as a mitigation tool.

were prioritized for PSPS benefits.[51] Accordingly, crews had to get the work done in an accelerated fashion before the peak Santa Ana wind season.

Furthermore, the costs in some SCE regions, such as North Coast and Rurals, were higher than initially anticipated. The North Coast region contains mountainous areas for which contractors' rates were higher than those in other flat-terrain areas, which we expect the mix of work by regions to continue in 2024. It also took longer to do the work in that type of terrain so there were more labor costs due to the additional time. A similar situation applied to the San Jacinto and Rurals regions where SCE encountered areas that were more challenging to complete covered conductor work due to factors such as terrain, narrow roads, limited space for staging, etc. In general, assets/equipment located in mountainous and remote areas sometimes required helicopter sets or special vehicles to reach the locations. This added costs associated with the additional environment review, additional permits, and potential monitors with construction crews on scheduled days of work. When the work involving helicopter sets are delayed or cancelled due to weather or resource constraint, it impacts the request for other necessary resources. Long delays in schedule increase costs due to permitting re-application or re-submission. Additionally, mountain areas have time restrictions in which work can only be conducted. In this case, premium time is needed for work outside of the time restrictions, such as weekends and nights. The necessary adjustments to work activities as a result of these constraints resulted in increased costs. SCE has experienced material and labor cost increases as recently as of Q1 2022. These material cost pressures can be due to numerous factors, including rising inflation in general.

While some of these historical impacts driving unit-cost pressures may not continue into 2024 (*e.g.*, COVID effects), others are likely to remain or even increase. Moreover, SCE expects global supply chain-related issues, inflation, and 2022 labor contract renegotiation results to increase covered conductor unit cost pressures going forward, but has not included any such assumptions in this initial Track 4 forecast. On balance, SCE's 2024 forecast unit cost of $649k (nominal $) is reasonable and conservative.

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[51] *See* SCE's Corrective Action Plan, R.18-12-005 dated February 12, 2021.

b) Vibration Damper Retrofit

The 2024 funding request for capital expenditures for Vibration Damper Retrofit is $608,000, which aims to reduce issues associated with Aeolian vibration on covered conductor.

(1) Work Description and Need

Vibration dampers can reduce wind-driven vibration (known as Aeolian vibration) that may lead to conductor abrasion or fatigue over time. This is an issue experienced by both bare and covered conductor. However, covered conductor is more susceptible to vibration because of the covering's smoothness (perfect cylinder) and the reduction of strand movement due to the covering.[52] If this vibration is not mitigated, long-term damage may reduce the covered conductor's useful life. The impacts will not happen immediately, but if left unmitigated, over time vibration can reduce the covered conductor's useful life from 45 years to an average of 25 years particularly in high-and medium-vibration susceptibility areas.

In 2019, SCE conducted a field vibration study on a covered conductor installation in SCE's area.[53] The purpose of the study was to determine the level of Aeolian vibration on covered conductor and verify the effectiveness of vibration dampers. The study utilized vibration recorders to monitor a 2-wire covered conductor span over a two-week interval, in which one wire had a damper installed and the other had no damper installed. The study concluded that covered conductor could experience strain from Aeolian vibration. Additionally, while the assessment was in process, SCE began observing cases of Aeolian vibration occurring on its covered conductor installations. Based on the observed vibration, the results of the field study, and additional analysis, SCE concluded that vibration dampers will be needed on covered conductors that meet certain tension criteria. In October

[52] The area where the wires are installed can affect susceptibility. If exposed to the same area and wind conditions, covered conductor is more susceptible than bare. If the areas differ, then there are cases where bare can be more susceptible than covered conductor. For example, a bare wire installed in an area with very flat terrain and sees a high frequency of wind conditions between 2-15mph will be more susceptible than covered conductor installed in a hilly terrain with plenty of trees.

[53] *See* WP SCE Tr. 4-02 Vibration Damper Retrofit, pp. 3-4.

2020, SCE published a vibration damper standard, which outlines vibration damper installation requirements on going-forward covered conductor installations.[54]

SCE also decided to evaluate the covered conductor installations constructed prior to the standard being published for vibration susceptibility. Previous installations were categorized into high-susceptibility, medium-susceptibility, or low-susceptibility areas.[55] SCE's analysis indicated that targeting high- and medium-susceptibility areas will be most cost-effective. An alternative would be to lower the tensions for covered conductor installed in high- and medium-susceptibility areas by re-sagging, or in some cases, re-conductoring the targeted spans, which would decrease the likelihood of Aeolian vibration. However, the costs would be much higher for this alternative than the proposed initiative of retrofitting the installations with vibration dampers. SCE will prioritize this work based on the wind-susceptibility study mentioned above. The work is spread out across SCE's HFRA, with the majority work focused in the North Coast and North Valley regions where susceptibility to Aeolian vibration is higher.

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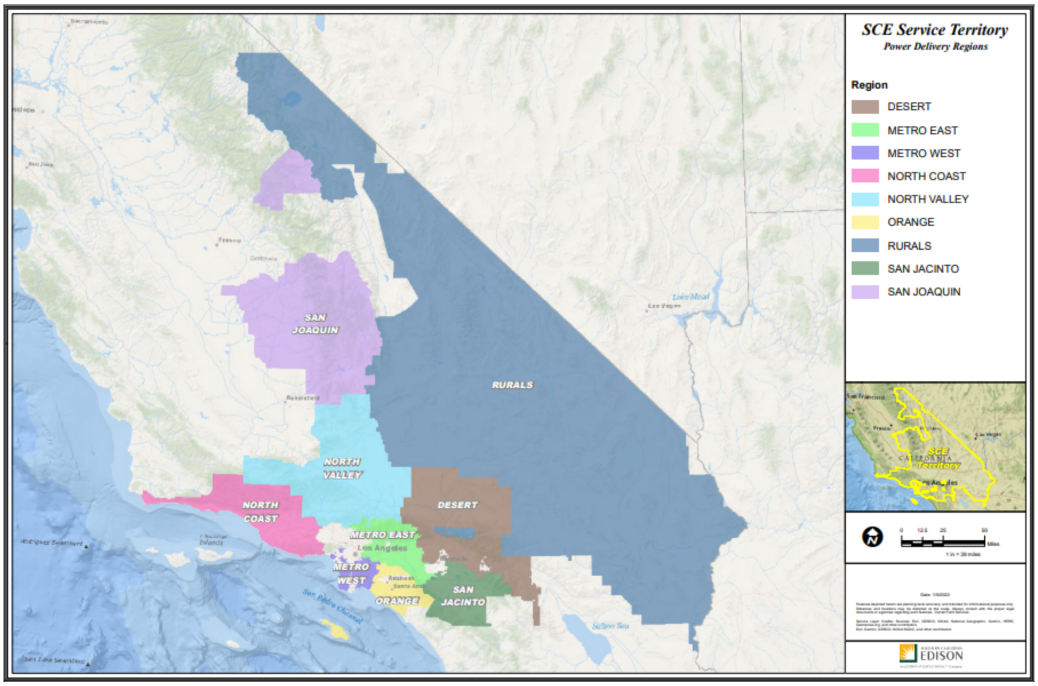
[54] However, on May 18, 2021, SCE issued an interim deviation from standards on vibration damper for covered conductor due to the temporary shortage of dampers caused by the severe supply constraints, labor issues, and shipping delays experienced by SCE's main vibration damper supplier. This deviation allows installation of covered conductor without dampers. This deviation only applies if the work location does not have the required dampers to complete the installation and will be in effect until December 31, 2021; dampers are still required to be installed for the work locations that have inventory on hand.

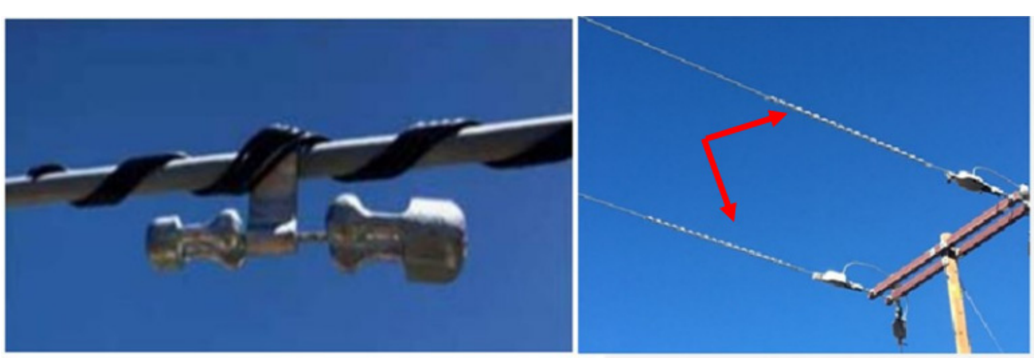
[55] High-susceptibility areas are near large bodies of water or with flat and open terrain. Medium-susceptibility areas are flat, open terrain or residential suburbs with some obstacles (trees, buildings, etc.). Depending on the terrain, the conductors may be exposed to a certain threshold of smooth and low speed winds which could induce Aeolian vibration on the covered conductor. For areas with more obstacles, this threshold is higher.

Figure V-15
SCE Service Area Regional Map



SCE uses two types of vibration dampers: Stockbridge and Spiral, as they maintain the useful life of covered conductor. Stockbridge dampers are used for covered conductor with a larger outer diameter whereas spiral dampers are used for covered conductor with a smaller outer diameter.[56]

Figure V-16
Types of Vibration Dampers: Stockbridge Damper (left) and Spiral Damper (right)



56 Spiral vibration dampers are not effective for larger-sized conductors.

(2) Capital Cost Forecast

(a) Scope and Cost

Based on the wind-susceptibility study, SCE identified approximately 2,800 structures in high and medium susceptibility areas that require a vibration damper retrofit. Table V-6 shows the forecast scope of the vibration damper retrofit in these areas from 2022 to 2024. SCE will begin retrofitting 100 structures in 2022, ramp up to 402 in 2023, and to 597 in 2024. Any lessons learned will be used to make improvements for future years. SCE estimates the 2024 forecast cost of vibration damper retrofit for 597 structures to be $608,000.

Table V-6
Vibration Damper Retrofit Scope (Number of Structures)

	Vibration Damper Retrofit						
	2019	2020	2021	2022	2023	Total 2019-2023	2024
Forecast	N/A	N/A	N/A	100	402	**502**	597

c) Tree Attachment Remediation

The 2024 funding request for capital expenditures for Tree Attachment Remediation is $16.819 million (nominal $), which aims to eliminate wildfire risks associated SCE's equipment on live trees.

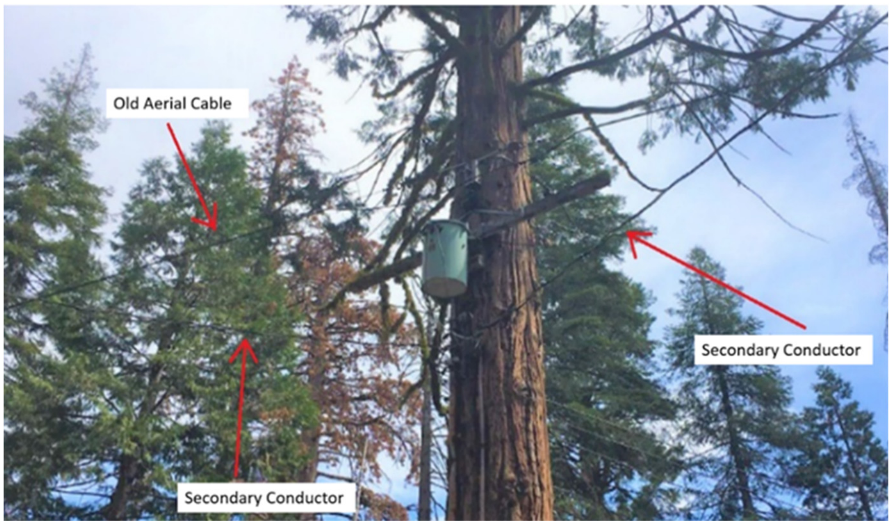
(1) Work Description and Need

Tree attachment remediation refers to the installation of new poles in order to eliminate instances where existing electrical equipment, including overhead conductor, is attached to trees. Older construction methods used in SCE's forested service areas leveraged existing trees to support overhead conductors instead of installing utility poles. These "tree attachments" do not meet SCE's current design standards. In addition, the Commission has correctly determined that tree attachments present a unique wildfire risk given climate-change driven impacts to forested environments and the increased risk of trees becoming diseased or dying.[57] The integrity of the trees cannot be verified using inspections and assessment techniques for poles. In addition, tree attachments increase the

[57] *See* D.21-08-036 at p. 205.

probability of faults and damages from vegetation contact and "fall-ins." Removing the electrical equipment and installing them on a new pole reduces ignition driver risks.

Figure V-17
An Example of a Tree Attachment Where Electrical Equipment Was Attached to a Live Tree



This activity relocates tree attachments from the tree to a pole to reduce the probability of faults and consequence of a spark close to vegetation. Note that most tree attachment work was completed with aerial cable[58] as that was the design standard at that time for areas with dense vegetation. If the existing tree attachment has aerial cable in good condition, SCE will relocate the aerial cable to a pole instead of installing covered conductor. If the aerial cable needs to be replaced, SCE will install like-for-like with aerial cable, consistent with our current engineering design standards for areas with dense vegetation within HFRA. SCE continues to prioritize the tree attachment remediations in HFTD Tiers 2 and 3, specifically most locations in the San Joaquin and Rural regions as shown in Figure V-17 above.

(2) Historical Variance Analysis

In the 2021 GRC Track 1 Final Decision, the Commission approved SCE's 2019-2023 forecast of $97.112 million to remediate approximately 3,200 tree attachments. In

[58] Aerial cables are underground cables used for the overhead distribution system, which are typically considered only in areas of dense vegetation where there are limitations on SCE's ability to trim trees.

2019 SCE remediated 101 tree attachments. Subsequently, circumstances arose during 2020 that affected SCE's tree attachment remediation plans. Specifically, several wildfires broke out across SCE's service area that destroyed 457 trees supporting SCE overhead conductor. Therefore, when SCE rebuilt the affected lines, it did so using poles instead of tree attachments and mainly aerial cable, which is consistent with SCE's current engineering standards in heavily forested areas (*i.e.*, reactive remediation). In addition, in 2020 SCE also proactively remediated an additional 44 tree attachments in areas not affected by the 2020 wildfires. Similarly, in 2021 SCE proactively remediated 358 tree attachments and reactively remediated another 180 tree attachments that were destroyed by storm conditions. Overall, from 2019-2021 SCE replaced a total of 1,140 tree attachments, which is 373 fewer than the authorized amount of 1,513 in that period (see Table V-7 below). The recorded expenditures, however, exceeded the authorized cost by approximately $3 million for this period, due to higher-than-anticipated costs and because the recorded expenditures include in-progress work.

Table V-7
Number of Tree Attachment Remediation Authorized and Recorded

SCE-2 Wildfire - WCCP							
Number of Tree Attachment Remediation	2019	2020	2021	2022	2023	Total	Forecast 2024
Recorded	101	501	538	N/A	N/A	1,140	N/A
Authorized (Track 1) and Forecast	358	481	674	770	914	3,197	500
Variance	257	(20)	136	N/A	N/A	373	500

Factors that contributed to the higher costs included the construction resource that performed the work (contractor vs. SCE's crews),[59] emergent vegetation management work necessitated by the remediation projects, a significant number of higher-cost pole replacements in addition to tree attachment remediations, and a higher unit cost in the San Joaquin region. For example, in the original unit cost estimate provided in Track 1, SCE assumed a one-to-one relationship between the removal of a tree attachment and installation of a new pole; that is, for every tree attachment there would only be one pole needed to replace it. However, as explained above, when the tree attachment remediation work was performed, all assets within the scope of work were brought up to existing

[59] The initial estimate was based on the Dinkey project which was performed in 2018-2019 and designed by SCE's planning team and constructed by contractors, whereas in 2020 and 2021 tree attachment remediations were both planned and constructed by SCE's crews.

standards. Therefore, the recorded costs for tree attachment remediations also included the respective costs. For example, SCE plans for tree attachment remediations between Pole X and Pole Y in a single work order. In between Pole X and Pole Y, there could be 40 poles, 2 miles of conductor, and 7 trees that the conductor was attached to. In this example, SCE would remove all 7 of the tree attachments, re-conductor, and set new poles to replace those 7. However, since in this example SCE is reconductoring from Pole X to Pole Y, the weight of the new aerial cable may be too heavy for some of those other 40 poles that were already there. Therefore, in that work order SCE would also have to replace, for example, an additional ten poles to carry the increased weight. Other assets, such as transformers, cross-arms, B-material, etc., may also need to be brought up to existing standards, and the costs for that work would be recorded in the same tree attachment remediation work order.

Furthermore, the initial estimate of the unit cost to remediate a primary and secondary tree attachment was approximately $36,000 and $25,000, respectively.[60] The blended unit cost observed for the 2021 work was approximately $50,000 due to the higher unit cost in the San Joaquin region. The combination of these ancillary costs resulted in a higher-than-estimated cost for tree attachment remediations.

(3) Capital Expenditure Forecast

(a) Scope and Cost

As of the end of 2021, there are approximately 2,300 tree attachments remaining to be remediated. Subject to resource availability and other operational considerations, SCE expects to remediate approximately 500 tree attachments in SCE's HFRA annually until all tree attachments are remediated. Given this is generally consistent with the volume of remediations performed in 2021, for 2024 SCE estimates the total cost of remediation to be approximately $16.8 million for 500 tree attachments.

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[60] *See* 2021 GRC Track 1, WPSCE04V05AP101, p. 254.

F. **Targeted Undergrounding**

This section discusses the scope and costs associated with the TUG Program in HFRA for installations forecast for 2024. The funding request for 2024 capital expenditures for TUG is $45.996 million (nominal $).

1. **Work Description and Need**

Undergrounding existing overhead power lines virtually eliminates the risk of ignitions and outages associated with drivers such as wire contact with objects (*i.e.*, vegetation, mylar balloons, debris, etc.) and wire-to-wire faults. In addition to those risk drivers, fault conditions can weaken and sometimes cause electrical stresses on hardware and insulators, leading to energized wire down events or electrical arcing. As discussed in detail previously in this chapter, undergrounding is therefore essential for severe risk areas with limited egress routes and areas immediately adjacent thereto. Moreover, while the deployment of covered conductor may significantly increase the wind threshold for de-energization during a risk event, covered conductor does not entirely prevent those de-energizations during extreme wind events. Undergrounding virtually eliminates the need to call PSPS events on circuits that are undergrounded.[61]

SCE evaluated potential undergrounding scope within Severe Risk Areas. Severe Risk Areas are defined as fire risk egress constrained areas, extreme high wind areas, and areas with extreme Technosylva consequence scores (*i.e.*, greater than 10,000 acres burned in simulated wildfire ignition consequence) as described above in Section D.1.a). If circuit segments are located in a Severe Risk Area and not already hardened, then SCE determines whether it is feasible to underground. If feasible, SCE proposes undergrounding the segments. If not feasible, SCE will harden with covered conductor and perform additional mitigations, such as inspections, vegetation management, and or additional mitigations as discussed in Section V.D.1.b).

Undergrounding of existing primary voltage overhead power lines involves digging a continuous trench approximately 24” in width and anywhere from 36” to 62” in-depth, depending on the

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61 However, there are still possible situations where underground portions of the circuit could be impacted by a PSPS event when the isolatable portion of the circuit includes both underground and/or covered conductor.

number of conduits required. Vaults and manholes will be required at regular intervals along this trench to accommodate cable pulling, electrical connections, and any underground equipment relocated from the existing overhead system. Since TUG focuses on reducing ignition risks (specifically focused on egress-constrained areas), SCE will only address energized electrical conductors (primary, secondary, and services) and does not currently anticipate including third-party communication infrastructure in the program. Overhead primary and secondary conductors, service wires, and SCE-only poles (i.e., not associated with a joint owner or renter) will be removed following the installation of the new equipment.

Typically, a line route needs to be determined when converting existing overhead lines to underground facilities. In urban areas, this route often can be the same as the existing overhead line assuming pre-existing underground utilities (e.g., natural gas, water, sewer, etc.) do not preclude the addition of a new duct and structure system. For example, this may involve moving a rear property pole line to curbside to avoid swimming pools, block walls, etc. But in more rural, coastal or mountainous areas, topography can present challenges. Lines may need to be moved to the roads to avoid steep terrain, heavy vegetation, water crossings, erosion concerns, and generally avoid environmental considerations associated with heavy equipment access to construct or maintain lines. Due to these topographical challenges with some existing overhead lines, vehicle access required for installing underground cable can be limited or unavailable, making undergrounding along the same route impractical. Therefore, overhead lines may need to be brought out to the public right of way for undergrounding, increasing the construction time for the undergrounding and number of miles undergrounded the existing overhead line length. Further, traffic control plans need to be developed and permits secured. Finally, individually serviced panels by the overhead system along the conversion route will need evaluation to determine if an upgrade is required to accommodate an underground electric service.

a) GSRP, GRC Track 1 and Track 3 Findings

In compliance with GSRP Settlement Agreement[62] and consistent with SCE's 2021 GRC Track 1 Testimony and SCE's 2020-2022 WMP, SCE assessed certain areas within its HFRA for undergrounding consideration. As part of its continued efforts to mitigate wildfire risks, SCE also indicated that construction for identified undergrounding areas would begin in 2021.[63] In Track 1 Direct Testimony, SCE submitted a forecast based on the number of miles expected to underground during the 2019 – 2023 period. Given the long cycle times for undergrounding circuitry, we estimated we would underground six circuit miles in 2021 and eleven circuit miles per year in 2022 and 2023. SCE substantially met its 2021 plan by completing approximately six circuit miles. For Track 1, SCE estimated the unit cost for undergrounding to be $3.37 million per mile (based on Rule 20A-related historical costs). The Commission adopted SCE's unopposed forecast for scope and unit costs in the Track 1 Final Decision.[64]

b) Variance Explanation

In 2021, SCE recorded $6.586 million in capital expenditures for projects within the approximate six miles completed in 2021, compared to the $23.047 million authorized for the six miles. There are several reasons for this variance. First, though the actual construction started in 2021, SCE incurred $0.78 million in capital expenditures in 2020. The costs were associated with survey maps and design costs for the plan years 2021-2022. Survey maps and design maps helped ensure existing and new electrical equipment and facilities are adequately identified, located, installed, and/or removed and covered under existing or new easements or rights of way. This work also ensured compliance with local and state guidelines and regulations relating to permitting, environmental, traffic control and other regulations. Second, when SCE's 2021 GRC Track 1 Application was developed in 2019, SCE's initial estimated unit costs[65] were based on completed Rule 20A projects, which include undergrounding

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62 Settlement Agreement Resolving All Issues for Southern California Edison Company's (U 338-E) Grid Safety and Resiliency Program Application, pp. 6-7.

63 *See* Exhibit SCE-04 Vol. 5, Wildfire Management, p. 48.

64 *See* D.21-08-036 at p. 214.

65 *See* WPS SCE-04 Vol.05A Pt.01. pp. 346-350.

overhead equipment such as secondaries and telecommunication wires. However, the completed TUG projects in 2021 had a low level of difficulty to construct and did not include secondaries, services, or telecommunication wires and thus resulted in lower costs.

Undergrounding costs per mile for distribution voltages can vary significantly based on population density, topography, permitting and environmental clearances, paving, and labor (e.g., SCE vs. contract labor). The initial miles SCE converted to an underground system in 2021 were located in sparsely populated areas. The topographical conditions of the selected miles were less expensive on a per-mile basis compared to steep, hilly terrain that are generally found in other parts of SCE's service area. Minimal bends and obstacles reduced the need for additional re-routing[66] circuitry for the underground conversion. The projects generally had no curbs or gutters, decreasing the need to re-pave after the underground installation was complete.

c) Capital Expenditure Forecast

(1) Basis for Capital Forecast

(a) Scope Forecast

Once potential underground scope (*i.e.*, overhead circuit segments) was identified using the decision tree discussed in Section D.1.b) SCE performed a feasibility analysis to determine which miles could be reasonably undergrounded. The feasibility assessments were performed by SCE personnel that have electrical and civil undergrounding expertise as well as local knowledge of the circuit segments related to terrain, service area, permitting requirements and constructability. The assessments resulted in a level of difficulty rating of low, medium, high, and not feasible. The assessments also included a rating for the length of time it would take from start to final construction with ranges of short, medium, and long. The main criteria SCE used to determine the level of difficulty

66 Re-routing requires additional underground miles compared to the overhead miles being replaced. For example, in the mountains an overhead line may go straight up a hill, but the underground miles may need to be installed under winding roads, resulting in more underground miles than overhead miles replaced.

to implement and to categorize TUG project duration[67] considerations are shown below in Table V-8 and Table V-9.

Table V-8
Undergrounding Difficulty Criteria

Difficulty	Description
Low	• **Typical setting: flat and rural areas** • Straight/minimal bends, none to minimal re-routing required • Less civil construction due to existing infrastructure • Minimal paving and equipment • Low number of transformers per mile required
Medium	• **Typical setting: medium density in residential/rural areas** • Some curves, minimal to medium re-routing required • Moderate difficulty of civil construction • Moderate re-paving and equipment needed • Medium number of transformers per mile required
High	• **Typical setting: rocky, hilly terrain and/or high population density** • Rugged terrain, significant re-routing required (e.g., follow switchbacks, rear property, etc.) • Extensive difficulty of civil construction (e.g., horizontal directional drilling) • High number of transformers per mile required • High cost of restoration due to landscaping • City or county's work moratorium • Substation getaway construction required • Long lead times and permitting/construction difficulties around railroads and bridges • Large flood control channels/wash/culverts
Infeasible	• Terrain or other parameters deem undergrounding construction infeasible (e.g., overhead directly above rocky mountains, not enough room to meet required clearances)

Table V-9
TUG Project Duration Considerations

Duration	General Description	Additional Details
Short (~25 months)	• Land is all or mostly franchise	• City/County permits • 1-2 Easements
Medium (~36 months)	• Land is a blend of franchise and private property	• Wetlands & Water • 5-10 Easements • Moderate traffic control
Long (~48 months)	• Land is limited to no franchise/mostly private property, in vicinity of certain landmarks	• Railroads • Bridges • Extensive traffic control • 10+ Easements (+influential areas) • Government lands • Multiple environmental reviews

[67] TUG project duration typically requires 2-4 years to scope, design, schedule, permit, construct, and put into service.

Once the feasibility analysis was completed, SCE then determined which overhead circuit segments to underground and for purposes of scope are discussed in circuit miles. SCE proposes to underground all feasible circuit miles in Severe Risk Areas as part of TUG.[68] SCE further analyzed the remaining circuit segments and removed any miles based on site-specific details that determine that location to be low fire consequence risk (*e.g.*, removed specific segments in Severe Risk Areas going over developed areas such as parking lots).

Based on the risk analysis, feasibility results and duration constraints,[69] SCE forecasts approximately 21.3 underground miles to be completed in 2024. The approximate 21.3 miles of undergrounding will replace 20 overhead primary miles.[70] The additional 1.3 miles of undergrounding is for re-routing, which is necessary to underground overhead circuits as well as undergrounding secondaries-specific segments. Re-routing is necessary at times to underground lines following a road whereas an overhead line can cross terrain where undergrounding is not feasible or impractical. An example of why re-routing is sometimes necessary is shown in Figure V-18. The green line represents the existing bare overhead conductor going across buildings. It is impractical to dig up trenches to convert an overhead distribution to an underground system under these buildings. Therefore, SCE needs to re-route and dig trenches along the road, as shown in the purple lines. Re-routing requires an additional length of conductor, labor, and materials.

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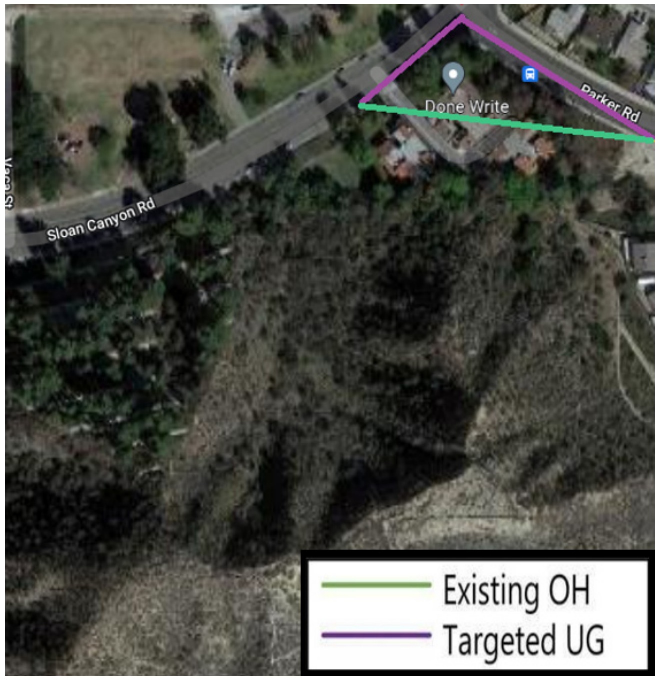
[68] For operational reasons, in some cases, it may be necessary for SCE to underground portions of circuits located outside of Severe Risk Areas.

[69] The time it takes to design the work and be operationalized by the end of 2024.

[70] The 1.3 miles is an estimate and does not reflect final engineering and construction realities. Moreover, going forward, one should not assume this ratio of overhead to underground conversion miles will be the same for future scope.

Figure V-18
Re-Routing Example



The miles for 2024 are a mix of low- and medium-difficulty miles with short durations. SCE analyzed the proposed 20 overhead primary conductor miles to be converted underground further to breakdown the miles into primary miles only, secondary miles only and co-located primary and secondary miles. The 2024 scope is broken out by conductor type and level of difficulty to implement in Table V-10 below. Additionally, SCE preliminarily identified 271 residential services and 84 non-residential services to underground as part of the 2024 TUG scope. The Track 4 scope was limited to only miles that have short project durations and that can therefore be completed by the end of 2024. All of the TUG miles scoped for 2024 are in Severe Risk Areas, which are defined as fire risk egress-constrained areas, extreme high wind areas, and severe consequence areas as described above in Section D.1.a)(1). Accordingly, all of the 20 miles scoped for 2024 are in the very riskiest areas of our service area that have not yet been hardened. Ten of the 20 miles are in the top 70th percentile of the risk-buy down curve and four of the 20 miles are in the top 90th percentile, even when based solely on Technosylva scoring (which does not incorporate egress risk). SCE prioritized scoping based on risk but deployment for each year is based on construction feasibility and thus some of the medium- and low-difficulty miles will get constructed sooner than they otherwise would have been if they had been installed purely based on risk-prioritization sequencing.

Table V-10
2024 Scope by Conductor Type and Difficulty to Implement[71]

Undergrounding Conductor Type	Low Difficulty Miles	Medium Difficulty Miles	Total Miles
Primary Conductor Only	9.5	5.6	**15.1**
Secondary Conductor Only	0.3	0.2	**0.5**
Co-located Primary & Secondary Conductors	3.6	2.1	**5.7**
Total	**13.4**	**7.9**	**21.3**

(b) Unit Cost Forecast

SCE developed unit cost forecasts for undergrounding primary circuit miles only, secondary circuit miles only, co-located primaries and secondaries, and for services.

Since Track 1, SCE further refined the cost by performing a desktop review of the feasible miles in the Severe Risk Area. This desktop review yielded difficulty factors and criteria described in Table V-11 Level of Difficulty to Implement, which we used to categorize low, medium, and high-cost ranges. Subject matter experts on underground circuit design reviewed the grouped criteria to develop a high-level cost range for the projects with various challenging implementation levels. This analysis provided an approximate range of costs that range from $1.2 million for low difficulty miles, $3.1 million for medium difficulty miles, and $4.8 million for high difficulty miles.

SCE developed a forecast to underground co-located primary and secondary miles using an adder to the unit cost of primary miles. Due to SCE's limited data on the cost to underground co-located primary and secondary miles, SCE relied on distribution designers and engineering expertise. SCE determined that a 15% adder was deemed to be appropriate for

[71] *See* WP SCE Tr. 4-02 TUG 2024 Forecast Breakdown, pp. 5-8.

undergrounding secondaries along the same trench as primaries based on the need for additional conduit, underground cable, and civil and electrical labor. The 2024 unit cost breakdown by conductor type and level of difficulty to implement are in Table V-11.

Table V-11
Unit Cost per Conductor Type and Level of Difficulty to Implement[72]
(Nominal $000)

Conductor Type	Cost Per Low Difficulty Mile	Cost Per Medium Difficulty Mile
Primary Conductor Only	$1,233	$3,098
Secondary Conductor Only	$1,233	$3,098
Co-located Primary & Secondary Conductors	$1,418	$3,562

SCE analyzed completed meter relocation work orders from 2016 to 2018, including undergrounding services for residential and non-residential meters. The completed work orders were used to develop an average service unit cost. SCE used the average cost-per-meter to forecast undergrounding services for the identified 271 residential and 84 non-residential customers within the 2024 TUG scope. This analysis resulted in capital expenditures of $3.48 million in 2024, as shown in Table V-12.

SCE's total TUG capital expenditure forecast is $45.996 million (nominal $) to underground approximately 21 miles. The 2024 scope is a blend of mainly low-difficulty miles with a few medium-difficult miles. SCE expects to have more miles with higher unit costs in future years as the mix of work shifts to more medium- and high-difficulty miles.

[72] *See* WP SCE Tr. 4-02 TUG 2024 Forecast Breakdown, pp. 5-8.

Table V-12
Summary of 2024 Forecast for Targeted Undergrounding[73]
(Nominal $000)

Conductor Type	Cost of Low Difficulty Miles	Cost of Medium Difficulty Miles	Cost of Total Miles
Primary Conductor Only	$11,677	$17,234	$28,911
Secondary Conductor Only	$403	$594	$997
Co-located Primary & Secondary Conductors	$5,094	$7,518	$12,611
Subtotal	$17,173	$25,346	$42,519
Services	**# of Customers**	**Average Cost per Meter Relocation**	**Total Services**
Residential Services	271	$5,892.00	$1,597
Non-residential Services	84	$19,609.00	$1,647
		Escalation Rate	1.072
		Subtotal	$3,477
		Total	**$45,996**

G. Rapid Earth Fault Current Limiter (REFCL)

In its 2019 WMP, SCE indicated that it would evaluate several forms of REFCL as part of its Alterative Technology Evaluations.[74] Testing from the Australian state of Victoria showed that REFCL can prevent an ignition even if there is direct contact of energized conductor with dry grass or vegetation.[75] Regulatory guidance has encouraged SCE and other California IOUs to accelerate REFCL pilot programs, as they have provided promising initial results as potentially relatively low-cost alternatives to address ignition risk associated with vegetation contact and wire downs[76] [77].

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[73] *See* WP SCE Tr. 4-02 TUG 2024 Forecast Breakdown, pp. 5-8.

[74] SCE's 2019 WMP, p. 72.

[75] *See* PG&E RAMP Proceeding (A.20-06-012) Post-SPD Evaluation Report Workshop, Safety Policy Division, California Public Utilities Commission, Dated December 8, 2020. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/meeting-documents/pge-post-ramp-spd-report-workshop-12-8-20.pdf.

[76] *See* Office of Energy Infrastructure Safety's "Final Evaluation of 2021 Wildfire Mitigation Plan Update Southern California Edison," dated August 18, 2021. p. 26. https://energysafety.ca.gov/wp-content/uploads/sce_2021wmp_finalactionstmt.pdf.

[77] *See* Office of Energy Infrastructure Safety's "Final Evaluation of 2021 Wildfire Mitigation Plan Update Pacific Gas and Electric," dated September 21, 2021. p. 26. (https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M417/K666/417666219.pdf).

1. **Work Description and Need**

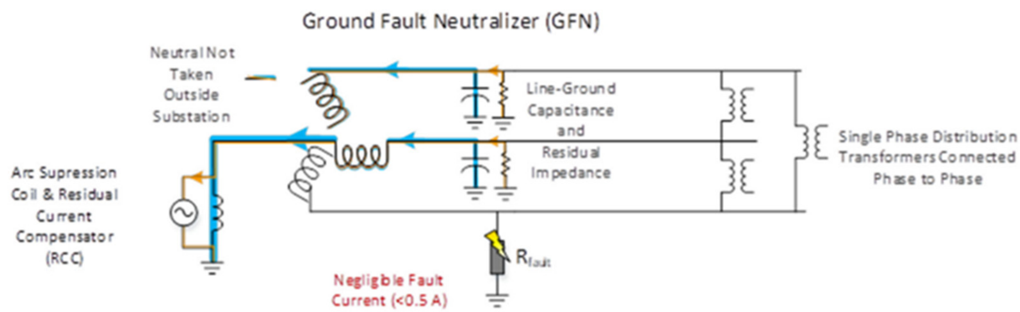
REFCL is a family of technologies that detects ground faults and rapidly reduces the fault current to a level much lower than traditional powerline designs. This technology works like a safety switch and reduces the likelihood of a fire ignition if a powerline comes in contact with the ground or a grounded object. Most public safety hazards from high voltage electrical equipment come from ground faults. This includes most downed wire incidents, energized conductor contacts, events involving underground equipment failures, arc flashes, step and touch voltage incidents and fire ignitions.

For its pilots in 2020 and 2021, SCE studied three variants of REFCL technology: Ground Fault Neutralizer (GFN), Resonant Grounding, and Isolation Transformers installed to target circuitry in high fire risk areas. SCE is exploring multiple approaches because SCE's system is not homogenous, these technologies require specific configuration, and assessing the most cost-effective solution will vary across SCE's system. In 2020, SCE energized one pilot: an overhead isolation transformer. In 2021 SCE energized three pilots: a Ground Fault Neutralizer, resonant grounding in a substation and a pad-mounted isolation bank. The pilot programs were designed to determine the feasibility of these technologies for wide-scale deployment on SCE's system.

a) Ground Fault Neutralizer

The most widely deployed variant of this technology for wildfire application is GFN, which consists of an arc suppression coil in parallel with a residual current compensator (RCC) inverter to cancel out the residual fault current. This is the technology applied by Australian utility companies as part of their REFCL programs. Figure V-19 below shows a schematic of the GFN technology.

Figure V-19
GFN Schematic



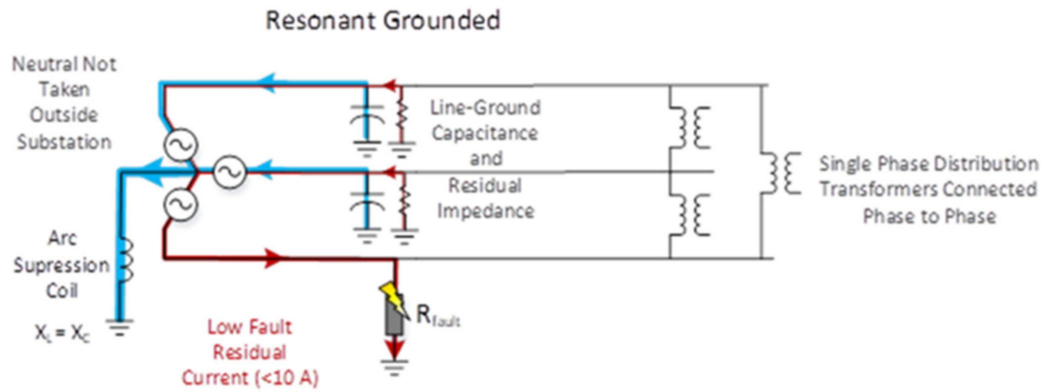
As indicated in its 2020-2022 WMP submitted in early 2020, SCE initiated design for a GFN field installation that would include site selection, material specifications, development of operating policies, development of engineering design documents and construction requirements, identification of industry vendors for GFN devices and development of remediations for expected challenges learned from Australian utility installations.[78] SCE installed, tested and put in-service a GFN at one substation in 2021, which covers approximately 170 circuit miles. GFN is the preferred REFCL design for large substations because those systems produce higher fault currents that require the additional inverter device to limit the fault energy.

(1) Resonant Grounding

Resonant Grounding with an Arc Suppression Coil (ASC) offers a simpler alternative for ignition reduction in smaller systems when compared with a GFN. Resonant Grounding does not include an inverter. The smaller system reference is governed by the line-to-ground capacitance and resistance of the network, as depicted in Figure V-20. The system quantities are proportional to the length of all the circuits out of a substation, with some consideration for differences between overhead conductor and underground cable systems. Resonant Grounding has been used by European utilities for reliability and safety benefits for many years. Installation of Resonant Grounding with an ASC involves less equipment and fewer complexities compared to GFN, however the reduction in fault current is also less. Figure V-20 below shows a schematic of the resonant grounding technology.

[78] SCE's 2020-2022 WMP, pp. 115-117.

Figure V-20
Resonant Grounding Schematic



SCE expects to use this technology at targeted substations that have relatively lower ignition risk or that are smaller. Small substations lack the length of circuitry across which to spread the relatively higher costs of a GFN, and resonant grounding alone can reduce fault currents to extremely low levels (albeit not as low as GFN). For the purposes of REFCL systems, the distinction between "large" and "small" substations primarily depends on the length of overhead and underground circuitry.

In 2020, SCE initiated design for an ASC field installation to convert a small substation in HFRA to Resonant Grounding. This design included substation site selection, material specifications, development of operating policies, development of engineering design documents and construction requirements, identification of industry vendors for ASC devices, and development of remediations to expected challenges learned from Australian utility installations. SCE installed, tested and put in-service the ASC at one substation in 2021, which covers approximately 40 circuit miles.

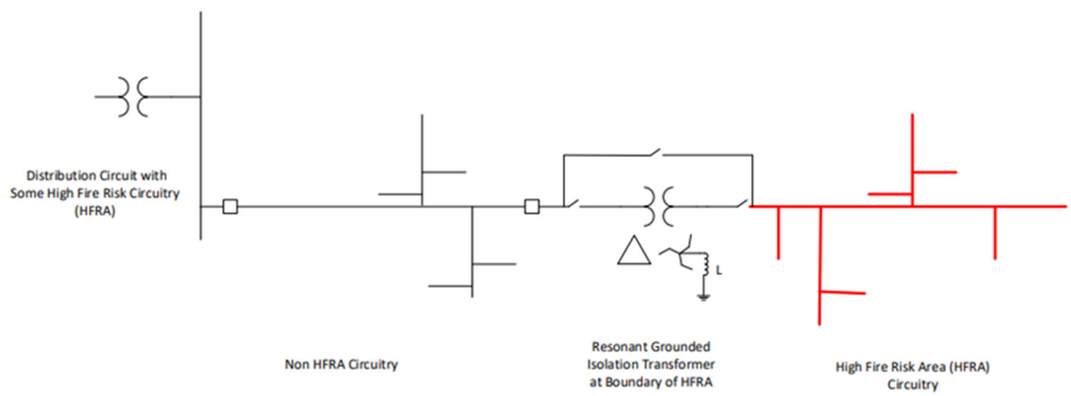
(2) Isolation and Step-Down Transformer

In addition to application of the GFN or ASC devices at substations, SCE has developed REFCL options for targeted circuitry grounding conversions. The grounding conversion projects utilize an isolation transformer, or in some cases modifications to grounding schemes at existing step-down transformers. The equipment application allows targeted circuitry to be converted to the

REFCL system. In general, this targeted REFCL application approach focuses on HFRA circuitry and avoids other expenses from the substation-based equipment applications. The typical example application is for substations where only a portion a circuit(s) extends into the HFRA.

The use of ungrounded or resonant grounded isolation transformers in small systems has been shown to meet the REFCL requirements. SCE determined, through testing[79] and review of the Australian REFCL Program, that the Isolation Transformer REFCL scheme is expected to reduce probability of ignition from single phase-to-ground faults by at least 90%.[80] Figure V-21 below shows a schematic of the typical application for Isolation Transformer technology.

Figure V-21
Isolation Transformer Schematic



In 2020, SCE completed a pilot installation at one location and developed the operating practices and construction requirements associated with application of these systems. The initial installation applied an overhead isolation transformer for the REFCL grounding conversion. In 2021, a larger pad-mounted isolation transformer was developed and installed increasing the amount of circuit loads which could converted to the REFCL system. In 2022 and 2023 SCE is focusing on optimizing the design of the pad-mounted isolation transformer design and related resonant grounding conversion equipment for deployment in future years. An additional isolation transformer is expected to

[79] SCE's engineers published a paper on the IEEE website with the following reference: J. Rorabaugh et al., "Resonant Grounded Isolation Transformers to Prevent Ignitions from Powerline Faults," in IEEE Transactions on Power Delivery, doi: 10.1109/TPWRD.2020.3030220.

[80] *See* SCE's 2021 WMP, p. 173.

be completed during this time period, utilizing pad-mounted equipment for both the isolation transformer as well as any associated automatic recloser installations.

b) Historical Variance Analysis

SCE incurred $1.855 million in capital expenditures during 2020 on the GFN pilot project. Costs included engineering for the installation of a GFN at the Neenach Substation, and SCE also purchased and received all the long lead-time materials in advance of the construction start date of February 1, 2021. In 2021, the GFN at Neenach was constructed, tested and commissioned for a total capital cost of $2.71 million.

Other capital expenditures in 2020 were incurred for installation of a single overhead Isolation Transformer on one circuit out of one substation at cost of $205,289. In 2021, SCE installed a pad-mounted Isolation Transformer on one circuit out of one substation at a cost of $473,640.

c) Basis for Capital Forecast

(1) Scope and Unit Cost Forecast

(a) Ground Fault Neutralizer

In 2024, SCE plans to install GFNs at two substations for a total capital expenditure of $13.2 million. Based on the success of the Australian program and initial SCE projects a continued scale up of the GFN technology is proposed. Substations were selected by an analysis of risk reduction and operational considerations of the projects. For 2024 scope a base cost of $5 million was used based on the costs for one substation completed in 2021. Installation of GFNs can range from $5 million to $10 million depending on the size of the substation and the extent of modifications to existing infrastructure. Both of the substations will require two ground fault neutralizers instead of one. Two GFNs are required for all substations with two B-Bank transformers. This was estimated to increase project costs by $1.5 million based on similar work and SME analysis. Additional costs come from replacing phase-to-neutral connected transformers which are incompatible with this technology. Only one of the substations has any of these transformers requiring replacement but for some future projects this may be one of the main costs. *See* WP SCE Tr. 4-02 GFN Cost Estimate Breakdown p. 9.

(b) Isolation Transformer

In 2024, SCE plans to install five isolation bank REFCL applications at an estimated cost of $0.804 million per installation, for a total cost of $4.02 million. The forecast increased unit cost, as compared scope of the one completed project in 2021, for 2024 projects are driven by differences in incorporating pad-mounted equipment design, land acquisition, capacitive balancing unit(s), and increased capacity for additional customer loads beyond the isolation transformer. In addition, in 2024 SCE plans to complete an additional five Resonant Grounded System conversion projects at a forecast cost of $0.322 million each, for a total cost of $1.61 million. The grounding conversions are very similar to isolation bank installations except the main recloser and transformer components will already be installed and system retrofits can be done at lower cost for the conversion. These grounding conversion installations will commonly include a grounding bank, capacitive balancing unit(s), a variable inductance, and circuit balancing cost.

H. Early Fault Detection

Early Fault Detection (EFD) sensors can continuously monitor lines and proactively detect undesirable, degraded or pre-failure system conditions. The sensors measure radio frequency electrical discharges that travel along the wire when an issue is present. The EFD system uses the measurements to provide locations of concern on the electrical system for further evaluation which may include proactive remedial action. Completion of these remediations/repairs prior to complete failure may prevent fault events that could lead to an ignition and often result in customer electric service outages.

1. Work Description and Need

SCE's present application of the EFD technology incorporates periodic review of the continuously-monitoring sensors' data to initiate circuit patrols to the identified area. The identified area typically ranges from a single structure to around 10 structures, depending on circuit topology and sensor placement. For circuits that transverse both non-HFRA and HFRA, the EFD sensor pair site selections can be prioritized to cover HFRA circuit sections over non-HFRA circuitry and do not require an entire circuit to be monitored by EFD devices.

SCE's existing pilot program, and other data from the supplier, has shown the EFD alerts correspond to degraded and undesirable conditions on electrical facilities. These conditions include broken conductor strands, vegetation contact, degraded connections/splices, and insulator degradation. EFD can detect conditions for repair which may not be found with present inspection methods, or alternately may be found sooner or more efficiently with the use of the EFD technology.

The EFD technology is relatively new but is being adopted by utilities in HFRA circuitry applications where the consequences of faults and failures extend beyond customer outages (i.e., present ignition risks).[81] The focus for the technology presently is improvement in situational awareness of electrical asset conditions to reduce electric system fault- and ignition-related events. SCE's present applications for the EFD technology include both transmission and distribution circuit radio frequency monitoring for electrical asset degradation.

In 2020-2021, SCE developed installation standards, and installed and commissioned 125 EFD installations on Distribution circuits, as well as 13 installations on sub-transmission circuits. From 2022 through 2023, SCE plans to install an additional 150 EFDs, expanding the installation base and validating next-generation EFD equipment. The next generation of EFD equipment is expected to provide increased data sampling rates which may improve detection sensitivity and enable potential features described in section b below. Between October 2020 and December 2021 through its existing installed base, SCE evaluated 10 instances where the EFD technology detected undesirable, degraded, or pre-failure system conditions. A summary of the findings from the EFD evaluations is set forth below:

- Six conditions involving damaged conductor such as broken strands from a gunshot (see Figure V-22 and Figure V-23) and expected fault from a prior conductor clash/slap event. Conductor was repaired or replaced for these six cases.
- One primary surge arrester exhibiting arcing activity; the arrester was replaced to remediate the condition.

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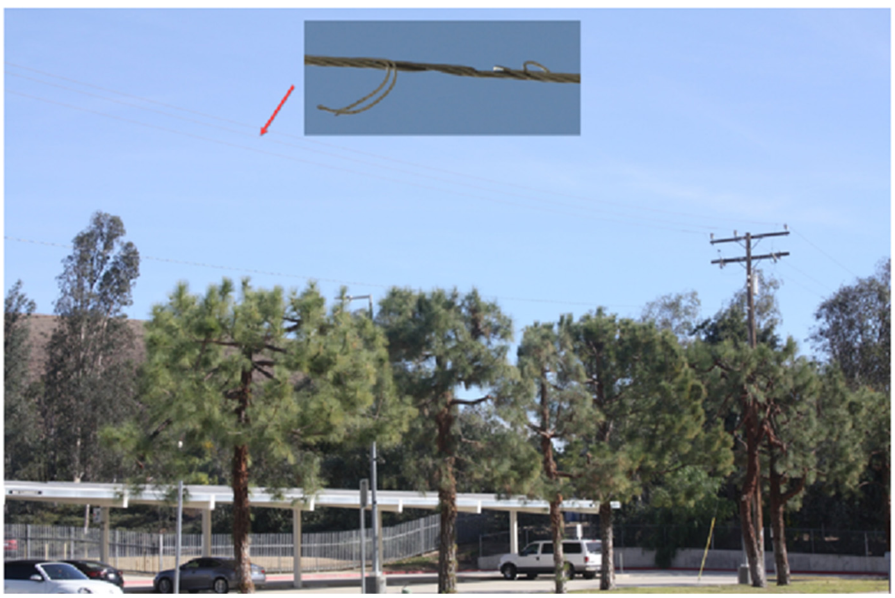
[81] *See* EFD SWER Trial Final Report dated June 23, 2019. https://www.energy.vic.gov.au/__data/assets/pdf_file/0021/461145/EFD-SWER-TrialFinal-Report.pdf

- One instance of vegetation grow-in to primary, where vegetation trimming was able to remediate the issue.
- Two additional issues detected but were remediated outside of EFD project intervention.
    - One mylar balloon contact (2021; EFD identified the issue 4.5hrs before the balloon was removed from lines due to a customer call).[82]
    - One broken transformer tap (2021; EFD detected arcing activity one hour before SCE meters reported low voltage).

Figure V-22
An Example Where EFD Detected Conductor Damage Due to Gun Shot(s)



[82] The mylar balloon event proved particularly interesting as it provided insight into the sensitive detection capability of EFD and potential for improving near real time situational awareness.

Figure V-23
An Example Where EFD Detected Conductor Damage Due to Gun Shot(s)

a) Potential Benefits of EFD

The information from EFD sensors can readily be used for system improvements and repairs for bare and covered conductor systems. Covered conductor may also have additional use cases for EFD by monitoring for insulating covering degradation. SCE is researching the capabilities for EFD to create alerts for sustained vegetation and other contacts that can degrade the covering. The system may also offer detection of degraded components for underground systems, though monitoring of UG facilities in not the focus for the project. Additional capabilities or use cases may also be possible with broader deployments, continued development of advanced data algorithms, and hardware improvements (e.g., increased sampling rates expected be available beginning in 2022). Some future potential benefits from EFD include:

- Operational Improvements:
    - Fault location detection algorithm based on radio frequency emissions from a fault event. This information may be used to perform detailed patrols to locate

the cause of a fault helping prevent a future re-occurrence and may also be helpful in reducing restoration times following an outage.

  - Energized wire down detection capability for covered or bare conductor. The EFD alerts alone may offer operational improvements for detecting energized wire down. Additionally, energized wire down detection capabilities may be further improved by coupling EFD alerts with SCEs existing machine learning algorithm, which incorporates meter data to identify these adverse conditions.
  - Near-real-time circuit disturbance monitoring to aid with operational activities. For example, during elevated fire conditions a circuit may be monitored by EFD for changes in baseline radio frequency activity (e.g., from sudden and progressively worsening vegetation contact) and provide situational awareness for operational decision-making. This could lead to enhanced ability to proactively de-energize a circuit or initiate a circuit patrol to the identified location(s).

- Condition-based replacement prioritization:
  - The EFD sensor detections for a circuit or system as a whole may provide a method for scoring large-scale project work such as cable replacement or transmission line reconductoring. In general, historical data is the primary driver for these types of programs, however near-real-time continuous monitoring from EFD may provide new methods for identifying and prioritizing this type of work.

2. **Forecast**

a) Historical Variance Analysis

Installation of EFD sensors began in March 2020. During 2020 and 2021, SCE spent $1.3 million and $3.1 million respectively to install 138 sensors on both Distribution and sub-transmission circuits.

b) Basis for Capital Forecast and Unit Cost

In 2024, SCE plans to install EFD sensors at 150 locations for a total capital expenditure of $5.92 million. Average cost per installation of approximately $39.5k for future installations is based on SCE's experience installing the 138 sensors in 2020 and 2021 as well as expected higher material costs in 2024. Installations in 2024 will be selected by prioritizing ignition risk reductions expected from the technology. SCE will select scope circuits based on the aggregate risk reduction per the expected sensor pair installations. To select the highest scope takes the aggregate risk on a circuit divided by the estimated EFD installations for the circuit establishing a proxy RSE which then risk ranks installations. This approach helps manage impacts from circuit dynamics of length and risk reduction. Detailed scope and site selections are then made from this circuit selection list. Application limitations such as lack of cellular communication or construction variants for EFD sensors that are not yet available may cause certain installations to be passed over until technical solutions are available in future scope efforts. Circuit topology plays a factor in scope selection and may also cause some circuitry to be removed during the scoping process. An example of this situation may be on circuits that appear to have substantial overhead line sections in HFRA; however, these line sections are sufficiently far apart to require more EFD sensors to monitor the conductor, thus increasing cost and lowering the proxy RSE.

I. Distribution Fault Anticipation

In 2019, SCE initiated a pilot to study Distribution Fault Anticipation (DFA) technology. This technology was developed collaboratively by Texas A&M Engineering and Electric Power Research Institute, Inc. (EPRI) and reads current and voltage signatures that are indicative of potential equipment failures, such as conductor degradation from repeated contact with other conductors or contact with foreign objects under windy conditions. DFA is one of the few commercial systems available to provide capabilities to detect pre-fault conditions prior to system failures and providing fault or other event data for assessments. SCE is not requesting funding for 2024 for DFA in this filing.

The pilot's focus was to test whether DFA could be effectively deployed on SCE's system and would not produce an abundance of nuisance incipient fault alarms (*i.e.*, "false alarms"). The pilot also provided SCE valuable experience with the product to refine anticipated application expenses and operational hands-on training with utilizing the product.

In the Track 1 Final Decision, no capital or O&M funding was approved for further deployment over the 2021-2023 GRC period, but the Commission agreed that "the initial findings from the DFA pilot are encouraging and, considering the length of time between GRCs, permit[ted] SCE to include a request for this activity for 2024 along with the final pilot results in Track 4 of this proceeding."[83] In part because SCE had already committed to its planned 2021 DFA installation scope in its OEIS-approved 2021 WMP Update, SCE completed the in-flight installations, but subsequently decided to not pursue originally-planned 2022-23 DFA installation scope in light of the Track 1 Final Decision's guidance.

1. Work Description and Need

As part of the pilot project, SCE installed 60 DFA devices from 2019 through early 2020. During 2020, Texas A&M/EPRI provided SCE with data storage, software to remotely access data, software to automatically interpret DFA data, and support in the form of researchers that worked with SCE personnel to identify how to integrate DFA with other SCE tools and systems. SCE installed and commissioned an additional 130 DFA devices in 2021 and installed an additional 25 DFAs in 2021 and commissioned in 2022. Selection was based on a number of criteria including the number of outages (both momentary and sustained), the number of circuits a substation served that fell within the HFRA, the proportion of circuit miles that were overhead, and the availability of rack space within the relevant substation. SCE has a total of 215 DFA devices installed, all providing data that is now being used to evaluate this technology and to determine if DFA is a technology SCE will continue to employ as a component of its comprehensive grid hardening efforts.

As of Q4 of 2021, SCE has received and analyzed 1,068 "alerts" initiated by the DFA pilot program initial installations. The bulk of the alerts do not require additional review as they are not identified as incipient fault events. Examples of many of these events are non-recurring faults, when

[83] D.21-08-036, pp. 213-214.

breakers close, and other normal operational events. Some of the highlights of alerts that were associated with system anomalies are summarized below:

- 2 faults related to Fault Induced Conductor Motion (FICM)
- 18 events classified as arcing
- 28 capacitor bank arcing or re-strike events
- 29 re-occurring faults

Currently, the data from the later-installed, additional 155 DFA installations is relatively minimal, as those projects were only commissioned in late 2021. DFA continually monitors and applies pattern recognition algorithms to detect and report events or abnormalities for investigation and potential repair. The automated reports and triggers can be used to focus on specific distribution circuits for inspection and further data analysis. SCE will continue to evaluate previous installations' performance to evaluate whether DFAs should be employed as a long-term tool to improve the safety and reliability of SCE's distribution system. In addition to DFA, SCE is utilizing other systems such as smart meters, remote monitored intelligent electronic devices (IEDs), and power system analysis modeling software to further improve benefits from the remote data provided by DFA.

In 2022, SCE will continue to monitor and evaluate the benefits of existing DFA units with vendor support but does not plan on installing DFAs on additional circuits until that evaluation is complete. SCE anticipates incurring expenses on an ongoing basis to maintain existing installations as long as DFAs are operational in the field. Should SCE determine that DFA is an effective long-term solution, SCE will request an appropriate level of funding in its 2025 GRC request.

J. **<u>HFRA Sectionalizing Devices</u>**

As part of SCE's grid hardening efforts, sectionalizing devices, such as Remote-Controlled Automatic Reclosers (RARs) and Remote-Controlled Switches (RCSs) are deployed in HFRA to mitigate fault-related ignition risks and isolate circuit segments to reduce the scope of PSPS events. Sectionalizing devices also include performing upgrades to Circuit Breaker (CB) Relay Hardware for Fast Curve (FC) Settings which reduce fault energy by increasing the speed with which a relay reacts to most fault currents. SCE is not requesting funding for 2024 for HFRA Sectionalizing Devices in this filing.

1. Work Description and Need

A relay is a device designed to trip a circuit breaker when it detects a fault, which is an electrical disturbance in the power system accompanied by a sudden increase in current. The CB then interrupts the current flow, or in other words, cuts off the power supply to minimize damage to the circuit. SCE initiated a program to deploy FC settings at substation CB relays. CB relays with conventional settings take a certain time to detect and respond to a fault while FC settings increase the speed in which the relay detects a fault. SCE developed a plan to upgrade old electromechanical relays with new microprocessor relays, and in some cases update microprocessor relay settings to enable Fast Curve settings for the remaining HFRA feeder circuits.

SCE initially targeted updates to circuits serving HFRA that had CBs with existing microprocessor-based relays. These previous activities concentrated on relay setting updates and not relay hardware replacements. A greater portion of the 2021 activity required relay hardware upgrades to accommodate the FC settings integration, which are more costly than setting upgrades that do not require hardware replacement. Also during 2021, SCE refreshed the distribution circuit list after an internal quality control audit of HFRA circuits found additional circuits in need of FC settings updates. The additional circuits were added to SCE's 2022-2023 scope.

SCE is performing a circuit evaluation for PSPS-driven grid hardening work to develop targeted plans for grid hardening and circuit modifications to reduce PSPS impact. This evaluation may result in the installation of HFRA sectionalizing devices to reduce the PSPS frequency, duration, and the number of customers impacted. When SCE completes this evaluation and determines the appropriate scope for future work, SCE will request an appropriate level of funding in its TY 2025 GRC request.

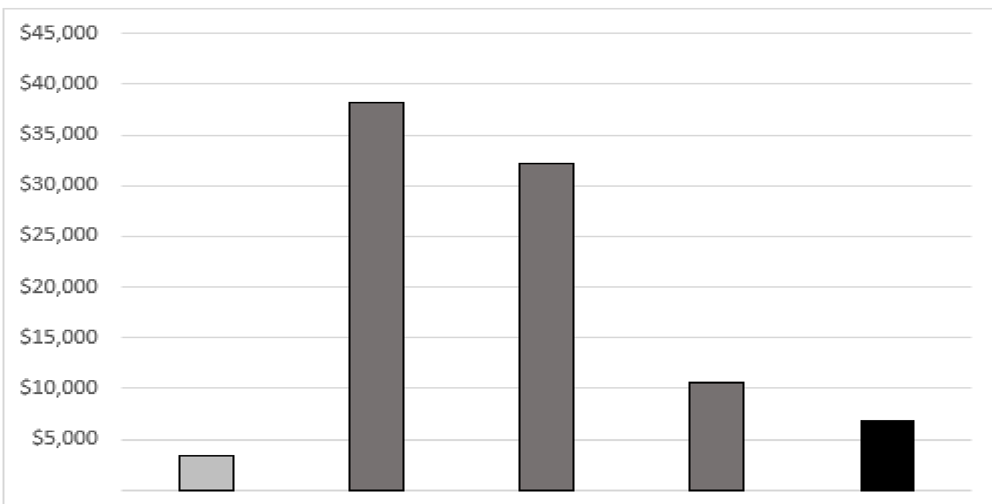
VI.

ORGANIZATIONAL SUPPORT AND SAFETY SOLUTIONS

A. Overview

The costs covered in this section are for Safety Oversight Support and Organizational Support. Figure VI-24 below summarizes the costs associated with this activity as well as the 2024 forecast. Activities within this section include contractor oversight and safety support and funding for the Wildfire Safety Organization that that centrally manages and provides oversight for SCE's wildfire mitigation efforts.

Figure VI-24[84]
O&M Summary
Organizational Support
O&M Authorized, Recorded, and Forecast
(Constant 2018 $000)



Track 1 Authorized*	Recorded			Track 4 Forecast
2021	2019	2020	2021	2024
$3,354	$38,160	$32,137	$10,517	$6,898

		Track 1 Authorized*	Recorded			Track 4 Forecast
	Subactivity	2021	2019	2020	2021	2024
1	Organizational Support	$3,354	$38,160	$32,137	$10,517	$6,898
	Total Expenses	**$3,354**	**$38,160**	**$32,137**	**$10,517**	**$6,898**

* Authorized 2022 and 2023 are equivalent to 2021 authorized (in constant 2018 dollars) after removing the impact of the Track 1 Decision's post-test year attrition mechanism

84 The 2024 forecast for Organizational Support includes $0.208 million in the sub-activity Talent Acquisition. This work should not be included in the 2024 Organizational Support forecast, however it was discovered shortly before the Track 4 filing. It will be removed and reflected in a future errata submission.

B. Safety Oversight Support

1. Work Description and Need

In 2019, SCE brought in Professional Safety Solutions (PSS) as a contractor to strengthen contractor oversight and safety support and to proactively address SCE's wildfire management efforts. New regulatory requirements associated with wildfire mitigation during this time necessitated a level of labor resources far exceeding SCE's existing in-house capabilities to promote safe contractor work practices. During 2020, PSS conducted frequent field visits to the contractors each month with the sites being selected randomly. At each of these field visits, PSS made safety observations. Issues identified by PSS were addressed on-site with the contractor crews involved. Through this process, PSS identified over a thousand opportunities for improvement with our contractor workforce. These opportunities for improvement included job site planning, proper use of vehicles and construction equipment, protection from electrical contact and arc flash, identifying instances where people were at risk of falling or at risk due to proximity to overhead hazard work, and effective uses of personal protective equipment. After each observation, PSS sent a follow-up email to the contractor representative, SCE representative, and SCE safety team.

In addition, PSS produced observation reports, weekly reports and monthly contractor specific reports, which were shared with the contractors and affected business units. These reports were eventually streamlined into a contractor safety dashboard maintained by SCE eliminating the need for separate reports. Safety Oversight Support provided by PSS has been instrumental in SCE's mission to help eliminate serious injuries and fatalities by augmenting our oversight capabilities and providing essential data for SCE's safety team to directly communicate to SCE organizational units and contract leadership.

2. Historical Variance Analysis

In 2020, Safety Oversight Support incurred $6.17 million in O&M expenses. In 2021, Safety Oversight Support incurred $4.88 million in O&M expenses. The work in 2021 followed the same pattern of randomly selecting contractor sites to visit, conducting rigorous inspections at the site, and providing safety suggestions for the crews and the contractor. The change from 2020 to 2021 was a result of a more limited geographic scope targeted in 2021 (*i.e.*, focusing only on HFRA vs. the entire service area).

3. Safety Oversight Support O&M Forecast

SCE's 2024 forecast for Safety Oversight Support is $4.88 million, based on last year recorded 2021 O&M expenses. SCE will conduct a similar amount of work for Safety Oversight Support in 2024, focusing our safety efforts in the HFRA, and maintaining the same cadence of frequent visits to randomly selected sites. SCE will maintain the same level of support to monitor new standards and ensure construction practice changes are being followed properly.

C. Organizational Support

1. Work Description and Need

The Wildfire Safety organization (formerly Grid Resiliency & Public Safety PMO) continues the centralized management and oversight of SCE's wildfire mitigation efforts that began in 2018. The volume of wildfire mitigation-related work associated with coordinating, planning, project managing, and reporting across the enterprise and to external entities continues to persist and requires rapid execution to meet short timeframes.

The Wildfire Safety organization also oversees Organizational Change Management (OCM) activities to ready operations to adopt changes to the type and scope of work, business processes, and technological tools and systems to perform SCE's wildfire mitigation work activities.

2. Historical Variance Analysis

In 2019, SCE incurred $38.20 million in O&M expenses for supplemental PMO resources. In 2020, Organizational Support incurred $23.39 million in O&M expenses. In 2021, Organizational Support incurred $3.66 million in O&M expenses for consultant support. Activities that continued to receive support in 2021 included WMP performance and regulatory work, the Aerial inspections program and process enhancements, centralized Lidar program assessment, and OCM support (primarily for inspection programs and PSPS).

3. Organizational Support O&M Forecast

SCE's 2024 forecast for Organizational Support is $2.02 million, based on last year recorded 2021 O&M expenses, adjusted down to reflect reductions anticipated in ongoing costs for consulting support. SCE's build up in the area of wildfire management support programs internally, has reduced the need for consultant support. Based on this ramp down of support needs, SCE has reduced its forecast from 2021 recorded amounts of approximately $3.66 million to $2.02 million for consultant support in 2024. Support includes but is not limited to: developing processes, systems, and strategies to ensure our reporting capabilities are thorough and built to manage frequently changing external requests to consume high volumes of data in varied formats; ensuring adoption of frequently changing technologies used by the workforce to manage their daily output; and using industry expertise to consult operational organizations on modifying business processes, approaches with programs such as targeted undergrounding, PSPS, and inspection strategies and tools.

VII.

ENHANCED OPERATIONAL PRACTICES

A. Overview

Pursuant to Commission regulatory requirements as well as its own internal engineering standards, SCE regularly inspects the electrical equipment within its service area to ensure the provision of safe and reliable power to our customers. Beginning in 2018, SCE introduced new techniques into its inspection program, namely Infrared Inspections (IR), primarily directed at distribution assets, and combined IR and corona scans for transmission assets. These programs identify heat spots and temperature differentials which may indicate problems that are not visible to the naked eye. In 2019, SCE inspected most of its structures in the HFRA within a few months prior to the start of the traditional wildfire season. In the second half of 2019, SCE launched the Inspection Redesign initiative to examine and further improve upon the inspection program in the HFRA. SCE commenced this new inspection strategy, which combined the inspection criteria for wildfire risk-focused inspections (formerly Enhanced Overhead Inspections (EOI), and distribution Overhead Detail Inspections (ODI), transmission and generation).[85] The Inspection Redesign initiative has implemented certain programmatic improvements. For example, SCE inspections now electronically capture significant quantities of data about our structures. While this slightly increases the cost-per-inspection, it allows SCE to accumulate valuable data that we are now testing using advanced analytical techniques which has allowed us to better track the overall health of our assets and improve our risk modeling. As another example, the traditional ground-based inspections conducted in compliance with GO 165 have been supplemented in several ways in our Enhanced Inspection Methods regime for the HFRA (discussed further below). Most significantly, we have introduced extensive use of drones and helicopters to carry

[85] SCE also performed inspection and remediation work on certain legacy utility-owned hydroelectric generation assets located within HFRA, such as powerhouses. SCE has not included testimony on this specific aspect of inspection and remediation work due to its relatively immaterial cost impact compared to the same work SCE performed on our distribution and transmission assets. For additional details on this generation-specific sub-component of inspection and remediation work, please refer to WP SCE Tr. 4-02 – Generation, pp. 11 - 12.

out aerial inspections, allowing us to see the tops of structures and conductors, which are sections that are rarely visible from the ground level.

In 2020, in response to evolving conditions, SCE introduced a new inspection methodology as part of the Inspection Redesign initiative, known as the Areas of Concern, or AOCs which is described in more detail in Section VII-D-e below. AOCs are specific geographic areas identified through a combination of environmental conditions, such as an abundance of dry fuel and exposure to high winds. In 2021, SCE expanded on the AOCs effort to include a Summer AOCs readiness season in addition to the Fall AOCs readiness season. The AOCs are now integrated with our other inspection routines. In 2022, SCE is adding enhanced transmission conductor and splice inspection methods in HFRA to complement existing processes to help prevent ignitions.

All inspections are conducted with the intent of identifying problems or potential problems on our system. When a problem is identified, through either ground, aerial, infrared, corona scans or identified in an AOCs, a notification is generated. A notification is then given a priority: P1, P2 or P3, depending on the severity of the risk created by the identified condition, and the notification is then scheduled for remediation. Remediation costs may be either an O&M expense or a capital expenditure pursuant to existing accounting standards and requirements.

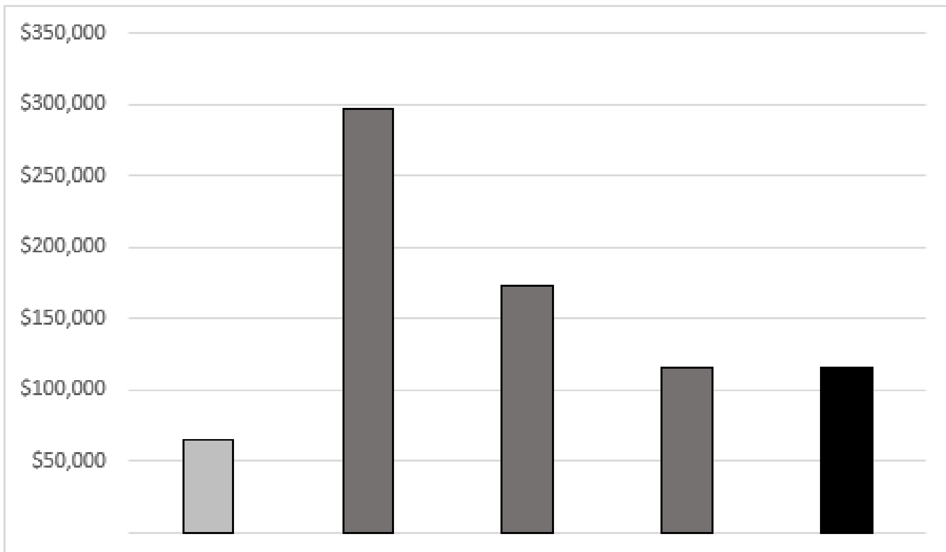
In summary, the portfolio of inspection programs within HFRA is outlined below in Table VII-13 which shows the inspection types and cycle times for both distribution and transmission followed by descriptions of historical and forecast costs for these activities thereafter.

Table VII-13
Portfolio of Inspection Programs

Inspection Type	Description	Distribution Cycle Time	Transmission Cycle Time
HFRA Ground	Compliance based inspections from the ground vantage point	Target every 3 years (5 years at minimum)	3 years
	Comprehensive risk-based inspections from the ground vantage point	As Identified	As Identified
HFRA Aerial	Accompany compliance based inspections from the aerial vantage point	Target every 3 years (5 years at minimum)	3 years
	Accompany comprehensive risk-based inspections from the aerial vantage point	As Identified	As Identified
Transmission Enhanced Inspection Methods	Method to find anomalies which are not apparent or visibly exposed	-	Dependent on work scope
Infrared (IR) Inspections and Corona Scans	(Dist. & Trans) IR - Thermal differences among components and equipment (Trans.) Corona Scans - Detect temperature consistencies that are not visible	As Identified	As Identified
Areas of Concern (AOCs) - Ground-Based & Aerial	Similar to ground & aerial however determined by fuel & weather conditions	Annually dependent on emergent conditions	Annually dependent on emergent conditions

B. O&M Request – Enhanced Operational Practices Summary

Figure VII-25[86]
O&M Summary
Enhanced Overhead Inspections and Remediations
O&M Authorized, Recorded, and Forecast
(Constant 2018 $000)



Track 1 Authorized*	Recorded			Track 4 Forecast
2021	**2019**	**2020**	**2021**	**2024**
$65,659	**$297,241**	**$172,538**	**$115,806**	**$115,195**

		Track 1 Authorized*	Recorded			Track 4 Forecast
	Sub Activity	**2021**	**2019**	**2020**	**2021**	**2024**
1	Inspections	$27,784	$103,992	$109,470	$67,554	$67,088
2	Remediations	$27,161	$191,313	$59,495	$44,095	$44,205
3	HFRI Technology Solutions	$10,714	$1,937	$2,545	$3,552	$3,296
4	Vegetation Management Technology Solutions			$1,028	$606	$606
	Total Expenses	**$65,659**	**$297,241**	**$172,538**	**$115,806**	**$115,195**

* Authorized 2022 and 2023 are equivalent to 2021 authorized (in Constant 2018 dollars) after removing the impact of the Track 1 Decision Post-Test Year attrition mechanism.

**For 2020 recorded expense regarding Distribution Infrared (IR), SCE is still reconciling the final number, which will be reflected in SCE's TY 2025 GRC forecast as appropriate.

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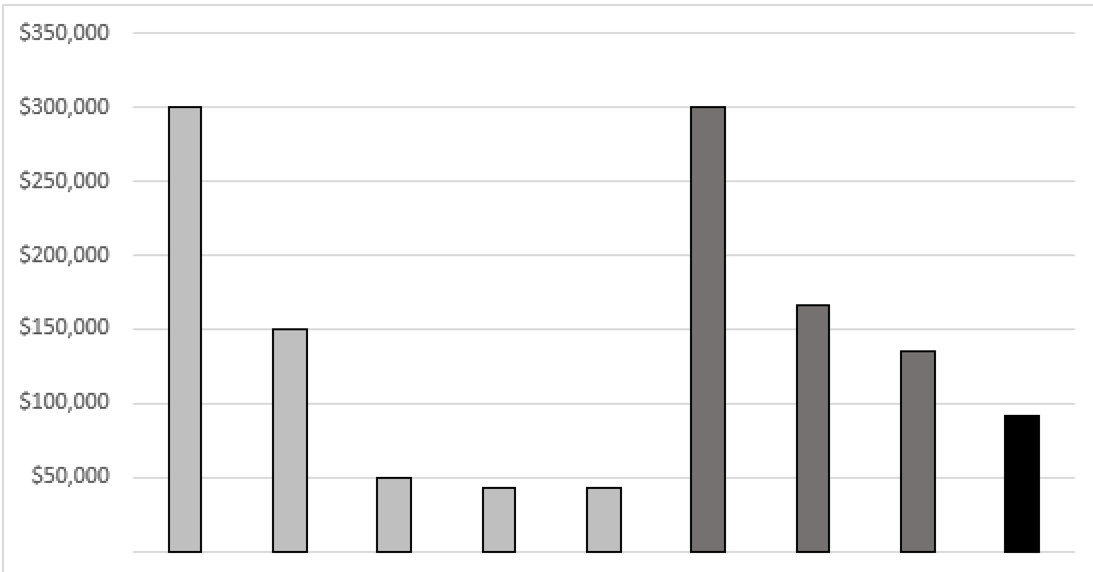
86 Figure VII-25 includes $0.606 million in 2021 Recorded and 2024 Authorized of Vegetation Management Technology Solutions, which is discussed in the Vegetation Management chapter Technology Solutions

(Continued)

C. Capital Request – Enhanced Operational Practices Summary

Figure VII-26[87]
Capital Summary
Enhanced Overhead Inspections and Remediations
Capital Authorized, Recorded, Forecast
(Nominal $000)



Track 1 Authorized					Recorded			Track 4 Forecast
2019	**2020**	**2021**	**2022**	**2023**	**2019**	**2020**	**2021**	**2024**
$300,592	**$149,378**	**$49,553**	**$43,572**	**$43,009**	**$300,592**	**$166,138**	**$135,028**	**$91,908**

		Track 1 Authorized					Recorded			Track 4 Forecast
	Sub Activity	**2019**	**2020**	**2021**	**2022**	**2023**	**2019**	**2020**	**2021**	**2024**
1	Remediations	$282,982	$126,022	$42,840	$41,065	$40,418	$282,982	$121,292	$96,120	$81,232
2	HFRI Technology Solutions	$17,610	$23,356	$6,712	$2,507	$2,592	$13,391	$28,700	$27,903	$7,969
3	Vegetation Management Technology Solutions						$4,219	$16,147	$11,005	$2,707
	Total Capital	**$300,592**	**$149,378**	**$49,553**	**$43,572**	**$43,009**	**$300,592**	**$166,138**	**$135,028**	**$91,908**

section. Regarding Inspections, the 2024 forecast is $0.466 million less than the 2021 recorded amount primarily due to training delivery and seat time costs that are currently being forecast elsewhere as part of SCE Chapters 1-4. In addition, regarding HFRI Technology Solutions, the 2024 forecast is $0.256 million less than the 2021 recorded amount primarily due to the vegetation management software Survey123 that brought into replace Clearion. This is a one-time, non-recurring cost, however, as SCE will be deploying Arbora. Accordingly, SCE has not included this cost in its 2024 forecast.

87 Figure VII-26 includes recorded expenditures for Vegetation Management Technology Solutions, which is discussed in the Vegetation Management chapter Technology Solutions section.

D. Inspections

1. Work Description and Need

a) HFRA Ground

(1) Distribution

SCE incurred $7.79 million (2018 constant dollars) in O&M expenses in 2021 to perform HFRI inspections on approximately 180,000 distribution structures.[88] [89] Rather than inspecting all HFRA structures, SCE used the risk-informed approach developed in the Inspection Redesign program to identify high- and medium-risk structures for inspection.

Distribution ground-based inspections are performed pursuant to compliance requirements, risk-informed assessment, or through the AOCs process. Each distribution structure in HFRA is required to be inspected at least once every five years, per GO 165. However, beginning in 2022, SCE will endeavor to inspect all distribution structures within HFRA at least once every three years to further reduce ignition risk.

Further, SCE performs an annual risk assessment on distribution structures that may drive more frequent inspections for some structures. The structures to be inspected on a more frequent basis (e.g., annual frequency) are selected by those that make up the highest wildfire risk as defined by the structure's risk. As risk levels vary across SCE's HFRA, a targeted quantitative approach is being deployed to balance risk reduction, resource availability and costs. Structures are prioritized for inspection based on POI and consequence. In determining the inspection scope, SCE incorporates the latest risk modelling capabilities as well as the need to reserve execution capacity for emergent AOCs.

Each inspection is completed by an inspector, who is an Electric System Inspector (ESI), performing a comprehensive inspection survey. Each year, inspections are targeted to

[88] SCE also performed inspection and remediation work on certain legacy utility-owned hydroelectric generation assets located within HFRA, such as powerhouses. SCE has not included testimony on this specific aspect of inspection and remediation work due to its relatively immaterial cost impact compared to the same work SCE performed on our distribution and transmission assets. For additional details on this generation-specific sub-component of inspection and remediation work, please refer to WP SCE Tr. 4-02, pp. 11 - 12.

[89] Comprised of approximately 131,000 HFRI, 14,000 AOCs and 35,000 compliance inspections.

occur before peak wildfire season, which typically begins in September. SCE plans to inspect 140,000 distribution risk-informed structures in 2024 within HFRA, representing approximately 95% of the modelled relative ignition risk associated with our overhead distribution assets. In addition, in 2024 SCE plans to inspect 30,000 structures in HFRA identified through AOCs and 10,000 structures through traditional compliance-based inspections. Combined, as outlined below in Table VII-14, SCE's planned 2024 inspections will target 63% of the structures in HFRA, which cumulatively account for 97% of the relative total modelled ignition risk associated with overhead distribution structures. In addition to identifying structures in need of remediation, the additional data capture of asset information helps SCE improve existing or create new models, respond to the various detailed reporting and data provision requirements from the Commission and Office of Energy Infrastructure Safety, and further enhances SCE's wildfire risk mitigation capabilities.

Table VII-14
% of HFRA Distribution Ground Inspections by Category, 2024

HFRI	Compliance	AOCs	Total
49%	4%	10%	63%

In addition, SCE added enhanced data collection capability to the inspection survey for all distribution inspection categories which are HFRI Inspections, HFRA Compliance, and Non-HFRA Compliance. The enhanced capability captured more granular levels of information related to assets such as transformers, splices, guy, number of crossarms, switches, and configuration. SCE expanded this data collection effort into non-high fire areas in 2020 to better understand the life cycles of assets on its system and associated failures. Enhanced data capture during all types of distribution inspections enables SCE to capture more information on SCE's assets, including critical asset inventory data previously not obtained during inspections. The costs incurred under HFRI Inspections included costs associated with the data capture process from both HFRA and non-HFRA. This helps SCE to develop the overall risk model and become more effective.

Ground inspections are one component of how SCE inspects overhead distribution equipment. As discussed further below, SCE complements these ground inspections with aerial inspections. Performing ground inspections help detect equipment and structure conditions that are difficult to identify via aerial inspections (*e.g.*, aerial inspections do not inspect spans), such as damaged conductor and missing cotter keys as shown in Figure VII-27 and Figure VII-28 below. Aerial inspections help to detect equipment and structure conditions that are difficult detect via ground inspections such as deterioration on the top of a distribution crossarm or a missing cotter key on a large transmission structure.

Figure VII-27
Damaged Primary Conductor on a 12kV Circuit
Distant (left) and At Close Range (right)

Figure VII-28
Damaged Primary Condcutor (left) and Missing Cotter Key (right) on 12kV Circuits

(2) Transmission

SCE incurred $2.00 million (2018 constant dollars) in O&M expenses in 2021 to perform HFRI inspections on approximately 21,000 transmission structures.[90] Rather than inspecting all HFRA structures, SCE used the risk-informed approach developed in the Inspection Redesign program to identify high- and medium-risk structures for inspection.

For transmission in HFRA, ground-based inspections are identified by a combination of compliance requirements, risk-informed assessment, or through the AOC process. Although each structure is inspected at least once every three years, annual risk assessment may drive more frequent inspections for some structures. Each inspection is performed by either a Transmission Senior Patrolman or Lineman, both of which are Qualified Electrical Workers (QEWs).[91] Each year, inspections are targeted to occur before peak wildfire season, which typically begins in September.

SCE plans to inspect 13,600 transmission risk-informed structures in 2024 within HFRA, representing approximately 91% of the modelled relative ignition risk associated with our transmission assets. In addition, in 2024 SCE plans to inspect 3,000 structures in HFRA identified through AOCs and 2,600 structures through traditional compliance-based inspections. Combined, as

[90] Comprised of approximately 14,000 HFRI, 1,000 AOCs and 6,000 compliance inspections.
[91] QEWs are individuals who have a minimum of two years of training and experience with exposed high-voltage circuits and equipment.

outlined below in Table VII-15, SCE's planned 2024 inspections will target 52% of the structures in HFRA, which cumulatively account for 97% of the total modelled relative ignition risk associated with transmission structures.

Table VII-15
% of HFRA Transmission Ground Inspections by Category, 2024

HFRI	Compliance	AOCs	Total
37%	7%	8%	52%

Transmission HFRI inspections have evolved since launching the effort in late 2018 into early 2019. While the resources to do these inspections remain the same (i.e., Transmission Senior Patrolmen and Linemen), the tool being used has evolved. SCE began using an iPad-based inspection form for these inspections in 2019, which made SCE's form more efficient and added new questions and data capture prompts. For instance, a question was added to capture the location of C-hooks in HFRA. In addition, questions have been added or refined to better capture risks associated with missing or damaged cotter keys and pins, damaged or improperly installed guy anchors and overgrown brush adjacent to transmission lines. These improvement examples represent SCE's commitment to continually visiting the survey form and ensure that lessons learned are applied.

b) HFRA Aerial

In addition to ground-based inspections, SCE determined that aerial inspections could meaningfully supplement these inspections to identify deterioration or unfavorable asset conditions that are not visible from the ground. As a result, SCE launched the aerial inspection program in 2019 to perform HFRI aerial inspections to complete a 360-degree view of structures and equipment. The primary objective of the aerial inspection program is to inspect assets from a top-down view and identify ignition risks on assets located within HFRA that are difficult to identify via ground inspections. Aerial inspections are performed by drones and/or helicopters capturing high-definition digital photographs of each scoped HFRA overhead structure, including but not limited to pole tops, wooden crossarms, steel structures, and attached conductors/hardware. Drones are primarily utilized, however in some cases helicopters may be used to capture structures that have access restrictions and/or located within rural and mountainous areas. During the planning process, numerous factors including noise pollution, residential and rural geographical considerations, safety, and aircraft maneuverability contribute to the decision as whether to utilize an Unmanned Aerial System (UAS) (i.e., drone).

For distribution aerial, SCE spent \$53.06 million in 2020 and \$38.48 million in 2021, and for transmission aerial, SCE spent \$27.72 million in 2020 and \$15.49 million in 2021. These costs were incurred to conduct approximately 168,000 and 180,000 distribution aerial inspections in 2020 and 2021, respectively. For transmission aerial inspections, these costs were incurred to conduct approximately 31,000 and 21,000 aerial inspections in 2020 and 2021, respectively. SCE forecasts the cost for remediations that result from these inspections in Section VII-C.

AOC-focused aerial inspections are performed in the same manner as HFRI aerial inspections for distribution and transmission structures. Similar to HFRI aerial, each year inspections are targeted to occur before peak wildfire season, which has typically begun in September. The AOCs scope has a higher priority when compared to risk-based inspections due to the on-the-ground current fuel and weather conditions that drive AOCs' risk and require more immediate inspection.

(1) Distribution & Transmission

SCE plans to inspect 140,000 aerial distribution risk-informed structures in 2024 within HFRA, representing approximately 96% of the modelled relative ignition risk associated with our overhead distribution assets, and which is comparable to the amount of inspections SCE performed in 2021. In addition, in 2024 SCE plans to aerially inspect 30,000 structures in HFRA identified through AOCs. As outlined below in Table VII-16, SCE's planned 2024 inspections will target 63% of the structures in HFRA, which cumulatively account for 97% of the total modelled relative ignition risk associated with overhead distribution structures.

Table VII-16
% of HFRA Distribution Aerial Inspections by Category, 2024

HFRI	AOCs	Total
53%	10%	63%

SCE plans to aerially inspect 16,200 transmission risk-informed structures in 2024 within HFRA, representing 91% of the modelled relative ignition risk associated with our transmission assets, which is comparable to the number of inspections SCE performed in 2021. In addition, in 2024 SCE plans to inspect 3,000 structures in HFRA identified through AOCs. As outlined below in Table VII-17, SCE's planned 2024 inspections will target 52% of the structures in HFRA, which cumulatively account for 97% of the total modelled relative ignition risk associated with transmission structures.

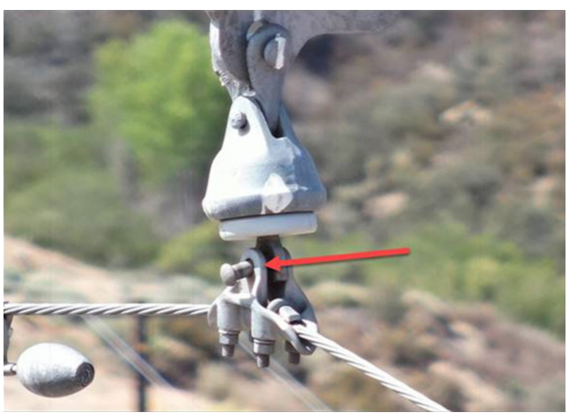
Table VII-17
% of HFRA Transmission Aerial Inspections by Category, 2024

HFRI	AOCs	Total
44%	8%	52%

Images captured from aerial inspections allow for a detailed review with respect to an alternative vantage point of assets. In addition, views from above are the primary tool to provide insight into asset condition and such perspectives cannot be captured from the ground. Figure VII-29 below shows a deteriorated crossarm on a distribution pole which is not able to be seen from the ground. Figure VII-30 and Figure VII-31 show missing transmission cotter keys that due to the size of the structures can be difficult to observe from the ground.

Figure VII-29
Distribution Deterioriated Crossarm
Distant (left) and At Close Range (right)

Figure VII-30
Transmission Missing Cotter Key
Distant (left) and At Close Range (right)



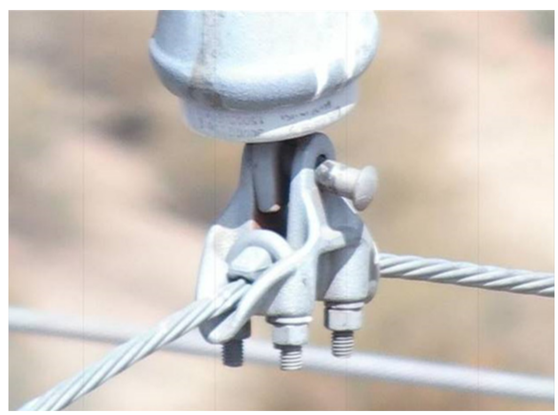


Figure VII-31
Transmission Missing Cotter Key
Distant (left) and At Close Range (right)

Subsequently, each photograph is examined by qualified contracted resources (e.g., journeyman linemen) and the results are analyzed and documented. A condition assessor inspects the aerial photographs of the assets, assessing the structural and equipment condition while recording answers to questions to an inspection form. An inspector can disposition the assets into various categories, depending on the condition of the asset. If an inspector identifies an immediate ignition risk, they route that structure to an SCE QEW, also known as a Field Specialist, who validates the issue and creates a notification in the data system. The Field Specialist also provides a description of the issue so that field crews can appropriately plan and execute remediations. This process is consistent with traditional inspections, where a crew is sent out to assess the issues prior to remediation.

The aerial inspection scope is defined annually based on a risk model. Once aerial scope is identified and finalized, it is compiled into flight blocks – which include commonly located assets in a specified geographical area – after which dates are created for both the start and completion of each flight block. These dates are adjusted based on airspace conflicts, weather, access, Temporary Flight Restrictions (TFR), or other aerial factors. After scope, schedule, location, and deliverables are finalized, the aerial inspection team reviews asset locations to determine whether the structures should be flown by helicopter or UAS. This determination helps decide which vendors will be permitted to bid for the scope.

Once the scope is awarded, the aerial team conducts a contractor safety and alignment meeting going over the area vendors may be flying, customer contact protocol, and previous captures that have led to notifications. Following this initial meeting a weekly vendor meeting is established to review inspection progress, adjust projections, and provide performance feedback. Each day before flights, the contracted aerial team engages SCE Air Operations (AirOps), who is responsible for de-conflicting the airspace and request flight approval for the following day. The aerial team also notifies other internal and external stakeholders about the location of that week's operations via email. These stakeholders include Local Public Affairs (LPA), Government Affairs, Tribal Lands, Customer Service, Edison Security Operations Center (ESOC), Corporate Communications, Social Media Relations, Distribution Districts, and Transmission Grids. The vendors utilize a shot-sheet to obtain the required images and later download them (meeting SCE cyber security requirements) onto a secure cloud platform. These images are then distributed to the inspectors for completion of condition assessments. Upon review of the images, if an inspector identifies an immediate ignition risk, they route that structure to a SCE Field Specialist, who validates the issue and creates a remediation request or notification in SCE's data system (*i.e.*, SAP).

In addition to assessing aerial images, the Aerial Inspection program is the central repository in charge of collecting and storing LiDAR (Light Detection and Ranging). LiDAR is a surveying inspection method that measures the distance to a target by illuminating the target with pulsed laser light and measuring the reflected pulses with a sensor. Differences in laser return times are then used to make digital three-dimensional representations of field condition at the time of survey. This LiDAR data is currently captured by and processed by a helicopter vendor and used to enhance SCE's geolocation information by providing more accurate latitude and longitude values for a given structure. The data is also used in the assessment of vegetation clearance for the Vegetation Management group. Another use case for LiDAR data is for engineering analysis. Engineering groups such as Civil

Engineering use the data on the geographical characteristics surrounding and effecting SCE structures in the field.

In 2022, SCE is investigating opportunities to utilize LiDAR that is currently being collected by various departments for other inspection capabilities. In addition, SCE is exploring potential solutions that will allow for the visualization of collected LiDAR that could potentially enhance the inspection process and may also help to mitigate risks (*e.g.*, structural issues, conductor tension, etc.) to the organization.

Beginning in 2022, the new 360 approach (the combination of ground & aerial inspections for distribution for 33kV and below) will consist of performing inspections on the same day in the field. The success of the 2022 distribution rollout will be incorporated into a 2023 transmission roll out. The current traditional approach consists of a ground and aerial inspection taking place during separate time periods. The 360 approach will include a survey on the spot mobilizing a single resource to perform both the ground and aerial inspection. The benefits of this 360 approach are expected to be less customer impacts, more efficient notification prioritization, safety benefits for field personnel, consistent asset data capture, as well as reduction in environmental impacts (e.g., reduced driving in the field). For the most part, inspections will not be performed by one individual, but instead by both an inspector and a pilot. In some cases, a single inspector will perform an inclusive inspection (ground and aerial). At this point it is not entirely clear the extent to which SCE will realize future cost savings from the new approach, but SCE does expect to at least avoid future cost increases. A quality review of a pre-determined percentage will be performed to ensure consistency and aptitude of inspection. At the present time, it is believed that similar magnitude of structures within HFRA will be inspected as seen in previous inspection years. All inspection scope depends on risk modeling and will thus vary.

c) Transmission Enhanced Inspection Methods

SCE is adding enhanced transmission conductor and splice inspections methods (LineVue, X-Ray and Conductor Sampling) in HFRA to complement existing inspection processes as part of HFRI inspections to help prevent future ignitions. SCE identified 57 transmission wire down events that occurred in the last five years throughout the SCE service territory, with most failures attributed to conductor and splices. Conductors and splices can fail due to age, weather, contact from object, and other factors that can lead to wire downs. To reduce transmission conductor wire down events, SCE plans to use enhanced inspection methods to identify anomalies and any underlying issues in order to replace or remediate conductors and/or splices that have a higher probability of failure. In addition, these methods help to capture issues that may not be visibly apparent to the human eye or other inspection technologies.

LineVue, X-Ray and Conductor Sampling, as shown below in Figure VII-32, were chosen for their enhanced inspection methods of finding anomalies which are not apparent or visibly exposed.

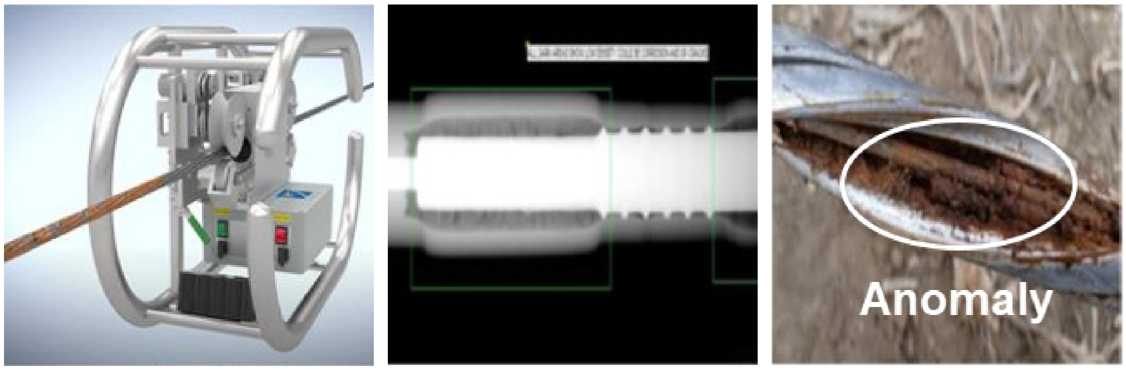
- LineVue determines the deterioration of the steel core cross-sectional area of the conductor steel core and detects any localized breaks or corrosion pits on the steel wires and loss of zinc galvanized layer. Alternatives for LineVue that SCE considered included Infrared (IR) inspections, Ultraviolet (UV) inspections, High Fire Risk-Informed (HFRI) inspections, and Aerial Transmission Inspections. However, these inspections rely on visual indicators, heat signatures, or partial discharges (signs which are only present when the equipment is close to failure) to find severe anomalies. Therefore, SCE found it prudent to perform LineVue inspections to help identify anomalies which are not visibly apparent or exposed such as conductor steel core and splice corrosion/deterioration.
- X-Ray is used on conductor splices to verify proper installation as well identify broken strands or deformities. X-Ray inspections are more effective than visual inspections in identifying these issues given the difficulty in seeing internal issues or improper termination installations. Ground inspections were considered as an alternative

however the inability to view any internal issues within a splice could potentially lead to low accuracy and it can be difficult for crews to reach the necessary locations. Aerial inspections were also considered as an alternative but similar to ground inspections, are less effective in identifying any internal issues.

- Conductor core sampling is an in-depth inspection performed on a 15-foot conductor section in a laboratory to determine the current health of conductor and estimates the component end-of-life. Currently, there are no viable alternatives to conductor core sampling. As part of this initiative selection, SCE evaluated practices throughout the industry and understands this activity to be widely utilized.

Not only do these activities help identify issues on the system, all three of these methods help gather more detail and data which are expected to be utilized in the future for an asset health index. The enhanced inspection methods LineVue and X-Ray can be performed either energized or de-energized. However, Conductor Sampling must be performed de-energized as an outage is required in order to safely remove the conductor. The region prioritization and RSE for all three of these new techniques are discussed in more detail within the 2022 WMP. Between 2022-2027 SCE plans to inspect between 500 to 750 of the highest risk-ranked segments and circuits in transmission HFRA using Enhanced Inspection methods. In 2024, SCE Plans to inspect 150 spans with LineVue, 70 splices with X-Ray, and analyze 15 conductor samples.

Figure VII-32
Transmission Conductor and Splice Assessment
LineVue (left), X-Ray (center) and Conductor Sampling (right)



d) Infrared (IR) Inspections and Corona Scans

SCE piloted IR inspections of energized distribution lines and equipment in 2017 and 2018 to help reduce equipment and conductor failure. Following the pilot, SCE deemed it prudent to inspect all distribution facilities in HFRA over a two-year cycle using IR technology. In 2019, SCE started a program to perform infrared and corona inspections of its overhead transmission system to detect thermal abnormalities that are leading indicators of faults. This program was started because in prior years (pre-2019) SCE experienced several splice failures, which occur when two sections of conductor that were bonded together subsequently are no longer being held by at least one of the conductor sections. Helicopters are used for these transmission inspections due to the long distances between structures and because these assets are frequently located on rugged terrain.

(1) Distribution Infrared (IR)

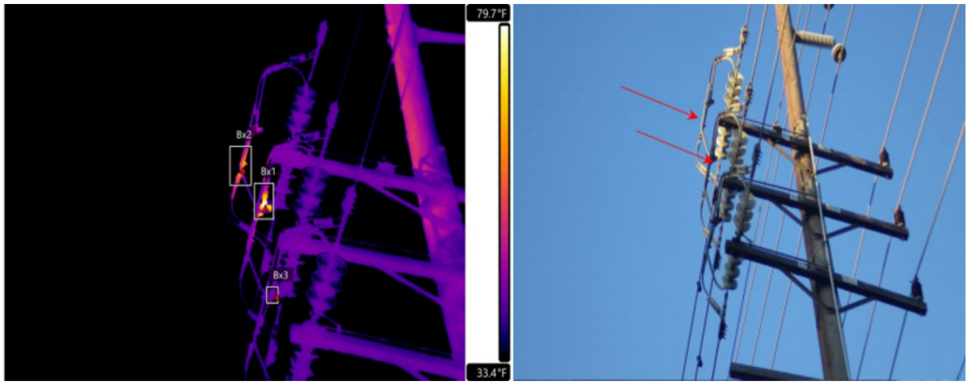
SCE incurred $0.460 million (2018 constant dollars) in O&M expenses in 2021 to perform inspections on approximately 4,400 overhead distribution circuit miles. SCE evaluated the need for IR inspections on its distribution circuits and found that these inspections offer a substantial benefit beyond standard visual inspections. The IR scan can detect temperature differences between components and identify heat signatures of components called "hot spots," that may indicate deterioration in structures and equipment not visible to the naked eye. Most inspections have been performed from vehicles; however, a small percentage of the inspections require the inspector to hike to the structure or perform the inspection from a helicopter.

Vehicle inspections utilize a two-person crew, with the passenger aiming an infrared camera at overhead facilities as the driver drives through the area. If a structure is out of range from the vehicle, the inspector will hike to the structure based on the inspector's estimation of the time required to hike to and from the structure and geographical constraints including terrain conditions. Typically, a 15-minute one-way hike to the structure is acceptable, provided there are no additional safety concerns. The driver remains with the vehicle while the inspector hikes to the structure. Helicopters are used when structures are inaccessible via a vehicle or hike, with only the inspector in attendance in comparison to a two-person crew for vehicles.

IR inspections can detect conditions that may indicate a wide range of anomalies, including, but not limited to, failing switch and fuse contacts, poor connections, loose bushings, overloaded/failing transformers, and other issues that can result in component failure. The images in Figure VII-33 below show a comparison of a thermal imagery (left) and a standard imagery (right). The IR scan image captures the temperature differences between components and identifies the "hot spots" and the component referenced for comparison. This condition would not have been captured during visual inspections.

In 2022, SCE will continue to perform IR scans on overhead distribution equipment throughout the HFRAs. Circuits in Tier 3 and Tier 2 HFRA are inspected every other year. Structures within the circuits are grouped by district which are then prioritized by relative risk. Risk is calculated by multiplying the POI by the Technosylva consequence, followed by the summation of the risk scores for each structure in the district. The sum of the relative risk scores are ranked highest to lowest and are then scheduled accordingly. Generally, the highest rank areas are performed during the first year of the two-year cycle (approximately 50% of the biannual scope), and the remaining during the second year. SCE plans to inspect approximately 4,400 distribution circuit miles in 2024 within HFRA.

Figure VII-33
Distribution Infrared (IR) Inspection
Thermal (left) and Standard (right) on 16kV Circuit



(2) Transmission (IR and Corona Scans)

In the first quarter of 2019, SCE launched the Transmission IR & Corona Scanning program. Specialized infrared and ultraviolet (Corona) light cameras are mounted to helicopters, which inspect the line, with special attention paid to splices, conductor connection/attachment points, and insulators. In 2021, SCE incurred $0.087 million in expense to perform IR and Corona scans on approximately 1,000 miles of transmission circuits deemed to be high risk within HFRA. SCE utilized internal resources to conduct all aspects of the IR and Corona inspections.

The Transmission IR & Corona Scanning program uses a risk prioritized method with consideration given to HFRA circuit miles and circuits completed in the previous year. The circuits are risk assessed by their probability of ignition and consequence levels and then prioritized and sorted by their calculated risk score. The circuits inspected in the previous year are removed from the priority list unless identified as one of the highest risk circuits. Finally, the scope is chosen by identifying the remaining circuits that should be inspected to inspect approximately 1,000 HFRA circuit miles annually with this program.

Similar to the distribution inspection protocol, the IR scan detects temperature differences and heat signatures of components, which may indicate problems that could result in component/conductor failure. Corona scanning is a technology that is only being used on transmission circuits in HFRA as insulator failures are not as common on distribution circuits. Corona identification is neither visual nor thermal. Corona detection is accomplished by identifying ultraviolet energy which is generated by electric discharge or "leakage" due to the ionization of air surrounding high voltage electric components. In some cases, the "leakage" is substantial enough that they may result in an arc flash and potential ignition. The Corona image easily identifies a conductor that has broken strands by showing the ultraviolet energy that is generated by electric discharge. It is very difficult to identify this type of issue with conventional photographs.

Transmission Corona scans are performed in conjunction with IR scanning. The infrared scan detects temperature differences and heat signatures of components, which may indicate problems not visible to the naked eye that could result in potential component/conductor failure. An example of an anomaly captured by a Corona scan is shown below in Figure VII-34**,** which shows a comparison of conventional, IR and Corona images of the same transmission line. Beginning in 2020, SCE's Air Operations division mounted an IR and Corona camera and flew the circuits to capture images as shown below in Figure VII-35. The images were then reviewed by SCE's Transmission Engineering department to identify any anomalies along the circuits and three P2 and 19 P3 corresponding remediation notifications were created.

Figure VII-34
Transmission 500kV Line
Visual (left), IR (center) and Corona Scan (right)

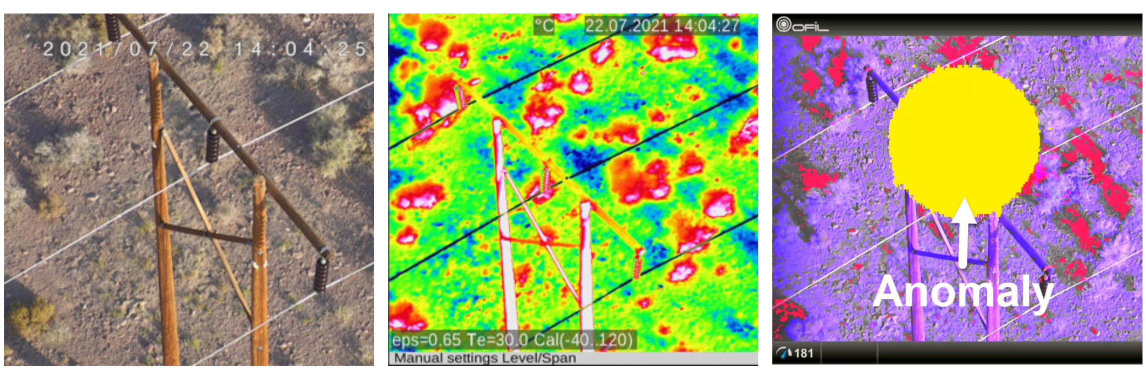


Figure VII-35
SCE Helicopters
Helictoper (left) and Mounted with IR & Corona Cameria (right)

e) Areas of Concern (AOCs) – Ground-Based & Aerial

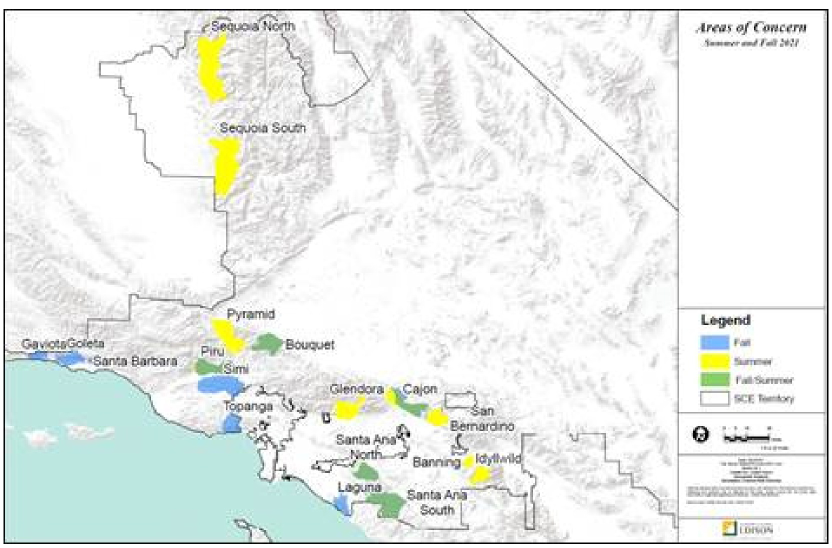
In 2020, SCE determined that ground inspections and remediation work in the AOCs were necessary to mitigate ignition risk and reduce the consequence risk of fuels-driven and wind-driven fires. AOCs are specific geographic areas (polygons) identified through a combination of environmental conditions, such as an abundance of dry fuel and exposure to high winds. SCE generally conducts HFRI by focusing on a defined list of structures based on either compliance or risk scores. The methodology to identify AOC polygons is based on several factors, including fire history, weather conditions, fuel type, exposure to wind, and egress, among others. The analysis to identify the AOCs scope of work include all distribution, transmission, and generation structures associated with whole circuits and vegetation within the surrounding topographical areas in the AOCs polygons. SCE plans its HFRI, AOCs, and compliance inspection work so that multiple inspections are not conducted on the same structure. As a result, a structure within the HFRA that may not otherwise have been inspected through a HFRI inspection but falls within an AOCs polygon will now be inspected as an AOCs inspection. AOCs inspections have a higher priority than HFRI inspections due to the AOCs risk being driven by current, on-the-ground conditions. Any notifications resulting from these inspections are then placed on a compliance remediation schedule. To focus resources on the highest-risk notifications and identify remediations that need to be accelerated prior to the start of wildfire season, SCE assesses each

AOCs notification on several dimensions: pending work on the structure, compliance deadlines, POI, and Technosylva consequence score.

In 2021, SCE conducted a Summer AOCs readiness inspection program, made up of 12 areas (to mitigate dry fuel-driven fires), and a Fall AOCs readiness inspection program, made up of 11 areas (to mitigate dry fuels and wind-driven fires) with five areas overlapping between seasons. Although there were some overlaps between seasons, inspections were performed only once.

Figure VII-36 below shows an example AOCs area from 2021. Additionally, the concept of the Fall AOCs pre-patrol was added. Fall pre-patrol allows SCE one final look at the Fall AOCs prior to the high winds and fire season. The pre-patrol consists of a slow vehicle-based patrol (where possible), which will look for P1 conditions (must remediate within 72 hours), mid-span clearance conditions (e.g., vegetation in lines or potential wire slap) and Communication Infrastructure Provider (CIP)/3rd party hazardous conditions.

Figure VII-36
Summer and Fall 2021 AOCs



In 2024, based on the AOCs' identification methodology that will be performed that year, SCE plans to inspect 30,000 distribution and 3,000 transmission structures. Additionally, vegetation management mitigations will be performed in the AOCs to reduce the risk of fuel-driven and wind-driven fires. AOCs ground-based and aerial inspections are performed in the same manner as HFRI inspections for distribution and transmission structures. Similar to both HFRI aerial and ground-based inspections, each year inspections are targeted to occur before peak wildfire season commences, which has typically begun in September.

(1) Distribution & Transmission

SCE recorded $0.100 million (2018 constant dollars) in O&M expenses in 2021 to perform AOCs inspections on approximately 30,000 distribution structures and approximately 3,000 transmission structures.[92] For distribution and transmission structures, in Summer 2021, SCE accelerated all structures in the existing HFRI inspection plan within the 12 AOCs and identified new structures to be inspected from the top five AOCs. In Fall 2021, all existing and newly identified structures that were scoped for HFRI inspections were accelerated to complete the inspections by August 2021. SCE anticipates that the 2024 AOCs scope will be similar to what was experienced in 2021 and 2022, however, specific scoping in that year will be dependent upon weather and fuel conditions.

[92] The recorded costs significantly understate the costs actually incurred for the AOCs inspections. For operational efficiency reasons, the work is being grouped with HFRA ground and aerial inspections, so much of the recorded costs of AOCs are subsumed in those categories. The process to identify the specific AOCs cost for future forecasting purposes is still under development and will be provided in the TY 2025 GRC (if available).

2. O&M Scope and Forecast Analysis

Table VII-18
Inspections
O&M Authorized, Recorded, and Forecast by Sub-activity[93]
(Constant 2018 $000)

	Subactivity	Track 1 Authorized* 2021	Recorded 2019	Recorded 2020	Recorded 2021	Track 4 Forecast 2024
1	HFRA Ground - Distribution	$23,988	$72,594	$10,338	$9,051	$8,638
2	HFRA Ground - Transmission		$27,914	$4,138	$2,019	$2,019
3	HFRA Aerial - Distribution		$3,484	$65,320	$40,350	$40,350
4	HFRA Aerial - Transmission			$27,724	$15,487	$15,487
5	Distribution Infrared (IR)	$343		**	$460	$406
6	Transmission (IR & Corona Scans)	$3,453	$1	$362	$87	$87
7	Areas of Concern (AOCs) - Ground-Based & Aerial			$1,589	$100	$101
	Total Expenses	**$27,784**	**$103,992**	**$109,470**	**$67,554**	**$67,088**

*Authorized 2022 and 2023 are equivalent to 2021 authorized (in constant 2018 dollars) after removing the impact of the Track 1 Decision's post-test year attrition mechanism

**For 2020 recorded expense regarding Distribution Infrared (IR), SCE is still reconciling the final number, which will be reflected in SCE's TY 2025 GRC forecast as appropriate.

a) Historical Variance Analysis

HFRI inspections are recorded as an O&M expense. From 2018 to 2020, there was a significant increase in inspection-related expense due to a ramp-up in this critical work. SCE spent $4.86 million in 2018, $104.00 million in 2019, and $110.26 million in 2020 which includes HFRI ground-based and aerial, IR, corona scans and AOCs ground-based and aerial. This increase was due to the new EOI/HFRI initiative that began in late 2018 and continued into 2019 and 2020 for both distribution and transmission, which included the establishment of an aerial inspection program to coincide with increased ground inspections in HFRA. Since 2020, SCE has adopted a risk-informed approach, which has changed the methodology by which assets are inspected. This new approach applies to HFRI and aerial inspections for both distribution and transmission and has driven the decrease from

93 These table includes consolidated figures. For additional detail see WP SCE Tr. 4-01 - O&M Financial Mapping pp. 161 - 162. Regarding HFRA Ground – Distribution, the 2024 forecast is $0.413 million less than the 2021 recorded amount primarily due to training and delivery seat time costs that are currently being forecast elsewhere as part of SCE Chapters 1 - 4. In addition, regarding Distribution Infrared (IR), the 2024 forecast is $0.054 million less than the 2021 recorded as the original forecast was discovered to be underestimated as SCE expects the scope of work performed to be similar in 2024. This figure will be updated and reflected in a future errata submission.

2020 to 2021 from $110.26 million to $67.55 million and has allowed a more focused effort for inspections. As discussed in this section, the majority of these costs are due to the introduction and refinement of our aerial inspection program in 2020. In 2019, approximately 300,000 assets were identified for aerial inspections; a majority of these were carried over into 2020 for completion. By 2021, the aerial inspection program had matured and gained operational efficiency. These costs have been incurred following a methodology that has been reviewed as part of the WMP.

b) Basis for forecast

To maintain compliance with regulations and to sufficiently address wildfire risk, SCE will continue to implement the portfolio of inspection activities in 2024 that it performed in 2021. As discussed within the work description and need section, the scope of work identified for each transmission and distribution inspection sub-activity in 2024 will remain largely consistent with the scope of work performed for each of those sub-activities in 2021. While it is possible there could be changes year-to-year in either scope or costs associated with each inspection sub-activity; overall, SCE anticipates the portfolio at-large should be generally consistent with the scope and costs incurred in 2021. In addition, SCE is implementing its new Transmission Enhanced Inspection Method sub-activity in 2022 to further address wildfire risk associated with transmission conductors and will continue that work through 2024. For these reasons, as well as those discussed in the policy section, SCE is using 2021 last year recorded as our forecast methodology. This approach will allow SCE to inspect approximately the same number of structures and to assess the same relative amount of risk.

E. Remediations

1. Work Description and Need

This section discusses the remediation activities for the notifications identified by the inspection programs discussed above which include HFRA ground, HFRA aerial, Transmission Enhanced Inspection Methods, IR Inspections and Corona Scans and AOCs – Ground-Based & Aerial. SCE incurred amounts of $96.12 million in capital expenditures and $44.09 million in O&M expenses for these remediation activities. Table VII-19 below summarizes the costs associated with the distribution (D) and transmission (T) remediation activities incurred in 2021.

Table VII-19
Summary of Costs in 2021 for Remediation Activities[94]
(Constant 2018 $000 for O&M, Nominal $000 for Capital)

Sub-Activity	Total Capital Expenditures	Total O&M Expenses
Remediations		
HFRI Remediations - D	$82,739	$37,643
HFRI Remediations - T	$13,381	$6,452
Total	$96,120	$44,095

SCE conducts the inspection programs as described above to identify GO 95-related correction issues through a remediation notification process. Remediation notifications identified through these inspections are prioritized based on the severity of the findings. The notification types and remediation timeframes as well as a breakdown of all notifications captured through SCE's various inspection programs are shown below in Table VII-20 and Table VII-21. Generally, remediations are completed pursuant to regulatory required timeframes. All remediations identified by an inspection are subject to the requirements of GO 95, Rule 18-B, which in part requires notifications in high fire areas that represent an elevated ignition risk to be recorded and scheduled to be completed within 6- and 12-month timeframes. Due to the unprecedented nature of dry fuel moisture content in SCE's HFRA, remediations resulting from AOC inspections are risk-ranked to prioritize the work. The remediation work can also include notifications from the previous year due if resource constraints, permitting delays, or other scheduling constraints prevented the work from being performed at that time.

94 SCE also performed inspection and remediation work on certain legacy utility-owned hydroelectric generation assets located within HFRA, such as powerhouses. SCE has not included testimony on this specific aspect of inspection and remediation work due to its relatively immaterial cost impact compared to the same work SCE performed on our distribution and transmission assets. SCE notes that the cost of this work is embedded ($61K for 2021) within distribution remediations for wildfire mitigation purposes. For additional details on this generation-specific sub-component of inspection and remediation work, please refer to WP SCE Tr. 4-02 – Generation, pp. 11 - 12.

Table VII-20
HFRA Notification Types and Remediation Timeframes

Priority	Remediation Timeframes	Examples
P1 issues require action 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.	Condition needs to be made safe within 24 hours, and work needs to start within 72 hours.	Vegetation touching line, broken crossarm or insulator, burned connector, wire lying on crossarm and pins backing out.
P2 issues are lower risk and therefore may be resolved within 24 months based on the existing safety or reliability condition and location. If the P2 issue is located within HFRA and poses a potential fire risk, remediation work is scheduled to be completed within 12 months. In an extreme fire threat area of Tier 3, the maximum remediation time is within 6 months.	Remediate within 6-12 months (depending on Tier 2 or 3 location).	Vegetation near line, deteriorated crossarm or splice, insufficient pole depth, damaged insulators.
P3 issues do not require near-term remediation as they do not pose material safety, reliability, or fire risks, and will either be repaired or re-evaluated at or before the next detailed inspection.	Remediation within 5 years.	Missing items; reflector strips, ground moldings, guy wire guards, high voltage signs, dampers damaged.

Table VII-21
HFRA Notifications Identified in 2021[95] [96]

Category	Distribution	Transmission	Total Notifications
HFRA Ground	11,054	1,471	12,525
HFRA Aerial	8,278	1,551	9,829
Transmission Enhanced Inspection Methods	-	5	5
Infrared (IR) Inspections and Corona Scans	50	3	53
Areas of Concern (AOCs) - Ground-Based & Aerial	2,987	193	3,180
Total Notifications	**22,369**	**3,223**	**25,592**

95 Since Transmission Enhanced Inspection Methods is a new initiative, the five notifications listed are an estimate and are discussed in more detail within WP SCE Tr. 4-02, p. 13 - Transmission Enhanced Inspection Methods.

96 Notifications for distribution includes both risk-informed and HFRA compliance while transmission includes only risk-informed. In addition, regarding aerial inspections, these figures represent findings prior to analyzing if the notification is valid or if it was previously identified by another inspection program.

a) HFRA Remediations – Distribution

In 2021, SCE completed repairs and replacements associated with approximately 21,500 distribution notifications identified through risk-informed and compliance-based inspections and prioritized those remediations based on regulatory compliance due dates. When scheduling and performing remediation work, SCE considers work bundling, outage requirements, permitting restrictions, crew availability and specialty equipment needs, in addition to the compliance-driven timelines required by GO 95. SCE bundles the work at the structure and circuit segment levels to the extent feasible for economic efficiency and to minimize the impact of remediation work on customers, as well as to reduce the volume of repeat outages, road closures and traffic restrictions. In certain cases, this results in future-year scope being accelerated in advance of the established compliance due date (*e.g.*, pole replacement being accelerated from a future year to align with a crossarm replacement on that pole due in the current year). This resulted in approximately 4,100 future-year notifications being brought into 2021 for completion. Additionally, there were several earlier-year due notifications that were not able to be completed due to prior-year operating constraints such as resource availability, permitting delays, and weather deferrals. Table VII-22 below shows the number of distribution notifications completed by capital and O&M and by priority level.

Table VII-22
Number of Capital and O&M Distribution Remediations
Completed by Priority Level in 2021

Priority	Capital	O&M	Grand Total
Priority 1	1,131	828	1,959
Priority 2	5,147	14,429	19,576
Subtotal	**6,278**	**15,257**	**21,535**
Priority 3	-	-	4,605
Total	**-**	**-**	**26,140**

In 2021, SCE completed 21,535 Priority 1 and Priority 2 distribution remediation notifications. Of those Priority 1 and 2 notifications, the five most frequent remediation-type categories were as follows: crossarm replacements, pole replacements, vegetation trims/removals, conductor repairs and replacements, and pole hardware replacements. Table VII-23 below further describes the types of issues found for each type of distribution notification.[97]

Table VII-23
The Most Common Types of Distribution Remediation Notifications

Category	Description
Crossarm	Deteriorated crossarms showing signs of excessive damage such as cracks, splits, pitting, or burns.
Pole	Visual failures identified as Priority 1 and 2 conditions: - Priority 1 requires immediate action. Split, decay, hole/boring, or other exterior damage that has significantly compromised the integrity of the pole. Failure is imminent. - Priority 2 issues are lower risk and therefore may be resolved within six months for Tier 3 or 12 months for Tier 2 within HFRA. Split or decay at a critical point of attachment, hole/boring that allows light through the pole, and significant exterior damage.
Veg. Trim	Vegetation growth that is encroaching on electrical equipment.
Conductor	Conductor damage, fraying, or clearance issues that require either repair or replacement.
Pole Hardware	Miscellaneous hardware repair and replacement on a structure including but not limited to installation of split bolts, line spacers, ridge-pin construction, lightning arrestors, and insulator replacements.
Guying	Damaged or loose guy wires and anchor attachments that may result in unbalanced strain on a pole.

In addition to the above remediation work, SCE field inspections of prior covered conductor installations determined a need to make minor repairs and updates to ensure the covered conductor installations fully adhere to SCE's standards and will perform as intended. In 2021 SCE spent $0.540 million[98] to address these findings on existing covered conductor installations. These field

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[97] SCE previously had a fusing program that was originally intended to be a mitigation SCE could complete quickly across HFRA to aid in risk reduction. This program proactively installed and replaced fuses and is anticipated to be completed in 2023. Therefore, it is not being included in Track 4; any future needs will be addressed as opportunity work. This aligns with SCE's position stated in footnote 72 from SCE's 2021 GRC Track 3 rebuttal testimony (at page 33).

[98] These O&M expenses are captured within HFRI Remediations – Distribution in Table VII-27.

inspections evaluated covered conductor installation adherence to SCE's standards.[99] SCE performed field inspections on 3,500 structures and found issues on approximately 595 of those structures.[100] The majority of the issues identified were associated with storm restoration work. The issues are grouped into six distinct categories as seen in Table VII-24 below. The vast majority of the issues resulted in minor repairs, which included the installation of lightning arresters, wildlife covers, the appropriate insulator and jumper, and covering the partially exposed conductor. This repair work was necessary to bring the equipment up to SCE's standards and prevent future failures that could potentially increase ignition risks.

SCE plans to perform field inspections on the remaining 9,000[101] completed structures. Assuming a similar find rate of 17%, SCE expects to remediate another 1,530 structures that were involved in covered conductor installations in 2018-2019. SCE is requesting a similar amount of $0.540 million for 2024 to remediate a third of those non-conformance issues. If left unmitigated, these issues can reduce the effectiveness of covered conductor.

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99 Standards were published in 2018 and construction started a few months after.

100 SCE performed field inspections on 3,500 structures, which represented a sampling of the 12,000 total structures completed in 2018 and 2019.

101 12,500-3,500=9,000 structures.

Table VII-24
Summary of Issues Associated with Covered Conductor Installed in 2018 and 2019

Construction Issue	SCE Standards Requirement
1. Missing Lightning Arrester on Equipment Pole	Lightning arresters must be installed on equipment poles on covered conductor systems.
2. Excessive Angle	The line angle must not exceed the critical crossarm angle limits per the table in SCE's standards. Apply the appropriate crossarm construction (i.e., double crossarm or double dead-ends) to reduce the mechanical stress.
3. Over-tensioned conductor	Must follow the correct methods and the new sag/tension tables for covered conductor as shown on the standards.
4. Wrong Material Used (Insulator and Jumper)	Must use polymer insulators with covered conductor. Must use the same covered conductor size for jumper wires.
5. Missing Wildlife Covers	Appropriate wildlife covers must be installed for dead-ends, connectors, fuses, lightning arresters, equipment bushings and potheads.
6. Partially exposed conductor	Any exposed conductor must be covered. For example: exposed parts of conductors at dead-ends, connectors, splices must be covered with the appropriate covers as specified in the standards.

(1) Capital

SCE completed capital distribution[102] remediations identified through ground-based, aerial and IR inspections. These remediations were prioritized based on compliance due dates. A large portion of the capital distribution remediations were pole replacements, but other equipment replacements are also included in this work such as pole hardware replacements, transformer replacements and conductor repair and/or replacement. Poles requiring replacement were due generally to visible deterioration such as rotting, avian damage, or excessive bowing and splitting or twisting.

Long span remediations involve distribution circuits of a certain length, spans with mixed conductor, spans that have a sharp angle, or spans that transition between vertical and horizontal configuration. All these types of long spans can have a higher probability of conductor clash

[102] SCE also performed inspection and remediation work on certain legacy utility-owned hydroelectric generation assets located within HFRA, such as powerhouses. SCE has not included testimony on this specific aspect of inspection and remediation work due to its relatively immaterial cost impact compared to the same work SCE performed on our distribution and transmission assets. For additional details on this generation-specific sub-component of inspection and remediation work, please refer to WP SCE Tr. 4-02, pp. 11 - 12 - Generation.

in adverse wind conditions. SCE is looking to further update the risk-informed approach to remediate remaining long spans, which could be bundled with locations already planned for covered conductor installations or proactively remediate remaining long spans with line spacers. For 2022, SCE is enhancing its risk methodology and prioritization using LiDAR measurements, conductor POI, and wind-related features to better target conductor clash scenarios for scoping long span remediations in 2023 and beyond. The timing of remediations is being reassessed as many spans have been or are planned to be remediated by covered conductor installations. Specifically, SCE is evaluating a line spacer installation program for higher risk spans not planned for covered conductor work by 2023. While there were minimal recorded costs for long span remediations in 2021, SCE forecasts significant work and costs in 2024.

(2) O&M

Approximately 36% percent of the remediations involved crossarm replacements and conductor-related repairs, which are the most labor-intensive among O&M remediations (*i.e.*, they drive the highest O&M expenses). Additionally, approximately 26% of repairs involved the repair of loose or damaged guy wires and trimming of vegetation to maintain the appropriate clearance to SCE's secondary and service wires. The vast majority of repair work was driven by Priority 2 notifications.

b) HFRA Remediations – Transmission

In 2021, SCE completed repairs and replacements associated with approximately 3,135 transmission notifications identified through risk-informed and compliance-based inspections. Similar to distribution assets, SCE's ground-based, aerial, infrared, and corona scans inspection protocols identified these necessary remediations, and SCE prioritized the resulting necessary repairs based on regulatory compliance due dates. SCE considered several additional factors when scheduling and performing compliance-drive remediation work, which, similar to distribution, outage requirements, permitting restrictions, crew availability and specialty equipment needs. Table VII-25 below shows the number of transmission remediations completed by capital and O&M and by priority level.

Table VII-25
Number of Capital and O&M Transmission Remediations Completed by Priority Level in 2021

Priority	Capital	O&M	Grand Total
Priority 1	0	0	0
Priority 2	212	2,923	3,135
Subtotal	**212**	**2,923**	**3,135**
Priority 3	-	-	-
Total	**-**	**-**	**3,135**

In 2021, SCE completed 3,135 P2 transmission remediation notifications. Of those P2 notifications, the five most frequent remediation-type categories were as follows: crossarm replacements, pole replacements, vegetation trims/removals, conductor repairs and replacements, and pole hardware replacements. Table VII-26 below further describes the type of issues found for each type of transmission notification.

Table VII-26
The Most Common Types of Transmission Remediation Notifications

Category	Description
Crossarm	Deteriorated crossarms showing signs of excessive damage such as cracks, splits, pitting, or burns.
Pole	Visual failures identified as Priority 1 and 2 conditions: - Priority 1 requires immediate action. Split, decay, hole/boring, or other exterior damage that has significantly compromised the integrity of the pole. Failure is imminent. - Priority 2 issues are lower risk and therefore may be resolved within six months for Tier 3 or 12 months for Tier 2 within HFRA. Split or decay at a critical point of attachment, hole/boring that allows light through the pole, and significant exterior damage.
Veg. Trim	Vegetation growth that is encroaching on electrical equipment.
Conductor	Conductor damage, fraying, or clearance issues that require either repair or replacement.
Hardware	Miscellaneous hardware repair and replacement on a structure including but not limited to installation of split bolts, line spacers, ridge-pin construction, lightning arrestors, and insulator replacements.
Guying	Damaged or loose guy wires and anchor attachments that may result in unbalanced strain on a pole.
Brushing	Removal of brush around a structure.
Tower Corrosion	Deteriorated towers showing signs of excession corrsion and damage such as cracks or burns.

(1) Capital

SCE completed capital remediations identified through risk-informed inspections, including ground-based, aerial, IR and Corona Scans. These remediations were prioritized based on compliance due dates. Most of the capital remediations were pole replacements, but other equipment replacements are also included in this work. Poles requiring replacement were due generally to rotting and/or aging, avian damage caused by woodpeckers, or excessive bowing and splitting or twisting. Other equipment replacement can include the new/reinforced towers, conductor replacement and the replacement of equipment on the structure (e.g., switches).

(2) O&M

SCE completed O&M remediations identified through risk-informed inspections, including ground-based, aerial, IR and Corona Scans. These remediations were prioritized based on compliance due dates. The most common O&M remediation was brushing or vegetation removal. This work entails clearing vegetation ten to fifteen feet around transmission structures within the transmission rights-of-way, as required by city or county fire codes pursuant to California Public Resources Code Section 4292. The crews also performed vegetation trims to control vegetation growth encroaching on electrical equipment. Other remediation work included the repair of electrical structure/equipment and replacement of more minor items, such as insulators. The remediations completed were Priority 2 issues, which typically require resolution within 6 or 12 months, depending on location and condition.

2. O&M Scope and Forecast Analysis

Table VII-27
Remediations
O&M Authorized, Recorded, and Forecast by Sub-activity[103] [104]
(Constant 2018 $000)

		Track 1 Authorized*	Recorded	Recorded	Recorded	Track 4 Forecast
	Subactivity	**2021**	**2019**	**2020**	**2021**	**2024**
1	HFRI Remediations – Distribution	$20,439	$162,177	$39,116	$14,271	$14,382
2	HFRI Remediations – Transmission	$6,721	$29,136	$18,166	$6,222	$6,222
3	Distribution O&M Breakdown Maintenance				$2,406	$2,406
4	Distribution O&M Preventive Maintenance				$19,008	$19,008
5	AOCs – Ground-Based & Aerial			$2,213	$2,188	$2,188
	Total Expenses	**$27,161**	**$191,313**	**$59,495**	**$44,095**	**$44,205**

* Authorized 2022 and 2023 are equivalent to 2021 authorized (in constant 2018 dollars) after removing the impact of the Track 1 Decision's post-test year attrition mechanism

a) Historical Variance Analysis

For HFRI O&M remediations from 2019 to 2021, there was a large decrease from $191.313 million in 2019 to $59.495 million and $44.095 million in 2020 and 2021, respectively. Regarding distribution remediations, SCE incurred $37.64 million in O&M expenses associated with completing 15,257 Priority 1 and Priority 2 distribution remediations in 2021. For transmission remediations, SCE incurred $6.45 million in O&M expenses for performing 2,923 P2 remediations in 2021. These figures also included costs associated with planning, design and engineering of notifications not completed in 2021. SCE also incurred $0.499 million in transmission work order-related expenses that must be done when capital additions or replacements are being performed. In addition, these transmission work order related expenses are not capitalized according to standard accounting guidelines.

The overall O&M decrease was primarily due to SCE's strategy in 2019 of inspecting all assets within HFRA while moving to an increasingly more targeted scope in 2020 and 2021, which utilized a more refined risk-based approach. While this strategy did lead to a reduction in recorded O&M in 2021, it was still an increase over the authorized amount of $27.161 million. The

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[103] HFRI Remediations - Distribution had a credit balance of $0.110 million in 2021, but SCE is requesting zero for 2024. *See* sub-activity Distribution Work Order Related Expense in workpaper WP SCE Tr. 4-01 - O&M Financial.

[104] AOCs – Ground-Based & Aerial is comprised of $1.958 million for distribution and $0.230 million for transmission.

increase is driven by the shift in inspection strategy, which increased the overall volume of inspections, an increase in contractor rate increases, and the introduction of AOC inspections.

b) Basis for forecast

The Track 4 2024 forecast is equal to the 2021 recorded amount for this activity. The work performed in 2021 is an appropriate approximation for the work anticipated to be performed in 2024. 2021 is a reasonable basis for the 2024 forecast as SCE anticipates the similar levels of inspections activities that drive remediation scope, contractor rates are not expected to decrease, and AOCs will continue to be performed resulting in emergent remediation work. SCE acknowledges that O&M remediation expense tends to be correlated with corresponding capital remediation expenditures, the forecast for which is lower in 2024 than 2021 recorded data. However, SCE's Track 4 forecast for O&M remediation expense remains at 2021 recorded spend levels. The reason for that is twofold: first, starting in 2021 SCE added additional questions to its inspection questionnaire, which has led to and is expected to continue to lead to increased numbers of minor (i.e., O&M) remediations. Second, over the last several years, SCE has accrued a material volume of P3 notifications, which typically lead to O&M remediations. SCE currently plans to do much of this work over the next several years.

For these reasons, as well as those discussed in the policy section, SCE is using last year recorded as our forecast methodology. This approach will allow SCE to remediate issues on approximately the same number of structures. To the extent that SCE records costs in excess of the 2024 forecast, those costs will be tracked in the appropriate memo account.

3. Capital Scope and Forecast Analysis

Table VII-28
Remediations
Capital Authorized, Recorded, and Forecast by Sub-activity[105]
(Nominal $000)

		Track 1 Authorized					Recorded			Track 4 Forecast
	Subactivity	**2019**	**2020**	**2021**	**2022**	**2023**	**2019**	**2020**	**2021**	**2024**
1	HFRI Remediations – Distribution	$229,992	$113,287	$29,754	$28,876	$27,888	$229,992	$81,531	$40,331	$20,898
2	HFRI Remediations – Transmission	$52,990	$12,736	$13,087	$12,190	$12,530	$52,990	$36,073	$13,380	$11,647
3	Distribution Capital Breakdown Maintenance (HFRA)								$9,561	$14,422
4	Distribution Capital Preventive Maintenance (HFRA)								$25,322	$21,359
5	Transmission Enhanced Inspection Methods									$1,126
6	Long Span Remediation								$92	$7,839
7	AOCs – Ground-Based & Aerial							$3,688	$7,434	$3,940
	Total Capital	**$282,982**	**$126,022**	**$42,840**	**$41,065**	**$40,418**	**$282,982**	**$121,292**	**$96,120**	**$81,232**

a) Historical Variance Analysis

From 2019 to 2021, there was a large decrease from $282.98 million in 2019 to $121.29 million and $96.12 million in 2020 and 2021, respectively. The capital decrease was primarily due to the new EOI/HFRI initiative that began in late 2018 for both distribution and transmission for inspections and the resulting remediations. Regarding distribution remediations, SCE incurred $82.74 million in capital expenditures for performing 6,278 P1 and P2 distribution remediations in 2021. 2,576 of the distribution remediations performed were related to pole replacements. 1,071 distribution remediations required pole hardware (comprised primarily of lightning arrestors), 643 for transformer replacements and 1,071 for conductor repair and/or replacement. For transmission remediations, SCE incurred $13.38 million in capital expenditures for performing 212 P2 transmission remediations in 2021. 208 of the transmission remediations performed were related to pole replacements. The remaining 4 transmission remediations were regarding tower equipment replacements. These figures also included costs associated with planning, design and engineering of notifications not completed in 2021.

As SCE moved from the original strategy to inspect every asset in HFRA in 2019 to a more refined risk-informed approach in 2020 and 2021, this resulted in the highest risk structures being inspected annually, which ultimately resulted in fewer remediations being identified. While SCE's

105 AOCs – Ground-Based & Aerial is comprised of $3.086 million for distribution and $0.85 million for transmission.

capital costs did decline in 2021, these costs were still above the authorized amount of $42.84 million. This increase over the authorized amount was driven by the evolution of the inspection program since the original GRC forecast which included a shift in inspection strategy, which increased the overall volume of ground and aerial inspections.

b) Basis for Forecast

This Track 4 forecast is composed of remediations associated with the inspection types as discussed in Section VII-B.[106] SCE summarizes the individual methods used to forecast each of these components below, and provides further detail in workpapers:[107]

- Distribution and transmission EOI/HFRI remediation expenditures for ground, aerial and AOCs are based on a forecast of capital notifications identified from EOI inspections that require capital remediation, while cost per notification is based on previously completed notifications.
- Transmission Enhanced Inspection Methods are based on a forecast of notifications identified from LineVue or conductor sampling inspections that require capital remediation, while cost per notification is based on current estimates to reconductor.
- Long span remediation capital expenditures are based on a bottoms-up forecast of needed material and labor to implement these mitigations.

F. Technology Solutions

1. Summary of O&M and Capital Request

SCE's O&M and capital requests for HFRI Technology Solutions are presented in Figure VII-25 and Figure VII-26. The O&M requests of $3.296 million is based on 2021 last year recorded spend, but adjusted downward to account for an in-flight project that has been completed and no longer

[106] Basis for capital forecast regarding IR inspections and Corona scans for distribution and transmission have been excluded due to the minimal amount that is anticipated in 2024.

[107] Refer to WP SCE Tr. 4-02, pp. 14 - EOI-HFRI Remediations – Distribution, pp. 15 - EOI-HFRI Remediations – Transmission, pp. 13 - Transmission Enhanced Inspection Methods and pp. 16 - Long Span.

will be required in 2024. SCE's capital request of $7.969 million in 2024 is less than SCE's 2021 recorded costs. The development and adoption of these new technology capabilities and advancements were initiated in 2021 and will continue development into 2022 through 2024. Most of the wildfire initiatives associated with technology development needed to support the critical mitigation work necessary to safeguard the grid will reach the end of their development life cycle in 2024; therefore, SCE's capital request is less than 2021 recorded costs.

SCE's 2021 O&M spent is below the 2021 authorized amount of $10.714 million due to the Track 1 forecast assumption that the development of the technology solutions would be completed, and much higher O&M would be required for cloud licenses, cloud usage, and the maintenance and support of the technology tools.

2. <u>Work Description and Need</u>

a) <u>Technology Support Tools</u>

SCE continues to maintain accounting of its technology development and implementation efforts for HFRI Inspections in the Technology Support Tools sub-activity. The technology solutions in support of the HFRI Inspections efforts are broken down into three wildfire mitigation workstreams: Inspections, Data Governance, and Remediation. The work description and need, scope, and forecast for both O&M and capital follow in accordance with this categorization.

(1) <u>Inspections</u>

Since 2019, SCE has been progressively implementing new technology solutions in support of SCE's Inspection Redesign effort, transitioning from a compliance-, time-based inspection to a risk-informed inspection process. These solutions support inspectors with improved processes and data to inform decisions regarding the health of the transmission and distribution field assets in HFRA. It also aims to better integrate the Aerial and Ground inspection business processes for both Transmission and Distribution, as well as to provide information and analytics on field assets across inspection, data collection, and remediation on a single digital platform. In addition, the solutions leverage new technology capabilities like artificial intelligence and machine learning (AI/ML), assisted reality, and automation to increase the overall operational efficiency, consistency, and data quality.

(2) Data Governance

Several of SCE's wildfire mitigation initiatives have resulted in the gathering of massive amounts of remote sensing data, such as images, videos, and LiDAR (Light Detection and Ranging) data to aid in the identification and remediation of asset failures and hazards related to SCE's assets located in HFRA. The scale of this data collection makes it too large and complex to be stored, managed, and analyzed using traditional data-processing solutions and requires an effective and reliable, cloud-based modern data solution.

SCE conducted a series of internal workshops to gather information on as-is processes and tools that are used to manage and report out on data related to assets, wildfire mitigation initiatives (vegetation management inspections, vegetation management projects, asset inspections, and grid hardening), PSPS events, and risk events (wire-down event, ignitions, and unplanned outages). Information gathered from the workshops was used in the development of a technology roadmap and conceptual design for the establishment of a centralized wildfire data repository. At the core of the roadmap, data is centralized and available to share using application programming interface(s) (APIs) and advanced analytics.

The implementation of a centralized and fully mature modern data solution will enable SCE to a) effectively intake, organize, store, analyze, and visualize remote sensing metadata collected for wildfire mitigation initiatives, such as Aerial Inspections, Ground Inspections, Vegetation Management, etc.; and b) enable SCE's data scientists to develop, train, test, and deploy machine-learning models at a scale in order to improve decision- making with various business processes.

(3) Remediation

A recent study conducted by SCE showed remediation work and work order closures could take as long as five weeks to process using the current manual paper-based system. It is important that infrastructure work be scheduled and executed in a manner that prioritizes the critical needs in HFRA, minimizes outages to SCE's customers, and maintains safety for the public and SCE's crews in the field. FMP360 is the technology support tool that will automate high fire risk notifications and help expedite the execution and closure of work orders. FMP360 will replace the current paper-based remediation process, and significantly reduce the time delay from when the work was performed to when the work is marked complete in the SAP system. This tool will integrate with the source data in Consolidated Mobile Solution (CMS) to ensure timely documentation and closure of notifications in real-time. CMS is a system of record for field remediation work that FMP360 connects to. FMP360 also provides SCE transparency into schedule work by contractor or region.

As part of the support for remediation, SCE will also implement the Scope Mapping Tool to assist with prioritizing, scheduling, and executing work in the field. The Scope Mapping Tool is a suite of GIS viewers. The Scope Mapping Tool identifies the need for a new integration for work order bundling to bring in near real time inspection, notification, and work data from various existing enterprise data sources.

3. O&M Scope and Forecast Analysis

SCE incurred $3.552 million in O&M spend for Technology Support Tool in 2021. The 2021 recorded O&M spend for this activity can be classified into these categories: licensing and subscription fees, maintenance & operational support, basic end-user operational change management support, and data charges. Licensing and subscription fees include application licenses and vendor support associated with the various technology solutions. The maintenance and operational support includes the setting up and installation of appropriate software for iPads, as well as the labors costs related to the extraction, consolidation, and automation of the wildfire data for SCE's Quarterly Data Reports to Energy Safety. Data charges make up most of the costs incurred in 2021 in support of HFRI inspection efforts to capture multiple asset attributes in the form of a digital survey. It includes data plans for airtime usage on the iPads, cloud data storage and consumption costs.[108]

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[108] Consumption costs refer to on-going costs for the amount of storage and computing resources used in a cloud-based application.

Table VII-29[109]
Technology Solutions
O&M Authorized, Recorded, and Forecast by Sub-Activity
(Constant 2018 $000)

		Track 1 Authorized*	Recorded			Track 4 Forecast
	Subactivity	**2021**	**2019**	**2020**	**2021**	**2024**
1	HFRI Project Management Support	$10,714				
2	Technology Support Tools		$1,937	$2,545	$3,552	$3,296
	Total Expenses	**$10,714**	**$1,937**	**$2,545**	**$3,552**	**$3,296**

* Authorized 2022 and 2023 are equivalent to 2021 authorized (in constant 2018 dollars) after removing the impact of the Track 1 Decision's post-test year attrition mechanism

a) Historical Variance Analysis

The O&M costs increased from $1.937 million in 2019 to $3.552 million in 2021 due to the growing scope changes for additional technology capabilities and enhancements to support the end-to-end aerial and ground inspection processes for Transmission and Distribution. Some of the contributors to the increase in costs are: (1) the increased usage of data plan, cloud data storage, and consumption for the deployment of the iPads for inspection and remediation efforts; (2) licensing and subscription fees for vendor support on various technology solutions; (3) maintenance and operational support for labor costs associated with the maturity with the centralization of wildfire data, development of more rigorous data governance processes, access and integration of real-time data; (4) pre-project planning activities, such as business requirements development and conceptual solution engineering, data migration and cleansing; and (5) operational change management, which may include end-user training associated with the post implementation of the technology. End-user training includes developing training materials and providing training to end-users.

b) Basis for Forecast

Although SCE utilizes 2021 last year recorded costs to form the basis of this forecast, SCE anticipates spending significantly above the 2021 recorded amount for this activity in 2024 for trailing on-going subscription, maintenance and support and cloud application consumption costs. Accordingly using the 2021 last year recorded as the forecast is conservative. On-going

[109] The authorized amount for HFRI Project Management Support reflects the IT activities authorized in the 2021 GRC Final Decision, D.21-08-036.

maintenance and support are essential post-implementation activities to ensure business application and system availability and reliability. On-going maintenance and support include: (1) access to externally hosted computing platforms; (2) access to break/fix support to ensure software application and systems are available and reliable; (3) version upgrades to ensure software is current and secure; (4) access to vendor updates to provide security updates to protect against cyber threats; and (5) cloud storage and consumption costs.

4. Capital Scope and Forecast Analysis

Table VII-30
Technology Solutions
Capital Authorized, Recorded, and Forecast by Sub-Activity
(Nominal $000)

		Track 1 Authorized					Recorded			Track 4 Forecast
	Subactivity	**2019**	**2020**	**2021**	**2022**	**2023**	**2019**	**2020**	**2021**	**2024**
1	Technology Solutions						$4,219	$16,147	$11,005	$2,707
	Total Capital						**$4,219**	**$16,147**	**$11,005**	**$2,707**

a) Technology Support Tools

SCE forecast $7.969 million in capital expenditures for Technology Support Tools in 2024. The capital efforts for this activity are categorized into three wildfire mitigation workstream: inspections, data governance, and remediations. The project scopes for each of the wildfire mitigation workstreams are discussed below.

(1) Inspections

SCE plans to incur capital expenditures in 2024 for further advancement of capabilities on the cloud-based InspectForce common platform support of additional assisted reality features using artificial intelligence, machine learning, and predictive/prescriptive algorithms to keep pace with the development requirements. Planned technology capabilities and enhancements also include the ability to capture and validate information in the field following asset failures as well as the completion of new construction and utilization of additional types of data (including LiDAR and IR) to advance the overall inspection product.

(2) Data Governance

SCE has completed (1) the foundational infrastructure setup for the use of Google Cloud Platform (GCP), and (2) network connectivity between SCE's data center and GCP, including basic cybersecurity protection implementation. For instance, the Ezy Data Project, which runs on the GCP, was initiated in 2020 to develop solutions to manage unstructured data and enable an enterprise AI platform for SCE. The Ezy Data Suite of tools enabled automatic detection and organization of over thirteen million images collected during the year for Aerial Inspections, and enabled inspectors to easily search and retrieve structure-specific images needed for desktop electric system inspections with sub-second response times. In addition, the Ezy Data solutions significantly improved the efficiency of Aerial Inspections and was instrumental in helping to ensure SCE's continued ability to perform Aerial Inspections under COVID-19 shelter-in-place conditions.

In the coming years, the efforts surrounding Ezy Data will focus on delivering data integration, and analytics solutions for effective management and utilization of LiDAR in support of a variety of use cases, such as vegetation encroachment, asset geolocation management, joint pole usage, pole lean assessment, clearance distances assessment, etc. Additionally, we expect AI and ML algorithms to analyze LiDAR to identify potential ignition risks to continue to improve in accuracy.

The Wildfire Safety Data Management (WiSDM) project has been initiated for implementing the developed roadmap, which is anticipated to advance SCE's data governance capabilities. As such, WiSDM completed Solution Analysis, where an approved solution architecture was defined along with detailed system requirements that will be utilized for traceability and testing. In 2022, the WiSDM project will move into the design and build phase of the centralized data repository and data portal with testing and final implementation occurring in early 2023. By 2024, WiSDM will transition to operations for on-going maintenance and support.

(3) Remediations

SCE plans to deploy FMP360 to all distribution line construction and transmission contractors. As part of the plan, the team will be taking proactive measures to further mitigate potential risk, such as partnering closely with the product vendor to accelerate introduction of enhancements, provide additional training to internal technical resources to progressively reduce SCE's dependency on the external vendor, support the service transition, and allocate additional business subject matter experts to the gatekeeper role in FMP360 to approve contractor work.

In 2021, the development of the Scope Mapping Tool was completed, and deployment was planned. Prior to the planned deployment of the application, new requirements emerged due to changes in the Distribution Wildfire Management Report Structure, which require additional integrations to be developed. The additional data integration, and the functionality required to leverage the data, are core to the WMP reporting scope, and thus warrant a deferment of the implementation to avoid incomplete set of data being utilized in the Scope Mapping Tool, which may cause potential data integrity issues in reporting. SCE plans to assess the new requirements for the Scope Mapping Tool by first quarter of 2022, and then develop, test, and implement the changes by fourth quarter of 2022. The forecast for 2024 is allocated to 1) meet new requirements to consume and reflect data from the Distribution Wildfire Management Team Report, 2) support additional end user functionality to analyze additional data, and 3) maintenance and upgrade of the application.

b) <u>Historical Variance Analysis</u>

The capital expenditures increased from $13.391 million in 2019 to $28.700 million in 2020 and then were reduced to $27.903 million in 2021 as some of the capital projects began to phase out and transition into normal business operations.

In 2019, the technology focus was on 1) deployment and procurement of mobile hardware devices, iPads and Microsoft Surface Pro 6 tablets, 2) additional functionality integration for mobile applications, reporting dashboards, web forms, and aerial viewer, 3) development, testing, and deployment of front-end applications to integrate with ArcGIS online and back-end integration with SCE's enterprise asset management systems (SAP) for notification automation, 4) development and deployment of application to support prioritization, scheduling, and completion of HFRI inspections and notifications, and 5) development and deployment of the Fire Incident Preliminary Analysis (FIPA)

Analytics software solution to incorporate cloud, visualization, and advance analytics capabilities to improve the tracking of ignitions near SCE facilities and document the root cause of the ignition.

As the suite of wildfire mitigation programs expand in 2020, and to meet the scale and growth of these programs, SCE continues to develop and adopt new technological capabilities and advancements to support the critical mitigation work necessary to safeguard the grid. In addition, in response to the new regulatory requirements imposed by Energy Safety on extensive data reporting and analysis, SCE focused on the development of solution architecture for cloud data storage and established a centralized wildfire data repository. Some of the technology development and adoption in 2020 are 1) the roll out of the InspectApp to support the distribution ground inspection process, 2) the integration of Assisted Reality Camera Application into the InspectApp to improve the quality and consistency of images captured, 3) the initiation of WiSDM and Ezy Data projects to help SCE advanced its data governance capabilities toward a centralized wildfire data repository used for data reporting, analytics and submission, and 4) the initiation of FMP360 and Scope Mapping Tools to support remediation work associated with prioritization, scheduling, and processing and closing of work orders.

Some of the technology-focused remediation and inspection initiatives that started in 2019 phased out and transition into normal business operations, therefore, the reflection of a decrease in capital expenditures from 2020 to 2021.

c) Basis for Forecast

The 2024 capital forecast of $7.969 million for the projects within this activity was developed using SCE's internal cost estimation model. This cost estimation model was utilized to forecast SCE's IT capitalized software projects in Track 1 of this proceeding, which the Commission adopted in its entirety. This model utilizes industry best practices and SCE subject matter expertise to estimate project cost components. SCE's forecast for these projects includes cost for SCE employees, supplemental workers, and consultants, as well as software and vendor costs, and hardware costs.[110]

[110] See WP SCE Tr. 4-02 HFRI Technology Solutions, pp. 17 – 20.

VIII.

VEGETATION MANAGEMENT

A. Overview

In the late 2010s, the threat posed by California wildfires and the significance of their consequences required SCE to act with urgency to revamp and expand its routine vegetation management practices with deeper and more expansive trims. The Commission shared this need for urgency, as demonstrated by D.17-12-024 (HFTD Decision). The HFTD Decision adopted new fire-safety regulations, including increasing the recommended minimum clearance from vegetation to SCE assets and electric facilities and specifying that these recommended clearances be obtained at the time vegetation is trimmed to mitigate the risk of breaching minimum required clearances during the period between trims.[111] The Commission concluded that although these changes in regulations would result in increased costs, "such costs are offset by the substantial public-safety benefits of keeping bare line conductors clear of vegetation…."[112]

In A.18-09-002, in our Grid Safety and Resiliency Program (GSRP) Application, SCE also introduced the Hazard Tree Management Program (HTMP) as an additional vegetation management program to mitigate fire risk created by trees outside of the minimum clearance zone.

SCE committed to further comprehensive vegetation management activities as part of its three-year Wildfire Mitigation Plan (WMP) filed in 2020, and the subsequent 2021 update thereto.[113] This included expanded pole brushing of distribution poles in HFRA, LiDAR inspections for vegetation encroachments along transmission and distribution circuits, supplemental patrols in AOC's during the Summer and Fall months, and other measures. These actions, approved by the Wildfire Safety Division and its successor agency the Office of Energy Infrastructure Safety (OEIS), went beyond the scope of

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[111] The HFTD Decision required compliance with the new clearance requirement in Tier 3 areas by September 30, 2018, and in Zone 1 and Tier 2 areas by June 30, 2019.

[112] *See* D.17-12-024, p. 102.

[113] Many of these commitments were also part of SCE's 2019 WMP, but generally grew in scope with the 2020 filing.

historical vegetation management operations and were necessary and appropriate to meet the ongoing threats of catastrophic wildfires and climate change.

In the 2021 Track 1 Final Decision, the Commission adopted the Vegetation Management Balancing Account (VMBA) and consolidated SCE's Routine Vegetation Management programs (inclusive of pole brushing), HTMP, and the Dead and Dying Tree Removal program under one balancing account—for both HFRA and non-HFRA portions of our service area—to capture SCE's evolving and growing scope of vegetation management work.

On January 1, 2020, the Legislature implemented SB 247, which set a substantially higher pay rate for tree trimmers in California.[114] Because the 2021 GRC was filed in 2019, prior to SB 247's enactment, SCE could not have foreseen or factored into its vegetation management forecasts the costs associated with SB 247. SCE proposed to revise its 2021 Test Year forecast for all Vegetation Management activities as part of the update phase of Track 1 (including SB 247-related and other higher costs resulting from contract renegotiations).[115] While it acknowledged that "it is reasonable to expect some level of cost increase associated with the passage of SB 247,"[116] the Commission did not adopt SCE's updated Vegetation Management forecast, based on its view that SCE's request from a procedural standpoint exceeded the appropriate categories for Update Testimony.[117] In Track 3 of this proceeding, SCE provided calendar year 2020 recorded line clearing costs, and identified that approximately $135 million of those 2020 recorded costs was attributable to SB 247; that analysis was uncontested.[118] Thus, even though the Commission adopted SCE's 2021 forecast for Routine Vegetation Management, the authorized amount for 2021 and the post-test years did not include the substantial impact of SB 247 on the cost of tree trimming.

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[114] SB 247 raised the rates for tree trimmers to match the first period apprentice linemen (QEWs). Please see SCE's Track 3 testimony for a detailed background of SB 247.

[115] Please refer to Exhibit SCE-24, Supplemental Testimony on Vegetation Management. SCE submitted this supplemental testimony on July 1, 2020.

[116] D.21-08-026 at p. 183.

[117] D.21-08-036 at CoL 68.

[118] SCE also identified an additional $9.5 million in SB 247 costs incurred for its HTMP. The Dead and Dying Tree program was not in the scope of Track 3, but additional SB 247-related costs were also incurred in 2020 for that program.

The implementation of SB 247 in 2020, re-negotiated labor contracts, new wildfire mitigation activities, newly identified emergent work, expanded pole brushing, and LiDAR programs collectively increased the costs of SCE's vegetation management programs well beyond what was authorized in Track 1 for 2021. This chapter includes our updated cost forecasts for vegetation management O&M expense. Since 2021 is the last year for which SCE has recorded costs, SCE's 2024 forecast is based on costs incurred in 2021 for all Vegetation Management activities authorized in Track 1, including the recorded costs in the Vegetation Management Balancing Account (VMBA) and the incremental recorded Environmental Services Department (ESD) costs in FRRMA that were directly incurred to support Vegetation Management activities.[119] As discussed below, those costs represent a reasonable and conservative approximation of the baseline annual costs SCE will incur for its Vegetation Management activities on an on-going basis. Sections VIII.B-F below summarize the scope of work, key drivers for the work, and regulatory mandates that result in the level of O&M expense forecast for 2024 Vegetation Management activities. This chapter includes analyses of (1) O&M and capital funding authorized in Track 1 compared to recorded amounts in 2021, and (2) the 2024 Test Year O&M forecast relative to historical spending. This chapter also includes a discussion of Technology Solutions, which represent applications that are vital to supporting all Vegetation Management programs.

1. Summary of Vegetation Management's O&M Request

a) Last Year Recorded Costs in 2021

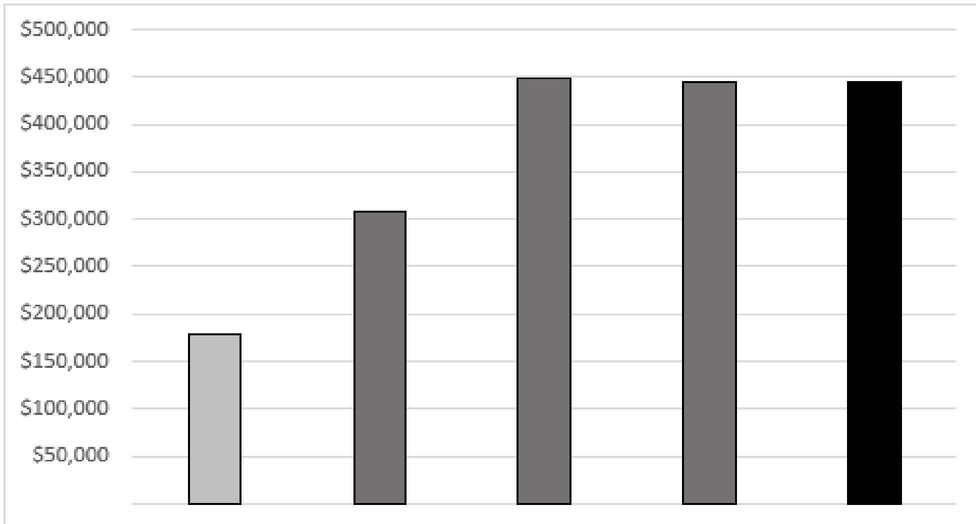
As discussed at length below, SCE based its 2024 forecast on its 2021 recorded spend in all Vegetation Management programs. Since the VMBA tracks costs on a total-portfolio basis, SCE is requesting 2024 funding for vegetation management at the portfolio level as well for activities that are necessary to maintain compliance with the Commission's and other agencies' regulations and to help safeguard customers from wildfire risk and maintain electric system reliability.

2021 authorized funding escalated to 2024 dollar would be inadequate for the reasons mentioned previously. SCE's Track 1 forecast in its opening testimony could not and did not

[119] Prior to 2021, relevant vegetation management-related ESD expenses were recorded in the Fire Hazard Prevention Memorandum Account (FHPMA), which is now closed.

incorporate the impact of SB 247 which came into effect after our application was filed. SB 247 greatly increased the cost of performing vegetation management in California due to the statutory increase in wages. New contract negotiations amidst a constrained labor market since 2019 increased costs for vegetation management activities as well. Additionally, as described in our approved Wildfire Mitigation Plans since 2019, SCE has increased the scope of several of its programs including HTMP, pole brushing, LiDAR inspections, and emergent work preceding peak fire season to enhance its wildfire mitigation strategy. Figure VIII-37 shows the year-over-year growth in Vegetation Management O&M expense from 2019-2021. Figure VIII-37 clearly demonstrates that 2021 authorized revenues are grossly insufficient to cover 2021 – and expected ongoing – actual costs. Finally, the structure of the VMBA ensures that customers are fully insulated from any potential over-collections in 2024 – which SCE does not currently believe is a reasonably likely result. If for some reason the 2024 adopted forecast in Track 4 exceeds 2024 recorded costs, customers will receive a full refund for the delta.

Figure VIII-37[120]
Vegetation Management's O&M Summary
2021 Authorized, 2019-2021 Recorded, and 2024 Forecast
(Constant 2018 $000)



Track 1 Authorized*	Recorded			Track 4 Forecast
2021	**2019**	**2020**	**2021**	**2024**
$178,930	**$308,295**	**$448,539**	**$444,827**	**$444,827**

		Track 1 Authorized*	Recorded			Track 4 Forecast
	Subactivity	**2021**	**2019**	**2020**	**2021**	**2024**
1	Routine Vegetation Management	$119,725	$262,985	$367,305	$396,523	$396,523
2	Dead & Dying Tree Removal	$35,120	$30,399	$34,664	$16,019	$16,019
3	Hazard Tree Management Plan	$24,085	$14,911	$46,570	$32,285	$32,285
	Total Expenses	**$178,930**	**$308,295**	**$448,539**	**$444,827**	**$444,827**

* Authorized 2022 and 2023 are equivalent to 2021 authorized (in constant 2018 dollars) after removing the impact of the Track 1 Decision's post-test year attrition mechanism

As shown in Figure VIII-37, in 2019, SCE's recorded spend in vegetation management was $308.3 million, prior to when: (1) SB 247 materially increased labor rates for California utility tree-trimmers; (2) SCE expanded its existing programs (such as HTMP, Pole Brushing, LiDAR, and supplemental patrols in Areas of Concern) to mitigate against wildfire; and, (3) SCE introduced new environmental support (discussed below). By 2021, the impact of SB 247, other labor cost increases, and other increased costs of performing vegetation management work stabilized to roughly $444.82 million, an increase of nearly 45% from 2019 levels before accounting for escalation.

[120] Figure VIII-37 excludes $0.606 million of Technology Solutions for recorded 2021 and forecast 2024. These expenses are included as part of Enhanced Operational Practices.

Table VIII-31 illustrates the stark variance between what was authorized in 2021 for Vegetation Management O&M versus what SCE actually incurred. SCE incurred 148% *more* in 2021 than what was authorized in vegetation management costs. Since all the factors contributing to these cost increases are still in place and expected to continue or be exacerbated due to inflationary pressures, 2021 recorded amounts are a conservative estimate of 2024 expected costs.

Table VIII-31
Vegetation Management O&M Variance from
2021 Recorded to 2021 Authorized
(Constant 2018 $000)

2021 Authorized	2021 Last Year Recorded	Variance
$178.93	$444.83	$265.90

Table VIII-32 further breaks down the variance between what was recorded in 2021 versus what was authorized in the 2021 GRC for Vegetation Management's main activities of Routine Vegetation Management, Dead & Dying Tree Removal Program, and Hazard Tree Management Plan.

Table VIII-32
Vegetation Management
O&M Activities 2021 Authorized, 2021 Recorded, and 2024 Forecast
(Constant 2018 $000)

		Track 1 Authorized*	Recorded			Track 4 Forecast
	Subactivity	**2021**	**2019**	**2020**	**2021**	**2024**
1	Routine Vegetation Management	$119,725	$262,985	$367,305	$396,523	$396,523
2	Dead & Dying Tree Removal	$35,120	$30,399	$34,664	$16,019	$16,019
3	Hazard Tree Management Plan	$24,085	$14,911	$46,570	$32,285	$32,285
	Total Expenses	**$178,930**	**$308,295**	**$448,539**	**$444,827**	**$444,827**

* Authorized 2022 and 2023 are equivalent to 2021 authorized (in constant 2018 dollars) after removing the impact of the Track 1 Decision's post-test year attrition mechanism

b) <u>Increase Authorized Funding Eligible for Soft Cap and Continue VMBA</u>

In accordance with the Track 1 Final Decision, SCE proposes the Commission extend SCE's Vegetation Management Balancing Account (VMBA) through 2024 and its soft cap of

115% over the authorized amount based on the last recorded year of 2021. As it stands, the current authorized amount of $178.93 million (2018 dollars) does not in any way meaningfully reflect the true operating costs of performing vegetation management in California. Accordingly, SCE proposes setting the 2024 authorized revenues at the 2021 last year recorded amount, and to maintain the existing 115% soft cap trigger on that revised amount of $444.83 million. In doing so, SCE also requests the Commission clarify that it is reasonable for SCE to record vegetation management-related ESD[121] costs in the VMBA because they are all costs necessary to support vegetation management. Updating SCE's authorized revenues to reflect more current levels will reduce the chances of necessitating yet another reasonableness review for 2024 costs above the artificially low 2021 authorized amount, which will definitely be necessary for calendar year 2021,[122] and almost certainly will be necessary for calendar years 2022 and 2023. Setting 2024 authorized revenues for these pass-through O&M costs at realistic levels will help break the repetitive cycle of after-the-fact reasonableness reviews and instead facilitate SCE's vegetation management resources' ability to focus on mitigating wildfire and public safety risks in their day-to-day operations. Doing so will help to obviate pressure on already-constrained Commission and party resources and will also be consistent with the Amended Scoping Memo's over-arching objective that Track 4 should "not place additional material burden on parties to this proceeding."[123]

2. **Summary of Vegetation Management's Capital Request**

Figure VIII-38 below represents the 2019 – 2021 recorded and 2024 capital request for Vegetation Management Technology Solutions as discussed in the Technology Solutions section.[124]

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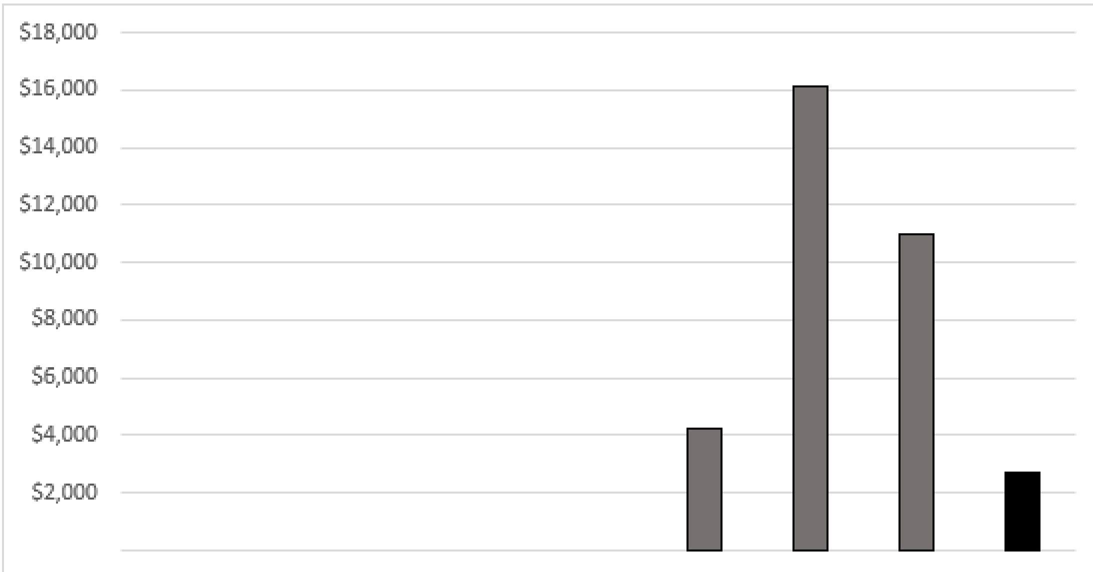
[121] ESD's costs to support vegetation management-related, routine line-clearing activities were recorded in the FRRMA for 2021. Going forward, however, SCE is seeking clarification that it can record all vegetation management-specific ESD support costs in the VMBA.

[122] *See* Exhibit SCE-01, II.B regarding SCE's forthcoming incremental cost recovery Application.

[123] Amended Scoping Memo at p. 8.

[124] *See* Section VIII.E below.

Figure VIII-38[125]
Capital Summary
Vegetation Management
Capital Authorized, Recorded, and Forecast
(Nominal $000)



Track 1 Authorized					Recorded			Track 4 Forecast
2019	2020	2021	2022	2023	2019	2020	2021	2024
-	-	-	-	-	$4,219	$16,147	$11,005	$2,707

		Track 1 Authorized					Recorded			Track 4 Forecast
	Subactivity	2019	2020	2021	2022	2023	2019	2020	2021	2024
1	Technology Solutions						$4,219	$16,147	$11,005	$2,707
	Total Capital						**$4,219**	**$16,147**	**$11,005**	**$2,707**

B. Routine Vegetation Management

Historically, Routine Vegetation Management has been executed as a compliance activity pursuant to General Order 95 and California Public Resources Code §4292 and §4293. In the past three years, however, SCE has expanded this program to more proactively mitigate wildfire risks.

1. Work Description and Need

Routine Vegetation Management activities include pre-inspections, trimming and removal of trees, expanded clearance distances, quality assurance/checks, supplemental patrols, pole

[125] Vegetation Management capital is included as part of Figure VII-26 in Enhanced Operational Practices.

brushing, and substation-associated vegetation management work. The program is designed on an annual cycle, and with respect to most activities, follows the following process: a pre-inspection, leading to a prescription (*i.e.*, a mitigation) where necessary, the completion of the prescription (*i.e.*, trimming and/or other measures such as removal and debris management), a job-related quality assurance function performed by an internal SCE arborist, and a program-wide quality control function performed by an independent contractor. In cases where the prescription poses significant changes from previous maintenance activities on a particular tree, as is often the case with implementing expanded clearances, a contracted customer coordinator will obtain customer approval if appropriate.

For routine line clearing, SCE-approved pre-inspection prescriptions are given to trimming/removal contractors. The contractor performs proper directional trimming techniques and crown reductions to minimize any adverse tree health and/or structural integrity conditions and to encourage future tree growth away from SCE overhead lines. The contractor is responsible for cleanup and disposal of all debris generated from line-clearing activity. In the course of performing maintenance work, the contractor may identify trees not prescribed by the pre-inspector, within the applicable Regulatory Clearance Distance (RCD). In this situation, contractors will trim or remove any additional vegetation meeting the required conditions after receiving SCE approval to do so. In most occurrences, trimming will conclude 30 days after the pre-inspection prescriptions are provided to the contractor.

Maintenance practices for dealing with vegetation in close proximity to Transmission and Distribution assets are generally identical. However, with respect to Transmission, SCE considers how Transmission lines sag lower in hot conditions and when more load is carried, and also that their weight will cause them to sway in windy conditions. This sag and sway movement is commonly referred to as "conductor dynamics." SCE's line clearing program for transmission considers conductor dynamics when defining the clearance distances that need to be maintained.

One distinct function related to line clearing along distribution circuits, as opposed to transmission circuits, is that SCE performs supplemental patrols, during the summer months in areas where topography or vegetation conditions are known to pose a threat to SCE's facilities during extreme weather events. These supplemental patrols provide additional verification of compliance with the clearance distances required by G.O. 95 and PRC §4293.

a) Effectiveness of Expanded Routine Line Clearing Activities for Wildfire Mitigation

SCE has seen a correlation between its expanded line clearance programs (seeking to achieve the expanded recommended clearance distances set forth in the HFTD Decision and GO 95, Rule 35, Appendix E) and a lower amount of Tree Caused Circuit Interruptions (TCCI).[126] This information was reported in the 2022 WMP Progress Report Working Group Update and is reflected in Table VIII-33 below. This data highlights a decrease in outages associated with vegetation-caused events since the advent of enhanced clearances. Details about the reported events include confirmed tree-related events (TCCI) by SCE field verification, and are categorized as Grow-In, Blow-In, and Fall-In events.

Table VIII-33
Average Events Pre & Post Clearances[127]

Average Events Pre & Post Enhanced Clearances

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

2. GRC Track 1 Final Decision

The Commission approved SCE's GRC Track 1 request of $107 million for Distribution Routine Vegetation Management and $12.76[128] million for Transmission Vegetation Management in its entirety. SCE's forecast methodology was based on "modeling assumptions for HFRAs and non-HFRAs

[126] 2022 WMP Progress Report.
[127] For a more detailed discussion, please see SCE 2022 WMP, p. 700. SCE acknowledges that there were multiple on-going programs, such as WCCP, etc., that may also drive the reduction of TCCIs.
[128] Adopted O&M costs were in 2018 dollars.

that incorporate current clearance standards, trimming contractors' estimates, as well as executed contract rates; distribution pre-inspection forecasts based on 2018 recorded costs, with updates to reflect increases in inventory and inspection prices; transmission pre-inspection forecasts based on the cost to fly and translate LiDAR for field usage; and quality assurance based on the number of inspectors and hours required."[129] As discussed below, in Track 4, SCE is proposing an extension of authorization of SCE's Routine Vegetation Management activities, but with an update to the authorized funding to reflect the actual costs that SCE has and will continue to incur to perform this work – including appropriately incorporating the new statutorily required higher contractors' rates caused by SB 247 and other labor cost pressures, incorporating unavoidable costs not anticipated at the time of SCE's 2021 GRC application (*e.g.*, environmental constraints), reflecting the expansion of existing programs (*e.g.*, pole brushing), and allocating funding to new vegetation programs and activities implemented after 2019 that serve to further protect customers against wildfire and public safety risks.

3. Forecast

SCE's 2024 forecast is based on the last recorded year of 2021. There are many factors that can affect the overall cost of Routine Vegetation Management work in a given year. Below, SCE describes the various factors that drove the costs incurred in 2021, and adjustments SCE made to safely execute its vegetation management work. For 2021, SCE recorded lower total trim counts compared to historical averages, but incurred higher costs related to the factors discussed below. Going forward, SCE anticipates 2021 recorded costs for Vegetation Management on a portfolio basis are a reasonably accurate but conservative proxy for 2024 forecast costs. Even though the specific conditions and factors that will influence the precise costs of the various categories of routine vegetation management work in 2024 cannot be known at this time, SCE believes the totality of work and associated costs incurred in 2021 provides a reasonable indication of the overall costs SCE will incur to perform its routine vegetation management work in 2024. For example:

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[129] D.21-08-036, p. 561.

- 2021 recorded reflects the higher cost of vegetation trimming and removals due to higher contractor costs. These costs are reflected in the Trims and Removal sub-activity shown in Table VIII-37 below.
- 2021 was the first full calendar year to reflect the cost of SCE's newer wildfire mitigation activities, such as the full deployment of the Areas of Concern supplemental patrols program.
- In 2021, SCE engaged in new and expanded responsibilities that were integral to daily vegetation field operations, such as customer notifications, increased traffic control, and obtaining environmental approval for a greater number of work points.
- In 2024, SCE anticipates performing at least the same volume of trims performed in 2021, and likely more.
- In 2021, SCE continued its expanded pole-brushing activities, as provided for in its approved WMP. These pole-brushing activities go beyond the pole brushing scope originally contemplated in the 2021 GRC, with the intent of mitigating wildfire risks and increasing grid resiliency. SCE continues to refine its approach to expanded pole brushing to incorporate more risked-informed criteria when defining scope. Expanded pole brushing will continue in 2024, at levels likely to be similar to those performed in 2021.
- In 2021, SCE expanded its use of LiDAR beyond what was originally contemplated in Track 1, performing additional LiDAR inspections on Transmission circuits, as well as increasing its testing and use on Distribution circuits.
- In 2021, SCE ramped-up its environmental support program to address increased permitting requirements and ever-changing regulatory interpretation of environmental laws, which will continue to require similar resources in 2024.

Collectively, the cost drivers summarized above are reflected in Routine Vegetation Management sub-activities shown in Table VIII-34, and discussed in further detail below.

Table VIII-34
Routine Vegetation Management Sub-Activities
(Constant 2018 $000)

		Track 1 Authorized*	Recorded	Recorded	Recorded	Track 4 Forecast
	Subactivity	**2021**	**2019**	**2020**	**2021**	**2024**
1	Routine Vegetation Management					
2	Trims and Removal	$112,822	$254,145	$350,107	$330,091	$330,091
3	Quality Assurance	$1,816	$966	$3,955	$3,207	$3,207
4	Pre-Inspections	$493	$1,827	$1,744	$26,775	$26,775
5	Expanded Pole Brushing	$3,189	$1,616	$7,439	$10,993	$10,993
6	LiDAR Inspetions & Remediations	$1,404	$4,432	$4,061	$4,944	$4,944
7	Environmental Support				$20,514	$20,514
	Total Expenses	**$119,725**	**$262,985**	**$367,305**	**$396,523**	**$396,523**

* Authorized 2022 and 2023 are equivalent to 2021 authorized (in constant 2018 dollars) after removing the impact of the Track 1 Decision's post-test year attrition mechanism

a) <u>Higher Contractor Rates</u>

SCE experienced an increased cost-per-trim in 2021 due to three factors. First, SCE's Track 1 request could not have anticipated how SB 247 and contract renegotiations would drive vegetation management's contractor rates to nearly double, thereby resulting in an inadequate total authorized amount compared to the new higher cost of operations (as depicted in the table above). Second, SCE incurred higher contractor costs as it had to re-direct work among contractors at higher rates when two of SCE's contract tree trimming companies had to pause operations due to safety events. Third, SCE experienced environmental delays and costs, which were first-in-kind for vegetation operations, and which further increased the cost-per-trim. Table VIII-35 below details the average cost-per-trim in 2021. For comparison, in 2020, the total cost per trim was $361 based on 967,000 trims performed.

Table VIII-35
2021 Cost Per Trim[130]

Item	**Amount**
Trim Count	714,000
Total Cost Per Trim	$510

When contractors are involved in significant safety events, SCE may stop work and direct the contractor to perform a root-cause analysis to determine how to re-assess or change safety culture and practices to avoid future significant safety events. This work stoppage is referred to at SCE as a "safety stand-down." The safety of the public, our employees, and our contractors is our top priority. Tree trimming is an inherently hazardous activity and can have unpredictable outcomes even when all safety precautions are followed. Safety stand-downs are an important tool SCE exercises to promote safe work practices and corrective actions where needed.

When contractors are directed to stand-down due to safety incidents, SCE must still continue to perform vegetation management work and meet compliance deadlines. SCE has provisions in its vegetation management contracts that allow for "roving activities," which is when SCE directs one contractor to cover the work scope and geographic area that would ordinarily be covered by another contractor (the contractor on stand-down). Generally, roving activities occur every year, primarily due to delayed work, and result in increased rates because the expectation is that contractors take on additional scope outside their typical areas of operation and usually expedite work in a shorter time frame. Performing this work using other available contractor resources is essential to maintaining regulatory compliance and promoting public safety.

Environmental reviews also resulted in increased costs in 2021, compared to what was anticipated in the 2021 GRC. SCE enlists an independent environmental team to assess work with potential environmental impacts, which is discussed further below. Executing enhanced clearances, beyond the clearances established in years prior, results in additional scrutiny from environmental agencies due to the changed circumstances. Additionally, in 2021 SCE expanded the environmentally

[130] Includes total cost, including those due to SB 247/contract renegotiations and FERC-jurisdictional costs, and an average of non-HFRA and HFRA cost.

sensitive areas (ESA) map layer it uses to determine which work points (trees) require environmental review before work can begin. Being good stewards of the environment is a top priority of SCE. That said, it takes time to properly conduct environmental reviews, and those timelines can result in sub-optimal scheduling for the vegetation management contract crews, as contract crews may have to return to districts that they had already completed to address a single work item that was not yet cleared by environmental review. The re-routing of crews to accommodate environmental reviews led to an increase in costs from our contractors for changed work orders. Additionally, if an environmental review or obtaining environmental clearance from relevant agencies takes several months to complete, there can be increased monitoring/inspection costs because the vegetation management inspectors may need to re-visit the tree multiple times to validate that it is maintaining the required clearance distance during the review period. Environmental reviews of vegetation management work will continue to be a required component of SCE's vegetation management work.

SCE's 2021 work plan forecasted trimming of 835,000 trees. SCE did not meet this forecast in light of the factors discussed above. In 2024, SCE plans to achieve more trims, and forecasts that the future cost-per-trim will decrease as more trims are achieved. Because trim counts are expected to increase, and costs-per-trim are expected to decrease, on balance, total future costs are expected generally to be consistent with 2021 levels. Finally, SCE concluded negotiations in 2021 with contract crews, which will result in a $31 million increase for 2022. This will apply for the 2022-2023 contract years and was not reflected in 2021's last year recorded numbers. While contract costs for 2024 are not yet known, SCE does not reasonably believe they will be lower than 2021 rates.

As noted previously, the dynamic nature of SCE's vegetation management trimming work can lead to differences year-to-year in the costs for contractors to perform the required trimming work. As a result, 2021 reflects SCE best indication of the baseline contractor costs we expect to incur in 2024.[131]

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[131] The variability in Routine Vegetation Management costs results in part due to weather conditions, in particular on the amount of rainfall the previous year, as well as contemporaneous weather conditions. The 115% applied to the VMBA as SCE has proposed for 2024 is an appropriate reflection of the impact of weather variability for cost recovery purposes.

b) Area of Concern Inspections and Mitigations

AOCs are localized regions where SCE believes there is a higher potential for a significant fire to occur based on: 1) the last time the area has burned, 2) the fire history (frequency and seasonal occurrence), 3) the vegetation type and amount, 4) the current and expected fuel and weather conditions, 5) and the potential impact to communities and SCE infrastructure (Technosylva consequence scores). First implemented in 2020,[132] SCE identified 17 AOCs in its HFRA and set new Summer (June) and Fall (September) deadlines to expedite and complete work in the designated areas. SCE assessed trees and structures that were located in these AOCs and identified work that would not be completed by existing deadlines based on compliance line clearing or expanded pole-brushing schedules. Accordingly, SCE conducted supplemental inspections to address work that fell outside normal inspection schedules.

Considering current and prospective drought conditions in California, the need to identify and proactively remediate vegetation management in areas particularly susceptible to fuel-driven wildfire risk is likely to continue in 2024. While the specific geographic areas identified as AOCs may change depending on risk profiles and/or emergent environmental conditions, SCE expects the level of work— be it supplemental inspections or other new mitigations—to continue into 2024, thereby making 2021 work levels a reasonable forecast for 2024 work.

c) New and Expanded Responsibilities

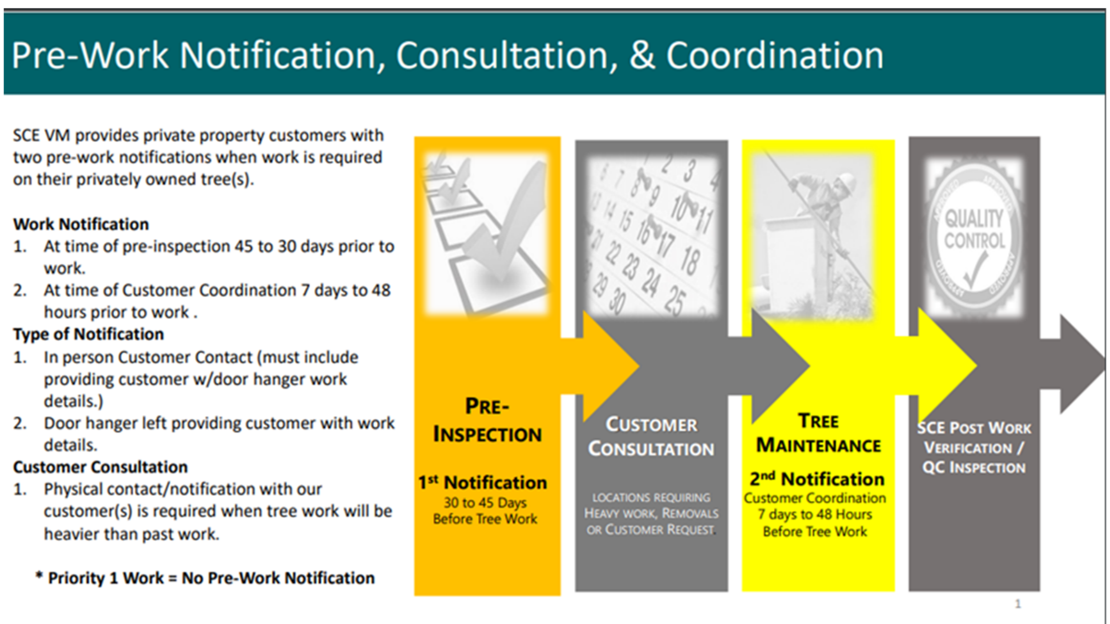
In 2021, SCE engaged in new and expanded responsibilities that are integral to daily vegetation field operations, such as customer notifications, increased traffic control, and obtaining environmental approval for work. Additional HFTD Decision clearance recommendations resulted in a more frequent need for SCE to enter onto customers' properties and perform more complicated trims or tree removals. As a result, SCE implemented a formal protocol for customer notifications. The costs of

[132] In 2020, the program was first named the Enhanced Dry Fuels Initiative (EDFI) before changing to Areas of Concern in 2021. This program was established after SCE had submitted its 2021 GRC Track 1 Application in 2019.

these customer notifications were not included in GRC's Track 1 request because a formal protocol was not in place for this activity.

The formal process for customer notifications begins when SCE first attempts to make phone or physical contact with customers in order to obtain permission to proceed with planned work. Should the customer refuse, SCE initiates an escalation process, which varies depending on the type of mitigation and/or customer refusal.[133] If escalated discussion attempts are unsuccessful, SCE sends a certified letter to the customer stating SCE's intention to proceed with work in accordance with Public Resource Code Section §4295.5.

Figure VIII-39
Pre-Work Notification, Consultation, Coordination[134]



Some cities or counties require different pre-work notifications for customers. SCE will typically meet with a city annually to provide the annual maintenance schedule of the vegetation management grids. Some cities also require SCE to provide weekly email notifications to

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133 Generally, the notification consultant or tree trimming contractor will attempt to meet face-to-face with the customer to address concerns and explain the mitigation process. When necessary, SCE personnel will also engage with the customer.

134 *See* WP SCE Tr. 4-02 Customer Notification Process p. 22, originally provided in SCE's data request response in PubAdv-SCE-T3-018-MCL, Q. 1 in Track 3 of this proceeding.

alert the city of the work being performed in the city. Other cities or counties require SCE to acquire permits to perform work in their respective areas. As shown in Figure VIII-39 above, the notification process begins at least 30-45 days ahead of a planned trim or removal.

SCE has also increased its use of traffic control contractors. As work around private residences has increased due to new expanded clearance requirements and recommendations, so has the need to help ensure traffic on these residential streets is monitored and controlled for the safety of trimming contractors and bystanders. Additionally, as an indirect result of 2020's nationwide move to remote work, there was a greater need to accommodate the higher number of customers who were home during ordinary work hours. SCE expects municipalities to continue to require an increased level of traffic control comparable to 2021 going forward.

d) Volume of Trims

In 2024 SCE anticipates performing at least the volume of trims and removals performed in 2021. The total trims in 2021 were lower than intended, due to the previously discussed safety stand-downs and the timelines associated with environmental reviews.[135] Although SCE does not have a precise forecast for the amount of trims we will completed in 2024, we are reasonably confident that 2021 reflects the minimum amount of trims, new wildfire mitigation activities, and emergent vegetation work that we will perform in 2024. Table VIII-36 shows a breakdown of year-by-year total trims completed in both HFRA and non-HFRA.

[135] If the safety stand-downs and environmental constraints did not impede the ability for contractors to complete their target prescribed trims, the total trims for 2021 were estimated to reach around 835,000.

Table VIII-36
Historical Volume of Trims in HFRA and non-HFRA[136]

Year	HFRA	Non-HFRA	Total
2019	418,112	308,485	726,597
2020	476,974	502,973	979,947
2021	316,674	397,299	713,973

In 2019, SCE was developing its expanded line-clearing practice and performed a total of 726,597 trims. In 2020, SCE ramped up this program to complete its first pass of roughly one million trees in both HFRA and non-HFRA. SCE anticipates its total trim count in 2024 will be somewhere in between the levels trimmed in 2020 and 2021, depending on contractor availability, scheduling capabilities, weather, and other factors. In 2019, SCE was developing its expanded line-clearing practice and performed a total of 726,597 trims. In 2020, SCE ramped up this program to complete its first pass of roughly one million trees in both HFRA and non-HFRA. SCE anticipates its total trim count in 2024 will be somewhere in between the levels trimmed in 2020 and 2021, depending on contractor availability, scheduling capabilities, weather, and other factors.

e) Pole Brushing

The pole-brushing program removes vegetation at the base of distribution poles to reduce the chance of ignition and/or fire spread due to a spark or contact with failed equipment. In addition, pole brushing has the secondary resiliency benefit of protecting the poles if a fire occurs for reasons other than failed equipment. California Public Resources Code §4292 requires utilities in certain areas and at certain times to "maintain around and adjacent to any pole or tower which supports a switch, fuse, transformer, lightning arrester, line junction, or dead end or corner pole, a firebreak which consists of a clearing of not less than 10 feet in each direction from the outer circumference of such pole or tower." In SCE's Track 1 showing, pole brushing was included as a line item within the Routine

[136] After filing Track 3, Vegetation Management conducted a data reconciliation that resulted in this updated 2020 total trim count.

Vegetation Management activity, and included a limited "expanded pole" brushing program representing 25,000 additional poles beyond those required by statute. Since 2019, SCE increased the scope of its expanded pole brushing activity with the specific focus of mitigating potential ignitions in HFRA.[137]

In 2021, SCE brushed approximately 163,000 poles for both statutory compliance and risk mitigation purposes. In 2022 and beyond, SCE is enhancing its risk-prioritization methodology for pole brushing to mitigate wildfire risk and add resiliency to our electric system.[138] In accordance with this new methodology, SCE forecasts to brush between 130,000 to 225,000 poles in 2022, which includes the statutorily-required poles, poles brushed as part of SCE's AOC supplemental patrols, and additional poles located in HFRAs that were identified based on risk and consequence analyses. The scope planned for 2022 is in line with the number of poles completed in 2021. Thus, 2021 represents an appropriate baseline for the pole brushing program in future years.

During 2019, when SCE's Track 1 showing was prepared, SCE's average unit cost per-pole was $16. In 2020, SCE cleared 230,000 poles (inclusive of compliance and expanded poles) for $10.2 million, at an average unit cost of $44 per-pole. In 2021, SCE cleared 163,000 poles for $13.8 million, at an average unit cost of $85 per-pole.[139] The cost to brush a pole has increased due to market pressures on labor, new labor contracts that went into effect in 2021, increased controls and scrutiny of contractors' work, and new data tracking requirements for contractors. While SCE does not anticipate these unit costs escalating at the same rate through 2024, we do foresee unit costs remaining at least at the levels recorded in 2021.

As a result of the expanded scope of pole brushing, the amount authorized in Track 1, which was based on a much smaller scope of expanded pole brushing, does not account for the

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137 *See* SCE's testimony in both Track 2 and Track 3 for a description of the "Expanded Pole Brushing" activity.

138 For 2022 and beyond, SCE will prioritize brushing poles in the following manner: compliance poles (non-exempt P.R.C. Section 4292 poles), poles in Areas of Concern, poles within HFRA that have the same type of equipment as the non-exempt P.R.C. Section 4292 poles, and additional poles identified by risk models and other SCE initiatives, such as HFRI, which demonstrate the highest risk. For a more detailed explanation, please see SCE's 2022 WMP Update.

139 *See* WP SCE Tr. 4-02 p. 23 – Pole Brushing.

volume of work planned in 2024. For the reasons stated above, it is reasonable to use 2021 recorded costs as the basis for the 2024 pole-brushing forecast.

f) LiDAR Inspections and Remediations

SCE utilizes LiDAR technology to inspect select transmission and sub-transmission lines in accordance with FAC 003-4, GO 95, Rule 35 and Public Resources Code 4293, to maintain appropriate clearances between SCE's lines and vegetation. LiDAR is a surveying inspection method that measures distance to a target by illuminating the target with pulsed laser light and measuring the reflected pulses with a sensor. Differences in laser return times are then used to make digital three-dimensional representations of field conditions at the time of survey. The data is then modeled against engineering information to determine the maximum sag and sway of the line in relation to the vegetation near those points. This form of inspection supplements the typical ground-based, visual vegetation management inspections to help maintain minimum clearance distances under maximum heat, wind, and load conditions. SCE provides LiDAR data to inspectors conducing foot patrols on circuits, when available, to assist them in identifying potential encroachments and help them validate that right of way clearances fully account for conductor dynamics.

Implementation of LiDAR for Bulk Transmission Lines was a 2019 WMP initiative. After the success of the initiative, which demonstrated the effectiveness of using LiDAR for Transmission right-of-way inspections, the use of LiDAR was operationalized in 2020 using the published class rating system. From 2022-2024, SCE will continue to work through challenges with how to further expand and deploy LiDAR along its distribution grid-based operation.

Transmission. In 2020 and 2021, approximately 1,700 and 1,590 transmission circuit miles were inspected, respectively. SCE plans to inspect at least 1,600 HFRA circuit miles using LiDAR technology in 2022. SCE expects to continue operating its LiDAR program in accordance with its designated class ranking system, and therefore expects this steady state of roughly 1,600 transmission circuit miles inspected to continue through 2024.

Distribution. In 2021, six distribution circuits (approximately 90 total miles) were chosen to be evaluated for using LiDAR prior to trims for the purposes of work identification, and seven distribution circuits (approximately 155 total miles) were chosen to be evaluated for the purposes of using LiDAR for quality control.

SCE anticipates 2021 to be a reasonable proxy for total miles flown and processed for LiDAR work in 2024.

g) Environmental Support

SCE's ESD provides environmental support for Routine Vegetation Management line clearing, HTMP, Dead and Dying Tree programs, and pole-brushing programs. In Track 1, SCE forecast approximately $2 million in ESD costs associated with Vegetation Management Routine Line Clearing activities.[140] The Commission approved that forecast, but through a separate Business Planning Element (BPE) that was not tracked in the VMBA.[141] In 2021, SCE incurred substantially more ESD costs associated with Vegetation Management activities (~$24 million total recorded) than the Track 1-authorized amount.[142] As discussed above, going forward starting in 2024, SCE proposes adding the specific ESD costs that are directly related to supporting Vegetation Management activities to the VMBA.

SCE's Vegetation Management program has evolved significantly since the issuance of the HFTD Decision, largely driven by SCE's efforts to mitigate wildfire risks and regulatory changes to clearance distance requirements and associated Commission recommendations,[143] as discussed above. Support for environmental reviews and associated costs have grown due to an increase in the volume of vegetation management activities as a direct result of the expanded clearance recommendations, and enhancement of the Environmental Sensitive Area (ESA) layer, as further discussed below.

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140 GRC Track 1, Exhibit SCE-06 V.04 Testimony, page 12, includes ESD's 2021 GRC total O&M request of $27.683 million. The approximately $2 million for environmental support of Vegetation Management resides within the $27.683 million in Figure II-5 Environmental Services Recorded 2014-2018/Forecast 2019-2021.

141 *Id.; see* D.21-08-036, p. 438.

142 In SCE's upcoming cost recovery Application for 2021 recorded wildfire mitigation and vegetation management costs above authorized amounts, SCE will seek cost recovery for the incremental amount of ESD costs for support of Vegetation Management Routine Line Clearing Activities through the FRRMA. Please see SCE-01.II.B. If necessary, SCE will continue this ratemaking treatment in 2022 and 2023 as well.

143 D.17-12-024 adopted regulations to enhance fire safety in the high fire-threat district by extending and providing clarification of various required and recommended vegetation clearance distances.

(1) Work Description and Need

Vegetation Management environmental support activities encompass desktop support (intake, coordination, review, reporting, development and maintenance of geospatial data management and analysis tools using Geographic Information Systems (GIS), Special Use Permit (SUP) tasks, and agency permitting) and field support (coordination, scheduling, surveys, monitoring, and reporting). Additionally, SCE implemented new processes in 2021 providing for environmental support for trouble orders and add-ons. Trouble orders may include vegetation management work to remediate Priority 1 (P1) emergency conditions related to vegetation. These include, for example, where an observed tree, or parts thereof, is expected to imminently fail and contact electric facilities, or where vegetation contact or arcing with bare-wire conductors is highly probable to occur in a high wind event due to the vegetation's proximity to the lines. "Add-ons" are instances where vegetation management crews identify additional work while in the field that was not prescribed by the pre-inspectors. SCE's ESD facilitates environmental review and support for these "add on" work points, which includes identifying the appropriate measures to take in the event a prescription changes in the field.[144]

SCE developed and implemented an ESA layer screening tool to target environmentally sensitive areas for review and improve compliance controls. The ESA layer was enhanced as part of SCE's continuous improvement in assessing trends in program compliance and adapting to increased permitting requirements and regulatory interpretation of environmental laws. This resulted in additional geographic areas being included in the ESA layer, meaning that additional vegetation management work points were required to undergo environmental review before work could be performed. Additionally, SCE identified more work based on the expanded clearance scope, which significantly increased consultant support of these activities and attendant costs. SCE anticipates it will maintain this level of consultant support through 2024.

[144] Appropriate measures include biological, archaeological, and waters desktop reviews and field support (surveys, monitoring, post assessment). For these types of activities, it may be the case that the identified "add on" work can proceed with no standard environmental measures or can proceed using the same measures attached to the original work point. In other instances, the work may require a standard environmental review, and work will not proceed until that review is performed.

SCE estimates desktop reviews and field support increased approximately 260% from 2020 to 2021.[145] The ESA layer enhancement helps facilitate SCE's compliance with environmental laws and regulations. The environmental laws and regulations that SCE is required to comply with include, but are not limited to:

- Federal Endangered Species Act (FESA)
- California Endangered Species Act (CESA)
- Migratory Bird Treaty Act (MTBA)
- California Fish and Game Code (FGC)
- California Environmental Quality Act (CEQA)
- National Environmental Policy Act (NEPA)
- California Fully Protected Species Regulations
- Federal Clean Water Act; Rivers and Harbor Act
- National Historic Preservation Act
- Archaeological Resources Protection Act
- Organic Act
- California Coastal Act

Environmental support for SCE's Vegetation Management programs is critical to help ensure compliance with federal and state environmental laws and regulations. Failure to comply with environmental laws and regulations could also result in violations, fines, penalties, and/or revocation of SUPs (which allow SCE to perform work on U.S. Forest Service and National Park Service lands).

(a) Scope and Forecast

In 2021, SCE recorded a total of approximately $24.4 million for all ESD support for Vegetation Management activities (including $20.5 million in O&M expense for environmental support of line-clearing and pole-brushing activities). As discussed above, for 2024 SCE intends to seek recovery of ESD costs through the VMBA.

[145] A work point is a field in SCE's work management system, ArcGIS, to geographically plot where vegetation work is required. SCE estimates the number of vegetation management work points supported for desktop reviews increased from approximately 96,000 in 2020 to 246,000 in 2021. For work points with desktop reviews performed, the number of work points which also required field support increased from approximately 17,000 in 2020 to 50,000 in 2021.

SCE's 2024 forecast for environmental support for Vegetation Management routine line clearing and pole-brushing programs is $20.5 million, which is based on SCE's 2021 recorded costs. SCE does not anticipate a reduction in routine line clearing program scope in 2024 as compared to 2021; accordingly, SCE's environmental support costs to support line clearing in 2024 are expected to be at least as high as 2021 costs.

For SCE's pole-brushing program, SCE believes that 2021 recorded costs are reasonably indicative of 2024 future expenses. 2021 costs for this activity were higher than in previous years, due to an additional volume of poles brushed, an increased number of poles requiring environmental support, and a higher number of work points located on government lands and requiring agency notifications. Consequently, in 2021, SCE ramped up its environmental support program to address increased permitting requirements and ever-changing regulatory interpretation of environmental laws.

While SCE's scope for 2024 ESD costs related to Vegetation Management activities is not yet certain, 2021 recorded costs for this work likely understates the amount of work that will be necessary (and associated costs that SCE will incur) in 2024. For example, going forward starting in 2022, environmental permitting requirements will specifically require SCE (and other utilities) to pay an environmental mitigation cost as a condition of obtaining the necessary permits. Furthermore, in future years SCE expects to incur additional costs for ESD services related to physical field monitors for work performed in or adjacent to State waters. Thus, SCE anticipates O&M spending in 2024 for ESD will actually be higher than 2021 recorded expenses.

C. <u>Dead and Dying Tree Removal Program</u>

The Dead and Dying Tree Removal program (formerly called the Drought Relief Initiative or the Bark Beetle Infestation Remediation program) was established as a result of the epidemic of dead and dying trees brought on by climate change and years of persistent drought. Resolution ESRB-4, General

Order 95, Rule 35 and Public Resources Code §4923[146] require that SCE mitigate the hazards posed by dead trees or those that are identified as structurally defective or otherwise likely to fail. Under the Dead and Dying Tree Removal Program, SCE conducts patrols in HFRA to identify and remove dead, dying, or diseased trees affected by drought conditions and/or insect infestation. Trees within strike distance of SCE overhead facilities that are dead or expected to die within a year are prescribed for removal.

1. Work Description and Need

Since 2004, Southern California forests have been devastated both by a bark beetle infestation and persistent drought (which are interrelated). SCE has continued to proactively remove dead and dying trees, including those impacted by bark beetle infestation and drought, which could fall on or contact SCE's electrical facilities. Unlike trees located near power lines that must be trimmed to prevent encroachment, large dead or dying trees can be located outside of the utility right-of-way and fall into power lines. For example, a dead 100-foot-tall tree rooted 70 feet from SCE's electrical facilities could fall into those facilities. SCE uses a contract workforce that surveys and identifies dead and dying trees on an ongoing basis. Only trees identified as at risk to contact SCE's electric facilities are added to an inventory for removal. Since trees continue to die as a result of drought, the same geographical areas may be patrolled multiple times a year in support of drought remediation. SCE has multiple contractors working to remove the dead and dying trees.

2. GRC Track 1 Findings

In Track 1, SCE included drought-related remediation work, including bark-beetle-related remediation work, as part of forecast O&M costs, consistent with SCE's request that all

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[146] Additionally, on October 30, 2015, Governor Brown Proclaimed a State of Emergency related to record drought conditions and epidemic infestations of native bark beetles and directed utilities and local governments to take efforts to remove dead and dying trees in high hazard areas that threaten power lines. *See* Proclamation of a State of Emergency, Oct. 30, 2015, available at: https://www.ca.gov/archive/gov39/wp-content/uploads/2017/09/10.30.15_Tree_Mortality_State_of_Emergency.pdf. On August 31, 2017, Governor Brown issued Executive Order B-42-18 concerning "the tree mortality resulting from severe drought and bark beetle infestations across several regions of the State" and ordered that the provisions of the October 30, 2015 Emergency Proclamation remain in full force and effect. *See* Executive Order B-42-17, August 31, 2017, available at: https://www.ca.gov/archive/gov39/2017/09/01/news19936/index.html.

Vegetation Management Program costs be included in a single balancing account.[147] In the Track 1 Final Decision, the Commission approved SCE's uncontested forecast request for $35.12 million.

3. **Forecast**

In its 2021 GRC Track 1 Application, SCE's forecast was based on 2018 last year recorded data, with the assumption that costs would remain steady through 2023. The underlying rationale was that California's severely dry conditions that afflicted much of the state over the last decade, and which were particularly widespread in 2020-2021, would continue to cause damage that would require mitigation for years to come. Additionally, in 2021, SCE first identified the Goldspotted Oak Borer[148] in its territory, which will lead to additional diseased trees requiring mitigation. For these reasons, SCE believes the prescriptions for removals will either increase or at least stay the same as 2021.

The majority of costs associated with the Dead and Dying Tree Removal Program relate to tree removals. In 2021, though SCE's inspectors identified a similar number of trees for removal/mitigation (this identification of a tree for removal/mitigation is referred to as a "prescription") as in 2020, SCE was not able to complete many of the prescribed removals due to contractor safety stand-downs[149] and environmental constraints.[150] For this reason, SCE incurred lower costs in 2021 than authorized. The relatively low number of removals in 2021 relative to the prescribed removals, however, is not consistent with prior years' performance. SCE anticipates it will ramp up 2022 removals beyond the level performed in 2021.

As a result of the delays caused by the safety stand-downs and environmental constraints, SCE was only able to remove 3,424 trees in 2021, which was less than half of the total prescription amount of 8,249.

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[147] D.21-08-036, CoL 70.

[148] The Goldspotted Oak Borer (GSOB) is an invasive pest contributing to on-going oak tree mortality across California. The GSOB burrows deep in the core of the tree, laying larvae, cutting off water supply, and attacking one branch at a time until the tree is completely dead.

[149] For a more detailed discussion of the impact of contractor safety stand-downs, please refer to Vegetation Management's Routine Maintenance section above.

[150] For a more detailed discussion of the impact of environmental constraints, please refer to Vegetation Management's Routine Maintenance section above.

SCE's Track 4 Forecast is based on Last Year Recorded 2021 spend of $16.02 million.[151] Given the unusually low number of removals performed in 2021, the level of spending for the Dead and Dying Tree Removal Program in 2021 represents the minimum of what SCE expects to incur in the future for this program. SCE anticipates future spending in 2022-2024 will be closer to 2021 authorized levels ($35.1 million), based on the historical spend of the program over the past few years and the re-emergence of extreme drought conditions in 2021.[152] For example, SCE's 2022 WMP Update forecasts the program will incur costs of $36.4 million in 2022. Below, Table VIII-37, shows historical spend for this program, which hovers above $30 million:

Table VIII-37
Dead and Dying Tree Removal Program Recorded Costs for 2019-2021
(Constant 2018 $ in Millions)

2019	**2020**	**2021**	**2021 Authorized**
$30.40	$34.66	$16.02	$35.12

Given the Governor's proclamation and continued drought conditions, SCE will need to continue removing dead and dying trees within the utility strike zone into the foreseeable future, including in 2024.

D. Hazard Tree Management Program (HTMP)

SCE expanded its efforts to mitigate vegetation-related wildfire risks by implementing a Hazard Tree Management Program (HTMP) in 2019. HTMP assesses the structural condition of healthy trees that could fall into or otherwise impact electrical facilities and potentially lead to ignitions and outages. These trees can be located up to 200 feet on either side of SCE's electrical facilities (*i.e.*, the Utility Strike Zone), which is significantly beyond the 4-foot clearance compliance requirement for HFRA or the recommended 12-foot clearance zone for distribution-voltage lines, adopted by the Commission in

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[151] Within the $16.02 million in recorded expense is approximately $0.58 million in ESD costs specifically related to this program.

[152] The 2021 Water Year (from October 1, 2020 to September 30, 2021) was California's second driest year on record due to extreme heat and lack of rain and snow. *See* State of California, California Drought Conditions, 2021 Overview, available at: https://drought.ca.gov/current-drought-conditions/#:~:text=2021%20overview%20The%20water%20year%20that%20ended%20September,California%20are%20now%20under%20a%20drought%20emergency%20proclamation.

General Order 95, Rule 35, Appendix E. After an assessment is performed, SCE remediates the risk, as applicable, according to a risk-based approach that is consistent with industry practices.[153] SCE uses contract resources to perform mitigations, such as trimming or removing, whose rates are directly impacted (increased) by the implementation of SB 247.

1. Work Description and Need

Introduced in the 2018 GSRP and reinforced in each of SCE's WMPs thereafter, HTMP mitigates the risk of ignition from vegetation and trees that could fall into SCE's lines. The program is designed to help SCE identify trees not targeted by other vegetation management programs that may be hazardous to SCE's assets and are located beyond the compliance zone. SCE based its initial HTMP inspection schedule on a risk-informed methodology,[154] which ranked and prioritized the riskiest circuit miles in SCE territory, while also considering tree density and operational efficiencies. Through HTMP, SCE performed a variety of mitigation activities as identified from inspections, leading up to and including the removal of hazardous trees.

a) Tree Assessment Process

Once a circuit is scheduled for inspection, SCE completes a detailed assessment to identify which trees could potentially fall into or otherwise impact electrical facilities in HFRA. In this assessment, International Society of Arborists (ISA)-certified arborists inspect the area on either side of SCE's electrical facilities within the Utility Strike Zone (USZ) from which a tree or a portion of a tree could strike or impact electric facilities. The area inspected on either side of SCE's electrical facilities can vary significantly (up to 200 feet) based on the height of the trees, slope conditions, and potential for wind-driven vegetation. The arborists enter their data in the Tree Risk Calculator[155] to compute a Risk Score. This score is considered by the arborist and helps inform their prescription for each hazard tree.

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153 *See* "International Society of Arboriculture's Tree Risk Assessment Qualification," www.isa-arbor.com.

154 In 2022, SCE plans to transition the basis of its circuit prioritization to the Tree Risk Index. Please see SCE's 2022 WMP Update for more details on the Tree Risk Index.

155 The Tree Risk Calculator is a separate tool from the Tree Risk Index. The Tree Risk Calculator is used to assess an individual tree for potential mitigation, whereas the Tree Risk Index identifies the priority in which the circuits are inspected for HTMP.

The 2018 GSRP Settlement included a requirement for SCE to retain a third-party vendor to produce a HTMP effectiveness study. In response to this, SCE retained an independent third-party contractor, Mesa Associates, to evaluate HTMP effectiveness. Mesa Associates reviewed SCE's Tree Risk Calculator and deemed it "effective at streamlining the process of gathering tree risk data and ranking these risks; it identifies a hazardous tree and provides a suggested timeframe for mitigation to reduce the potential wildfire risk resulting from a tree impacting the power lines or other utility infrastructure."[156] Mesa Associates concluded: "SCE's HTMP and Tree Risk Calculator are effective and needed components of SCE's Wildfire Mitigation Plan to identify and assess trees that pose a potential fire risk to utility infrastructure within HFRA in SCE's service area."[157]

b) Enhanced Efforts to Obtain Property Owner Approval

Most trees identified for mitigation through the HTMP reside on non-SCE property; thus, property owner approval is required to remove or mitigate the trees. SCE continues to take additional measures to contact property owners when tree removal is recommended, and as part of public outreach to educate customers. At times, the property owner does not occupy the property, which requires SCE to perform a public property records search to identify property owners and obtain contact information. It is not uncommon for property owners to oppose removing trees that are not currently dead or dying. In these cases, SCE attempts to negotiate with property owners to reach mutually-acceptable resolutions (*e.g.*, providing replacement trees).

c) Tree Removal and Mitigation

Many of the trees that pose a threat to electrical facilities must be mitigated through removal. Other mitigation options include: partial tree removal where major branches are removed; palm frond removal; and monitoring, where the tree does not need removal or partial removal yet but may in the future. Tree mitigation and removals are performed by contractors using a combination of industry-standard methods such as: (1) directional felling, (2) climb-sectionalize, (3)

[156] *See* SCE's GRC Track 3's Appendix A-26 to A-28 for "Effectiveness Study of Southern California Edison's Hazard Tree Management Plan and Tree Risk Calculator for Hazard Tree Identification and Mitigation", pp. 26-27.
[157] *Ibid*.

crane, and (4) high hazard.[158] Once trees are felled, the resulting debris is either removed or left for the customer's personal use based on customer preference. All removals and mitigations are timed to follow program guidelines. Remediations are determined based on the assigned risk score from the Tree Risk Calculator combined with professional judgment. Generally, trees with a risk score of 1-49 do not require remediation. Trees with a risk score of 50-99 require remediation within 180 days of SCE's obtaining access and authority to complete the remediation. Trees with a risk score of 100 or more require remediation within 24 hours of observation.[159]

d) Program Management, Environmental Compliance, and Quality Assurance/Control

Program Management functions provide scheduling, oversight, and research activities required to optimize HTMP. Activities include: prioritizing work (e.g., where inspections should be performed); planning and scheduling inspection and mitigation/removal contractor work; managing the property ownership approval process, including interfacing with property owners and federal, state and local agencies; community outreach; and critical office functions, such as providing accounting, invoicing, reporting, and project management support (*e.g.*, obtaining required permits from government agencies and maintaining tree inventory data).

SCE also uses biological and archaeological consulting firms to assess impacts to sensitive biological and cultural resources, as required, in areas where SCE will be removing trees. These consultants monitor and guide work in potentially sensitive environmental areas, conduct field surveys, develop special training for tree removal crews, and prepare documentation and reports.

Finally, SCE performs Quality Assurance-related functions for HTMP. A Quality Assurance function acting independently from the program management function confirms that contractors have performed the required work in accordance with their contract and SCE internal

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[158] Refer to SCE's 2021 GRC (Track 1) WP SCE-02 Vol. 06A, pp. 168-169 – Industry Standard Removal Methods.

[159] These risk scores serve as a guide for the arborist. The arborists select the proposed mitigation after considering all factors. Thus, having a lower risk score does not necessarily mean a mitigation will not be recommended for that particular tree.

standards, verifies that the inspectors correctly identified subject trees and performed threat assessments, and confirms the accuracy of the inventory of mitigated trees. SCE also performed Quality Control related to the HTMP in 2021. This included QC verification of 100% of the removals and mitigations performed (i.e., verifying the tree was in fact removed), as well as QC review of a sample of the tree risk assessments performed by HTMP assessors in 2021.

2. GRC Track 1 Findings

The Commission adopted a $24.085 million authorized 2021 forecast for HTMP. This was based on the following assumptions: 75,000 trees assessed per year (modeled after SCE's 2020-2022 WMP data), a tree failure and removal rate of 11%, and property owner incentives and program management costs corresponding to the revised scope of tree removals.

Table VIII-38
HTMP Recorded Spend and 2021 Authorized
(Constant 2018 $ in Millions)

2019	2020	2021	2021 Authorized
$14.91	$46.57	$32.28	$24.09

3. Forecast

Since its inception, the HTMP has seen variability in the number of trees that require a full hazard tree assessment or mitigation. In 2020, SCE performed 100,350 assessments, 10,887 removals, and 1,297 mitigations. In 2021, SCE completed 131,307 assessments (assessors inspected 600 circuits), 2,815 removals and 575 mitigations. As discussed in prior sections of this testimony, contractor safety stand-downs and environmental constraints hindered SCE's ability to complete planned work, thereby resulting in lower-than-anticipated total mitigations. Based on historical data and lessons learned, SCE found it is difficult to predict the exact number of trees with strike potential because tree inventory requiring remediation is unknown and varies drastically depending on location and density.

In 2022, SCE is shifting its HTMP target to be based on circuits inspected and not the number of tree assessments performed. SCE's 2022 target is to inspect 330 circuits and assess any trees with strike potential along those circuits. In 2023, SCE plans to inspect an additional 211 circuits according to its multi-year HTMP plan. In 2024, SCE will be working through planned removals identified in prior years. For example, the timeline between assessment and removal can be longer than 180 days if SCE requires permits from agencies, must gain permission from a customer, and/or is delayed due weather constraints. Since SCE has assessments planned through 2023, there will be work in 2024 to mitigate the identified risks. Although the initial pass of hazard tree inspections will be completed by 2024, SCE is transitioning to a long-term approach to regularly inspect and mitigate hazard trees with strike potential. Accordingly, some volume of hazard tree remediation will continue as part of regular operations.

SCE's proposed forecast for 2024 is based on 2021 recorded expenses, which total $32.28 million.[160] This forecast incorporates the most recently recorded contractor costs to perform much of the HTMP work, as well as the latest information on the current tree mitigation inventory and work plans for 2024.

4. Scope

Table VIII-39 below presents a detailed breakdown of the assessments, prescriptions for removals and mitigations, removals, and mitigations completed in 2019, 2020, and 2021. Even though fewer removals and mitigations were performed in 2021 than in prior years, there is always the issue of latent work related to unachieved prescriptions (roughly 3,000 prescriptions identified in 2021 but not performed will be carried over to future years). Overall, SCE considers the 2021 last year recorded spend for HTMP to be a reasonable proxy of 2024 forecast costs. Like all 2024 Vegetation Managements costs, however, any recorded spending over or under Track 4-authorized amounts will be tracked in the VMBA. That delta will be eligible for recovery from, or returned to, customers, respectively (on a VMBA-wide portfolio basis), consistent with the VMBA preliminary statement.

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[160] Included within the $32.28 million in 2021 recorded expense for HTMP is $3.31 million for ESD support costs directly related to this program.

Table VIII-39
2019 -2021 HTMP Assessment, Mitigation, and Removal Counts

HTMP Activity	2019 Units	2020 Units	2021 Units
Assessments	119,201	100,350	131,307
Prescriptions for Removals and Mitigations	15,723	4,914	6,297
Removals	5,275	10,887	2,815
Mitigations (Trims)			
Prunes	388	1,140	476
Skirt Palm	5	157	99
Total Trims	393	1,297	575
Mitigations and Removals	5,668	12,184	3,390

Below is a detailed breakdown of the associated recorded costs for assessments, removals, and mitigations completed in 2019, 2020, and 2021.

Table VIII-40
2019-2021 HTMP Recorded Costs
(Constant 2018 $ in Millions)

HTMP Sub-Activity	2019 O&M Recorded	2020 O&M Recorded	2021 O&M Recorded
Assessments	$ 3.51	$ 4.49	$ 7.19
Removals	$ 10.68	$ 39.62	$ 21.87
Mitigations	$ 0.46	$ 0.66	$ 0.33
Program Management	$ 0.26	$ 1.80	$ 2.86
Property Owner Incentives	-	-	$ 0.03
Total	$ 14.91	$ 46.57	$ 32.28

E. Technology Solutions

3. Summary of O&M and Capital Request

SCE's O&M and capital requests for Vegetation Management Technology Solutions are presented in Table VIII-41 and Table VIII-42. The O&M forecast of $0.606 million is based on Last Year Recorded 2021 spend. SCE's budget-based capital forecast is $2.707 million. As discussed in detail below, much of the development and implementation work for SCE's integrated vegetation management platform, Arbora, will be completed from 2021 to 2022, with the rollout of HTMP and Routine Line Clearing functionality to all users anticipated in 2022. The 2024 capital forecast is based on performing a required routine refresh for the iPad devices that are used in the field and further advancement of capabilities on the common platform.

Table VIII-41[161]
Technology Solutions
O&M Authorized, Recorded, and Forecast by Sub-Activity
(Constant 2018 $000)

		Track 1 Authorized*	Recorded			Track 4 Forecast
	Subactivity	**2021**	**2019**	**2020**	**2021**	**2024**
1	Technology Solutions			$1,028	$606	$606
	Total Expenses			**$1,028**	**$606**	**$606**

* Authorized 2022 and 2023 are equivalent to 2021 authorized (in constant 2018 dollars) after removing the impact of the Track 1 Decision's post-test year attrition mechanism

Table VIII-42
Technology Solutions
Capital Authorized, Recorded, and Forecast by Sub-Activity
(Nominal $000)

		Track 1 Authorized					Recorded			Track 4 Forecast
	Subactivity	**2019**	**2020**	**2021**	**2022**	**2023**	**2019**	**2020**	**2021**	**2024**
1	Technology Solutions						$4,219	$16,147	$11,005	$2,707
	Total Capital						**$4,219**	**$16,147**	**$11,005**	**$2,707**

[161] The O&M and capital recorded and forecast for this activity is being reflected in Enhanced Operational Practices Figure VII-25 and Figure VII-26.

4. Work Description and Need

As part of the 2020-2022 Wildfire Mitigation Plan and long-term strategy, SCE developed an Integrated Vegetation Management (IVM) software solution that aims at integrating programs across the organization to streamline vegetation-related work efforts that can overlap across large geographic areas. Built on the Salesforce platform, Arbora is a single, scalable, and easy-to-use system that allows SCE and its contract partners to manage and execute vegetation management efforts more effectively. Prior to Arbora, managing and monitoring work for each vegetation program required reliance on multiple systems, use of Excel spreadsheets and paper records to create, update, and close work activities, manage schedules, and view up-to-date reports. As vegetation management programs expand in scope and user base, systems and processes become increasingly complex to scale and maintain.

Arbora was designed to support vegetation management programs, such as the Dead and Dying Tree Removal Program (formerly known as Drought Relief Initiative (DRI)), HTMP, Routine Line Clearing and Non-Routine (emergent and remaining vegetation activities such as pole brushing) work. In Q3 2020, SCE launched the first iteration of Arbora to a pilot user group supporting the Dead and Dying Tree Removal program. At the end of Q4 2020 and into 2021, SCE expanded from Dead and Dying Tree Removal program to a combined Dead and Dying Tree Removal program and HTMP integration. Designs for Routine Line Clearing and Non-Routine programs also commenced in 2021 and are scheduled for development and piloting in 2022. The full rollout of HTMP and Routine Line Clearing programs on the Arbora platform to all users is anticipated in 2022, with the completion of Non-Routine program rollout to all users in 2023.

5. O&M Scope and Forecast Analysis

In 2021, SCE spent $0.606 million in O&M costs for Wildfire Vegetation Management Technology Solutions activities. These activities can be classified into two primary groups: licensing fees and subscriptions, and operational maintenance and support. Licensing fees and subscriptions include the application and platform licenses and vendor support associated with the Arbora product. Operational maintenance and support include the labor costs related to the ongoing maintenance of the technology solutions, code maintenance, break/fix support, integration with new systems and applications, training, and organizational change control.

a) Historical Variance Analysis

SCE did not incur O&M costs for Vegetation Management Technology Solutions in 2019 because the programs in this activity were still in the planning and development stages. In 2020, SCE did incur some O&M costs related to licensing costs of the software after the first pilot go-live date. In 2021, SCE capitalized most of the licensing fee costs during the continued development of the software solution, pursuant to standard accounting rules. Accordingly, the O&M spend for Arbora decreased from $1.028 million in 2020 to $0.606 million in 2021. The remainder of the O&M costs for Vegetation Management Technology Solutions consist of Organizational Change Management (OCM), training, field services support, and maintenance costs.

b) Basis for Forecast

The $0.606 million forecast for O&M for the Wildfire Vegetation Management Technology Solutions efforts in 2024 was developed using 2021 last year recorded costs. This methodology is consistent with how SCE has forecasted O&M spend across virtually all wildfire mitigation and vegetation management categories in Track 4. However, due to the stage of the projects within the Wildfire Vegetation Management Technology Solutions category, SCE expects its actual 2024 O&M costs to be significantly higher than the forecast requested in this filing. In 2024, SCE anticipates the implemented capital applications will have transitioned to operations, and much of the development and associated capital spend will be completed, while the O&M spend will be significantly higher due to on-going operational costs of the cloud-based solutions. For purposes of this Track 4, SCE is only requesting the amount of 2021 recorded costs, but we anticipate incurring significantly higher O&M licensing fees and software subscription costs and operational maintenance support in 2024.

6. Capital Scope and Forecast Analysis

In 2024, SCE will continue to enhance and evolve the Vegetation Management technology solutions to adapt to growing business needs and an increasingly complex set of data gathering, analysis, and reporting requirements imposed by the Office of Energy Infrastructure Safety in the WMP process. The $2.707 million in forecasted capital dollars will accommodate the routine refresh of the iPads devices that are used in the field and further advancement of capabilities on the common platform. With the rapid advancement in new and emerging technologies, these capabilities include the potential for incorporating artificial intelligence, machine learning, and predictive and prescriptive algorithms to keep pace with the developing requirements as well as the utilization of additional types of data, such as LiDAR, to advance the overall inspection product.

a) Historical Variance Analysis

SCE's capital expenditures increased from $4.219 million in 2019 to $16.147 million in 2020 and then decreased to $11.005 million in 2021.

In 2019, SCE procured and deployed iPad devices in support of inspection and mitigation efforts and developed ArcGIS Survey123 to meet the critical system need for line clearance work. As discussed above, in 2020, SCE launched the first iteration of Arbora to a pilot user group supporting the DRI program and then expanded development to a combined DRI/HTMP. SCE continued the design and development effort for Arbora into 2021 for DRI/HTMP as well as design for Pole Clearing, Routine, and Non-Routine programs. The capital expenditures decreased in 2021 due to the final development completion of ArcGIS Survey123.

b) Basis for forecast

The 2024 capital forecast of $2.707 million for the projects within this activity was developed using SCE's budget-based IT cost estimation model. This cost estimation model was utilized to forecast SCE's IT capitalized software projects in Track 1 of this proceeding, which the Commission adopted in its entirety. This model utilizes industry best practices and SCE subject matter expertise to estimate project cost components. SCE's forecast for these projects includes cost for SCE employees, supplemental workers, and consultants, as well as software and vendor costs, and hardware costs.[162]

[162] *See* WP SCE Tr. 4-02 Vegetation Management Technology Solutions, p. 24.

IX.

PUBLIC SAFETY POWER SHUTOFFS

A. Overview

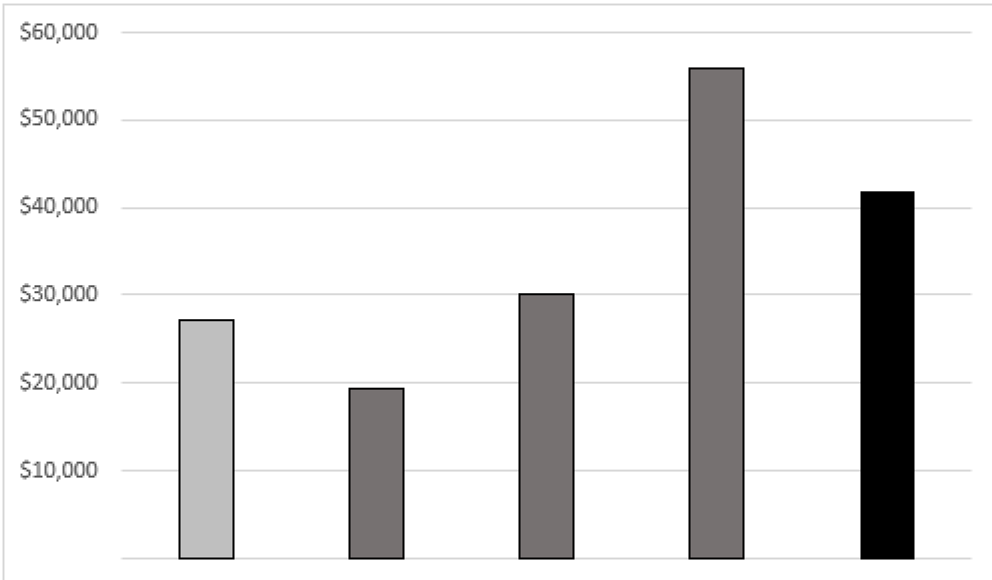
SCE continues to undertake significant efforts to protect public safety and mitigate the risk of wildfires associated with electric facilities by developing a robust infrastructure program to manage wildfire-related risks. Proactive de-energization of power lines due to risk of significant wildfire, referred to as Public Safety Power Shutoffs (PSPS), remains an important tool in protecting public safety and mitigating wildfire risk under severe weather conditions. The feedback we received throughout the PSPS events in 2020, in President Batjer's letter on January 19, 2021, and during the public Commission meeting on January 26, 2021, crystallized the areas we must improve. SCE has clearly heard the message from customers, regulators, government officials, and public safety partners that it must do more to reduce the need for PSPS going forward, perform PSPS effectively when it is necessary, and communicate its wildfire mitigation and PSPS-related plan, process improvements, and support programs in a clear and useful manner. In 2021, SCE developed a comprehensive Action Plan that described over 130 concrete activities targeted at reducing the frequency, scope and impact of PSPS during the 2021 fire season. These activities were directly responsive to the issues raised in President Batjer's January 19 letter and during the January 26 Commission meeting, as well as the concerns raised by our customers and public safety partners. In some cases, these Action Plan activities expanded the scope and urgency of existing PSPS work activities and resulted in incremental and unplanned spend across the PSPS program.

SCE recognizes that while PSPS lowers the risk of wildfire ignitions, it also has very real impacts on our customers, including service disruptions and other hardships associated with the loss of power. SCE expects PSPS events to become less frequent as it continues its grid hardening work and executes its wildfire mitigation initiatives. SCE's PSPS actions are guided by four fundamental objectives: (a) to protect public safety; (b) to keep the power on for as many customers as possible; (c) to communicate clearly and accurately; and (d) to minimize the impact of de-energizations through customer programs. This chapter addresses the need and supporting forecasts for the execution and customer support-related activities that enable SCE to safely and effectively use PSPS as a necessary tool to mitigate wildfire risk. SCE has identified this portfolio of activities and associated work volumes using a risk-informed approach.

1. Content and Organization of Chapter

This chapter presents SCE's 2024 O&M expense and capital expenditure forecast for PSPS Execution and PSPS Customer Support activities, as well as Technology Solutions that support these activities. The funding request presented in this chapter will allow SCE to continue its efforts to protect public safety while continuing to reduce the need for – and improve the execution – of PSPS. This chapter summarizes the scope of work, key drivers for the work, and the level of O&M and capital requested for PSPS activities. In support of this, SCE has developed processes and procedures for programs specifically targeted to reduce this risk and mitigate the impacts of outages. Below SCE discusses (1) PSPS Execution, which includes the processes for activating an Incident Management Team to manage a potential PSPS event and related costs and programs; (2) PSPS Customer Support, which provides support to impacted customers and communities in the event of an actual PSPS event; and (3) Technology Solutions, to support PSPS-related work.

Figure IX-40[163]
O&M Summary
Public Safety Power Shutoff
O&M Authorized, Recorded, and Forecast
(Constant 2018 $000)



Track 1 Authorized*	Recorded			Track 4 Forecast
2021	2019	2020	2021	2024
$27,234	$19,374	$30,135	$55,916	$41,736

	Track 1 Authorized*	Recorded			Track 4 Forecast
Sub Activity	2021	2019	2020	2021	2024
PSPS Execution	$14,027	$14,056	$14,442	$17,904	$17,904
PSPS Customer Support	$12,360	$3,787	$10,477	$32,110	$19,113
PSPS Technology Solutions	$847	**$1,532**	**$5,216**	**$5,902**	**$4,720**
Total Expenses	**$27,234**	**$19,374**	**$30,135**	**$55,916**	**$41,736**

* Authorized 2022 and 2023 are equivalent to 2021 authorized (in Constant 2018 dollars) after removing the impact of the Track 1 Decision Post-Test Year attrition mechanism.

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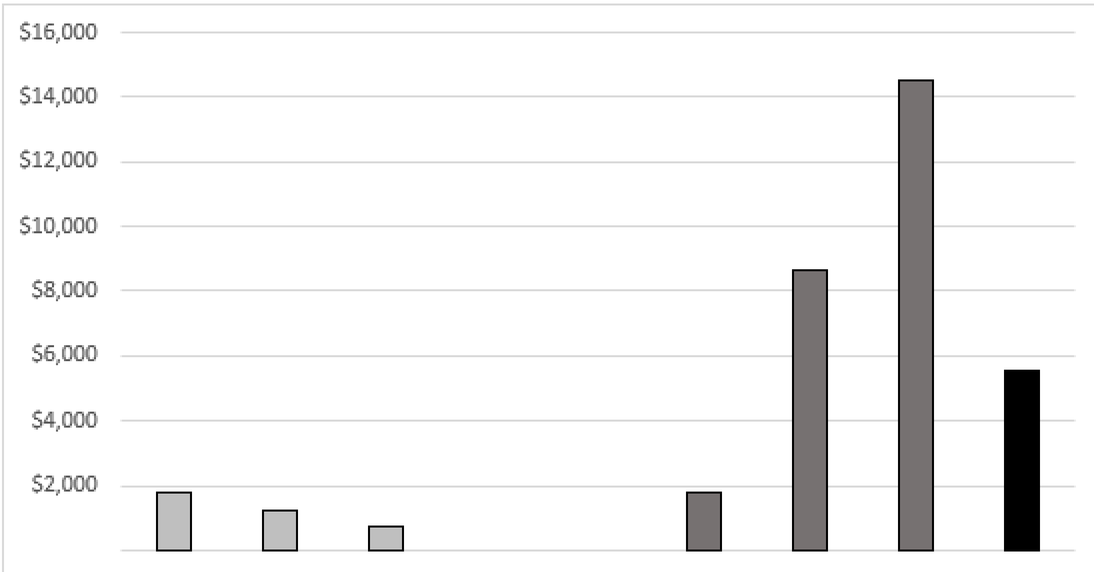
[163] Figure IX-40 excludes $17.492 million in Aerial Suppression for 2021 recorded and 2024 forecast. Aerial Suppression is discussed in the Aerial Suppression chapter. The table also excludes sub-activities PSPS Customer Care Project and Rate & Compliance Marketing as there are no associated authorized amounts or 2024 forecasts. Historical costs for these sub-activities can be located in WP SCE Tr. 4-01 - O&M Financial Mapping pp. 161-162 in the section Activities Excluded from Sub-Activity Tables. This workpaper also includes financial mapping.

Figure IX-41
Capital Summary
Public Safety Power Shutoff
Capital Authorized, Recorded, and Forecast
(Nominal $000)



Track 1 Authorized					Recorded			Track 4 Forecast
2019	**2020**	**2021**	**2022**	**2023**	**2019**	**2020**	**2021**	**2024**
$1,766	**$1,234**	**$756**	-	-	**$1,766**	**$8,639**	**$14,526**	**$5,530**

	Track 1 Authorized					Recorded			Track 4 Forecast
Sub Activity	**2019**	**2020**	**2021**	**2022**	**2023**	**2019**	**2020**	**2021**	**2024**
PSPS Technology Solutions	$1,766	$1,234	$756			$1,766	$8,639	$14,526	$5,530
Total Capital	**$1,766**	**$1,234**	**$756**			**$1,766**	**$8,639**	**$14,526**	**$5,530**

B. <u>PSPS Execution</u>

SCE is focused on reducing wildfire ignition impacts by continuing to undertake significant efforts to further advance its robust infrastructure and operational program to manage wildfire-related risks. The 2021 wildfire season clearly demonstrated the continued urgency of wildfire prevention, event response and emergency preparedness. In fact, four of the twenty largest wildfires in California's history took place in 2021 as drought conditions intensified across the state. At certain times in 2021, weather and fuel conditions became so severe that SCE implemented multiple back-to-back PSPS events to mitigate wildfire ignition risks. Despite having to implement these PSPS events, SCE demonstrated progress in both the reduction of PSPS events and associated impacts to customers, and the protection of public safety, including life and property.

During the 2021 fire season, SCE customers experienced a decrease in PSPS impacts compared to the 2020 season: 9 PSPS activations, ~85,000 customer de-energizations, and ~105 million customer minutes of interruption (CMI), with no major wildfires in HFRA associated with SCE infrastructure.[164]

SCE was able to achieve these outcomes primarily due to the prescriptive mitigation plans we implemented for those circuits that have been frequently impacted by PSPS. These plans consisted of accelerated grid hardening – which allows SCE to raise the wind-speed thresholds for de-energizations, circuit segmentation, operating protocols, and customer programs. While these efforts represented significant progress in the reduction of impacts from PSPS events, continued emphasis on grid-hardening-related mitigations will reduce the need to resort to PSPS de-energization and will in turn reduce customer impacts.

SCE expanded customer offerings and improved communications with public safety partners to help mitigate the impacts of PSPS. In 2021, SCE's Action Plan[165] included the goals of reducing the need for PSPS, executing PSPS events more effectively with transparency into the decision-making process, mitigating the impacts of PSPS events, keeping partners and customers clearly and consistently informed, and enhancing and improving post-event reporting. As of the end of 2021, SCE completed most of the activities identified in the Action Plan. In addition, following the PSPS events initiated in 2021, SCE continued to revise its processes and protocols to incorporate lessons learned during previous de-energizations and re-energization activities. SCE also conducted several table-top simulation exercises, and incorporated learnings from these activities into our PSPS processes.

1. **<u>Summary of O&M Request</u>**

In 2024, SCE forecasts $17.904 million in O&M expense for this activity. This is the same cost as 2021 recorded. PSPS Execution is made up of sub-activities that drive the preparation,

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[164] Defined as April to November 2021. The January 2021 PSPS event is considered part of the 2020 fire season because it was driven by 2020 weather and fuel conditions and managed with 2020 tools and capabilities.

[165] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M369/K084/369084054.PDF.

communication and management of PSPS events. These include PSPS Execution Incident Management Team; Line Patrols; Customer Side Generators; Community Resource Centers (CRCs) and Community Crew Vehicles (CCVs); Advanced Unmanned Aerial Systems; PSPS Operations; and Town Hall Community Meetings, all of which are described below.

2. Work Description and Need

a) PSPS Execution Incident Management Team (IMT)

SCE has established and trained a dedicated PSPS IMT team staffed solely for the purpose of responding to PSPS events and advancing operational protocols and enhancements during normal daily operations. A dedicated team creates greater consistency across PSPS activations when communicating with customers and public safety partners. Additionally, this specialized team is able to quickly adapt and make changes from one event to another. The Incident Command System (ICS) is typically utilized by private and public organizations across the country as a best practice for emergency response, regardless of incident size or type. ICS has been successfully utilized at SCE for several years, allowing for the IMT to respond in a cohesive, integrated manner during any activation, including those related to wildfires and PSPS events. Additionally, SCE maintains a comprehensive annual training and exercise routine to ensure continuous improvement. This program closely adheres to State and Federal emergency management guidance for readiness standards.

The PSPS IMT oversees and executes PSPS protocols, which detail how PSPS activation, notification, de-energization and service restoration processes work (*e.g.*, roles and responsibilities, decision-making processes, and execution). The team relies on a multitude of necessary tools and technology to monitor ongoing weather circumstances that could impact grid operations. These tools and technology are used to help SCE anticipate the need for possible PSPS activation, monitor weather events, evaluate real time forecasts, provide communications to affected communities, and enable the IMT under the leadership of the Incident Commander to make complex decisions about when to implement and when to end PSPS events. When SCE forecasts that windspeeds will breach circuit-specific thresholds for activation and monitoring for potential PSPS, SCE activates its PSPS IMT and begins preparations for the upcoming event (notifications, pre-patrols, etc.). The IMT uses a variety of factors to guide its decision on whether de-energization on each circuit or circuit segment is necessary, including the Fire Potential Index (FPI) and real-time data from weather station sensors and field observers (if available). When fire risk conditions subside and safe conditions are validated by field resources, SCE begins patrolling impacted circuits to check for any risks that could potentially present a public safety hazard when re-energizing circuits. Once field resources confirm that it is safe to re-energize the circuit(s), power is restored, and local government and customers are notified of re-energization. The order in which circuits are re-energized depends on many factors including, but not limited to, consideration of affected essential services, damage to electrical and other infrastructure, and circuit design/topology.

In 2021, SCE's recorded O&M costs for the PSPS IMT sub-activity were $3.430 million and SCE's Track 4 forecast for 2024 is the same. SCE's recorded and forecast costs for this sub-activity relate to PSPS IMT activations and dedicated IMT labor resources activities, which develop PSPS protocols and processes, manage PSPS activations, and incorporate lessons learned from past events into protocols and process going forward. Because PSPS will still be a necessary wildfire mitigation measure in 2024, SCE must maintain the functionality and capacity of the IMT that has been developed, which is why SCE is forecasting 2024 amounts for the sub-activity at the level of recorded expense in 2021.

b) <u>PSPS Operations</u>

The PSPS Operations department is staffed with functional area managers, technical specialists, advisors, and support staff who have responsibility for cross-organizational coordination, circuit switching plan development, operational compliance, training, continuous improvement of processes, program management, and related initiatives. During a PSPS activation, PSPS Operations personnel staff a specialized Task Force in the PSPS IMT with Transmission, Substation, and Distribution electric grid operations expertise. When activated, this Task Force is a part of the overall IMT structure and is responsible for providing oversight and guidance for the execution of PSPS protocols on the transmission and distribution grids in SCE's HFRA. This includes proactive de-energization of circuits within SCE's HFRA, upon approval by the Incident Commander, if data sources indicate that local weather conditions pose an imminent and significant threat to public safety. Once the threat to public safety has abated and the hazardous weather conditions have subsided, PSPS Operations coordinates post-event circuit patrols by field personnel to help ensure any damage found is repaired before lines are re-energized. PSPS Operations activities include reviewing and updating switch plans and procedures for over 1,000 HFRA circuits, including developing reconfiguration options to minimize customer impacts during PSPS events.

In 2020, SCE incurred $1.202 million in O&M expense for this sub-activity as full-time employees started to be hired. In 2021, with a full staff of employees now hired for "blue-sky"[166] PSPS Operations work and PSPS IMT event management, SCE's recorded O&M expense was $5.511 million. SCE forecasts the same amount for 2024 as this work is a continued necessity for PSPS readiness and execution, which we anticipate continuing into 2024.

c) Line Patrols

Line patrols are an important part of SCE's PSPS program and are one of many inputs that the PSPS IMT considers when initiating PSPS Protocols. Line patrols provide critical sources of situational awareness that allow for the execution of SCE's PSPS protocols before and during a PSPS event, and after weather conditions have abated. Before an event, line patrols are carried out by QEWs (*e.g.*, Troublemen, Senior Patrolmen, etc.) to examine SCE assets for any potential concerns that may be exacerbated by the upcoming wind event. During an event, qualified personnel can be deployed to HFRA to take live wind readings, visually inspect SCE's overhead circuit integrity, and to watch for other inclement hazards (*e.g.*, airborne debris). These LFOs may be performed by one or more vehicles or on foot, as appropriate, depending on congestion, visibility, accessibility, time urgency and topography. LFOs provide real-time data back to SCE's Emergency Operations Center. After concerning weather conditions have abated, SCE dispatches qualified personnel again to perform restoration patrols on all circuits that experienced a PSPS de-energization to help ensure that it is safe to re-energize the line (*e.g.*, to help ensure there are no foreign objects on SCE's overhead circuitry).

166 Blue sky refers to the everyday work the team does when they are not in an activation (process and procedural advancement, etc.).

In 2021, SCE's recorded O&M expense for this sub-activity was $3.266 million. For purposes of this Track 4, SCE forecasts the same amount for 2024 as this work is expected to continue.

d) Mobile Generator Deployment

Because PSPS may disrupt electric services to critical electrical loads and essential customers, SCE has implemented several programs to offer targeted assistance through backup generation. In preparation for the 2021 PSPS season, SCE planned backup generation activities across a variety of use cases. Principal among these were underground load blocks, in which SCE engineered and modified circuitry to interconnect mobile generators to serve areas of very low fire risk, should the upstream feed be interrupted. SCE prepared five circuits with this capability.

SCE may also deploy temporary mobile generators for critical facilities to assist maintaining electric service for essential safety and public services emergencies. These case-by-case decisions are made by the IMT in coordination with county emergency management offices, based on the unique circumstances associated with each event. SCE begins to assess emergency generator deployment once the PSPS IMT is activated and emergent public safety needs are identified.

In 2021, SCE retained more than forty mobile generator units for the duration of the season to help ensure availability when needed. In 2021, SCE recorded $4.107 million, $1.89 million over SCE's 2020 recorded expenses of $2.214 million. This increase was due to the need to retain specific generators for the entire year to help ensure availability of required units during the 2021 PSPS season. SCE will continue to deploy temporary mobile generators for critical facilities to assist maintaining electric service for essential safety and public services emergencies. As such, SCE's 2024 forecast aligns with recorded 2021 costs.

e) Community Resource Centers (CRCs) and Community Crew Vehicles (CCVs)

During PSPS de-energization events, customers often need access to services such as power sources for the charging of devices and medical equipment, and information on the event such as event duration. To meet these needs, SCE provides in-person local support to its customers through CRCs and CCVs. CRCs provide services such as access to device charging, restrooms, water, snacks, and resiliency kits (which contains a tote bag, LED lightbulb or flashlight, pre-charged phone battery, ice voucher, personal protective equipment (*e.g.*, masks, hand sanitizers, etc.)).[167] In December 2021, SCE began offering medical thermal bags and ice vouchers for individuals who need to keep medication cool. CRCs also provide an opportunity for customers to sign up for PSPS alerts, update their SCE contact information, and receive answers regarding PSPS and SCE's customer assistance programs or customer account questions.

CCVs are deployed into the impacted PSPS event areas and supplement our CRCs. SCE uses mobile CCVs as needed to reach affected communities that do not have a CRC location in their community or as a supplement to CRCs. SCE has designed and outfitted these vehicles with the required equipment and technology to enable SCE staff to transport and distribute water, snacks, and resiliency kits to communities potentially impacted by a PSPS event. CCVs can be quickly activated to serve customers and can be set up in open areas without a standing facility and/or in remote areas. CCVs are especially useful in limiting indoor interactions during the COVID-19 pandemic.

As of December 31, 2021, SCE has contracts with 62 CRCs in different locations and can currently activate approximately 15 of these locations simultaneously across its service area, including deploying CCVs as needed. In 2021, SCE activated CRCs on 22 locations for a total of 50 days and deployed CCVs on 31 locations for a total of 66 days in multiple counties (Mono, Inyo, Kern, Ventura, San Bernardino, Orange, Los Angeles, Santa Barbara and Riverside) to support community members during PSPS events. Approximately 6,500 customers visited the CRCs and CCVs during PSPS events in 2021. SCE continues to work with regional local government and community stakeholders to identify new sites and needs.

The 2021 recorded O&M expense for CRCs was $0.523 million, approximately $0.75 million less than the 2021 GRC-authorized amount. SCE purchased approximately 15,000 Customer Resiliency Kits and 1,000 Medical Thermal Bags, which cost $0.77 million, which have been and/or will be distributed to customers during PSPS de-energization events. SCE records the cost of the

[167] Contents of the resiliency kits provided to customers may be adjusted as needed.

Customer Resiliency Kits and the Medical Thermal bags as they are being distributed in the field. But due to fewer PSPS de-energization events, SCE distributed fewer Customer Resiliency Kits and Medical Thermal bags than anticipated.

SCE's 2024 O&M cost forecast for Community Resource Centers is $0.523 million, based on Last Year Recorded methodology for 2021 recorded costs. While SCE is forecasting 2024 expenses based on 2021 recorded costs, SCE expects O&M expenses in 2024 to be higher because SCE anticipates a similar or higher number of CRCs and CCV activations as in 2021, assuming similar or worse weather conditions, and due to expenses related to the replenishment of customer support supplies, as well as augmented staff support to increase the number of CRCs/CCVs that may be activated simultaneously, if needed.

f) Advanced Unmanned Aerial Systems (UAS) for PSPS

In 2019 through 2020, SCE continued development of UAS capabilities with a focus on PSPS response, system resiliency, and WMP initiatives via Inspection protocols. Industry developments have enabled better access to more advanced capabilities such as automated flight operations. SCE has pioneered this approach as a means to enhance operational safety while using UAS for PSPS patrols. Automated flights over terrain-challenged segments of circuits have demonstrated a reduction in PSPS Patrol times conservatively estimated to be 50% or better. For 2022, our strategy is to couple automated flight with prior beyond visual line of sight (BVLOS) successes. This will enable BVLOS PSPS patrols to move from demonstration status to true work method. During 2020 and 2021 the roles of SCE's UAS-capable workforce expanded tremendously. As these new operators gain experience, operations such as automated flight and BVLOS are expected to become common methods. In addition, technological and regulatory advances have made true BVLOS (without the reliance on a Special Government Interest, or SGI waiver) attainable to the utility markets. SCE will further evaluate real-time application of artificial intelligence and machine learning (AI/ML) in conjunction with automated flight capability. Unlike human-directed automated flight, AI/ML automation removes the human from the loop and enables automated response to triggering events and/or inspection schedules. Early entrants into this field are becoming available although adaptation to utility applications will require research and development. Adaptation of this discipline will leverage a maintained partnership with the FAA and will likely be a multi-year effort. To date this partnership has already yielded UAS policy developments on a national scale in the form of SGI waiver availability for research and development purposes. Prior to this partnership SGI waivers were only available as an emergency response.

SCE's recorded $2,000 in 2021 direct[168] O&M expense for this sub-activity and SCE's forecast for purposes of this Track 4 is the same.

g) PSPS Response & Compliance

In 2019, SCE established a dedicated Wildfire/PSPS Response group within the Business Resiliency Department to provide direct support for PSPS and wildfire mitigation efforts. This includes supporting high-impact work activities for implementing the PSPS protocols; implementing enhanced situational awareness tools, such as supercomputers, high-resolution forecasting, high definition (HD) cameras, and weather stations; and developing processes and procedures to help ensure compliance with regulatory mandates. In 2020, SCE onboarded additional full-time resources for the dedicated IMT resources and recorded $0.657 million in O&M costs. These employees developed several additional capabilities around PSPS IMT programs and processes to enhance situational awareness tools and technologies and build external engagement and compliance activities. In 2021, SCE had 12 full-time resources and recorded $1.022 million in O&M costs. Also, in 2021, SCE hired a contractor to help with compliance activities and identified several technology improvements to streamline our operations, provide a common operating picture and enhance timely response operations. SCE forecasts the same in 2024 for coordinating SCE's response and customer support during a PSPS event.

[168] As a broader organization, SCE incurs far more O&M expense for UAS activities. However, the vast majority of such costs are borne by the individual business units requesting the services (*e.g.*, T&D); thus, those embedded costs are not separately recorded or forecasted here.

h) Town Hall Community Meetings

SCE holds wildfire safety community meetings to share information about its WMP, PSPS, customer programs, and emergency preparedness resources. In 2018 and 2019, SCE hosted the meetings in-person in communities in HFRA, where customers had the opportunity to interact with SCE staff and ask questions. In 2020 and 2021, the meetings were held virtually due to the COVID pandemic and were offered to all customers in HFRA. In 2022, SCE plans to continue to host the community meetings virtually. The recordings of the meetings and presentation decks are posted on SCE's website at www.sce.com/wildfiresafetymeetings. In 2021, SCE recorded $10,000 dollars in O&M expense for this sub-activity and for purposes of this Track 4 forecasts the same in 2024.

3. O&M Scope and Forecast Analysis

***Table IX-43*[169]**
PSPS Execution
O&M Authorized, Recorded, and Forecast by Sub-Activity
(Constant 2018 $000)

		Track 1 Authorized*	Recorded	Recorded	Recorded	Track 4 Forecast
	Subactivity	**2021**	**2019**	**2020**	**2021**	**2024**
1	PSPS Execution IMT	$282	$4,106	$4,076	$3,463	$3,463
2	PSPS Operations			$1,202	$5,511	$5,511
3	Line Patrols	$10,196	$9,159	$5,070	$3,266	$3,266
4	Mobile Generator Deployment	$1,724	$11	$2,214	$4,107	$4,107
5	Community Resource Centers	$1,278	$44	$924	$523	$523
6	Advanced Unmanned Aerial Systems Study	$101	$1	$158	$2	$2
7	PSPS Response & Compliance			$657	$1,022	$1,022
8	Town Hall Community Meetings	$447	$734	$141	$10	$10
	Total Expenses	**$14,027**	**$14,056**	**$14,442**	**$17,904**	**$17,904**

* Authorized 2022 and 2023 are equivalent to 2021 authorized (in constant 2018 dollars) after removing the impact of the Track 1 Decision's post-test year attrition mechanism

a) O&M Historical Variance Analysis

SCE was authorized $14.027 million in 2021, with the Commission adopting SCE's Track 1 cost forecast in full. Since the time of SCE's 2021 GRC application in August 2019, SCE determined that increased and dedicated resources had to be assigned to PSPS activities in order to effectively plan, manage and execute program activity that was not previously experienced at SCE.

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[169] Excludes Aerial Suppression sub-activity O&M costs, which are discussed in Chapter XI.

In 2021, SCE recorded $17.904 million in O&M expense. Much of the increased spending in 2021 was due to the staffing of PSPS Operations, though these increases were somewhat offset by underspending in PSPS-related line patrols (which recorded $3.266 million relative to the $10.196 million authorized, largely due to fewer PSPS events being called in 2021 than anticipated). SCE's recorded costs in 2021 were $5.511 million for PSPS Operations (the 2021 GRC-authorized amount was zero because this was not a forecast activity at the time). PSPS Execution Incident Management Teams (PSPS IMTs) were established with the necessary tools and technology to monitor ongoing weather and circumstances. SCE's 2021 recorded costs for PSPS Execution IMT were $3.463 million, compared against $282,000 authorized, and included labor and non-labor costs in support of the PSPS IMT activities. Specifically, SCE incurred unanticipated costs for additional full-time employees to address PSPS activities.

b) <u>Basis for Forecast</u>

While SCE's continued grid hardening work is expected to lead to a reduction in PSPS events, it is currently infeasible to quantify those anticipated reductions with any reasonable degree of precision given that PSPS events are dependent on weather and fuel conditions. Accordingly, SCE cannot precisely forecast how many PSPS events may occur in 2024, and currently anticipates the need to maintain and enhance its capabilities to response to PSPS events. It is also important to note that, while some activities like Line Patrols are PSPS frequency-dependent, others are not. Activities like PSPS Operations and PSPS Execution IMT include labor costs for full-time employees that work on PSPS, regardless of whether SCE is actively managing an event or not. Together, the PSPS Operations and IMT staff allow for subject matter experts to continually improve PSPS protocols and tools during non-event times, and then use those protocols and tools to most effectively respond to inclement weather that drives PSPS activation. Without these dedicated individuals, SCE would need to revert back to only using staff pulled from their ordinary day job to manage PSPS events, which would result in SCE losing important subject matter expertise that currently allows team members to continue focusing on PSPS protocols after events, allowing for improvement and refinement. Further, as is evident from SCE's experience in the 2021 fire season,[170] PSPS events can occur throughout the year and are not isolated to a particular "season" of the year. Going forward, the impacts of climate change, drought, and emergent weather conditions have the potential to exacerbate the year-round potential for PSPS events called to mitigate wildfire risk.

As the PSPS Execution work performed in 2021 is expected to be necessary in 2024, SCE based its 2024 forecast on 2021 recorded expenses. While individual sub-activity expenses in 2024 may increase or decrease relative to 2021 recorded costs, as a portfolio SCE anticipates its PSPS Execution 2024 expenses to be in line with 2021 recorded costs. In fact, 2024 expenses may be higher than 2021 recorded costs. As shown in SCE's 2022 WMP Update, SCE anticipates increased work in this area, and it is possible that expenses in 2024 may exceed the forecast provided in Track 4.

C. PSPS Customer Support

Electricity is an essential service. Disruption to this service can be detrimental to customers, and SCE does not take lightly decisions to de-energize customers for any amount of time. However, extreme weather conditions at times require SCE to consider proactively de-energizing overhead power lines to mitigate wildfire ignition risk. If we have to do this, SCE will activate its PSPS event process, which entails implementing a series of detailed notifications to our customers, public safety power partners, and other entities on potential PSPS activity.

Throughout the course of the year, SCE provides consistent and frequent messaging designed to build customer awareness and understanding of what a PSPS event is, how it could impact them, and encourage and aid customers to build their own resiliency plans for de-energization. SCE's PSPS Customer Support strategy uses a mix of communication channels to provide this awareness and information.

1. Summary of O&M Request

In 2024, SCE forecasts $19.113 million in O&M expense for this activity, which is less than SCE's 2021 recorded costs. SCE's forecast for 2024 for this activity is less than 2021 because SCE

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[170] There were 9 PSPS Events during the 2021 fire season -April; June; September; October (4 events); and November (2 events).

anticipates with the success of its Critical Care Backup Battery Program, expense for this program will decrease because the eligible unserved customer base will decrease.

This expense consists of various O&M sub activities, which are: PSPS 2-1-1 Service, Critical Care Backup Battery Program, In-Language Advertising & Translations, Surveys, Community-Based Organizations and Staffing, Customer Research and Education, eMobility Phase 2, PSPS Newsletter, Portable Power Station Rebate Program, Resiliency Zones, Portable Generator Rebate Program.

2. Work Description and Need

a) PSPS 2-1-1 Service

D.21-06-034 requires electric IOUs to administer a program to support resiliency for customers with Access and Functional Needs (AFN) in preparation for and during the anticipated duration of a PSPS event.[171] As a result, the electric IOUs developed the PSPS 2-1-1 Service pilot as a statewide solution that provides 24 x 7 live support during PSPS events, providing information and referrals to resources for customers with AFN. PSPS 2-1-1 Service connects customers with AFN who are experiencing a PSPS event to direct services such as shelf-stable food, hot meal delivery, transportation, and/or temporary shelter. When not providing assistance during PSPS, 2-1-1 focuses on outreach to at-risk customers, focusing on those customers with AFN who are living in SCE's HFRA. PSPS 2-1-1 Service's focus during periods in which a PSPS event is not taking place is to evaluate resiliency plans of customers with AFN, connect them with existing programs that can help them prepare for outages, and assist them in completing applications for SCE programs such as CARE/FERA, Medical Baseline, etc. SCE's partnership with 2-1-1 can also connect customers with community-based organizations (CBOs) across its service area. These CBOs offer social services to the community that may mitigate the impact of PSPS (*e.g.*, an organization that could lend a battery to power accessible technology or a food pantry to replace spoiled food.)

[171] *See* D.21-06-034, p. A.10.

SCE launched the pilot in August 2021 and began providing 24 x 7 live support to customers during PSPS events in October 2021. From inception to December 2021, PSPS 2-1-1 Service has provided active PSPS response to 147 SCE customers, 34 of which have been confirmed to be customers with AFN. Additionally, PSPS 2-1-1 Service has screened about 9,000 SCE customers who meet AFN criteria; therefore, these customers are eligible for Care Coordination, a component of PSPS 2-1-1 Service, which helps customers plan for PSPS events and enroll in other SCE programs and rebates (*e.g.*, Medical baseline, CARE/FERA, etc.). Approximately one thousand SCE customers expressed interest in Care Coordination.

SCE incurred $1.526 million in 2021 for the development and administration of the PSPS 2-1-1 Service pilot. While pilot development costs will not reoccur in 2024, the pilot will provide services for the full year moving forward, which includes project administration costs, system mapping, database enhancements, needs screening, resiliency planning, and live response, as either required by D.21-06-034 or recommended via feedback from the Statewide AFN Council. Although PSPS 2-1-1 Service is a pilot program with an end date of August 2023, SCE anticipates that it will still administer a program to support resiliency for customers with AFN in preparation for and during the anticipated duration of a PSPS event as required by D.21-06-034. SCE's 2024 O&M forecast for this service for AFN customers aligns with recorded 2021 costs because SCE anticipates providing the same service to at-risk customers.

b) Critical Care Backup Battery (CCBB) Program

In October 2019, Governor Newsom signed SB 167 into law, which authorizes electrical corporations to deploy backup electrical resources or provide financial assistance for backup electrical resources to those customers receiving medical baseline allowances and who meet specified requirements. In July of 2020, SCE launched the Critical Care Backup Battery (CCBB) program to provide a battery-powered portable backup solution to operate critical medical equipment during power outages due to PSPS events or other emergencies. The CCBB program addresses the needs of SCE's income-qualified Medical Baseline (MBL) customers residing in HFRA by fully funding the cost of a battery-powered portable backup solution to operate medical equipment during PSPS events.

In 2021, SCE expanded the CCBB program to include customers who are 1) enrolled in MBL; 2) enrolled in either the CARE or FERA program; and 3) that reside in the HFRA.[172] Additionally, SCE increased program awareness through marketing and outreach by utilizing direct mail, outbound phone calls, door knocking, and through increased engagement with CBOs to help inform and educate their community members.

Since launching the CCBB program in 2020, SCE has enrolled over 6,900 customers in the program, and has deployed over 6,700 free portable back-up batteries to eligible customers. In 2020, SCE deployed approximately 700 portable back-up batteries at a cost of $2.332 million. SCE made significant progress in the CCBB program in 2021. Between January 2021 and December 2021, SCE deployed over 6,000 free portable backup batteries to eligible customers, resulting in SCE incurring $19.352 million in expense in 2018 constant dollars. Due to the success of the program, SCE anticipates that expense for this program will decrease in 2024 to $6.397 million because the eligible unserved customer base will continue to shrink as the program grows. SCE will continue to offer the CCBB program to newly identified eligible customers, will deploy backup batteries to all eligible customers who choose to participate in the program, and will adjust the program outreach and strategy as needed to serve all eligible customers.

SCE did not include CCBB in its Track 1 request, and therefore the Track 1 Final Decision did include funding for this program.

c) Customer Contact Center Support

SCE's Customer Contact Center provides support to customers during PSPS events by answering questions, providing resource information, resolving concerns, addressing emergency issues, escalating potential issues that arise as needed, and delivering safety messaging to keep the public safe. SCE also leverages contract call center vendors to handle outage calls and deliver safety messages. SCE's Customer Contact Center must be available to respond customers during PSPS events and may require extended scheduled work hours for staff to ensure response times are reasonable.

[172] Critical Care MBL is a subset of MBL. Prior to February 2021, customers eligible for CCBB had to be 1) enrolled in Critical Care MBL, 2) enrolled in either the CARE or FERA program, and 3) reside in the HFRA.

The 2021 recorded costs for PSPS Customer Contact Center Support were $0.007 million due to a lower volume of PSPS-related outage calls. The actual 2021 call volume for PSPS events was just over 3,000 calls, compared to approximately 45,000 PSPS calls in 2020. Using the Last Year Recorded methodology based on 2021 actuals, SCE forecasts $0.007 million for Customer Contact Center Support for 2024.

d) Community Outreach and In-Language Advertising & Translations

SCE seeks to continuously increase customer awareness and understanding of PSPS events and how to prepare for them. As part of these efforts, SCE ran a multilingual advertising campaign in 2021. The campaign's objective was to educate customers and the public on PSPS, including the conditions that trigger a PSPS, how to prepare for a PSPS and other emergencies, SCE's actions to mitigate the risk of wildfires, and programs and resources for customers impacted by PSPS. It included newspaper, radio, digital, social media, search ads and direct customer mailings.

The 2021 PSPS advertising campaign achieved over 832 million impressions. The year-end customer awareness of the campaign was at 60%, above SCE's internal 2021 goal of 50%, and the customer perception that SCE takes proactive measures to protect communities from wildfires was at 67%, above the 2021 goal of 64%. The 2021 advertising campaign was translated into 19 languages. The total campaign spending was $7.011 million, of which $2.119 million was incurred from in-language advertising and translation.[173] SCE forecasts the same expenses in 2024 for continued work in this area.

e) Surveys, Community-Based Organizations, and Staffing

In 2021, SCE conducted pre- and post-season surveys to evaluate the effectiveness of its wildfire safety and preparedness communications and outreach to customers in general. These pre- and post-season surveys were offered to customers in 19 languages in addition to English. In addition, SCE continued to partner with an extensive network of CBOs enlisted to conduct in-language wildfire safety/PSPS preparedness customer education and outreach throughout its service

[173] Execution activities under Community Outreach are funded through the GRC Activity PSPS Execution, while translation-related work is funded through the GRC Activity PSPS Customer Support.

area, with particular emphasis on HFRA. Approximately 50 CBOs that conducted outreach in HFRA were incentivized according to SCE's pay-for-performance framework. SCE also incurred expenses for management of the wildfire-specific CBO performance-based compensation, cross-IOU collaboration, and other critical functions and work required to comply with the Commission-mandated prevalent language requirements as set forth in D.20-03-004.

In 2021, SCE recorded $0.733 million in O&M costs and anticipates continuing this work in 2024. As such, SCE's 2024 forecast aligns with recorded 2021 costs.

f) Customer Research and Education

SCE engages in customer research and education to understand how best to educate customers at the right time and through the right channels regarding wildfire mitigation activities, in particular PSPS. SCE procures algorithm-based predictive demographic data from information compiled by Acxiom, a third-party company that collects demographic data. SCE uses the data to develop a complete picture of SCE customers impacted by PSPS events and to better understand SCE's customers' attitudes and perceptions of PSPS events so that SCE can enhance targeted communication. SCE also conducts tracking studies to measure and track customer awareness and preparedness of customers during a PSPS event, as well as measure the impact and effectiveness of SCE's communication efforts. In addition, after a PSPS event, impacted customers are sent a Voice Of the Customer (VOC) survey requesting their feedback on how SCE can improve the PSPS experience. The survey results are sent to a vendor, and the vendor conducts analysis on the data and reports customer sentiment towards PSPS and identifies improvement opportunities. In 2021, SCE incurred $0.840 million in costs for the activities discussed above, as well as costs to develop an AFN customer education outreach flyer; to develop an online self-certification form for SCE's customers who have not signed up for SCE's MBL program or are not themselves eligible but have someone in their household who would be significantly impacted by the interruption of power during a PSPS event; and to begin the development of automated personalized communications, which would automatically send out communications based on event triggers.

SCE's 2024 forecast of $0.840 million O&M forecast for Customer Education and Outreach efforts was developed using the Last Year Recorded methodology based on 2021 recorded costs, as the activities and associated costs are representative of the work we expect to perform in 2024.

g) eMobility Phase 2

The PSPS OIR Phase 2 Decision (D.20-05-051) required the IOUs to implement pilot projects to investigate the feasibility of mobile and deployable electric vehicle Level 3 fast charging for areas impacted by PSPS events.[174] SCE investigated the commercial availability of a mobile electric vehicle chargers (MEVC) and found that no off-the-shelf MEVC existed that met SCE needs. A request for information (RFI) and subsequent request for qualifications (RFQ) were released and awarded in 2021 for the development of a custom solution to pilot and test safe and reliable mobile electric vehicle charging in areas impacted by PSPS events. The vendor selected, PowerFlex, has been working closely with SCE on the design specifications of the MEVC through 2021, resulting in SCE incurring $0.050 million in 2021 O&M expense. SCE forecast $0.050 million in 2024 for the use of MEVC that is under development. SCE's 2024 forecast uses the Last Year Recorded methodology based on 2021 recorded costs, consistent with how SCE has forecasted O&M spend across other categories.

h) PSPS Newsletter

In Q2 2021, SCE's PSPS Newsletter was sent to all SCE customers in both HFRA and non-HFRA, with content specific for those in HFRA. The HFRA version of the Newsletter focused on SCE's PSPS decision-making factors. The non-HFRA version focused on emergency preparedness and included an overview of PSPS. Both versions provided an update on SCE's wildfire mitigation efforts, emergency preparedness websites and ways to sign up for alerts and helpful customer programs, including Medical Baseline. A list of SCE customer service contact numbers and website pages was also included. Electronic copies of the newsletter versioned in the 19 languages prevalent in SCE's service territory were made accessible to customers via SCE's Wildfire Communications Center on sce.com.

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[174] *See* D.20-05-051, Appendix A, p. 7.

In August 2021, SCE sent a bilingual letter and flyer requesting master-metered customers (*i.e.*, landlord/property owner) to educate their sub-metered tenants about wildfires and provide PSPS information including steps they can take to prepare in advance and stay safe during a PSPS outage. The mailing included seven copies of the bilingual tenant education flyer. Electronic copies of the flyer in English, Spanish, Chinese, Vietnamese, Korean and Tagalog were made accessible to customers via SCE's Wildfire Communications Center on sce.com. SCE also sent periodic "Dear Neighbor" letters to customers most frequently impacted by PSPS to provide important updates regarding SCE's efforts to strengthen the grid and reduce the number of PSPS events.

In 2021, SCE spent $1.818 million on these activities. The majority of the 2021 recorded costs for this activity are associated with sending the above-mentioned PSPS Newsletter to all ~5 million customers in SCE's service area.

In 2024, SCE forecasts $1.818 million in costs for PSPS Newsletter, which is the same as 2021 recorded expenses. This funding will enable SCE to maintain and expand vital communications to customers serviced by impacted circuits. SCE anticipates it will continue to implement many of these same communication tactics going forward, but also recognizes the need for flexibility to identify and implement new communications opportunities that will help to ensure customers stay informed about PSPS preparedness and SCE's PSPS-driven grid hardening efforts. SCE will continue to receive feedback from our customers and work with all of our stakeholders through the WMP process to identify and implement new communications opportunities to keep our customers informed.

i) <u>Portable Power Station Rebate Program</u>

The Portable Power Station Rebate Program, previously called the Residential Battery Station Rebates, provides up to five $75 rebates to customers for purchasing a portable power station for their general home or small business resiliency needs. This program was initiated when SCE identified the need for battery backup to power small electronics including lighting, TVs, routers and modems, as well as the ability to charge devices such as cell phones, laptops and tablets in the event of an extended outage such as a PSPS event. The Portable Power Station Rebate Program is available to all

SCE customers residing in a HFRA or served by circuits passing through HFRA that may benefit from having a battery backup for their home resiliency and electric device charging needs. As of December 31, 2021, SCE issued 1,761 Portable Power Station rebates.

In 2021, SCE recorded $0.174 million in O&M costs for this program and based its 2024 forecast on 2021 recorded expenses. SCE will continue to assess the effectiveness of the portable battery rebate program to identify opportunities to enhance the offering as appropriate. Consideration will be given to adjustments to the rebate amount, eligibility criteria, and the list of eligible products.

j) Resiliency Zones

SCE developed the Resiliency Zones Pilot program in 2020 to target remote communities impacted by multiple PSPS events in 2019.[175] The Pilot funded the cost of switching infrastructure and deployment generator costs for up to three customers in each remote community (for a total of 21 sites) providing essential services (fuel, mini-mart, pharmacy, etc.). The Pilot also sought the support of County and Community leaders to identify customers for participation in the Pilot.

SCE executed four agreements in 2020 and continued to target the remote communities identified in 2019. In 2021, SCE executed four additional Resiliency Zone agreements for sites located in Bridgeport, Lee Vining, Mammoth Lakes and Stallion Springs for a total of eight Resiliency Zone sites. Construction on the last is expected to be completed in Q2 2022.

The eight Resiliency Zone sites are located in the following remote communities:

- Three in Agua Dulce (contracted in 2020)
- One in Cabazon; (contracted in 2020)
- Two in Bridgeport/Lee Vining; (contracted in 2021)
- One in Mammoth; and (contracted in 2021)
- One in Tehachapi (contracted in 2021).

SCE will not pursue new customers in 2022 but will continue to incur costs for the existing customers for generators deployed during PSPS events. Funding to support these generator

[175] Acton and Agua Dulce (Los Angeles County); Tehachapi (Kern County); Mammoth and Bridgeport/Lee Vining (Mono County); Cabazon and Idyllwild (Riverside County).

deployment costs will be needed through February 2027. SCE forecasts the funding required to support these eight Resiliency Zone sites in 2024 is $1.22M, however following the 2021 last year recorded methodology SCE is requesting $0.242 million in O&M for the deployment of generators during PSPS events.

k) Portable Generator Rebate Program

The Portable Generator Rebate program, previously called the Well Water Generator Incentive, was developed to assist customers residing in HFRA and impacted by a PSPS event by offsetting the cost of purchasing a portable backup generator. During community meetings facilitated by SCE in 2019 and 2020, specifically in areas dependent on electricity to pump water, SCE learned that some customers may not be able to access water during PSPS de-energizations. SCE launched this program initially in June 2020 by offering a $300 rebate on the purchase of a qualified backup generator, and further enhanced the rebate amount to $500 for income-qualified customers (*e.g.*, those enrolled in CARE or FERA). In July 2021, SCE revised the program eligibility requirements and rebate amounts, based on customer survey feedback. The water pumping dependency eligibility requirement was removed and enrollment in the MBL program was added to increase accessibility. The rebate was reduced from $300 to $200 to support increased customer participation due to the removal of the previous limit on eligibility to water pumping dependency customers.

SCE targets customers living in HFRA communities or surrounding communities that receive their power from a circuit fed from a HFRA circuit, whose electrical needs may extend beyond the limited power supply offered by a portable power station. As of December 31, 2021, SCE issued 666 Portable Generator rebates.

In 2021, SCE recorded $0.316 million in O&M costs to support the Portable Generator Rebate program. SCE will continue to assess the effectiveness of the rebate program to identify opportunities to enhance the offering as appropriate. Consideration will be given to adjustments to the rebate amount, eligibility criteria, and the list of eligible products. SCE's 2024 cost forecast to support the Portable Generator Rebate program is $0.316 million for future program enhancements to address customer needs.

3. O&M Scope and Forecast Analysis

Table IX-44[176]
PSPS Customer Support
O&M Authorized, Recorded, and Forecast by Sub-activity
(Constant 2018 $000)

		Track 1 Authorized*	Recorded	Recorded	Recorded	Track 4 Forecast
	Subactivity	**2021**	**2019**	**2020**	**2021**	**2024**
1	PSPS 2-1-1 Service				$1,526	$1,526
2	Critical Care Battery Backup Program			$2,332	$19,352	$6,397
3	Customer Contact Center Support	$2,997			$7	$7
4	Community Outreach and In-Language Advertising & Translations		$4,403	$5,706	$7,011	$7,011
5	Surveys, CBO, and Staffing			$497	$733	$733
6	Customer Research and Education	$5,759	($633)	$1	$840	$840
7	eMobility Phase 2				$50	$50
8	PSPS Newsletter	$3,604	$17	$1,650	$1,818	$1,818
9	Portable Power Station Rebate Program			$47	$174	$174
10	Resiliency Zones			$17	$242	$242
11	Portable Generator Rebate Program	($0)		$228	$358	$316
	Total Expenses	**$12,360**	**$3,787**	**$10,477**	**$32,110**	**$19,113**

* Authorized 2022 and 2023 are equivalent to 2021 authorized (in constant 2018 dollars) after removing the impact of the Track 1 Decision's post-test year attrition mechanism

a) Historical Variance Analysis

The 2021 recorded costs for PSPS Customer Support are approximately $32.110 million in O&M, as compared to $12.360 million authorized in Track 1. In 2021, SCE substantially increased its efforts to build awareness and reduce impacts to customers of PSPS events. This, in part, resulted in a significant increase in its recorded costs compared to 2019-2020; SCE recorded costs of $3.787 million in 2019 and $10.477 million in 2020. SCE's increase in recorded costs was due to SCE's successful implementation of PSPS support programs such as the Critical Care Backup Battery Program ($19 million in 2021), the 2-1-1 Service pilot, and other programs and pilots to support customers during de-energization events. In addition, in 2021, SCE's recorded costs increased due to Commission compliance requirements, such as the-mandated prevalent language requirements as set forth in D.20-03-004.

[176] Table IX-44 excludes sub-activities PSPS Customer Care Project and Rate & Compliance Marketing as there are no associated authorized amounts or 2024 forecasts. Historical costs for these sub-activities can be located in WP SCE Tr. 4-01 - O&M Financial Mapping pp. 161 - 162 in the section Activities Excluded from Sub-Activity Tables. This workpaper also includes financial mapping.

b) Basis for Forecast

SCE based the PSPS Customer Support forecast of $19.113 on 2021 recorded costs because, with the exception of the Critical Care Backup Battery Program, SCE anticipates it will continue to prepare its customers for de-energization events initiated to reduce wildfire ignition risk. While individual sub-activity expenses in 2024 may increase or decrease relative to 2021 recorded, as a portfolio SCE anticipates its PSPS Customer Support 2024 expenses to be in line with 2021 recorded.

D. Technology Solutions

SCE continues to improve the PSPS programs and protocols to minimize the potential risk of wildfire from electrical infrastructure and minimize customer impacts through technology investments. PSPS remains an important wildfire mitigation tool of last resort that SCE employs to safeguard the customers and communities we are privileged to serve. The technology solutions described below directly align with that critical public safety mission. Regarding cost planning, the switch to primarily Software-as-a-Service (SaaS) technology solutions will generate a shift from capital expenditures to O&M expenses for ongoing operational costs.

1. Summary of O&M and Capital Request

SCE's O&M and capital requests for PSPS Technology Solutions are presented in Figure IX-41 and IX-42. The O&M requests of $4.720 million is based on Last Year Recorded 2021 and has been downwardly adjusted to account for the changes in scope for the Emergency Outage Notification System. SCE's capital requests of $5.530 million in 2024 is budget-based as discussed in detail below, most of the development and implementation work in IMT Customer Notification will be in years 2022 to 2023 for the Centralized Data Platform. The 2024 capital forecast is required to support the capability enhancements and stabilization of the Centralized Data Platform.

This activity consists of three O&M sub activities: Emergency Outage Notification System, IMT Customer Notifications, and SCE.com and Public Safety Partner Portal as further discussed below. It also consists of three capital sub-activities: HERMES, Centralized Data Platform, and SCE.com and Public Safety Partner Portal as further discussed below.

2. **Work Description and Need**

a) Emergency Outage Notifications System / IMT Customer Notifications

SCE provides event notifications to its stakeholders and customers and understands they have different needs and require varying methods of alerts and notifications. For example, Public Safety Partners (including first responders and local governments) require as much lead time as practical to begin contacting constituents and preparing to respond to potential de-energizations. To support this need, SCE provides priority notification to these agencies, as well as to critical facilities and infrastructure customers, between two to three days before a potential PSPS de-energization if weather conditions can be predicted this far in advance. This information is also posted to SCE.com three days in advance when possible. Additional alerts and update notifications to these agencies are then provided once a day to maintain operational coordination. SCE sends initial alerts and warning messages to other impacted customers up to two days in advance of a potential PSPS event via their preferred method of communication (e.g., text, e-mail, and voice call). Notifications are then made to these customers if there is updated information regarding the ongoing potential PSPS event.

The Emergency Outage Notifications System (EONS) is the primary tool used to keep customers informed before, during, and after emergency outages, including PSPS events. EONS allows SCE to communicate to all customer classes impacted by PSPS via their preferred channel, whether it is email, voice calls, and/or text messages. PSPS notifications translation are available in 23 languages. In 2021, SCE further enhanced the system to send notifications in the customer's preferred language, which they can select from the six core languages available in the new preference center.

b) HERMES

In 2022, SCE launched the Hazard Event Restriction and Management Emergency System (HERMES), which is a new technology to identify wildfire risk to the distribution system. A common use of HERMES will be to implement restrictions for parts of the system with a high risk of wildfires to lower the ignition risk from electrical system equipment. As a component of the Grid

Management System (GMS),[177] HERMES utilizes automation in the GMS by enabling GMS to recognize hazardous conditions in high-risk areas and execute optimized switching programs for PSPS de-energization events while deconflicting planned outages. HERMES will differentiate normal restrictions on parts of the distribution system from restrictions due to hazardous conditions associated with wildfire risk mitigation. These wildfire-related restrictions include event de-energization of the zone of concern (PSPS), limitations on field work, and imposing limits on certain automated devices (*e.g.*, reclosing, setting group behavior).

c) Centralized Data Platform (CDP)

SCE's goals in the 2021 PSPS Action Plan include improving data and reporting accuracy; establishing PSPS operational workflow, analytics and reporting; and enhancing the notification process and customer experience. SCE conducted an extensive review of all the ongoing IT processes and systems that support PSPS and identified the need for a CDP that would act as a foundation for PSPS data collection and help achieve the goals listed above. Based on the evaluation of potential solutions and vendors, SCE determined that Palantir was best suited to provide a CDP. In 2021, initial use cases, such as automating the Pre-Approved Monitored Circuit List (MCL) and the Period of Concern (POC) and visualization of weather forecast metrics, were implemented and began supporting operational PSPS activations. Additional use cases and enhancements are planned for 2022-23, and in 2024 work activities will involve completing enhancements based on evolving business needs such as simplifying architecture, removing complexities, adding automations, improving data validation and reporting accuracy, completing development of newly identified use cases, and supporting the stabilization phase.

d) SCE.com and Public Safety Partner Portal

SCE.com provides a dedicated, interactive, and informative webpage to help customers increase their awareness about PSPS, provide information about becoming more resilient

[177] GMS is an advanced software platform that integrates multiple electric system forecasting and analytics applications to enable grid operator to actively monitor and operate SCE's dynamic grid. The Commission adopted funding for GMS in D.21-08-036 (*see* COL 35).

during events, and receive up-to-date information regarding events in their area. Other information on SCE.com includes the impacts of de-energization, what resources are available during events and who the public should expect to hear from and when. The landing page is linked to other pertinent pages on SCE.com, such as the Outage Map, where PSPS-specific event information is available as well as information on activated CRCs and CCVs. The information provided on SCE.com is critical to SCE's customers and stakeholders. Based on the feedback collected in 2020 from surveys used to understand customer concerns, SCE found that customers had difficulty navigating its website for information about the outages. In 2021, SCE's PSPS Action Plan required SCE to deploy a series of features designed to make it easier for customers to access information. The changes for SCE.com include improving the consolidated outage map, providing current weather conditions and information from SCEs weather stations, and improving the PSPS alerts and customer preference flexibility options to enable customer engagement regarding wildfire-related risks and activities. SCE also deployed the seven-day PSPS Weather Awareness map. To help customers plan for a potential PSPS event, this map displays how counties in our service area could be affected by dangerous weather conditions up to seven days in advance.

Additionally, SCE's Public Safety Partner Portal launched in June 2021 offers Public Safety Partners the ability to register, view pertinent information related to PSPS events, as well as plan for PSPS events by leveraging the data provided in the Planning portion of the Public Safety Partner Portal. It is anticipated that the SCE.com enhancements listed above will be complete in 2022. Spending related to SCE.com in 2024 will consist primarily of O&M for operations/maintenance support and subscription services.

3. O&M Scope and Forecast Analysis

Table IX-45
Technology Solutions
O&M Authorized, Recorded, and Forecast by Sub-Activity
(Constant 2018 $000)

		Track 1 Authorized*	Recorded	Recorded	Recorded	Track 4 Forecast
	Subactivity	**2021**	**2019**	**2020**	**2021**	**2024**
1	Emergency Outage Notification System	$847	$1,532	$2,624	$3,482	$2,300
2	IMT Customer Notifications				$369	$369
3	SCE.com and Public Safety Partner Portal			$2,592	$2,050	$2,050
	Total Expenses	**$847**	**$1,532**	**$5,216**	**$5,902**	**$4,720**

* Authorized 2022 and 2023 are equivalent to 2021 authorized (in constant 2018 dollars) after removing the impact of the Track 1 Decision's post-test year attrition mechanism

a) Emergency Outage Notifications System / IMT Customer Notifications

In 2021, SCE incurred $3.851 million in O&M expenses for messaging services, phased updates to the EONS platform, and operational support for PSPS IMT customer notification. The phased update to the EONS platform was a one-time effort in response to the PSPS Action Plan requirements and includes PSPS alerts, inbound Integrated Voice Response (IVR), phone number routing process to determine and flag landline versus mobile numbers, PSPS automation, and functional parity for languages. These upgrades were necessary to keep SCE's partners and customers clearly and consistently informed during PSPS events. As this was a one-time effort, SCE has made a downward adjustment of $1.182 million to SCE 2024 forecast. The remainder of the expenses incurred in 2021 are recurring operational costs, which include messaging service subscription fees and operational support. SCE will continue to have the same operational support and subscription fees in place; the costs recorded for these expenses in 2021 is a reasonable and appropriate forecast for 2024.

b) SCE.com and Public Safety Partner Portal

In 2021, recorded spending of $2.050 million in O&M expenses, including contract costs for ongoing extensive support from the initial 2019 SCE.com updates and material and subscription costs. As primarily a development year, SCE incurred more capital expenditures compared to O&M spend. Although this Track 4 filing uses 2021 recorded O&M expenses for the basis of the forecast, due to the capital phase-out and the shift to ongoing enhancement and support over the life of the project, SCE's actual 2024 O&M spend will likely exceed the 2021 recorded costs.

c) Historical Variance Analysis

The O&M spend for PSPS Technology Solutions increased from $2.592 million[178] in 2020 to $5.902 million in 2021. The increased spend was primarily driven by ongoing improvement efforts to support the customer experience, including the implementation of the messaging services, phased updates to the EONS platform, and operational support for PSPS IMT customer notification. In 2020, most of the O&M spend was for operational platform support for (1) the increased site capacity and resiliency efforts driven in large by the increased number of PSPS events in late 2019, (2) a back-up site in the event the primary site is unavailable, (3) public alert notification, and (4) multicultural communications resource repository (MCRR).[179]

d) Basis for Forecast

The 2024 forecast is based on the 2021 recorded expenses for this sub-activity, which is consistent with SCE's wildfire mitigation-related O&M forecasts throughout this Track 4. However, as shown in SCE's 2022 WMP Update, SCE anticipates increased work in this area, and it is possible that recorded costs in 2024 may exceed this forecast.

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178 Emergency Outage Notifications Systems was part of the GSRP Settlement Agreement for 2019 and 2020 (approved in D.20-04-013); therefore, those costs are excluded from the 2019 and 2020 recorded O&M spend.

179 MCRR is the SharePoint site that houses in-language versions of various PSPS-related customer communications that are accessible to customers via SCE's Wildfire Communications Center. This scope of work was completed by IT in December 2020 and moving forward the process to make PSPS-related in-language communications accessible to customers will be referred to by the term Wildfire Communications Center.

4. Capital Scope and Forecast Analysis

Table IX-46
Technology Solutions
Capital Authorized, Recorded, and Forecast by Sub-Activity
(Nominal $000)

		Track 1 Authorized					Recorded			Track 4 Forecast
	Subactivity	2019	2020	2021	2022	2023	2019	2020	2021	2024
1	HERMES						$1,181	$1,527	$24	$1,043
2	Centralized Data Platform							$3,631	$11,217	$1,203
3	SCE.com and Public Safety Partner Portal						$585	$2,346	$3,285	$3,285
4	In-Language Requirements							$1,134		
5	Community Resource Centers	$1,766	$1,234	$756						
	Total Capital	**$1,766**	**$1,234**	**$756**			**$1,766**	**$8,639**	**$14,526**	**$5,530**

a) HERMES

In 2024, $1.043 million of capital investment is needed to complete the development and rollout phase of HERMES, a new technology to identify wildfire risk to the Distribution system. This cost is based on supplier estimates and anticipated SCE effort for finalization of detailed design and conducting implementation of the HERMES application.

b) Centralized Data Platform

The 2024 forecast is $1.203 million of capital expenditures to support the stabilization phase, complete future scope and develop new use cases in support of improving functionality and the customer experience such as simplifying architecture, removing complexities, adding automations, and improving data validation accuracy.

c) SCE.com and Public Safety Partner Portal

In 2024, SCE will need $3.285 million in capital investment to continue to review and refine the PSPS digital experience. Based on the feedback collected from surveys after PSPS events, SCE determines website and outage map improvements necessary for customers to increase awareness of wildfire mitigation activities, receive up to date information regarding events and learn when an event is impacting their area. Website improvements will include digital user testing and research, content audit, end-to-end journey mapping, and user experience design improvements to deliver a simplified user experience for customers. Outage map improvements will include the design, development, and testing of new functionality. It will also include messages, copy, and graphical updates to better educate customers on how to use the outage tools.

d) Historical Variance Analysis

The capital expenditure for PSPS Technology Solutions increased from $1.766 million in 2019 to $14.526 million in 2021. The increase of costs in 2020 was a result of the lessons learned from the PSPS events in late 2019, which created a significant load on the SCE.com website. Most of the work was related to increasing the site capacity and ensuring site resiliency to provide necessary information to customers even during large events when many people may visit the site simultaneously. SCE made enhancements and improvements in the Customer Notifications space. The scope of these works includes the PSPS Incident Commander Dashboard, Operational Data and GIS improvement, and Customer Notifications Enhancements. In addition, SCE developed a back-up site as an alternative in case the primary SCE.com site was not available. These ongoing enhancements and improvements continued into 2021. A significant contributor to the capital increase from 2020 to 2021 was the 2021 PSPS Action Plan, which identified the need for a CDP as the foundation for PSPS data collection.

e) Basis for Forecast

The 2024 capital forecast of $5.530 million for the projects within this activity was developed using SCE's internal cost estimation model. This cost estimation model was utilized to forecast SCE's IT capitalized software projects in Track 1 of this proceeding, which the Commission adopted in its entirety. This model utilizes industry best practices and SCE subject matter expertise to estimate project cost components. SCE's forecast for these projects includes cost for SCE employees, supplemental workers, and consultants, as well as software and vendor costs, and hardware costs.[180]

[180] See WP SCE Tr. 4-02 PSPS Technology Solutions, pp. 26 - 28.

X.

AERIAL SUPPRESSION

A. Overview

Since 2017, there have been multiple concurrent wildfires throughout California which have stretched the pool of aerial firefighting assets available in SCE's service area at critical times. The existing agency resource constraint has led to aerial firefighting (also referred to as aerial suppression) assets routinely being deployed outside of SCE's territory. The limited availability of fire agency resources has hindered fire suppression activities and increased the potential for major wildfires, putting SCE's customers, communities and infrastructure at greater risk. To address the challenge of limited locally available aerial firefighting assets, SCE has partnered with local county firefighting agencies since 2019 to create a quick reaction force (QRF) of aerial firefighting resources.

As part of this partnership, SCE funds up to five aerial firefighting helicopters, support personnel and equipment to bolster firefighting capabilities.[181] SCE's funding of "stand-by time"[182] contractually obligates these resources to be dedicated to the SCE service area during local fire events. Aerial firefighting assets are a key fire suppression tool, and SCE intends to continue working with county fire agencies to optimize the QRF program in 2024. Southern California is unique in that five of the six counties CAL FIRE contracts with to provide firefighting in state responsibility areas (SRAs) are within southern California (Santa Barbara, Ventura, Kern, Los Angeles, Orange). The fact that these are "contract counties" means they have the authority to act independently, or in this case as a collective group, to make changes in processes such as ordering and deploying resources.

These resources are capable of being deployed by these agencies virtually anywhere in SCE's service area, individually or all together. While aerial suppression resources will not be able to stop a fire at the onset, they have proven extremely effective at reducing the area of and assets burned and enabling faster response times. In addition, aerial suppression resources help lower emergency response

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[181] The O&M cost for Aerial Suppression is found under PSPS Execution but the work is discussed as a standalone Chapter here.

[182] Stand-by-time is the cost for all program resources to be available to use at their designated base locations throughout SCE service area, since they are unavailable for assignment outside of SCE's service area.

support costs and help minimize the impact of redirecting work crews from previously scheduled maintenance and construction work to emergency response.

B. Summary of O&M Request

The 2024 forecast is equal to the 2021 recorded expense of $17.492 million. As discussed in SCE's 2022 WMP Update,[183] SCE has collaborated with the stakeholders in the QRF and determined that an additional fire suppression helitanker would add value to this activity, so it is possible that expenses in 2024 will exceed this forecast based on the recommendations from the fire agencies. Under SCE's current plans, in 2024 Ventura County Fire Department's proposal to SCE will replace the leased Sikorsky-61 helitanker with a leased CH47 helitanker, resulting in increased costs. The agencies' proposed QRF model was to standardize all three large helitankers across Los Angeles, Orange and Ventura counties. This was not possible in 2021 or 2022 due to Coulson Aviation's[184] inability to provide a third equipped night-flying CH-47 for Ventura County. In addition, in 2021 SCE and its county partners learned that additional pilots would be needed in 2022 to support 24/7 operations, as well as an additional program manager to facilitate coordination with aerial assets among the counties. This too may increase cost pressures going forward for these indispensable assets.

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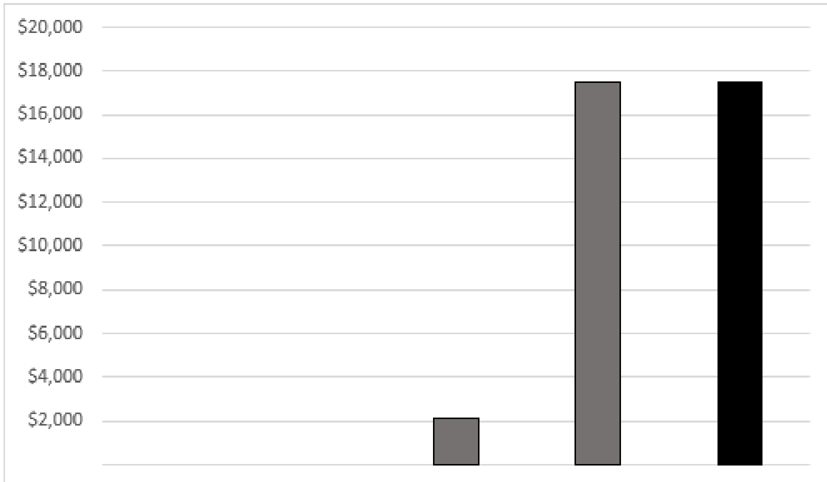
[183] The 2021 and 2022 WMP Section 7.3.10.3 discusses Aerial Suppression in detail.

[184] Leasing company for CH-47 helitanker.

Figure X-42[185]
O&M Summary
Aerial Suppression
O&M Authorized, Recorded, and Forecast
(Constant 2018 $000)



Track 1 Authorized*	Recorded			Track 4 Forecast
2021	2019	2020	2021	2024
-	-	$2,144	$17,492	$17,492

		Track 1 Authorized*	Recorded	Recorded	Recorded	Track 4 Forecast
	Subactivity	2021	2019	2020	2021	2024
1	Aerial Suppression			$2,144	$17,492	$17,492
	Total Expenses				**$17,492**	**$17,492**

* Authorized 2022 and 2023 are equivalent to 2021 authorized (in constant 2018 dollars) after removing the impact of the Track 1 Decision's post-test year attrition mechanism

1. <u>Work Description and Need</u>

Due to the limited availability of fire suppression resources available statewide, in 2021 SCE partnered with Los Angeles, Ventura, and Orange Counties to support their proposal to fund the stand-by time of up to five aerial suppression resources to reduce wildfire risk to SCE's system and help protect SCE's infrastructure and communities. SCE established a Memorandum of Understanding (MOU) funding agreement with each fire agency, pursuant to which SCE funds the cost of stand-by time for the helicopters, and each fire agency pays for flight time when the helicopters were used to fight

[185] Aerial Suppression is included in the PSPS Execution GRC Activity.

fires. Starting in 2021 and continuing on an annual basis, SCE consults with CAL FIRE contract county fire agencies (Orange, Los Angeles, Ventura, Kern and Santa Barbara County fire departments) on the optimal placement and use of the aerial suppression resources. However, operational decisions regarding where and when the assets are used is at the discretion of the individual fire agencies and are prioritized and deployed by a regional fire coordination center. The MOU specifies "use parameters" to ensure that the aerial suppression resources are supporting initial, incipient stage, and extended attack missions within the SCE service area. A regional fire agency coordination center maintains responsibility for directing the aerial suppression resources, using their existing prioritization and deployment process.

SCE will continue to monitor the access to aerial resources in SCE's service area and will revisit its approach annually to determine if SCE's approach in providing support should be adjusted based on the availability of statewide suppression assets. In 2021, SCE funded four aircraft and support resources (fuel truck, bus, maintenance staff, equipment etc.) based on the counties' proposal, which SCE plans to continue in 2024. In 2022, SCE will scale the program as needed up to five aircraft and support resources based on fire agencies' 2021-2022 proposals that indicate this is the optimal configuration. SCE assumes this will continue to be the case in 2024.

In 2021, there was a total of 1,369 drops on 56 different fire incidents. In 2021, the QRF made the first ever helicopter retardant hover fills and retardant drops on a fire in the U.S. Due to the fact that wildland fire spread and activity decreases at night because of higher humidity and lower wind speeds compared to daylight hours, the QRF is able to make significant progress in containing fires at night. There were 2,975,033 gallons of water dropped in total – with 1.1 million of those gallons dropped at night. The fleet also dropped 139,373 gallons of fire retardant with 38,786 gallons dropped at night, helping significantly reduce the consequences of wildfires, particularly wind-driven wildfires, in California.

C. O&M Scope and Forecast Analysis

Table X-47
Aerial Suppression
O&M Authorized, Recorded, and Forecast
(Constant 2018 $000)

		Track 1 Authorized*	Recorded	Recorded	Recorded	Track 4 Forecast
	Subactivity	**2021**	**2019**	**2020**	**2021**	**2024**
1	Aerial Suppression			$2,144	$17,492	$17,492
	Total Expenses				**$17,492**	**$17,492**

* Authorized 2022 and 2023 are equivalent to 2021 authorized (in constant 2018 dollars) after removing the impact of the Track 1 Decision's post-test year attrition mechanism

1. Historical Variance Analysis

In 2020, SCE's incurred $2.144 million in expense for a lease to fund stand-by-time for a Coulson-Unical CH-47 helitanker, beginning October 1 through late December, for use by OCFA (as discussed above). In 2020, SCE funded the stand-by time for a CH-47 helitanker for use by the Orange County Fire Authority (OCFA). The CH-47 is the world's largest and most capable heavy-lift fire helicopter, able to drop 3,000 gallons of water or retardant in a single pass. The twin-engine, tandem rotor helicopter is being leased from and is operated by Coulson Aviation.

In 2021, SCE's aerial suppression expense increased significantly to $17.545 million as SCE initiated the partnership with the Los Angeles, Orange, and Ventura County Fire Departments and began to contribute funding to the QRF. The MOU amount of $17.545 million includes a credit of $935,000 for the ten days the QRF was deployed outside of SCE's service area (i.e., total costs of $18.480 million minus 10-day credit of $935,000). SCE initially paid $15.675 million for a 150-day lease period and extended it for additional 30 days with extended lease amount of $1.870 million for net 20 days inclusive of the 10-day credit as described below.

Table X-48
2021 QRF Recorded O&M Costs
(Nominal 2021$)

Number	County	MOU Amount 2021	Lease Period	Extension Period	Lease Amount for extension
1	Los Angeles County Fire Department	$4,800,000.00	150 days	20 days	$640,000.00
2	Orange County Fire Authority	$7,725,000.00	150 days	20 days	$810,000.00
3	Ventura County Fire Department	$3,150,000.00	150 days	20 days	$420,000.00
	Sub Total	**$15,675,000.00**			**$1,870,000.00**
	Grand Total	**$17,545,000.00**			

Table X-49
Extension - for 20 days (10 days credit for fires in northern California firefight)

Number	Asset Type	Cost per day	Quantity	30 days	20 days	County
1	S-61 1000Gal. Helitanker	$21,000.00	1	$630,000.00	$420,000.00	Ventura County
2	CU47D Very Large Helitanker and support (fuel truck)	$32,000.00	1	$960,000.00	$640,000.00	Los Angeles County
3	S&76 helicopter (coordination)	$10,000.00	1	$300,000.00	$200,000.00	Orange County
4	ATGS/HLCO	$4,000.00	1	$120,000.00	$80,000.00	Orange County
5	Portable Retardant Plant and 12 hr supply of retardant	$5,500.00	1	$165,000.00	$110,000.00	Orange County
6	S-61 1000Gal. Helitanker	$21,000.00	1	$630,000.00	$420,000.00	Orange County
	Total	**$93,500.00**		**$2,805,000.00**	**$1,870,000.00**	
	10 days Credit for fires in N. CA fireflight	$935,000.00				

2. <u>Basis for forecast</u>

At the time SCE filed its 2021 Track 1 request in 2019, SCE did not anticipate the availability of the QRF partnership, and thus there is no authorized funding for this activity. However, the QRF partnership is valuable to SCE customers and our communities. In 2021, the QRF of aerial resources were effective at suppressing fire activity, based on helitanker performance reports and feedback from the fire agencies as quoted below.

> We found the QRF to be highly effective and a large contributor to the ground resources working the fire line at night," wrote Chad Cook, an Assistance Fire Chief for VCFD, and Operations Section Chief for California Incident management team 1 in a post-event report for the Alisal fire. "Our operational ground resources felt the support of fire suppression activities after dark yielded higher production rates.

> Climate change continues to affect the wildland fire environment in ways never before experienced," said OCFA fire chief Brian Fennessy, an early and consistent supporter of the utility-fire agency partnership. "Speed and force are key to successfully suppressing wildfires while small and before becoming mega fires.[186]

We also saw the additional benefits and effectiveness of the Coulson-Unical CH-47 helitanker, which has the capacity to carry three times more water or retardant compared to the smaller Sikorsky-61 helitanker. In 2022, SCE plans to continue with the 2021 configuration of the QRF of aerial resources, which included two CH-47 helitankers, one Sikorsky-61 helitanker, one Sikorsky-76 intelligence and recon helicopter and a mobile retardant base.

In 2024, SCE anticipates continuing the successful QRF partnership, and as a result, spending at least as much in 2021 plus yearly cost increases due to the increase in operational costs in each year. Therefore, the 2021 recorded amount is an appropriate forecast for 2024 costs for the Aerial Suppression activity.

[186] https://energized.edison.com/stories/heavyweight-firefighting-aircraft-knocks-out-emerging-wildfires

XI.

ENHANCED SITUATIONAL AWARENESS

A. Overview

Comprehensive situational awareness is fundamental to SCE's operational decision-making, service delivery and all-hazards emergency response. To increase situational awareness, SCE created the Situational Awareness Center (SA Center) where weather forecasts, analytics, and hazard advisories to support the execution of core business functions are developed. Additionally, the Fire Sciences team has two fire meteorologists who assess fire potential daily and provide fire spread modeling analytics during PSPS events and otherwise upon request, along with meteorologists on the weather services team. Enhanced situational awareness provides a better understanding of the nuances associated with critical system operations, including granular weather conditions across the system and other external factors that affect the daily operation of the grid and increases SCE's ability to effectively respond to emergencies. Additional tools, including access to high resolution weather and fire modeling products, made possible through high-performance computing cluster (HPCC) technology, are utilized by SCE's Fire Science team and meteorologists to enhance situational awareness. These tools increase SCE's capacity to better forecast elevated weather conditions and potential wildfire activity, which in turn leads to better decision-making information during regular operations and emergencies and are used by our fire management officers.

Since inception of the weather station program in 2018, SCE has installed more than 1,400 weather stations across its service area. In 2021, SCE continued to progressively deploy hundreds of additional weather stations to enhance situational awareness and increase predictive modeling capabilities regarding potentially dangerous winds and elevated fire potential. In addition to wind, fuel conditions play a very significant role in the determination of wildfire risk. This is particularly true of the more extreme dry fuel conditions that were experienced in 2020.

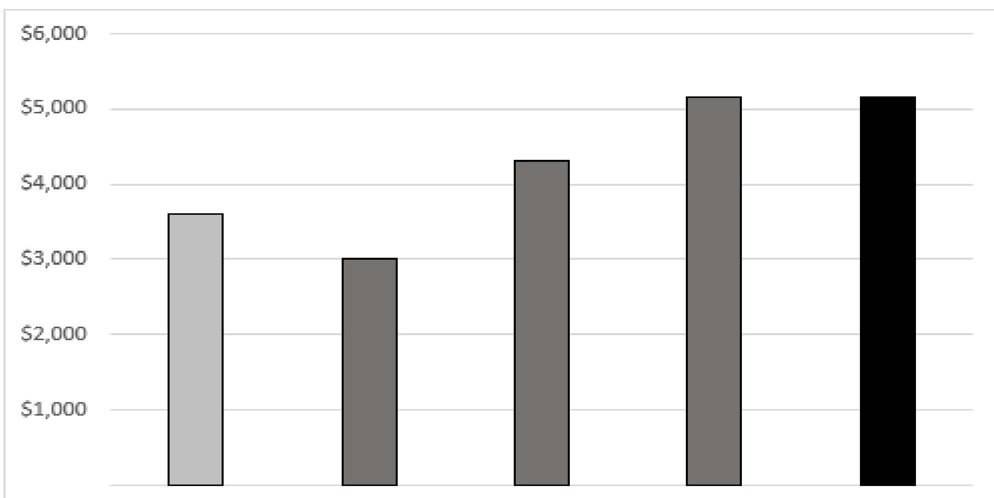
In 2022, SCE plans to deploy an additional 150 weather stations, as well as utilize machine learning (ML) to further advance our predictive modeling capabilities of potentially dangerous winds and elevated fire potential. SCE will also deploy up to 20 additional high-definition (HD) wildfire cameras to expand coverage in areas with limited viewshed capabilities due to differentiating factors such as topography, blind spots around SCE infrastructure, lack of visibility of wildland urban interface, to name a few; currently our cameras provide visibility to approximately 90% of our HFRA. SCE will also continue to enhance our fire spread modeling and other weather modeling applications to increase our situational awareness of weather, dry vegetation, and fire activity.

1. Content and Organization of Chapter

This chapter includes the initiative and activities related to HD cameras, Weather Stations, and Wildfire Response, Modeling, Analysis, & Weather Forecasting.

B. Summary of O&M and Capital Request

Figure XI-43
O&M Summary
Enhanced Situational Awareness
O&M Authorized, Recorded, and Forecast
(Constant 2018 $000)

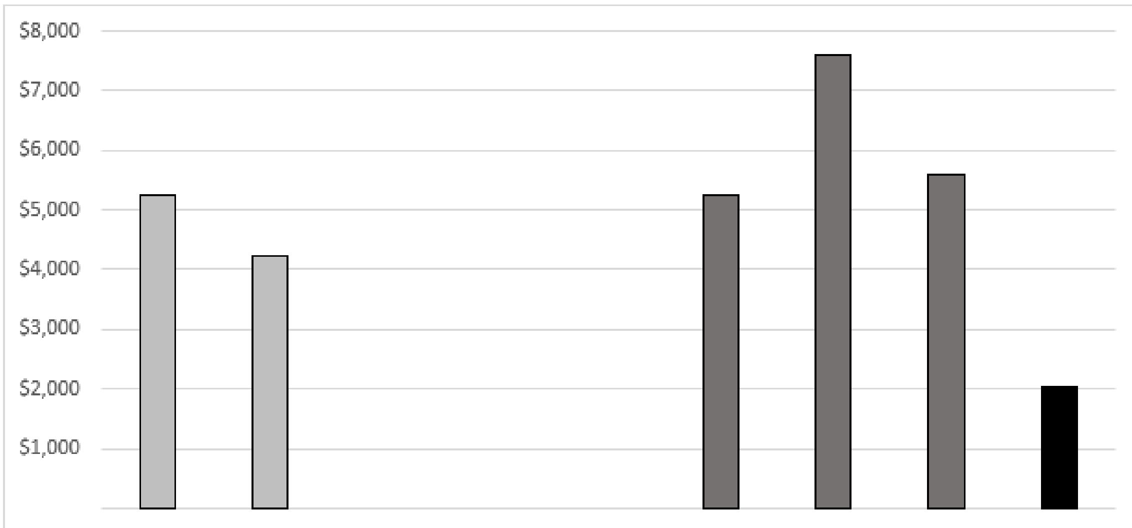


Track 1 Authorized*	Recorded			Track 4 Forecast
2021	2019	2020	2021	2024
$3,594	$3,016	$4,304	$5,149	$5,149

		Track 1 Authorized*	Recorded	Recorded	Recorded	Track 4 Forecast
	Subactivity	2021	2019	2020	2021	2024
1	HD Cameras	$1,651	$459	$2,177	$2,858	$2,858
2	Weather Stations	$1,463	$1,217	$2,019	$1,931	$1,931
3	Wildfire Response, Modeling, Analysis, & Weather Forecasting	$480	$1,339	$108	$360	$360
	Total Expenses	$3,594	$3,016	$4,304	$5,149	$5,149

* Authorized 2022 and 2023 are equivalent to 2021 authorized (in constant 2018 dollars) after removing the impact of the Track 1 Decision's post-test year attrition mechanism

Figure XI-44
Capital Summary
Enhanced Situational Awareness
Capital Authorized, Recorded, and Forecast
(Nominal $000)



Track 1 Authorized					Recorded			Track 4 Forecast
2019	**2020**	**2021**	**2022**	**2023**	**2019**	**2020**	**2021**	**2024**
$5,252	**$4,233**	**-**	**-**	**-**	**$5,252**	**$7,603**	**$5,607**	**$2,023**

	Track 1 Authorized					Recorded			Track 4 Forecast
Sub Activity	**2019**	**2020**	**2021**	**2022**	**2023**	**2019**	**2020**	**2021**	**2024**
HD Cameras	$970	$224				$970	$94		$130
Weather Stations	$4,282	$4,009				$4,282	$7,509	$5,607	$1,893
Total Capital	**$5,252**	**$4,233**				**$5,252**	**$7,603**	**$5,607**	**$2,023**

The Enhanced Situational Awareness forecast takes into consideration vendor contracts for HD cameras, Weather Station maintenance and service fees as well as labor costs for related sub- activities. In 2021, SCE recorded O&M expense of $5.149 million and capital expenditures of $5.607 million for HD cameras, Weather Stations, and Wildfire Response, Modeling, Analysis, & Weather Forecasting. In 2021, SCE installed 406 weather stations, 0 HD cameras, and incurred O&M expenses related to Wildfire response, Modeling, Analysis, and Weather Forecasting as discussed below.

SCE anticipates actual O&M expenses in 2024 to be above 2021 recorded costs but for purposes of this Track 4 is requesting the 2021 last year recorded amount. SCE's 2024 forecast is expected to exceed 2021 recorded amounts because SCE plans to expand this work, including Wildfire response, Modeling, Analysis, and Weather Forecasting staffing needs. O&M costs for the HD cameras are mainly driven by the data plan subscription and the annual maintenance expenses, meaning costs will increase as we add an anticipated 60 additional cameras to our network in years 2022-2024. Similarly, O&M costs for Weather Stations will increase due to adding 345 weather stations to the existing network, increasing the support services and data subscription plan-related costs.

SCE's Track 4 2024 capital forecast is $2.023 million dollars, which includes $0.130 million for HD cameras and $1.893 million dollars for Weather Stations. In 2024, SCE plans to install up to 20 new HD cameras and 55 weather stations across SCE's HFRA and may need to replace 115 weather stations as they reach the end of their natural lifecycles.[187]

C. Work Description and Need

1. Weather Stations

SCE's weather stations provide data such as sustained wind speed, wind gust speed, direction of wind, humidity, temperature, etc. Adding these microclimate monitoring capabilities to the SCE service area has increased our situational awareness for severe weather/high wind events and provides more granular data to existing weather forecast models. This microclimate weather station investment increases SCE's ability to safely and efficiently monitor adverse weather conditions related to electrical assets.

Observations from weather stations are key inputs into machine learning models. The machine learning models reduce forecast bias by using SCE's network to gain understanding of the typical forecast error in past events and applying that knowledge to future predictions from our in-house models. SCE's weather stations will also be used as part of an academic partnership geared towards improving situational awareness during PSPS and non-PSPS events. University collaborators will use SCE's network to derive a high-resolution (sub-kilometer) gridded observation source that can be procured in real time to aid in PSPS decision-making. The research and new output will create

[187] These anticipated replacements will be either portions of weather stations or full weather station replacements.

actionable weather information in areas that SCE's network does not directly cover and help meteorologists and grid operations specialists make more informed decisions regarding circuit sectionalization investments and PSPS execution. Finally, the weather station observations provide additional circuit climatology information to meteorologists after a sufficient record is obtained, which helps SCE identify circuits that are in typically wind-prone locations or less windy locations and might be subject to weather model errors. SCE plans to deploy 345 total weather stations between 2022 and 2025, including 55 in 2024 that are the subject of this Track 4.

2. High Definition Cameras

HD camera live feed information is critical to fire agencies for effectively deploying air and ground resources to limit and contain fires in their early stages, as well as to SCE's Fire Management team for gathering early information for asset protection. Although SCE has access to fire progression information through other public means (*e.g.*, monitoring news channels and 911 calls) and can dispatch personnel to determine fire severity, SCE selected to deploy HD cameras to expedite information gathering regarding fire progression. Fire agencies find the HD cameras extremely beneficial for their fire containment and public protection efforts. SCE partnered with the University of California, San Diego (UCSD) and the University of Nevada, Reno (UNR) to procure, install and maintain pan-tilt-zoom HD cameras. UCSD and UNR served as technical, research, and execution partners for the deployment of the HD cameras. SCE also worked with local and state fire agency personnel to support deployment and will continue to incorporate impacted fire agencies throughout SCE's HFRA to provide HD camera live feeds. SCE will continue to collaborate with UCSD on an ongoing basis. SCE has already installed 166 HD cameras through 2021, providing visual coverage of approximately 90% of our HFRA. However, SCE has since identified blind spots in this coverage. SCE plans to install up to 20 HD cameras in 2024 to continue to increase coverage; SCE will evaluate equipping HD cameras with AI capabilities. This will enhance the HD cameras' ability to send timely and more accurate information on fire activity than can be provided by satellite technology and provide increased visibility of identified blind spots to help SCE fire management staff. It will also assist fire agency personnel to quickly assess and respond to reported fires more accurately.

3. Wildfire Response, Modeling, Analysis & Weather Forecasting

SCE continues to advance weather modeling and situational awareness capabilities to better understand wildfire risks and more precisely target PSPS de-energization events to affect as few customers as reasonably possible, while still addressing dangerous fire threat conditions. We are also continuing to implement technology advancements, such as a next-generation weather modeling system and integration of satellite imagery to collect additional information on weather, fuels and fire activity.

Since the program's inception in 2018, SCE has installed more than 1,400 weather stations in our HFRA. We will also continue to enhance our fire spread modeling and other weather-modeling applications to increase our situational awareness of weather, dry vegetation, and fire activity.

D. O&M and Capital Scope and Forecast Analysis

Table XI-50
Enhanced Situational Awareness
O&M Authorized, Recorded, and Forecast by Sub-activity
(Constant 2018 $000)

		Track 1 Authorized*	Recorded	Recorded	Recorded	Track 4 Forecast
	Subactivity	**2021**	**2019**	**2020**	**2021**	**2024**
1	HD Cameras	$1,651	$459	$2,177	$2,858	$2,858
2	Weather Stations	$1,463	$1,217	$2,019	$1,931	$1,931
3	Wildfire Response, Modeling, Analysis, & Weather Forecasting	$480	$1,339	$108	$360	$360
	Total Expenses	**$3,594**	**$3,016**	**$4,304**	**$5,149**	**$5,149**

* Authorized 2022 and 2023 are equivalent to 2021 authorized (in constant 2018 dollars) after removing the impact of the Track 1 Decision's post-test year attrition mechanism

Table XI-51
Enhanced Situational Awareness
Capital Authorized, Recorded, and Forecast by Sub-activity
(Nominal $000)

		Track 1 Authorized					Recorded			Track 4 Forecast
	Subactivity	**2019**	**2020**	**2021**	**2022**	**2023**	**2019**	**2020**	**2021**	**2024**
1	HD Cameras	$970	$224				$970	$94		$130
2	Weather Stations	$4,282	$4,009				$4,282	$7,509	$5,607	$1,893
	Total Capital	**$5,252**	**$4,233**				**$5,252**	**$7,603**	**$5,607**	**$2,023**

1. HD Cameras

During 2022-2024, SCE forecasts an increase in HD camera-related capital expenditures. SCE plans to install up to 20 additional cameras per year during 2022-2024 for a total of 60 new cameras added to SCE's HD camera network.

In 2021, SCE recorded $2.858 million dollars for O&M and zero dollars in capital expenditures. In 2024, SCE anticipates O&M expenses to exceed 2021 recorded expenses due to increasing recurring operating costs as well as an additional 60 new cameras to maintain. The main driver for increased O&M expenses is the recurring operating cost of each additional camera, which is approximately $21,000 per camera for recurring operational data costs and maintenance.

2. Weather Stations

In 2021 SCE recorded $1.931 million dollars for O&M expense and $5.607 million dollars in capital expenditures. SCE expects higher O&M spend in 2024 compared to 2021 recorded costs as a result of additional weather stations on the network. The increase will be driven by data services and subscription plans, and projected increased yearly cost from the vendor by about 12%. The increased O&M expenses will be driven by SCE's planned installation of 270 weather stations in 2022-2023 and 55 additional stations in 2024.

3. Wildfire Response, Modeling, Analysis, & Weather Forecasting

In 2021, SCE recorded $360,000 and for purposes of this Track 4 filing forecasts the same spend in 2024. In 2019, SCE created SA Center and hired one additional meteorologist in 2020 who was providing weather forecasts, analytics, and hazard advisories to support wildfire mitigation activities and PSPS Execution. SCE also hired a fire scientist, a fire meteorologist, and a fire management officer to expand and enhance existing wildfire mitigation capabilities. The SA Center is equipped with additional situational awareness tools, including access to high resolution weather and fire modeling products made possible through HPCC technology. These tools increase the company's capacity to better forecast elevated weather conditions and potential wildfire activity to better inform decision making during regular operations and emergencies.

4. **O&M Historical Cost Variance**

HD cameras: The major component of O&M expense incurred for the HD cameras is driven by the data subscription fees, which are paid on a per-camera basis. Accordingly, the historical variance is largely driven by how many cameras are in operation in any given year, and at what point during that year. Accordingly, because SCE did not pay for all 91 cameras installed in 2019 for the entire year, SCE only recorded $0.459 million in O&M expense. In 2020, SCE incurred licensing costs for those 91 cameras as well as an additional five cameras installed that year, incurring O&M expense of $2.177 million. In 2021, while SCE did not install additional cameras, subscription fees on a per-camera basis increased; accordingly, SCE incurred O&M expenses of $2.858 million.

Weather Stations: From 2018 to October 2020, SCE installed 1,057 weather stations in HFRA and commenced planning and siting for installations in 2021. In 2019, SCE's O&M expenses began increasing due to the increasing installation of weather stations. In 2020, SCE's O&M expenses continued to increase due to the expansion of SCE's weather station network, as we installed 593 additional weather stations. This trend continued in 2021, installing 406 weather stations to gather additional information in the HFRA. These installations were prudent in order to keep enhancing forecasting capabilities and for granular data for PSPS operations. In 2021, SCE's recorded cost was $1.931 million (versus $1.463 million authorized in Track 1).

Wildfire Response, Modeling, Analysis, & Weather Forecasting: In 2019, SCE's recorded cost was $1.339 million dollars, which was utilized to focus on advancing our weather modeling and situational awareness capabilities to better understand the factors leading to increased wildfire risk. In 2020, SCE's recorded cost was $108,000 as a result of building up the team. In 2021, SCE's recorded cost was $360,000 (versus $480,000 authorized in Track 1). In 2024 SCE anticipates expenses to exceed 2021 recorded costs due to the required resources including one meteorologist, two fire scientists and a fire management officer.

5. **Capital Historical Cost Variance**

SCE incurred $12.855 million in capital costs for HD Cameras and Weather Stations during 2019 and 2020, as we installed 96 cameras and 945 weather stations in key locations to support our wildfire mitigation and response efforts. In 2021, SCE's recorded capital expenditures were $5.607 million and exceeded the planned quantity of installations on both HD cameras and weather stations.

a) HD Cameras and Weather Stations

Table XI-52
Number of Installs per year

	2019	2020	2021
HD Cameras	91	5	0
Weather Stations	352	593	406

In 2019 and 2020, SCE surpassed the WMP goal of 62 camera installations, with 96 cameras installed and surpassed the WMP goal of 925 weather station installations, with 945 weather stations installed. In 2021, SCE installed 406 weather stations (compared to a WMP goal of 375) and also retrofitted 358 weather stations with larger solar panels and larger batteries to increase network stability.

6. Basis for Forecast

a) HD Cameras

During the 2022-2024 period, SCE plans to install 60 new HD Cameras across SCE's HFRA as shown in Table XI-53 below. In addition to the 60 new installations, SCE will replace HD cameras on an as-needed basis as they reach the end of their natural lifecycles. SCE forecasts $127,500 in capital expenditure in 2024 for the HD camera systems, camera kits, and network/routing devices for 20 HD cameras. These additional cameras will address identified blind spots and will better help protect the communities SCE serves as well as our own infrastructure.

Table XI-53
HD Cameras Capital Forecast

Year	Qty	Cost /Unit	Total
2022	20	$6,375	$127,500
2023	20	$6,375	$127,500
2024	20	$6,375	$127,500

b) Weather Stations

Weather stations have both a capital and O&M component. In 2024, SCE forecasts $1.893 million in capital costs for the deployment, retrofit and installation costs for Weather Stations. In 2024, SCE plans to install 55 new weather stations in SCE's HFRA, with the possibility of replacing 115 weather stations reaching end-of-life and to retrofit cellular-only stations to dual communications with satellite terminals.

The major component of O&M expenses incurred for the Weather Stations is due to the support services and data subscription fees. These charges are paid as a per station cost, therefore increased installs results in an increased O&M cost. There have also been more installations in 2019 through 2021 than planned, with an increase in data subscription plans, which has resulted in O&M overages in subsequent years. The decision to install more weather stations than committed to in the various WMPs increased additional intelligence for Weather Services, Fire Scientists, and PSPS operations, which has proven beneficial. The information provided by the weather stations is critical when it comes to PSPS events providing opportunities to reduce customer impacts. The intelligence gathered from the weather stations help further refine PSPS de-energization and re-energization decision-making. Weather stations provide critical real-time data that help SCE surgically make these de-energization and re-energization decisions on circuits in HFRA subject to PSPS. Installing additional weather stations provides SCE granular information at a circuit level in an effort to impact as few customers as possible.

SCE is working to develop a strategy for weather station replacements and has included a forecast of expected replacements during 2022–2024, which includes:

Table XI-54
Weather Stations Capital Forecast

Weather Stations			
Year	**Qty**	**Cost /Unit**	**Total**
2022	175	$10,330	$1,807,750
2023	95	$10,330	$981,350
2024	55	$11,570	$636,350

In 2024, SCE's capital forecast includes an increase of 12% in unit cost for labor and material due to increased prices from the vendor.

XII.

FIRE SCIENCE AND WEATHER AND FUELS MODELING

A. Overview

SCE has used data derived from our weather stations and other sources in combination with fire science and weather and fuels modeling techniques to develop new predictive models that help us focus our wildfire mitigation efforts and strategies more effectively. This work is comprised of two separate but related programs: Fire Science and Weather and Fuels Modeling.[188]

SCE will pursue an aggressive fire science strategy for the continued improvement of situational awareness, fire spread modeling, and the ongoing assessment of the potential for wildfires to occur. While SCE made significant progress in each of these areas in 2020 and 2021, a path toward full maturity is necessary to meet the increasing demands of all wildfire mitigation efforts. More specifically, the FPI, which is a core component of the PSPS program, will need to be further refined beyond its current state to address several current limitations. In addition, fire spread modeling is becoming increasingly important to help with wildfire mitigation in both the short- and long-term timelines. In the short-term, fire spread modeling will be key in the scoping and de-scoping of circuits targeted for de-energization during PSPS.

While SCE has begun evaluating fire spread predictions and their associated consequences during such events, the absence of third-party fire suppression in the prediction calculations precludes the ability for SCE to use this important tool at this time. By 2024, SCE expects this capability to be at a maturity level in which it can be fully incorporated into the PSPS decision-making process. In the long-term, SCE will continue to use fire spread modeling to inform decisions on grid hardening activity and their associated priorities. Also, remote sensing will be used to objectively identify areas where significant wildfire activity may occur. This is critical for targeting areas where inspections, vegetation

[188] In Track 1 this activity was referred to as Fire Science and Advanced Modeling. In Track 4, this activity is referred to as Fire Science and Weather and Fuels Modeling to more accurately reflect the nature of the work, and to align with the two programs discussed in SCE's 2022 WMP Update.

clearance, and the remediation of P2s should be accelerated.[189] Specifically, a new situational awareness tool using remote sensing will be developed by 2024 to help identify these areas. Finally, a significant investment is being made to develop a tool that will allow SCE's meteorologists and fire science team to easily visualize internal and external weather and fuels models on a map overlaid with existing infrastructure. This is vital to understanding details about where the most critical weather and fire potential may occur and will help with making more informed decisions.

1. Content and Organization of Chapter

SCE's Fire Science program was developed for the purpose of gathering all the latest relevant scientific and technological advancements to help mitigate risks from wildfires associated with utility infrastructure. This involves the integration of multiple scientific disciplines to synthesize and analyze data to help model atmospheric conditions and assess fire potential. Weather and Fuels modeling spans multiple areas, including modeling weather and vegetation conditions, as well as modeling the spread and behavior of wildfires. Modeling atmospheric conditions that can result in catastrophic wildfires is a critical component of situational awareness and effective wildfire mitigation planning and execution. It is the foundation of the PSPS program as customer notifications for such events is based on weather and fire potential forecasts. In many ways, Fire Science serves as the basis and foundation for all wildfire mitigation activities within SCE. Many of Fire Science's activities, such as Fire Spread Modeling and Fuel Sampling, are critical to SCE's situational awareness, for PSPS support and day-to-day operations.

Fire Science and Weather and Fuels Modeling activities include the following: For Fire Science: 1) Fire Potential Index (FPI), 2) Fire Spread Modeling, 3) Fuel Sampling, 4) Surface and Canopy Fuels Mapping, 5) Remote Sensing, and 6) Fire Science Enhancements. For Weather and Fuels Modeling: 1) Advance Computer Modeling Hardware, 2) Circuit Geometry Updates, 3) Data Manager, 4) Live Fuel Moisture (LFM) Models, 5) Machine Learning, 6) Self-Organizing Maps (SOMS) Pilot

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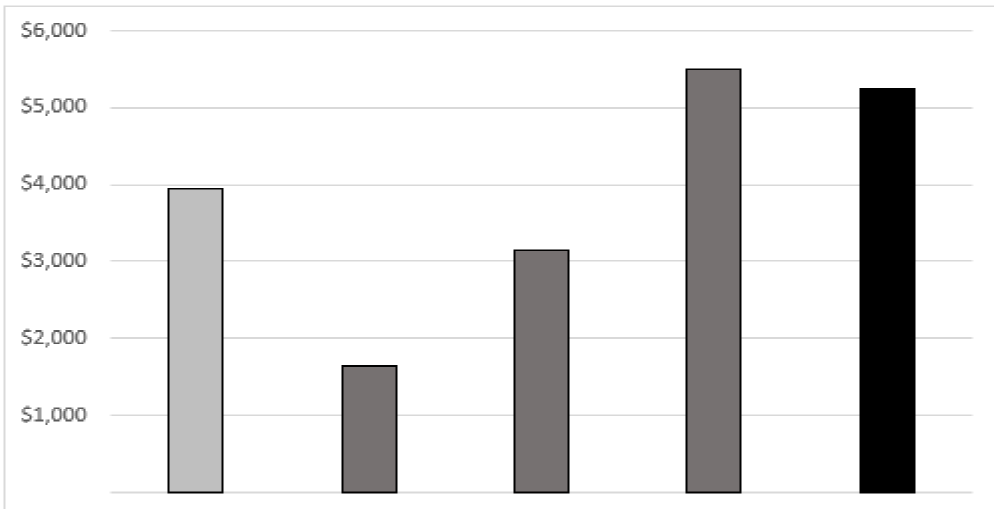
[189] As discussed in Chapter VII, a "Priority" is when an anomalous condition is identified during an inspection on a distribution or transmission structure that needs to be corrected. The condition is given a prioritization rating of either 1, 2 or 3, depending on the severity of the condition.

Project, 7) Weather Visualization Tool (Software), and 8) European Center for Median-Range Weather Forecast (ECMWF).

B. Summary of O&M and Capital Request

Figure XII-45[190]
O&M Summary
Fire Science and Weather & Fuels Modeling
O&M Authorized, Recorded, and Forecast
(Constant 2018 $000)



Track 1 Authorized*	Recorded			Track 4 Forecast
2021	2019	2020	2021	2024
$3,948	$1,638	$3,157	$5,508	$5,257

		Track 1 Authorized*	Recorded	Recorded	Recorded	Track 4 Forecast
	Subactivity	2021	2019	2020	2021	2024
1	Advanced Modeling Computer Hardware	$1,682	$736	$1,564	$2,337	$2,337
2	Fire Science Enhancements		$810	$403	$531	$531
3	Fire Spread Modeling				$1,432	$1,432
4	Fuel Sampling Program	$196	$91	$188	$200	$200
5	Remote Sensing	$1,467	($0)		$16	$16
6	Surface and Canopy Fuels Mapping	$604		$1,002	$451	$200
7	Weather and Fuels Modeling				$541	$541
	Total Expenses	$3,948	$1,638	$3,157	$5,508	$5,257

* Authorized 2022 and 2023 are equivalent to 2021 authorized (in constant 2018 dollars) after removing the impact of the Track 1 Decision's post-test year attrition mechanism

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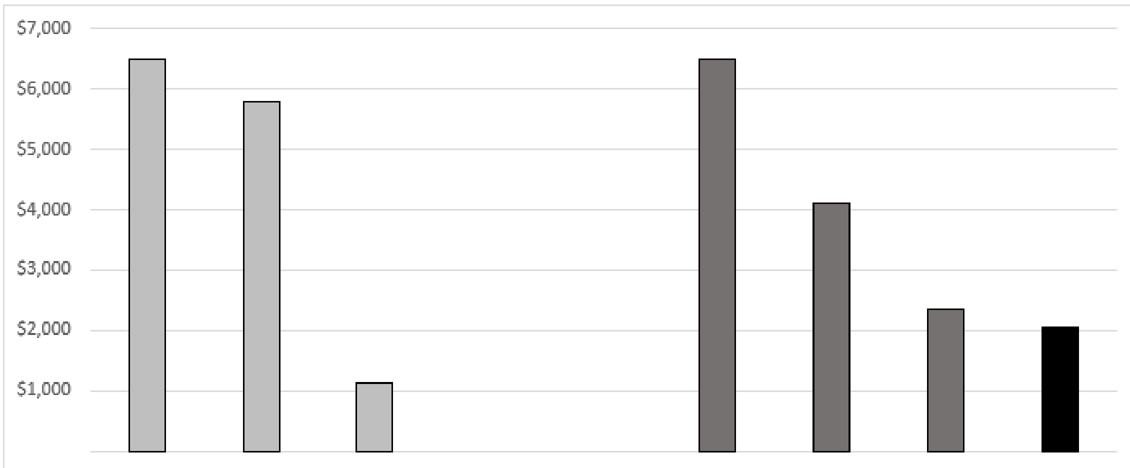
190 Excludes sub-activities Advanced Weather Modeling Tool and High Resolution Weather-Related Study as there are no associated authorized costs or 2024 forecasts. Historical costs for these sub-activities are in WP SCE Tr. 4-01 - O&M Financial Mapping pp. 161 - 162 in the section Activities Excluded from Sub-Activity Tables. This workpaper also includes financial mapping.

Figure XII-46[191]
Capital Summary
Fire Science and Weather & Fuels Modeling
Capital Authorized, Recorded, and Forecast
(Nominal $000)



Track 1 Authorized					Recorded			Track 4 Forecast
2019	2020	2021	2022	2023	2019	2020	2021	2024
$6,487	$5,787	$1,129	-	$0	$6,487	$4,106	$2,340	$2,046

	Track 1 Authorized					Recorded			Track 4 Forecast
Sub Activity	2019	2020	2021	2022	2023	2019	2020	2021	2024
Advanced Modeling Computer Hardware	$6,446	$4,810	$1,129		$0	$6,446	$3,835	$2,340	$2,046
Operational Analytics	$40	$977				$40	$271	$0	
Total Capital	$6,487	$5,787	$1,129		$0	$6,487	$4,106	$2,340	$2,046

In 2021, SCE's recorded O&M costs for the above-noted activities was $5.508 million and SCE's 2024 forecast is $5.257 million dollars. The reduction in SCE's 2024 forecasts reflects a one-time, non-recurring cost adjustment related to subscription fees, as further discussed in Surface and Canopy Fuels Mapping below.

1. Fire Science

SCE's Fire Science activity includes multiple projects and sub-activities that affect situational awareness, PSPS, and various grid hardening efforts, all of which either indirectly or directly support the goal of reducing the threat of wildfires associated with utility equipment. Therefore, it is

[191] Excludes the Asst Risk Modeling sub-activity as it represents only 2021 recorded costs and no 2024 forecast. For that cost see WP SCE Tr. 4-01 - Capital Financial Mapping in the section Activities Excluded from Sub-Activity Tables.

expected that all of these work activities will continue at either the same pace or greater in 2024 (as compared to 2021).

a) Fire Potential Index (FPI)

Since the FPI is one of the pillars for determining when or if to initiate a PSPS event, it is imperative that work to improve the accuracy of wildfire assessment continues. SCE's current FPI is a direct input into PSPS calculations and provides an estimate of the potential risk of fire ignition and spread at the circuit level. To enable more targeted PSPS decision-making that has the potential to reduce the number of customers impacted by PSPS, the FPI was calibrated to better understand the index output in the context of historical fire activity. The FPI can then be enhanced to develop more accurate estimates of the potential risk of fire ignition and spread at the circuit level, including at the transmission and sub-transmission circuit level.

In 2021, SCE completed an in-depth calibration of its FPI so that the index output (with numbers ranging from 1-17) would have meaning and context with respect to historical fire occurrence data. In 2022, SCE is running FPI 2.0[192] in parallel with the current FPI to demonstrate the difference and improvements over the current index, and will make refinements to FPI 2.0 as needed, based on its evaluation of the outputs. It is anticipated that FPI 2.0 will be used operationally by 2024, but if it is still in test and evaluation mode, there will be a concentrated effort to migrate to this improved version of the index during this time. This will require further analysis of the index to demonstrate its effectiveness in capturing large fire potential more precisely.

b) Fire Spread Modeling

Fire Spread Modeling will become an integral component of PSPS operations by 2024. During this time, current limitations of our Fire Spread Modeling, such as the consideration of fire suppression and the number of buildings destroyed, will be addressed. Other improvements, such as crown fire behavior predictions and urban conflagration modeling are expected to occur during this time but with less certainty of completion. These improvements will pave the way for a smoother integration

[192] FPI 2.0 addresses several limitations of the current FPI model, which makes it more effective in assessing large wind-driven fire potential. *See* WMP 2022 Update, p. 97.

of consequence information into the PSPS decision-making process. In addition, these advancements will also help provide better fire spread predictions using historical data, and potentially using downscaled climate model data, to aid with the prioritization of long-term grid hardening projects.

SCE continues to make important investments in fire spread modeling technology to help identify areas that are at high risk for large wildfires, which can have devastating consequences. While this technology is currently being used to help assess fire potential during PSPS events, it is not currently part of the decision-making process during such times, which is the ultimate goal of this investment. As a result, SCE has identified additional functionality that is needed in order to meet that critical goal. This includes accounting for fire suppression when calculating risk and consequence metrics, as well as including an estimate of the number of potential structures that could be destroyed by a wildfire. SCE will coordinate closely with its vendor to ensure this added functionality will meet SCE's needs. SCE's Fire Science team will review the proposed methodology with the vendor and evaluate the enhanced capabilities during real-time PSPS events.

c) Fuel Sampling

SCE takes real-time measurements of vegetation moisture at 15 sites across its service area. Live fuel moisture sampling provides ground truth observations bi-weekly that: 1) help assess how receptive the fuels are to fire, and 2) help align FPI values when forecasts of live fuel moisture are misaligned with observations. The live fuel moisture sampling program will continue in its current state in 2024 with no major changes proposed.

d) Surface and Canopy Fuels Mapping

In 2020-2021, SCE through its vendor Technosylva, embarked on an extensive effort to create an updated fuels layer, which is primarily comprised of vegetation types and amounts. This fuels layer is a required input into all fire spread modeling calculations and therefore it is critical that it be as up-to-date as possible. As a result, SCE pays Technosylva a yearly subscription fee to periodically update this layer through each year to account for various land disturbances such as recent burn scars.

e) Remote Sensing

In 2021, SCE performed remote sensing piloting to observe winds above ground level and worked with San Jose State University to deploy this technology during several PSPS wind events. Remote sensing is a rapidly expanding, diverse industry that contains a broad array of applications, some of which can be used to obtain information on the characteristics and health of vegetation. Having this knowledge in semi-real time is important in understanding how much vegetation is on the ground, how old it is, what type it is, and how much moisture is in it, since these are all factors that play a significant role in the initiation and spread of wildfires. There will be a more concentrated effort in 2024 to leverage this technology to determine the status of the vegetation for the development of SCE's Seasonal Outlooks, AOCs, and which Fire Climate Zone operating restrictions are put in place and when.

f) Fire Science Enhancements

SCE's fire science enhancements are comprised of several efforts, which include the Weather and Fuels Climatology project. This project aims to provide historical context for current weather events, by developing a climatology of temperature, wind, humidity, vegetation moisture, and many other parameters at each grid cell across the SCE service area, based on access to an unprecedented and unique 40-year historical data set of weather and fuels. This historical database provides the information necessary to develop predictive models that will improve the overall understanding of environmental factors (weather and fuels) and their relationship with ignition drivers for wildfires associated with utility equipment. SCE will then use these models to inform wildfire mitigation activities and real-time decision-making for PSPS events. Other efforts include improving upon the 1-month- and 3-month-ahead forecasts of Santa Ana wind days, which is useful for the planning of inspections and remediations across the SCE service area.

2. Weather and Fuels Modeling

SCE's in-house weather and fuels modeling is foundational to PSPS and grid operations. Because knowing when and where severe weather conditions will impact SCE's infrastructure is important for an appropriate proactive response, it is vital that improvements to all in-house modeling capabilities continue. Many of these improvements will be driven by AI technology, statistical methods, and new dynamic models. In 2024, SCE will focus on improvements to wind speed forecasts at site-specific locations using machine learning modeling, the use of Self Organizing Maps as discussed below, and the development of local nowcasting techniques to better forecast which circuits may be impacted by PSPS and for how long, as well as improved probabilistic forecasts to help with forecaster confidence.

SCE is also partnering with academia in 2022 to devise a new method to derive more complete wind risk profiles along infrastructure during PSPS events. This tool will be initially developed in 2022, but maintenance of the operational system will be necessary in 2024, including potential adjustments of the tool based on new research or data from SCE's expanding surface observational network.

In addition to improved modeling capabilities, SCE will develop the maintenance of the weather and fuels visualization tool used to visualize both internal and external sources of meteorological and fire related data as discussed later in this chapter. This tool will be developed during the 2022–2023-time frame.

a) <u>Advanced Modeling Computer Hardware</u>

The use of high-performance computing is necessary to run SCE's in-house weather models, consisting of millions, if not, billions of computations to generate 1-km hourly outputs of weather, fuel moisture, and fire potential data daily. Each of SCE's High-Performance Computing Clusters (HPCCs) is the equivalent of approximately 250 laptop computers, which generate 10s of millions of data points a day. SCE initially purchased two HPCCs in 2019, then acquired two more in 2021. While SCE does not anticipate expanding its hardware capabilities, it does plan to eventually replace its existing HPCCs as their life cycle is around 5-6 years. As discussed below, SCE plans to replace two HPCCs in 2024.

b) <u>Circuit Geometry Updates</u>

Due to circuit geometry changes in the field associated with load swaps and circuit changes, it is essential that current circuit name and location information is utilized to inform circuit level forecasting within SCE's in-house weather model. This process ensures that circuit geometry updates are accurately reflected in circuit level forecasts and do not cause inaccuracies in downstream products used for PSPS decision-making. In addition, changes to circuit geometry need to be accounted for in the modeling as this will affect the calculation of FPI, wind forecasts, and thresholds along the HFRA circuits.

c) Data Manager

To enable a quicker and more efficient retrieval process of SCE's 40-year historical dataset, an application called the Data Manager was developed in 2021 by SCE's vendor Atmospheric Data Solutions, LLC. This tool allows users to query large amounts of data for use with analytics and data requests. The Data Manager improves data analysis by providing users with the ability to interact with SCE's historical data set quickly and efficiently to retrieve only the data needed for the analysis.

d) Live Fuel Moisture (LFM) Models

LFM models are machine learning-based algorithms that are used for assessing water content in the living vegetation and are a direct input into the FPI. Live fuel moisture is expressed as a percentage of the water amount compared to the dry weight of the vegetation and is used to determine the fuel's receptibility level to fire. In 2022 SCE will update its live fuel moisture models by incorporating additional vegetation species, with potential additional improvements by 2024. These improvements will help increase the accuracy of the FPI forecast.

e) Machine Learning

Weather model forecasts are subject to error from imperfect initial conditions sources, incomplete representation of the underlying terrain, and scientific unknowns affecting small-scale meteorological processes. These sources of error can be random or systematic (repeatable) and are some of the primary limitations of weather-model-based forecasts. To overcome these challenges, meteorologists can employ statistical methods such as machine learning to remove forecast biases from weather models resulting in improved forecasts when evaluated against observed values. SCE plans to equip 400 to 500 weather station locations with machine learning capabilities in 2022 at locations frequently impacted by elevated fire weather conditions and will continue to evolve the machine learning forecast program through 2024. Future development of machine learning model forecasts will include expanding the capability to include more weather station locations, possible retraining of the machine learning models to improve accuracy, and evaluation of new machine learning model approaches.

f) Self-Organizing Maps (SOMS) Pilot Project

All current weather forecast capabilities employed by SCE rely fully on predictive models that do not consider prior known outcomes as a possible forecast solution. Self-Organizing Maps (SOMS) provide an analog forecast approach where future forecast weather patterns are related to historic weather patterns with a degree of confidence. Matching up a forecast weather pattern to one that has been observed in the past gives meteorologists and fire scientists the ability to use prior knowledge of historical outcomes as a possible forecast solution. This will help identify areas possibly impacted by PSPS based on prior weather pattern experience. Such a tool will not only provide SCE another possible forecast scenario to evaluate but will also provide redundancy in the event another forecast system has a temporary issue.

g) Weather Visualization Tool (Software)

SCE is developing a Weather Visualization Tool that, along with a more robust graphic user interface (GUI), will allow users to view and analyze large amounts of internal and external weather and fuels data quickly and efficiently. This will represent a marked improvement over the current process in which users are retrieving information, primarily in static map form, from vendors and cannot effectively overlay SCE infrastructure on top of the forecast weather outcome to understand the risk profile. This new tool will allow SCE to visualize in-house and external weather and fuels model sources in a single location, will be dynamic, and will have access to SCE GIS layers important for making PSPS decisions. This will facilitate meteorologist/fire scientist analysis and improve communication of the expected weather impacts.

h) European Centre for Median-Range Weather Forecast (ECMWF)

The European Centre for Medium-Range Weather Forecasts (ECMWF) produces one of the most accurate weather model forecasts available. SCE pays an annual subscription to access this information. Data from the ECMWF provides a key input into SCE's in-house weather modeling system, which provides an additional forecast scenario that allows SCE to account for forecast uncertainty, provides a more robust ensemble forecast approach, and provides added reliability to SCE's forecast system in the event that data from the US National Weather Service is unavailable. The ECMWF model output is also a key data source for meteorologists to evaluate within the planned Weather Visualization Tool to understand weather impacts across the SCE territory.

3. O&M Scope and Forecast Analysis

***Table XII-55*[193]**
Fire Science and Weather & Fuels Modeling
O&M Authorized, Recorded, and Forecast by Sub-Activity
(Constant 2018 $000)

		Track 1 Authorized*	Recorded	Recorded	Recorded	Track 4 Forecast
	Subactivity	**2021**	**2019**	**2020**	**2021**	**2024**
1	Advanced Modeling Computer Hardware	$1,682	$736	$1,564	$2,337	$2,337
2	Fire Science Enhancements		$810	$403	$531	$531
3	Fire Spread Modeling				$1,432	$1,432
4	Fuel Sampling Program	$196	$91	$188	$200	$200
5	Remote Sensing	$1,467	($0)		$16	$16
6	Surface and Canopy Fuels Mapping	$604		$1,002	$451	$200
7	Weather and Fuels Modeling				$541	$541
	Total Expenses	**$3,948**	**$1,638**	**$3,157**	**$5,508**	**$5,257**

* Authorized 2022 and 2023 are equivalent to 2021 authorized (in constant 2018 dollars) after removing the impact of the Track 1 Decision's post-test year attrition mechanism

a) Historical Variance Analysis

In 2019, SCE's recorded O&M cost for these activities was $1.638 million, while in 2020 SCE recorded $3.157 million. In 2019 and 2020, SCE continued to develop and build upon its Fire Science program, which included the commencement and enhancement of in-house weather and fuels modeling, fuels sampling, and fire spread modeling for uses related to PSPS and other wildfire

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193 Excludes sub-activities Advanced Weather Modeling Tool and High Resolution Weather-Related Study as there are no associated authorized amounts or 2024 forecasts. Historical costs for these sub-activities can be located in WP SCE Tr. 4-01 - O&M Financial Mapping in the section Activities Excluded from Sub-Activity Tables. This workpaper also includes financial mapping.

mitigation efforts such as grid hardening. Due to the increasing demands to have more granular and more accurate weather, fuels, fire spread modeling, and fire potential forecasts, SCE incurred additional operating costs to enhance its in-house modeling capabilities with vendors Technosylva and Atmospheric Data Solutions, LLC (ADS) in 2021.

In 2021, the Track 1-authorized amount for O&M expense was $3.948 million. SCE incurred recorded costs of $5.508 million due to necessary and prudent spending on Advanced Modeling Computer Hardware, Fire Science Enhancement, Fuel Sampling program, Remote Sensing, Surface and Canopy Fuels Mapping, Fire Spread Modeling, and Weather and Fuels Modeling activities. While individual sub-activity expenses in 2024 may increase or decrease relative to 2021 recorded, as a portfolio SCE anticipates its Fire Science and Weather and Fuels Modeling GRC Activity 2024 expenses to be generally in line with 2021 recorded. That said, in 2024 SCE forecasts to spend $5.257 million in O&M costs due to the on-going effort to advance and mature the Fire Science program which will include the enhancement of its weather, fuels, and fire spread modeling activities. As noted above, SCE's reduced O&M forecast for 2024 as compared to 2021 is due to a one-time adjustment for non-recurring vendor fees that are not forecast to be incurred in 2024.

4. Capital Scope and Forecast Analysis

Table XII-56[194]
Fire Science and Weather & Fuels Modeling
Capital Authorized, Recorded, and Forecast by Sub-activity
(Nominal $000)

		Track 1 Authorized					Recorded			Track 4 Forecast
	Subactivity	**2019**	**2020**	**2021**	**2022**	**2023**	**2019**	**2020**	**2021**	**2024**
1	Advanced Modeling Computer Hardware	$6,446	$4,810	$1,129		$0	$6,446	$3,835	$2,340	$2,046
2	Operational Analytics	$40	$977				$40	$271	$0	
	Total Capital	**$6,487**	**$5,787**	**$1,129**		**$0**	**$6,487**	**$4,106**	**$2,340**	**$2,046**

[194] Excludes sub-activity Asset Risk Modeling as there are no associated authorized amounts or 2024 forecasts. Historical costs for this sub-activity can be located in WP SCE Tr. 4-01 - Capital Financial Mapping in the section Activities Excluded from Sub-Activity Tables. This workpaper also includes financial mapping.

The Advanced Modeling Computer Hardware is the only activity requiring capital spend in 2024. In 2021, SCE's recorded costs were $2.340 million, and in 2024 SCE forecasts $2.046 million to replace two HPCCs initially purchased in 2019.

a) Historical Variance Analysis

In 2019, SCE's recorded capital spend was $6.487 million for Advanced Modeling Computer Hardware, Asset Risk Modeling, and Operational Analytics. This included start-up costs for two HPCCs, along with their related licensing fees and support costs. SCE also pursued fire spread modeling capabilities through Technosylva, which included the software applications of FireCast, FireSim, and the WRRM. In 2020, SCE's expenditure $4.106 million compared to $5.787 million authorized included additional modeling data, licensing fees, and support fees. In 2021, SCE's recorded capital costs were $2.340 million as compared to $1.129 million authorized in Track 1, based on a forecast that assumed a single HPCC in 2021. However, SCE purchased two HPCCs for advanced modeling to facilitate the installation and operationalization of the Next Generation Weather Modeling System, allowing for more precise, higher resolution output. In addition, SCE performed additional work with Technosylva and ADS that included capital expenditures for Asset Risk analysis, additional subscription fees, and enhancements to previous modeling efforts.

b) Basis for forecast Capital Sub-activity

In 2021, SCE's capital expenditures included costs for obtaining and integrating new and/or improved science and technology to support wildfire mitigation activities across SCE's HFRA. SCE installed two HPCCs, extended PSPS forecasts from five to seven days and incorporated a European forecasting model to add redundancy and accuracy to the NextGen Weather Modeling System.

In 2024, SCE forecasts to spend $2.046 million in capital expenditures, relating to replacing the two HPCCs that were originally purchased in 2019.

XIII.

ENVIRONMENTAL REMEDIATION LIABILITY MANAGEMENT COSTS

A. Overview and Summary of O&M Request

The State Water Resources Control Board (SWRCB) annual fee is a new requirement for utilities imposed by Senate Bill (SB) 901. This fee funds SWRCB staff to develop a statewide permit for utility work required under SB 901 and ensure priority processing to support utilities' efforts to implement WMPs. This annual fee is an ongoing requirement from the SWRCB. SCE's 2024 O&M forecast for the recurring fee is $0.727 million, which is equal to SCE's 2021 recorded amount.

B. Work Description and Need

In September 2019, the SWRCB added a new annual fee for electric utilities with prepared WMPs as a requirement of SB 901. The SWRCB fee is for increased agency staffing that facilitates the agency's ability to do timely reviews and to authorize the work as applicable (*e.g.*, impacts associated with maintenance and modification within waters of the State). The SWRCB's current certification of the US Army Corps of Engineers Nationwide Permit (NWP) 57[195] for Utility Line Activities (formerly NWP 12) was developed in 2017 to expedite utility activities, but provides coverage for a limited scope that does not account for the impacts of large scale vegetation removal and other activities that utility companies are engaged in. SWRCB proposed to develop and implement a streamlined statewide permit/certification for Nationwide Permit 57 for utility work required under SB 901, which will be funded through the annual flat fee for electric utility companies, sized proportionally to the total number of overhead conductor miles (distribution and transmission) in HFTD. This fee is calculated at $43 per mile of overhead conductor identified as high risk or high threat in the utility's WMP.

C. O&M Scope and Forecast Analysis

SCE began to incur this fee in 2020, which is calculated based on number of overhead conductor miles (distribution and transmission) identified as high risk or high threat in the utility's WMP. In 2021,

[195] Nationwide Permit (NWP) 57 is a general permit issued by the U.S. Army Corps of Engineers under the authority of the Clean Water Act Section 404 that provides authorization of a suite of electric utility activities that impact federally protected waters of the U.S. The state certifies these permits through the Clean Water Act Section 401 Certification process.

the fee payment was $0.727 million, based on total number of 16,962 miles included in SCE's WMP at $43 per mile. The scope of work performed in 2021 is a reasonable approximation for the needed work which will take place in 2024. Thus, SCE's request to update its 2024 cost forecast to the 2021 recorded amount of $0.727 million is appropriate, and assumes no changes in factors impacting calculation of fee payment, such as the agency's allocation of costs among utilities and/or change in number of overhead miles within HFTD.

Table XIII-57
Environmental Remediation Liability Management Costs
O&M Authorized, Recorded, and Forecast by Sub-activity
(Constant 2018 $000)

		Track 1 Authorized*	Recorded	Recorded	Recorded	Track 4 Forecast
	Subactivity	**2021**	**2019**	**2020**	**2021**	**2024**
1	Environmental Remediation Liability Management			$606	$727	$727
	Total Expenses			**$606**	**$727**	**$727**

* Authorized 2022 and 2023 are equivalent to 2021 authorized (in constant 2018 dollars) after removing the impact of the Track 1 Decision's post-test year attrition mechanism

XIV.

NEW SERVICE CONNECTIONS

A. Overview

This section includes the capital expenditures that SCE incurs in responding to SCE's obligation to serve as well as customer growth, defined as customers increasing their service requirements or the addition of new customers altogether, which typically results in a meter installation. Essentially, New Service Connections are the capital expenditure output of the New Meters forecast set forth in Exhibit SCE-01, Chapter III.C. As discussed elsewhere in this filing, all activities for which SCE does not provide forecasts and supporting testimony are included in the post-test year escalation request. The Track 1 Final Decision authorized budget-based residential and commercial new service connections for the 2022 and 2023 forecasts.[196] Accordingly, SCE's Track 4 budget-based forecast for 2024 for this category of capital expenditures is separate and distinct from those activities included in the broader Track 4 escalation request.

In its 2021 GRC Track 1 showing SCE used the gross meter sets from the retail sales forecast presented in SCE-07 Vol. 01 as the basis for developing its capital expenditure forecasts for each new service connection work activity. For residential new service connections, the Track 1 Final Decision adopted SCE's calculated coefficients from its regression model as well as SCE's unit cost forecasts, but adopted a gross meter set forecast based on a 2015-2019 historical average.[197] For commercial new service connections, the Track 1 Final Decision adopted a forecast based on the average number of commercial meters installed over the last five recorded years (2015-2019). The commercial forecast was initially proposed by The Utility Reform Network (TURN) in its testimony, which SCE accepted while agreeing to investigate alternative fundamental drivers to better forecast commercial/industrial meter sets in the future.[198]

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[196] D.21-08-036, p. 548.
[197] D.21-08-036, pp. 143-145.
[198] D.21-08-036, pp. 145-147.

In SCE-01 Chapter III.C, SCE reemphasizes its reasons for disagreeing with TURN and the Track 1 Final Decision's adopted residential new service connections methodology, but nevertheless elects to not put forth a new forecast methodology in Track 4. As such, the 2024 residential and commercial new service connections forecasts included here represent a continuation of the Track 1 Final Decision's adopted methodology. The residential regressions and unit costs are unchanged, and the use of five-year historical average meter installs is also unchanged. The only change is updating the five-year average for more recently recorded years; thus, the five-year average represents 2017-2021.

Table XIV-58
2017-2021 Recorded Meters for Residential and
Commercial New Service Connections

	Year	Residential Gross Meter Sets	Commercial Gross Meter Sets
Recorded	2017	34,489	4,767
	2018	34,759	4,622
	2019	34,685	4,438
	2020	32,828	3,942
	2021	29,752	3,653

B. <u>Residential New Service Connections Capital Forecast</u>

SCE forecasts a total of $149.431 million following the Track 1 Final Decision's adopted methodology for 2021-2023 and updating the five-year historical gross meter sets for the most recent five years of 2017-2021.

Table XIV-59
Residential New Service Connections
Capital Authorized, Recorded, and Forecast by Sub-Activity
(Nominal $000)

	Track 1 Authorized					Recorded			Track 4 Forecast
Sub Activity	**2019**	**2020**	**2021**	**2022**	**2023**	**2019**	**2020**	**2021**	**2024**
Residential New Service Connections	$110,480	$117,144	$121,362	$129,660	$163,229	$110,480	$104,532	$101,784	$149,431
Total Capital	**$110,480**	**$117,144**	**$121,362**	**$129,660**	**$163,229**	**$110,480**	**$104,532**	**$101,784**	**$149,431**

C. Commercial New Service Connections Forecast

SCE forecasts a total of $91.196 million following the Track 1 Final Decision's adopted methodology for 2021-2023 and updating the five-year historical gross meter sets for the most recent five years of 2017-2021.

Table XIV-60
Commercial New Service Connections
Capital Authorized, Recorded, and Forecast by Sub-Activity
(Nominal $000)

	Track 1 Authorized					Recorded			Track 4 Forecast
Sub Activity	**2019**	**2020**	**2021**	**2022**	**2023**	**2019**	**2020**	**2021**	**2024**
Commercial New Service Connections	$94,111	$87,338	$90,656	$93,787	$96,958	$94,111	$97,590	$102,141	$91,196
Total Capital	**$94,111**	**$87,338**	**$90,656**	**$93,787**	**$96,958**	**$94,111**	**$97,590**	**$102,141**	**$91,196**

Appendix A

Witness Qualifications

SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY
OF KENNETH BORNGREBE

Q. Please state your name and business address for the record.

A. My name is Kenneth Borngrebe, and my business address is 2244 Walnut Grove Avenue, Rosemead, CA 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am Director of the Environmental Services Department. I am responsible for developing and implementing programs necessary for SCE to comply with applicable environmental requirements.

Q. Briefly describe your educational and professional background.

A. I hold a Bachelor Degree in Biology from the University of California Riverside and a Master of Business Administrations from California State University Los Angeles. I have twenty five years of experience in the development and implementation of environmental programs. I have fifteen years experience working for SCE. Prior to my role at SCE, I was the Manager of Siting and Permitting at First Solar Development, LLC.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of *SCE-02: Direct Testimony in Support of GRC Track 4 Activity Forecast Request*, as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. I have carefully reviewed and have adopted the testimony as my own.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY
OF DON DAIGLER

Q. Please state your name and business address for the record.

A. My name is Don Daigler, and my business address is 8631 Rush Street, Rosemead, CA 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am the Managing Director of Business Resiliency. I am responsible for Southern California Edison's overall Business Resiliency activities. I also manage the company's emergency management functions for all hazards facing the company's business lines, facilities, and people and lead the development and implementation of corporate Business Continuity Plans and Disaster Recovery Plans.

Q. Briefly describe your educational and professional background.

A. I have a Bachelor of Science in Liberal Studies with an educational focus on Health Physics and have more than 30 years of experience in the areas of national security and emergency management. My career includes 26 years of service in the federal government, where I have held several senior leadership positions, both in the field and at the policy level in Washington, D.C. Immediately prior to joining SCE, I was the Response Planning Director for the Federal Emergency Management Agency (FEMA), where I led all national and regional response planning activities and was the planning lead during several large scale disasters, such as hurricanes Sandy, Isaac, and Irene. In that capacity, I was also responsible for leading the agency's chemical, biological, radiological, nuclear, and explosives programs as well as the National Hurricane Program and Remote Sensing Program. Previously, I ran the Technology Integration Program for the Department of Energy's National Nuclear Security Administration, which developed specialized emergency response equipment. Before moving to Washington, D.C., I held leadership roles for the Department of Energy's Nevada Site Office, including the position of Director of the Homeland Security and Defense Division. My federal government experience also includes experience with the Environmental Protection Agency and the Department of Defense.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor the portions of *SCE-02: Direct Testimony in Support of GRC Track 4 Activity Forecast Request*, as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY
OF RAYMOND FUGERE

Q. Please state your name and business address for the record.

A. My name is Raymond Fugere and my business address is 3 Innovation Way, Pomona, CA.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am the Principal Manager of Wildfire Mitigation Strategy (WMS) within the Asset Strategy and Planning organizational unit of Southern California Edison (SCE). The WMS is comprised of three functions which are:

- Vegetation and Inspection which develops scope and strategy for SCE's wildfire inspection and maintenance programs.
- Wildfire Grid Hardening Strategy which develops the strategies on how SCE will harden its system to reduce wildfire risks.
- Wildfire Portfolio Optimization, which performs failure and root cause analysis of SCE facilities involved in fires, and then utilizes that information to develop an optimized and cohesive wildfire fire mitigation portfolio that is optimized to deploy the right mitigations in the right locations.

Q. Briefly describe your educational and professional background.

A. I hold a Bachelor of Science in Chemical Engineering from UC Santa Barbara. I joined SCE in 2014, in the capacity of Manager of FERC/NERC compliance. In 2015, I was moved into the position of Compliance Strategy Manager. In 2016, my title was changed to Maintenance and Inspection Manager. In 2019, I was promoted to Principal Manager of AA&DS. In 2021, during a reorg, I was placed into my current position. Prior to joining SCE, I worked at the California Public Utilities Commission for 14 years, in various capacities.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor the portions of *SCE-02: Direct Testimony in Support of GRC Track 4 Activity Forecast Request*, as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY
OF KRISTI GARDNER

Q. Please state your name and business address for the record.

A. My name is Kristi Gardner and my business address is 2 Innovation Way Pomona, CA 91768.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am a Principal Manager within the Asset Strategy & Planning organizational unit of Southern California Edison (SCE), leading Wildfire Safety Reporting and Project Management.

Q. Briefly describe your educational and professional background.

A. I obtained a Masters in Business Administration from University of Redlands. I am a utility professional with 23 years at Southern California Edison.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor the portions of *SCE-02: Direct Testimony in Support of GRC Track 4 Activity Forecast Request,* as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY
OF JEFF GOODING

Q. Please state your name and business address for the record.

A. My name is Jeff Gooding, and my business address is 2131 Walnut Grove, Rosemead, CA 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am the IT Principal Manager for Enterprise Architecture at Southern California Edison. I am responsible for managing and developing SCE's enterprise architectures, IT cost estimates, setting enterprise standards and designing technology solutions to meet business and customer needs.

Q. Briefly describe your educational and professional background.

A. I hold a Bachelor of Science Degree in Marketing Management and a Master of Business Administration from the California Polytechnic State University, Pomona. With over 30 years of software development and architecture experience, I have worked in varying capacities at several companies including: The Keith Companies from August 1988 to January 1990, David Evans and Associates, Inc. from January 1990 to March 1994, Rapid Access Systems, Inc. from March 1994 to June 1997, Cap Gemini/Ernst & Young, LLC (Ernst & Young, LLC was acquired by Cap Gemini) from June 1997 to 2003. In October 2003, I began to work as a Senior Systems Engineer at Southern California Edison. From there, I held management positions overseeing Edison SmartConnect (AMI), Smart Grid Systems Engineering, Enterprise Architecture for Energy & Security. I began my current position as IT Principal Manager for all IT Enterprise Architecture in March of 2019.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of *SCE-02: Direct Testimony in Support of GRC Track 4 Activity Forecast Request*, as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Rebuttal Testimony was prepared by and under my supervision.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?
A. Yes, it does.
Q. Does this conclude your qualifications and prepared testimony?
A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF VALARIE HERNANDEZ

Q. Please state your name and business address for the record.

A. My name is Valarie Hernandez, and my business address is 1515 Walnut Grove Ave., Rosemead, 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company (SCE).

A. I am the Principal Manager of Customer Care within SCE's Customer Programs and Services organzation. In this role, I am responsible for managing several functional areas of responsibility including, Customer care activities related to PSPS readiness and in event support, Income Qualified programs, and pricing.

Q. Briefly describe your educational and professional background.

A. I hold a Bachelor of Science degree in Organizational Leadership from the University of La Verne. I have over 30 years of experience in the utility industry and have held various positions of increasing responsibility across Southern California Edison including Customer Service, and Audits.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of *SCE-02: Direct Testimony in Support of GRC Track 4 Activity Forecast Request*, as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF MELANIE JOCELYN

Q. Please state your name and business address for the record.

A. My name is Melanie Jocelyn, and my business address is 1 Innovation Way, Pomona, CA 91768.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am the Principal Manager of T&D Vegetation Management Strategy & Planning at Southern California Edison. I am responsible for SCE and contract personnel supporting Vegetation Management activities throughout our service territory.

Q. Briefly describe your educational and professional background.

A. I hold a Bachelor of Science Degree in Environmental Policy Analysis and Planning from the University of California, Davis. I have worked for Southern California Edison since 2009 in project and leadership positions in the Transmission and Distribution organization related to quality, safety, and real estate. Most recently I was Principal Manager of Quality Oversight. I began my current position as Principal Manager of Vegetation Management in 2018.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of *SCE-02: Direct Testimony in Support of GRC Track 4 Activity Forecast Request*, as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY
OF MATTHEW PEACORE

Q. Please state your name and business address for the record.

A. My name is Matthew Peacore, and my business address is 2131 Walnut Grove Ave, Rosemead CA 91770

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am the IT Principal Manager for digital design and solutions as part of the Digital Accelerator organization. In this role I am responsible for:

- Developing and maintaining digital architectures and solution design
- Developing and managing advanced analytics solutions
- Developing and maintaining digital standards & methodologies and management of the digital center of excellence
- Managing digital products and developing & maintaining the portfolio roadmap for digital solutions

Q. Briefly describe your educational and professional background.

A. I have a Bachelor of Science degree in Mechanical Engineering from the University of Southern California (USC) as well as a Master of Business Administration from USC. For the past 24 years I have held various information technology leadership roles in application development, solution delivery, systems support, architecture and innovation, with expertise in analytics, supply chain management, sales, manufacturing, human resources, learning and development, engineering and energy/utilities. Of those 24 years, I have worked for the last 12 years at SCE, and prior to that at the Capital Group Companies and Mars Inc.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of *SCE-02: Direct Testimony in Support of GRC Track 4 Activity Forecast Request*, as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?
A. Yes, it does.
Q. Does this conclude your qualifications and prepared testimony?
A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY
OF BRANDON TOLENTINO

Q. Please state your name and business address for the record.

A. My name is Brandon M. Tolentino, and my business address is 3 Innovation Way, Pomona, CA 91768.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am the Director of Central Design and Engineering at Southern California Edison. My responsibilities include the oversight and resource and performance management of the distribution planning process and providing engineering, project management and design services supporting SCE's customers and the planning and operations of the distribution grid.

Q. Briefly describe your educational and professional background.

A. I hold a Bachelor of Science Degree in Electrical Engineering from the California Polytechnic State University, San Luis Obispo and I am a Licensed Professional Electrical Engineer in the State of California. I worked at Pacific Gas & Electric Company between January 2002 and May 2008. In May 2008, I began working as a Distribution Engineer at Southern California Edison. From there, I promoted through the various levels of Engineer, eventually becoming an Engineering Supervisor, and then an Engineering Manager 2. I was previously Principal Manager over Grid Modernization and Principal Manager of Distribution Engineering. I began my current position as Director of Central Design & Engineering in March of 2022.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of *SCE-02: Direct Testimony in Support of GRC Track 4 Activity Forecast Request*, as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?
A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY
OF EVANGELINE TORRES

Q. Please state your name and business address for the record.

A. My name My name is Evangeline Torres, and my business address is 2131 Walnut Grove, Rosemead CA 91770.

Q. I am a Principal Manager within IT's Enterprise Services - Solution Planning & Delivery T&D Portfolio organization. I have accountability for IT's software development and delivery of technology projects supporting Transmission & Distribution as well as the Asset Strategy & Planning organization. My role is to provide direction and oversight to a team of Senior Managers, Senior Project Managers, and Project Managers that directly manage the projects throughout their Software Development Lifecycle (SDCL). I oversee the SCE IT teams that partner with peer organizations to confirm the appropriateness of project estimates, utilize project governance committees to manage scope, adhere to the use of standard documentation, elicit clear requirements to reduce change requests, ensure the use of requirements trace-ability documentation to avoid gaps in development.

Q. Briefly describe your educational and professional background.

A. I have worked for Southern California Edison for over 30 years. My experience spans across Customer Service (CS), Transmission & Distribution (T&D), and IT. I have served as and operational supervisor and manager within CS and T&D as well as a Project Manager, Program Manager, and Portfolio Manager within CS, T&D and IT. I have managed operational improvement projects, organizational re-alignment projects, and for most of my career technology projects. I have several years of experience managing projects on the Client side having oversight of requirements development, process design, user acceptance testing, deployment management, and OCM. I also have several years of experience managing projects and managing project managers on technology projects throughout the projects SDLC within the IT organization. I have a bachelor's degree in Business Administration from the University of La Verne, a certification in "IT Essentials for Business Leaders" from Pepperdine Graziadino School of Business, completed the "Project Management Masters Certificate Program" from George Washington University/ESI, possess certificates in Project Fundaments, Risk

Management, Managing Multiple Projects from University of California Irvine, and completed an Organizational Change Management Certification from PROSCI .

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of *SCE-02: Direct Testimony in Support of GRC Track 4 Activity Forecast Request*, as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY
OF VIK TREHAN

Q. Please state your name and business address for the record.

A. My name is Vibhor 'Vik' Trehan and my business address is 1 Innovation Way, Pomona CA 91768.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

I am the Director of the Asset Management Program department within the Asset Strategy & Planning group of Southern California Edison's Operations organization. Primary responsibilities include overseeing asset engineering & strategic functions, leveraging data science & advanced analytics to inform asset risk models, and optimizing asset data to collectively guide a comprehensive asset management investment plan.

Q. Briefly describe your educational and professional background.

A. I hold a Master's of Science in Electrical Engineering from California State University, Fullerton and a Professional Engineering Certification. I began my SCE career as a Protection Engineer in 2004, and thereafter held multiple key positions in the areas of substation automation and commissioning. I managed substation's field crews responsible for inspection, maintenance, repairs and replacements of substation's major apparatus. Previously, I was also the Director of the Design Engineering and Work Management department within the Asset Management, Strategy & Engineering group of Southern California Edison's Transmission & Distribution organization providing engineering design services and overseeing engineering activities across Transmission, Distribution, Metering and Substation projects and programs.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor the portions of *SCE-02: Direct Testimony in Support of GRC Track 4 Activity Forecast Request,* as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?
A. Yes, it does.
Q. Does this conclude your qualifications and prepared testimony?
A. Yes, it does.

Appendix B

Joint IOU CC Effectiveness Workstream

Joint IOU CC Effectiveness Workstream
(Excerpt from 2022 WMP Update)

Introduction:

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

Overview:

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

- Benchmarking

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

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

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

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

The current type of covered conductor being installed in each of the utilities' service areas is an extruded multi-layer design of protective high-density or cross-linked polyethylene material. In this report, "covered conductor" refers generally to a system installed on cross-arms, in a spacer cable configuration, or as ABC. Table SCE 9-6, below, provides a snapshot of the approximate amount and types of covered conductor installed in the utilities' service areas.

Table SCE 9-6

Covered Conductor Type and Approximate Circuit Miles Deployed by Utility

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

Workstream Scope:

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

Benchmarking:

Each of the utilities' covered conductor programs have been informed by benchmarking. Benchmarking is a useful process to obtain insights, lessons learned, and continually improve performance. SCE, for example, previously researched covered conductor use in the U.S., Europe, Asia, and Australia. SCE benchmarked directly with 13 utilities abroad and in the U.S. and surveyed 36 utilities on covered conductor usage.[280] These efforts helped inform SCE's Wildfire Covered Conductor Program (WCCP). The utilities, as part of this joint working group, have conducted additional benchmarking. First, the utilities developed a survey consisting of 24 questions that focused on covered conductor usage, performance metrics, conductor applications, and system protection. The survey was then sent to approximately 150 to 200 utilities in the U.S. and abroad. To date, 19 utilities participated in the benchmarking survey[281] and are listed below.

1. American Electric Power
2. Ausnet Services
3. Bear Valley Electric Service, Inc.
4. Duke Energy
5. Essential Energy
6. Eversource Energy (CT)
7. Korean Electric Power Corporation
8. Liberty
9. National Grid
10. Pacific Gas and Electric Company
11. PacifiCorp
12. Portland General
13. Powercor
14. Puget Sound Energy
15. San Diego Gas & Electric
16. Southern California Edison
17. TasNetworks
18. Tokyo Electric Power Company
19. Xcel Energy

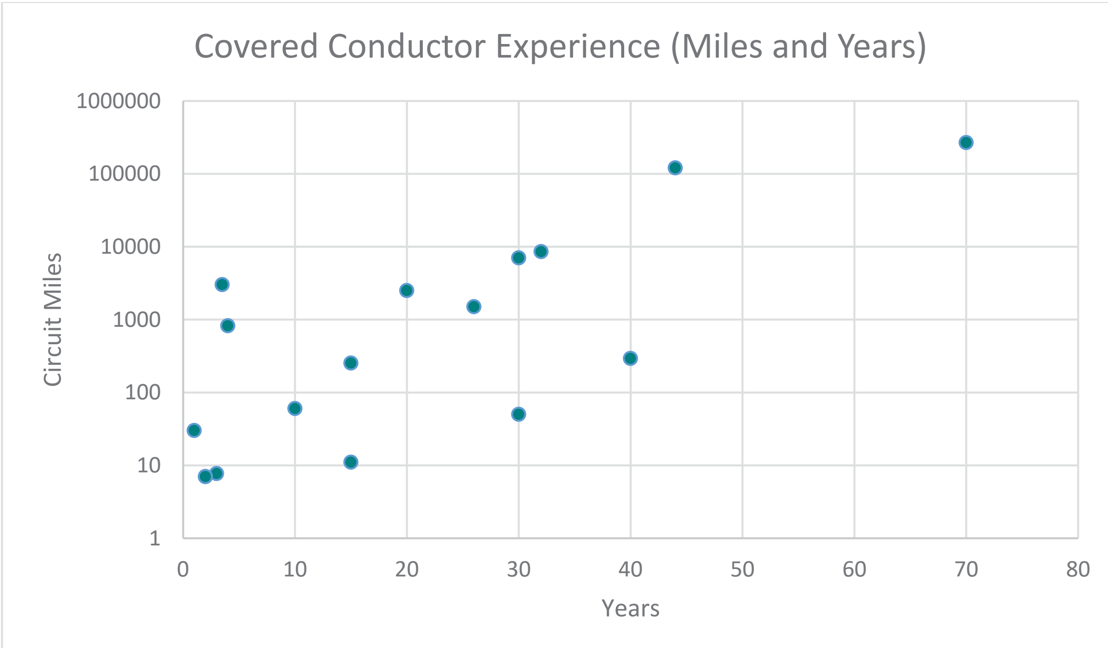
Approximately 90% of participants indicated the usage of bare conductor and covered conductor in their distribution systems. Respondents using spacer cable and aerial bundled cable were at 58% and 47%, respectively. Note that while covered conductor designs varied among the utilities, the majority (63%) of utilities use the three-layer jacket design. There was also a wide range of experience among respondents in terms of the number of years and miles installed, as shown in Figure SCE 9-14 below.

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

[281] *See* Covered Conductor Survey Results in Appendix 0.9.8.1

Figure SCE 9-14

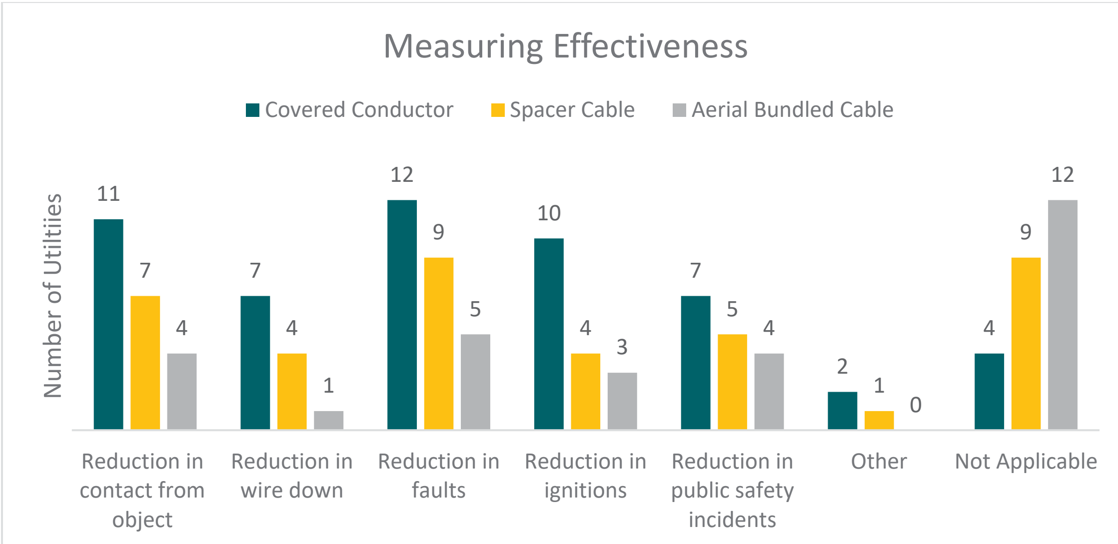
Covered Conductor (Open-crossarm and Spacer) Experience Among Respondents



Drivers for covered conductor deployment can vary by utility. Typical drivers include wildfire mitigation, reliability improvements, or reduction in public safety risk for contact with downed conductors. The utilities' performance metrics will differ depending on their associated drivers. The majority of utilities base the covered conductor's effectiveness in its ability to reduce faults and ignitions from contact-from-objects (CFO). These metrics are related to reliability and wildfire mitigation. Some utilities also measure the reduction in wire downs and public safety incidents to measure the covered conductor's effectiveness, which can be connected to public safety risk or ignition drivers. Figure SCE 9-15 illustrates the number of utilities using each metric to monitor the effectiveness of covered conductor, spacer cable, and aerial bundled cable.

Figure SCE 9-15

Covered Conductor Performance Metrics In Use by Utilities



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

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

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

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

Testing:

Testing workstream objectives are to evaluate, through physical testing, the performance of covered conductors as compared to bare conductors for historically documented failure modes. As an example, testing covered conductor performance in preventing incidental contacts that cause phase-to-phase and phase-to-ground faults caused by vegetation, conductor slapping, wildlife, and metallic balloons.[282] To meet this objective, PG&E, SDG&E, and SCE collaborated on conducting additional research and testing of covered conductor. This effort, now joined by PacifiCorp, BVES and Liberty, has two phases. The first phase, which is now complete, had objectives to identify failure modes for covered conductors, document a utilities' consensus FMEA for covered conductors, and to collect all previously conducted testing on covered conductor performance that informs on the performance of covered conductor for identified failure modes. Lastly, to perform comparison between covered versus bare conductor performance for failure modes tested. PG&E contracted with Exponent, Inc. (Exponent) to develop a report for Phase 1, which was completed in December 2021, summarized below, and attached as Appendix 9.8.2 to this update. The Phase 1 study was led by Exponent and consisted of a literature review, discussions with SMEs, a failure mode identification workshop, and a gap analysis comparing expected failure modes to currently available test and field data. The outcome of the Phase 1 report identified gaps in previous testing and is informing the scope of laboratory testing that is currently being planned for in the ongoing Phase 2 step of this sub-workstream. As discussed below, SCE, PG&E, and SDG&E are proceeding with testing.

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

While high-level, field-experience-based evidence of covered conductor effectiveness is plentiful, relatively few lab-based studies exist that address specific failure modes or quantify risk reduction relative to bare conductors. A high-level failure mode identification workshop was conducted to identify operative failure modes relevant to overhead distribution systems for both bare and covered conductors. The workshop included SMEs from the six California IOUs and Exponent and identified hazards and failure modes applicable to bare and covered conductors. In total, 10 hazards and 55 unique failure mode / hazard scenario combinations were identified through the failure mode workshop. Of the 10 hazards that affect bare conductors, covered conductors have the potential to mitigate six hazards. Mitigated hazards include tree/vegetation contact, wind-induced contact (such as conductor slapping), third-party damage, animal-related damage, public/worker impact, and moisture. The report includes a risk reduction assessment of the failure modes that affect both bare and covered conductors. The report also

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

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

SCE, PG&E and SDG&E are pursuing testing based on the results of the Phase 1 report and SME input. SCE established a test plan for both 17 kV[283] and 35 kV covered conductor designs and expects to conduct approximately 35 testing scenarios that cover various contact-from-object, system strength, flammability, and water ingress scenarios. PG&E is in process of developing a complementary test plan to ensure coverage of failure modes and additional covered conductor types that may not be included in the SCE test plan. SDG&E is assessing conducting, for example, environmental, service life, UV exposure, degradation and mechanical strength tests. The utilities are collaborating on the testing plans to ensure the gaps identified in the Phase 1 report are covered and SME input is considered.[284] SCE began testing on February 1, 2022 and anticipates its testing and review process to extend for several months. SDG&E and PG&E timelines have not been finalized but are anticipating testing to start around Q2 to Q3 2022. The utilities will collaboratively review and assess the results of the tests. After the test results are reviewed and any issues are addressed (e.g., additional tests), the utilities will prepare a report (or reports in phases as testing is completed) and make the report(s) available. The test results are anticipated to further inform effectiveness of covered conductor and potentially identify any needed changes in design and construction standards to ensure failure modes are further limited by the use of covered conductor. Beyond the testing process, in 2022, the utilities will continue to collaborate on methods to quantify risk reduction of covered conductor relative to bare conductors taking into account the testing results and will establish any next steps for this sub-workstream based on the results of the testing. The utilities will provide an update on these efforts in their 2023-2025 WMPs.

Estimated Effectiveness:

Each utility's covered conductor programs are different due to factors such as location, terrain, and existing overhead facilities. Similarly, the utilities are at different phases of installing covered conductor as some have just started deployment while others have deployed hundreds to thousands of miles of covered conductor. These features, amongst others, result in data, calculations, and methods of estimating effectiveness that are different. As such, the utilities have been working on understanding differences and discussing methods for better comparability. While the utilities may differ in their covered conductor approach, the utilities each estimate that covered conductor will reduce wildfire risk. The

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

[284] SCE, PG&E, and SDG&E are also collaborating on potential cost sharing.

utilities' estimated covered conductor effectiveness values range from approximately 60 to 90 percent at reducing outages/ignitions and/or the drivers of wildfire risk. Below, the utilities describe their data, analyses, and methods used to estimate the effectiveness of covered conductor to mitigate outages/ignitions and/or the drivers of wildfire risk and present their estimated effectiveness values. Collectively, the utilities summarize next steps to improve consistency of data, calculations and methods.

Covered Conductor Estimated Effectiveness:

SCE:

SCE's WCCP consists of replacing bare conductor with covered conductor, the installation fire-resistant poles (FRPs) where applicable, wildlife covers (animal safe construction), lighting arresters, and vibration dampers below 3,000 feet. These activities are accounted for when determining the overall mitigation effectiveness of SCE's WCCP. To determine the mitigation effectiveness of WCCP, SCE evaluated the ability for covered conductor and FRPs to address each ignition risk driver. SME judgment was used to determine the mitigation effectiveness of covered conductor; this judgment was informed by benchmarking, analysis, and testing. The following tables explain the reasoning behind the effectiveness values. Table SCE 9-7 below, includes only the covered conductor values and not the combined covered conductor and FRP values used in SCE's risk reduction calculation. Table SCE 9-8 below, includes only the FRP mitigation effectiveness values. Additionally, mitigation effectiveness values at 0% or that were not applicable were omitted from both tables.

Table SCE 9-7

SCE Covered Conductor Mitigation Effectiveness Estimate

Driver		Mitigation Effectiveness	Reasoning
D-CFO	Vegetation contact-Distribution	60%	SCE conducted analysis that involved establishing four vegetation sub-drivers based on SCE's experience with vegetation contact. The four sub-drivers are: Heavy Contact (Tree), Heavy Contact (Limb), Light Contact (Frond/Branch), Light Contact (Grow In). SCE analyzed historical vegetation fault data from 2015-2018 and determined that percentage of occurrence between all four sub-drivers. • Heavy Contact (Tree): 30% • Heavy Contact (Limb): 22% • Light Contact (Frond/Branch): 43% • Light Contact (Grow In): 5% SCE testing supported that covered conductor will be 99% effective against both Light Contact drivers, which accounts for 1% of the line potentially being uninsulated at connection points or dead-ends. Additionally, SCE also determined that covered conductor will not be effective against Heavy Contact (Tree) due to being unable to mechanically support the weight of a tree. Covered conductor was determined to be 50% effective against limb contact, conservatively assuming that the limb will exceed the conductor's

Driver		Mitigation Effectiveness	Reasoning
			strength 50% of the time. The overall mitigation effectiveness value for vegetation is based on the weighted average of all four sub-driver and was calculated to be 60%.
D-CFO	Animal contact-Distribution	65%	SCE conducted analysis that involved establishing animal contact sub-drivers in terms of equipment affected. These Animal Contact sub-drivers include Conductor/Wire, Fuse/BLF/Cutout, Terminations, Transformer, etc. The percent of animal contact faults were calculated per sub-driver using 2015-2020 data. Next, SCE used SME knowledge to establish the percent of wildlife covers existing in the system for the applicable sub-driver. Lastly, SCE assigned a preliminary mitigation effectiveness based on SME judgement per sub-driver. Covered conductor is considered 100% effective for Conductor/Wire Animal contact based on testing. Other equipment with associated wildlife covers were assigned a 90% effectiveness to account for the wildlife cover installation required during WCCP. The preliminary mitigation effectiveness was multiplied by the percent of wildlife covers not existing in the system to adjust for the possibility that pre-WCCP structures already have wildlife covers. The weighted average of this adjusted mitigation effectiveness was calculated to be 65%.
D-CFO	Balloon contact-Distribution	99%	Covered conductor is estimated to be 99% effective against contact with metallic balloons. This is supported by testing and accounts for approximately 1% of the line potentially being uninsulated at connection points or dead-ends.
D-CFO	Vehicle contact-Distribution	50%	SCE analyzed the composition of historical wire downs from vehicle collisions and found that nearly all ignitions from a vehicle collision are caused by conductor contact. SCE testing established the covered conductor is effective against conductor-to-conductor contact. However, there is uncertainty regarding the effectiveness of covered conductor during a wire down due to exposed conductor at the dead-end or break-point. To account for this uncertainty, a mitigation effectiveness of 50% was assumed.
D-CFO	Other contact-from-object - Distribution	77%	Analysis found that foreign material accounts for 77% of the “Unspecified” driver, while Ice/Snow accounts for the other 23%. While covered conductor is effective against foreign materials, it is not effective against ice/snow.

Driver		Mitigation Effectiveness	Reasoning
D-CFO	Connection device damage or failure - Distribution	90%	Assumption that infrastructure replacement will lead to 90% mitigation effectiveness. Reconductoring with covered conductor will facilitate the replacement of aged hardware. Some hardware used in new installation will also be improved technology.
D-CFO	Unknown contact - Distribution	77%	Weighted average of vegetation contact, animal contact, balloon contact, and other contact.
D-EFF[285]	Splice damage or failure — Distribution	90%	Assumption that infrastructure replacement will lead to 90% mitigation effectiveness. Reconductoring with covered conductor will facilitate the replacement of aged hardware. Some hardware used in new installation will also be improved technology.
D-EFF	Crossarm damage or failure - Distribution	50%	Covered conductor is estimated to be 50% effective against crossarm failure. Reconductoring with covered conductor will facilitate the replacement of aged crossarms. Additionally, testing illustrated that covered conductor significantly reduced leakage current on the crossarm, reducing the occurrence of damage due to electrical tracking.
D-EFF	Insulator damage or failure- Distribution	90%	Assumption that infrastructure replacement will lead to 90% mitigation effectiveness. Reconductoring with covered conductor will facilitate the replacement of aged insulators.
D-EFF	Wire-to-wire contact / contamination- Distribution	99%	Covered conductor is estimated to be 99% effective against wire-to-wire contact. This is supported by testing and accounts for approximately 1% of the line potentially being uninsulated at connection points or dead-ends.
D-EFF	Conductor damage or failure — Distribution	90%	Assumption that infrastructure replacement will lead to 90% mitigation effectiveness. Reconductoring with covered conductor will facilitate the replacement of aged conductor. Additionally, conductor failure due to faults will also be reduced because: (1) covered conductor will prevent contact-from-object faults from occurring and (2) the covered conductor will have a larger short circuit duty.
D-EFF	Insulator and brushing damage or failure - Distribution	90%	Assumption that infrastructure replacement will lead to 90% mitigation effectiveness. Reconductoring with covered conductor will facilitate the replacement of aged insulators.

Table SCE 9-8

[285] EFF represents Equipment / Facility Failure

SCE Fire Resistant Pole Mitigation Effectiveness

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

PG&E:

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

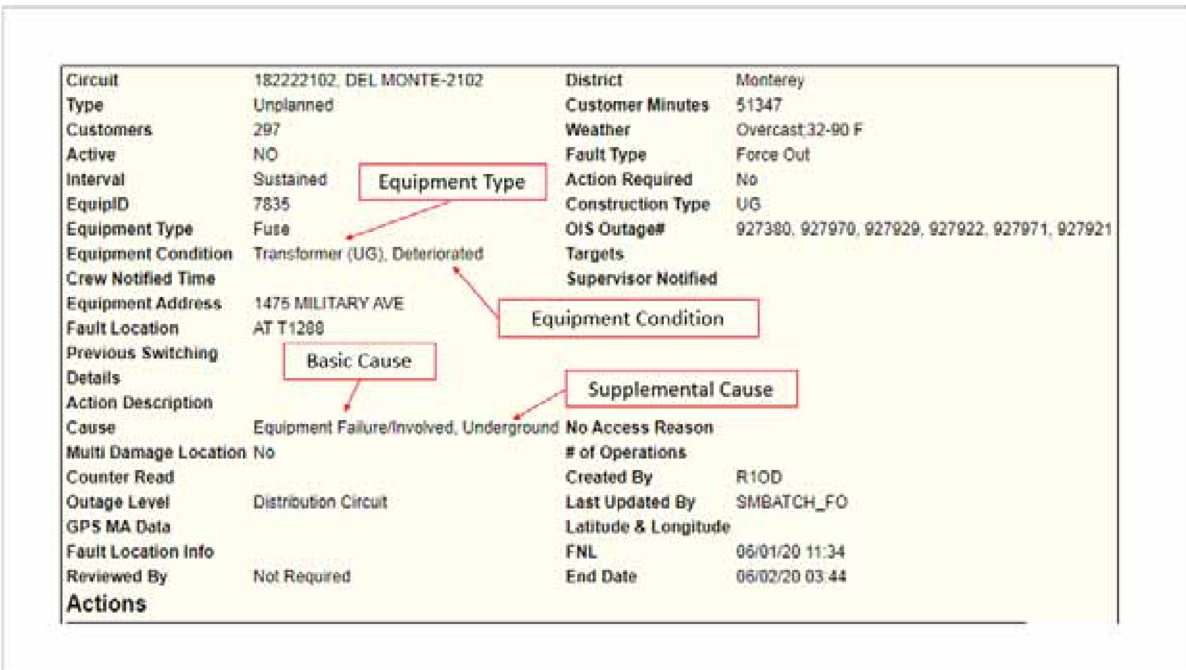
Determining whether a specific event could result in an ignition depends upon a wide variety of factors, including the nature of the event itself and prevailing environmental conditions (e.g., weather, ground moisture level, time of year). As PG&E does not have complete information to make this determination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

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

1. SMEs identified 4,336 distinct outages by using all known combinations of basic cause, supplemental cause, equipment type and equipment condition from the distribution outage database as show in Figure SCE 9-16 below. Whenever an outage is reported, an operator fills in different fields that provide information about the outage, through SME evaluation, it was decided that the combination of the four fields aforementioned provide an appropriate distinction of different outage types.

Figure SCE 9-16

PG&E Distribution Outage Database Record



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

Actions

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

   - All = Eliminates likelihood of a certain type of outage occurring resulting in an ignition
   - High = Reduces likelihood significantly of a certain type of outage occurring resulting in an ignition
   - Medium = Reduces likelihood moderately of a certain type of outage occurring resulting in an ignition
   - Low = Reduces likelihood minimally of a certain type of outage occurring resulting in an ignition

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

3. Each of qualitative categories were assigned a quantitative value, which measured the likelihood of outage reduction:
   - All = 90%
   - High = 70%
   - Medium = 40%
   - Low = 20%
   - None = 0%

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

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

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

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

The results from the analysis detailed in the steps above are interpreted as Overhead Hardening having an effectiveness of approximately 63% for sections where Overhead Hardening has been completed. Therefore, a section of a line that has been hardened is approximately 63% less likely to have an outage of any type. Similarly, a section of a line that has been hardened is approximately 63% less likely to have an outage of each of the drivers. Below, Table SCE 9-9 provides a summary of the results from the analysis.

Table SCE 9-9

PG&E Covered Conductor Mitigation Effectiveness Estimate

Driver	Count of Incident ID	Average of Overhead Hardening Effectiveness Percentage
Animal	36	76%
D-Line Equipment Failure	179	71%
Human Performance	3	0%
Natural Hazard	285	35%

Other	256	90%
Other PG&E Assets or Processes	15	47%
Third Party	20	62%
Vegetation	204	63%
Grand Total	**998**	**63%**

SDG&E:

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

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

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

In order to quantify the risk reduction of wildfires that would be achieved by covered conductor, SDG&E evaluated 80 events that resulted in ignitions. SMEs weighed in on the likelihood that covered conductor installation would prevent an ignition for the particular type of outage depending on the severity of the incident. As seen in Table SCE 9-10 below, the result is a reduction in ignitions from 80 to 28.4, and a resulting effectiveness estimate of 64.5%.

Table SCE 9-10

SDG&E Covered Conductor Mitigation Effectiveness Estimate

Fault/Ignition Cause	*Number of Ignitions*	*SME Effectiveness*	*Post-Mitigation Ignitions*
Animal contact	5	90%	0.5
Balloon contact	8	90%	0.8
Vegetation contact	10	90%	1.0
Vehicle contact	14	20%	11.2
Other contact	4	10%	3.6

Other	2	10%	1.8
Equipment - All	34	80%	6.8
Unknown	3	10%	2.7
Total	80	64.5%	28.4

PacifiCorp:

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

Spacer cable systems employ an engineered weak-link system where covered conductors are in a spaced bundle configuration. The bundle is supported by a high-strength tensioned cable which has shown to be able to support the cables even when the system is under extreme stress.[286] This system is secured to poles primarily with fixed or flex tangent brackets, in which the messenger is the only connected conductor. The covered conductors are not tensioned (nor are they structural members) and instead are held together with spacers attached to a tensioned messenger and placed approximately 30-feet apart. PacifiCorp's spacer cable systems are currently installed using components rated at or above 35 kV, where the only deviation is in the covered conductor itself, whereas it uses two voltage classes; 15 kV for energized voltages of 12.47 kV and below and 35 kV for energized voltages of 20.8 kV to 34.5 kV.

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

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

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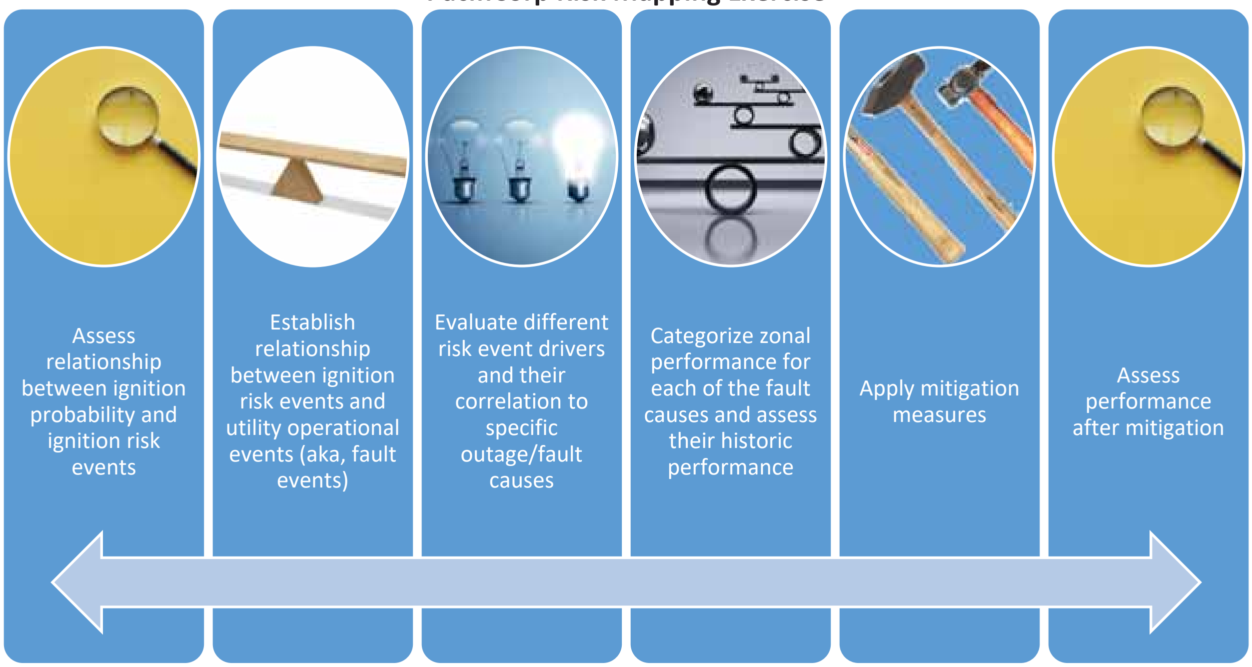
[286] Bouford, James D. "Spacer cable reduces tree caused customer interruptions." 2008 IEEE/PES Transmission and Distribution Conference and Exposition. IEEE, 2008.

The company prepared a mapping exercise to evaluate which risks could be addressed with what alternatives, recognizing that covered conductor and a variety of other measures might all be valid approaches. As a starting point, the company evaluated its outage data to align against risk event drivers and correlating against mitigation alternatives. This process is shown graphically in Figure SCE 9-17 below.

Figure SCE 9-17

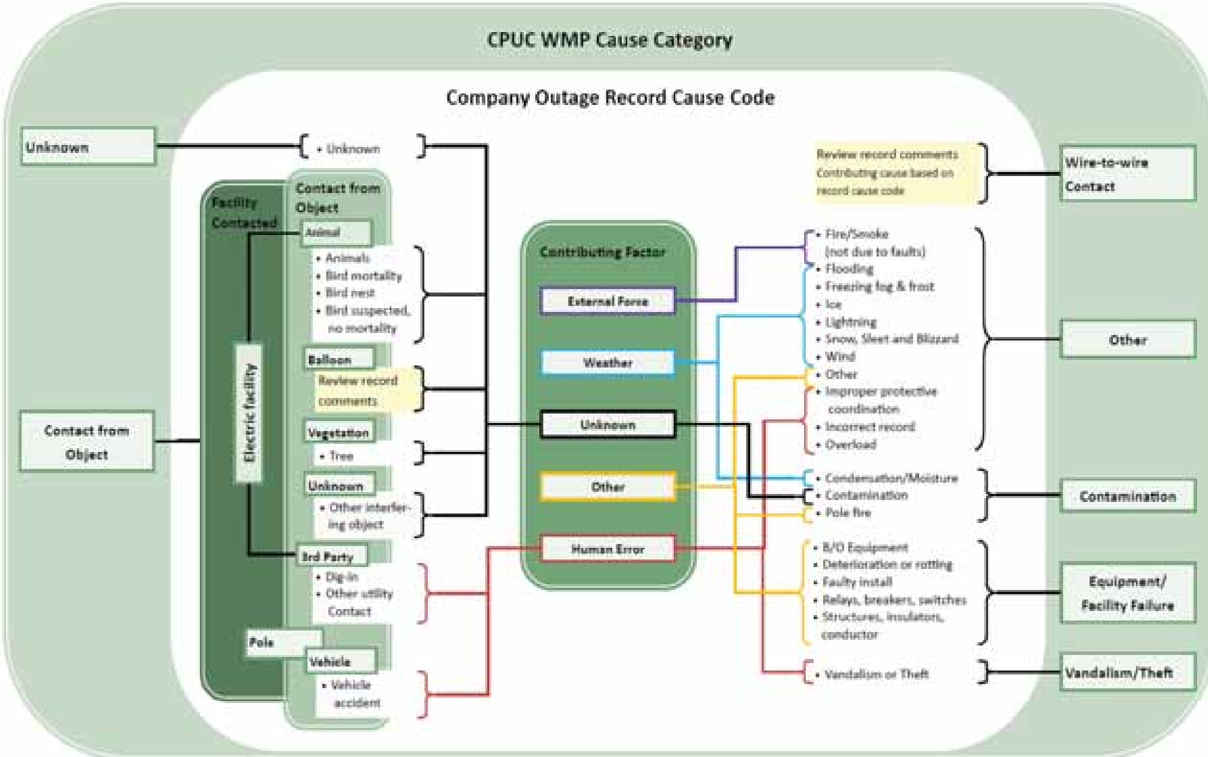
PacifiCorp Risk Mapping Exercise



With this process, as outlined below in Figure SCE 9-18, PacifiCorp evaluated outage causes (and sub-causes, as well as commented information) to establish a relationship between forced outages and risk event drivers.

Figure SCE 9-18

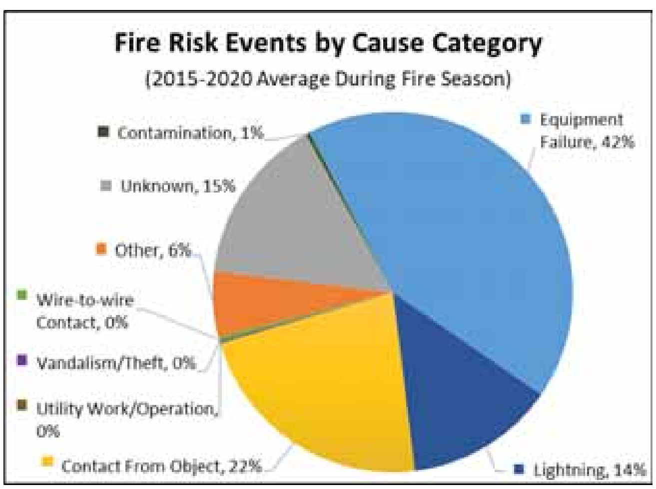
PacifiCorp Outage Cause Evaluation



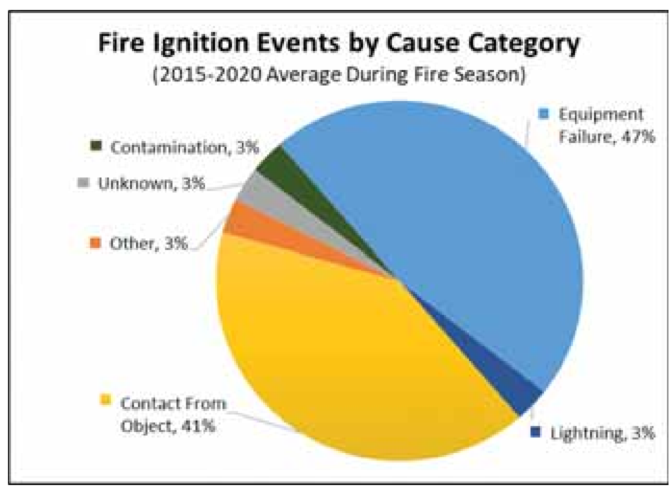
The company then determined the average percentage of fire risk events and ignition events over the 2015-2020 period as shows in the figures below.

Figure SCE 9-19

PacifiCorp Fire Risk Events by Cause Category



PacifiCorp Fire Ignition Events by Cause Category



The company then evaluated the probability (qualitatively scored and informed by the information above) of each ignition risk driver and its potential for ignition based on the season (fire and non-fire season) as shown in Figure SCE 9-20 below. It was also segmented by transmission and distribution system, since the probabilities of each risk event driver and ignition risk were not equivalent. Qualitatively, PacifiCorp designated each cause either a low (L), medium low (ML), medium (M), medium high (MH), and high (H) by fire and non-fire season for the likelihood of the cause to result in an ignition to help establish priorities of mitigations.

Figure SCE 9-20

PacifiCorp Fire Risk Events Assessment

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

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

In the future, as the company reconductors entire zones of protection, it will have better certainty about the effectiveness of the mitigation against each ignition risk driver within that zone. For the initial projects, the scoping was directly motivated by reducing contact, primarily vegetation outage rates, and as a result the outage rates being measured are directly influenced by that decision. Even though the data is not perfect, it still provides a valuable insight into the expected reduction in risk from covered conductor. As the company constructs more projects and as time passes for outage events to accrue, PacifiCorp expects to further refine the outage rate reduction by ignition risk driver. For the ignition risk drivers that it is not able to confidently measure, PacifiCorp takes the 90% reduction in outage rate and modifies it with SME input to create estimated effectiveness values. The ignition risk drivers, the estimated reduction, and the explanation is summarized in Table SCE 9-11 below.

Table SCE 9-11

PacifiCorp Covered Conductor Mitigation Effectiveness Estimate

Ignition Risk Driver	Estimated Effectiveness Percent Reduction	Discussion
Vegetation Contact	90%	Vegetation contact is one of two primary drivers for the pilot project selection.
Animal Contact	90%	Animal contact is the second of two primary drivers for the pilot project selection.
Balloon Contact	99%	In general, expect contact from balloons to be mitigated.
Vehicle Contact	90%	Due to the increased strength of spacer cable systems, combined with increased resilience to wire-to-wire contact, estimate a 90% effectiveness.
Equipment Failure	90%	Much of the equipment used to construct bare overhead systems is replaced with different components. Additionally, phase conductors are not under tension. This estimated effectiveness is not incorporating downstream equipment such as transformers and protective devices.
Wire to Wire Contact	99%	Due to the forces experienced from vegetation contact, instances of wire-to-wire contact have been observed. No faults occurred.
Contamination	75%	Risk of contamination is estimated to be reduced due to systems being insulated beyond their standard NESC minimum ratings.
Vandalism/Theft	50%	In general, spacer cable has less risk of conductor theft as well as vandalism. Believe there are two areas where there could be increased risk of vandalism and theft, for example, damage from “gunshot” to the conductor covering, and theft of copper ground wiring.

Ignition Risk Driver	Estimated Effectiveness Percent Reduction	Discussion
Lightning	50%	Given spacer cables unique design where the messenger (neutral) is the topmost conductor, it acts as a grounded shield wire for the phase conductors. In addition, earth grounds are utilized every approximately 500 feet to further ground the system. With diligence in lightning arrester placement, estimate a 50% reduction in lightning-related faults.
Third Party	90%	Third-party including contact from joint use, boom arms, etc. should be mostly mitigated with spacer cable.

BVES

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

Based on benchmarking with other utilities' estimated effectiveness against ignition risks, discussions with its covered conductor supplier, and the short amount of time that it has installed covered conductor, BVES believes that the estimate of effectiveness on ignition risk drivers in its service territory is approximately 90%. This is BVES's first initial look and as it installs more covered conductor and gathers more historical data, it will continue to assess the estimate of effectiveness. BVES presents its estimated effectiveness in Table SCE 9-12 below.

Table SCE 9-12

BVES Covered Conductor Mitigation Effectiveness Estimate

Ignition Risk Driver	Percent Reduction	Discussion (Contacts on Cover Conductor cable)
Vegetation Contact	90% +	Vegetation contact on 1, 2, 3 phase and/or neutral wire.
Animal Contact	90% +	Animal contact on 1, 2, 3 phase and/or neutral wire.

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

<u>Liberty</u>

To estimate the effectiveness of its Covered Conductor WMP initiative in mitigating wildfire risk, Liberty evaluated the ability of covered conductor to reduce each ignition risk driver, as seen in Table SCE 9-13 below. Liberty employed an internal risk working group to assess the effectiveness of covered conductor and other system hardening initiatives in reducing wildfire risk. This working group consisted of SMEs across its engineering, operations, wildfire prevention and regulatory teams. The SMEs convened weekly to discuss in detail each ignition risk driver and the mitigation effectiveness of covered conductor and other system hardening initiatives. SMEs referenced Liberty's historic outage data, including the location and cause of the outage and any associated dispatch or filed notes included in its outage management database. SMEs discussed the extent to which covered conductor would reduce, eliminate, or not have an effect on the likelihood of a specific type of outage occurring and leading to an ignition. Outages were classified by the ignition risk drivers listed in the table below and an estimated mitigation effectiveness percentage was developed for each risk driver.

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

Table SCE 9-13

Liberty Covered Conductor Mitigation Effectiveness Estimate

Ignition Risk Driver	Covered Conductor Mitigation Estimated Effectiveness (%)	Reasoning
Animal contact	90%	• Line is potentially uninsulated at connection points, transformer taps and dead-ends (locations with higher probability of animal activity).
Vegetation contact	95%	• CC will handle most tree branches falling on it, and grow-in, but not an entire tree (fall-in).
Vehicle contact	50%	• If a car takes a pole out, there is a reasonable chance the circuit will remain in service. • A wire-down event from car-hit-pole will result in fewer faults with covered conductor.
Conductor failure	80%	• Conductor not totally fail-proof from branches (larger, heavier, falling further) or tree falls, potentially breaking poles and crossarms. Steel poles/fiberglass crossarms might mitigate some of this vs. wood.
Conductor failure - wire slap	95%	• Covered conductor largely eliminates mid-span wire-slap phase-to-phase faults
Conductor failure - wires down	80%	• See logic for vehicle contact
Other - Including unknowns	75%	• Liberty suspects that many ‘unknown’ OMS outage cause codes are non-failure

Ignition Risk Driver	Covered Conductor Mitigation Estimated Effectiveness (%)	Reasoning
		wire slap, light veg contact, lightning or animal because no damaged component can be found as a reason for protective device operation.
Weather - Snow (better defined)	90%	• Liberty's covered conductor installation typically includes new poles and crossarms due to higher conductor loads. Poles designed to meet the GO 95 strength requirements.
Weather - Lightning	15%	• Messenger wire on ACS attracts lightning strikes away from conductors.
Weather - Wind	90%	• Covered conductor largely eliminates mid-span wire-slap phase-to-phase faults
Pole Fire	80%	• ACS prevents bare wire from laying on the cross-arm and burning. • Tree wire has multi-layer jacket which greatly reduces opportunity for bare wire contact with wood supporting apparatus.

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

Recorded Effectiveness:
The utilities are in the early phases of covered conductor deployment and measuring its effectiveness. Though the utilities' data is limited, the early outcomes, as presented below, show covered conductor effectiveness at reducing the risk drivers that can lead to wildfires range between approximately 60 to 90 percent, which is consistent with the utilities' estimated effectiveness values, benchmarking, past testing results, and the results of the Phase 1 testing report. With the limited amount of data and the fact that the utilities have taken different approaches to measuring the effectiveness of covered conductor, in 2022, the utilities will work towards developing a common methodology (or multiple methods) all utilities can use for better comparability. The utilities also plan to continue discussions with the IEEE DRWG on methodologies to measure the effectiveness of covered conductor as part of a peer-review process.

Below, the utilities describe data and analyses they have conducted regarding measuring the recorded effectiveness of covered conductor and collectively the utilities summarize future steps to improve these methods and updates to the data sets.

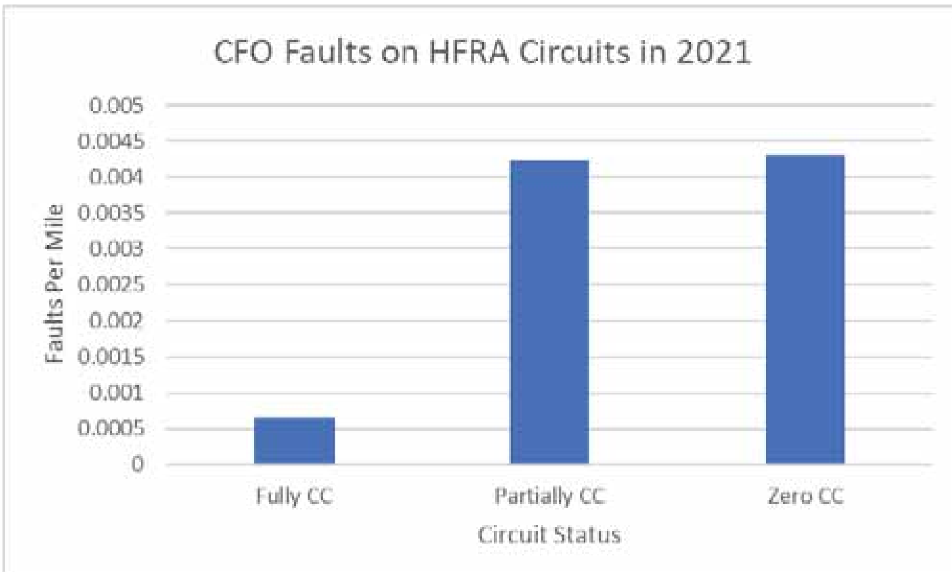
Covered Conductor Recorded Effectiveness:

SCE

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

Figure SCE 9-21

SCE Faults on HFRA Circuits in 2021



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

Since 2018, SCE has documented known contact-related events with covered conductor. In one instance, a tree fell on covered conductor lines, making contact with all three phases. In another case, energized covered conductor lines fell into adjacent trees after a vehicle struck a pole, as shown in Figure SCE 9-22 below. These events did not result in faults, wires down, or ignitions because covered conductor was deployed and provide examples of effectiveness of covered conductor in the field.

Figure SCE 9-22

Covered Conductor Contact with Vegetation After Car-Hit-Pole
Ojai, California – July 24, 2020

PG&E

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

The Overhead Hardening Program is still in its infancy which makes it difficult to have the amount of data needed to have statistical significance from this type of analysis. Initial analysis has been limited to counts of outages at the circuit segment level that compare the annual average from 2015-19 (pre-overhead hardening) to the 2020 (hardened) total count of outages where overhead hardening was completed in 2019 as shown in Table SCE 9-14 below.

Table SCE 9-14

PG&E Pre-Overhead Hardening Compared to Post Hardened Count of Outages

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

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

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

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

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

SDG&E

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

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

PacifiCorp

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

Table SCE 9-15 below shows the performance before and after covered conductor installation, with several of the more recent projects not yet having sufficient history to calculate the effectiveness. As such, the table below summarizes PacifiCorp's experience of about 15-20 miles of the total covered conductor installed.

Table SCE 9-15

Improvement Percentage for Covered Conductor/Spacer Cable Projects

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

This data is summarized graphically below in Figure SCE 9-23, where the improvement percentage is compared against the percentage of the ZOP that was reconductored. As can be seen, the higher the percentage of the ZOPs, the higher the recorded effectiveness when measured by faults (risk events) per mile.

Figure SCE 9-23

Percentage of Covered Conductor (Spacer Cable) in Zone Versus Improvement Percentage

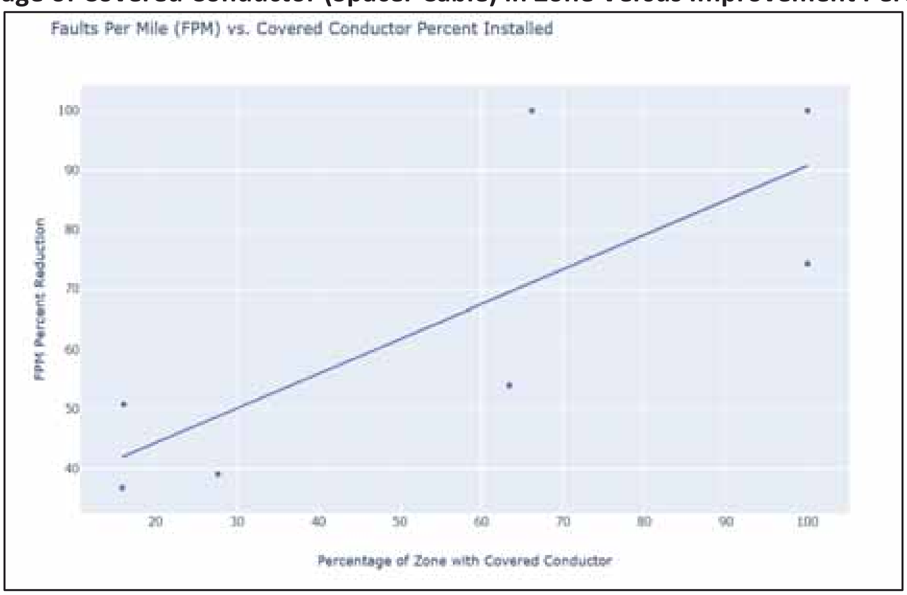
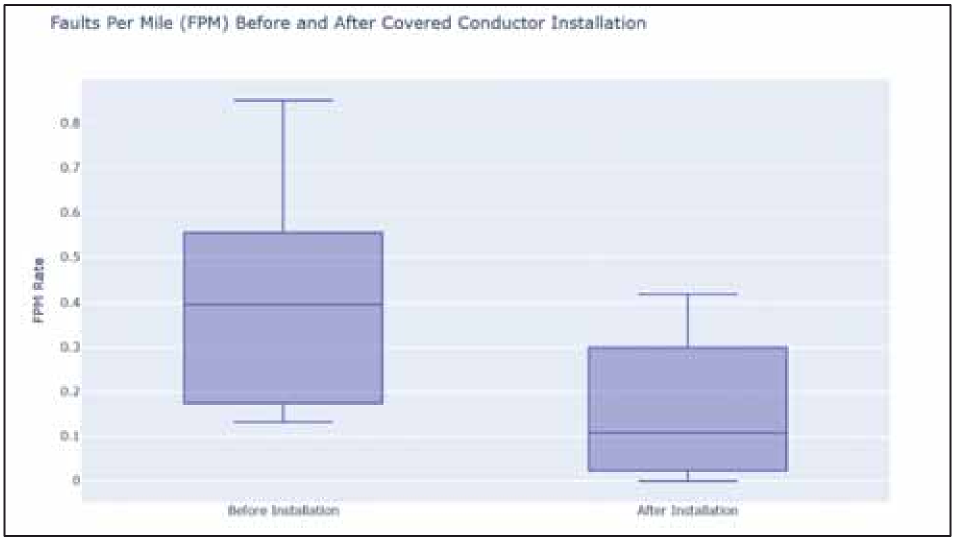


Figure SCE 9-24 below shows how the ZOPs performed before the mitigation was completed versus after the mitigation was completed, normalized based on the faults-per-mile recorded.

Figure SCE 9-24

Comparison of Faults Per Mile Performance Before Versus After Covered Conductor (Spacer Cable) Installation



PacifiCorp has also documented known contact-related events with covered conductor. As shown in Figure SCE 9-25 below, these events did not result in faults, wires down, or ignitions because spacer cable was deployed and provide examples of effectiveness in the field.

Figure SCE 9-25

Examples of Effectiveness of Covered Conductor to Risk Events

BVES

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

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

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

Currently, BVES has not had any outages, wire down, tree limbs and/or ignitions on the lines that have been covered. BVES is still in the early stages of its covered conductor program. As more areas are covered and as more time passes, BVES will be able to compile more recorded data to inform on the effectiveness of covered conductor. Table SCE 9-16 below provides a simple assessment of recorded outages since 2016 in BVES' system which shows a reduction of outages beginning in 2019.

Table SCE 9-16

BVES 2016-2021 Recorded Outages Assessment

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

<u>Liberty</u>

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

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

Table SCE 9-17

Historic Forced Outages by Risk Driver for Topaz 1261 Circuit (2017-2021)

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

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

- Only the approximate outage locations are documented by field crews. While the general area affected is valuable for evaluating performance, Liberty is working with its field crews to document location at a more specific level.
- There are limits to the way dispatchers code outages within Liberty's existing outage management system (OMS). Liberty is currently undergoing an upgrade to its OMS and is working with its operations, dispatch and engineering teams to improve the data and to identify outage metrics and risk drivers to include in the upgrade.
- The planned OMS upgrade will coincide with a budgeted GIS upgrade, closely followed by a budgeted AMI implementation. These combined implementations are expected to better capture cause documentation, geo location of faults, outage extent/duration, and protective device operation.

Next Steps

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

Alternative Comparison:

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

Covered Conductor System:

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

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

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

Alternatives:

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

Existing Bare Conductor System (status quo)

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

New Bare Conductor System (like-for-like replacement)

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

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

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

Spacer Cable System

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

Aerial Bundled Cable System

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

Underground System

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

Remote Grid

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

Comparison:

The utilities conducted workshops over multiple days to discuss each sub-driver (from Table 7.1 of the WMP Guidelines) and assessed whether the alternatives have lower, similar or higher effectiveness than a covered conductor system. The results are shown in Table SCE 9-18 below. A red arrow represents a lower effectiveness, an orange arrow represents similar effectiveness, and a green arrow represents a higher effectiveness.

Table SCE 9-18

Mitigation Effectiveness Comparison of Alternatives to Covered Conductor

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

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

Next Steps:
In 2022, the utilities plan to expand this assessment of alternatives to mitigate wildfire risk by including other technologies and mitigations such as replacing fuses, installing RARs/RCSs, as well as newer technologies that the utilities are exploring including, for example, REFCL technologies, OPD, EFD, and DFA. Additionally, the utilities will assess how to estimate the relative percent difference of effectiveness for the alternatives.

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

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

<u>SCE</u>
SCE activates PSPS largely based on two factors. The first factor used to drive PSPS decisions is the FPI, which estimates the likelihood of a spark turning into a major wildfire. FPI is calculated using forecasted wind speed, dewpoint depression, and various fuel moisture variables which are generated from SCE's customized version of the Weather Research and Forecasting (WRF) model. SCE's FPI scores range from 1 to 17, and any score at or above 12/13 (based on, for example, fire climate zone) is considered high risk. SCE reviews fire potential related products from the NWS and the GACC to confirm the wildfire threat related to PSPS. The second factor used to drive PSPS decisions is wind speed. SCE considers the NWS Wind Advisory levels (defined as 31 mph sustained wind speed and 46 mph gust wind speed) and the 99th percentile of historical wind speeds in the area to set activation thresholds. The Wind Advisory level is chosen because of the propensity for debris or vegetation to become airborne, while a circuit's 99th percentile wind speeds represent rare or extreme wind speeds that a particular circuit sees around four times per year. In 2021, SCE raised its de-energization thresholds for isolatable segments or circuits that have had covered conductor installed. The de-energization threshold for isolatable segments with

covered conductor is 40 mph sustained and 58 mph gusts, which aligns with the NWS high wind warning level for windspeeds at which infrastructure damage may occur. [287]

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

PG&E

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

PG&E's thresholds for PSPS are based on a risk assessment that combines the probability of utility related outages and ignitions, called the Ignition Probability Weather (IPW) model, and the probability of catastrophic fires, called the Fire Potential Index (FPI). This combination is called the Catastrophic Fire Probability (CFPD) and is given by the equation:

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

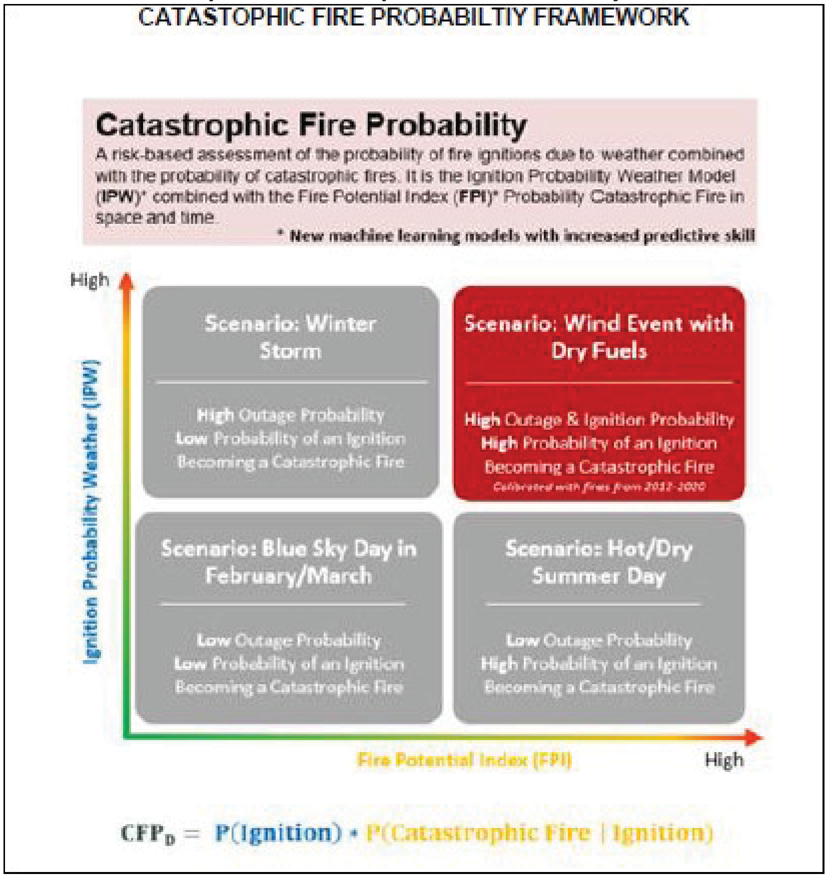
The IPW is a function of grid-performance given the weather conditions and is built using historical hourly weather data, outages, and ignitions in a machine learning model framework for localized areas. The guidance values PG&E utilizes when making a PSPS decision through the lens of this framework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

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

infrastructure would have been de-energized using this analysis. The conceptual CFPD framework is presented in Figure SCE 9-26 below.

Figure SCE 9-26

PG&E Conceptual Catastrophic Fire Probability Framework



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

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

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

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

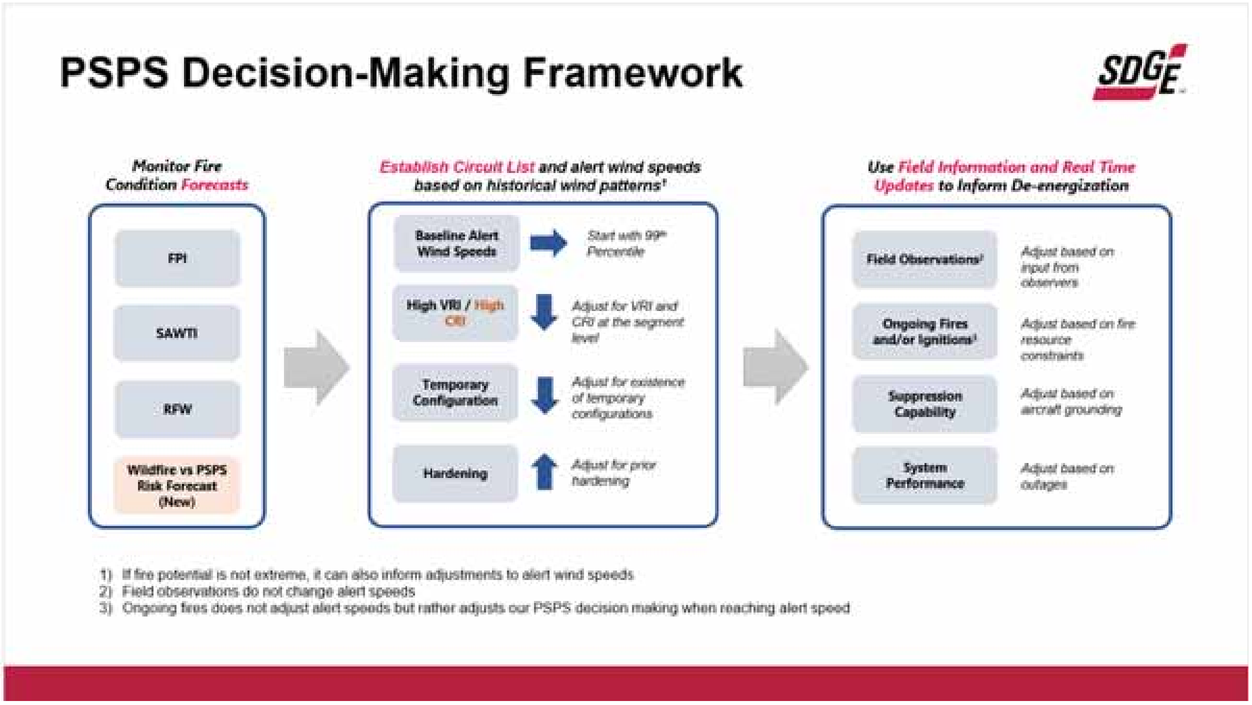
<u>SDG&E</u>

SDG&E utilizes multiple factors to assist in the decision to de-energize. See Figure SCE 9-27 below, that illustrates this PSPS decision-making framework. Some factors pertain to information in the field based on known compliance issues on the electrical system, active temporary construction/configuration of the electrical system, and a Circuit Risk Index (CRI) to identify locations in the system with a potential of having higher failure rates. Due to the dynamic nature of wildfire conditions SDG&E uses a real–time situational awareness technique to determine when to use PSPS, considering a variety of factors such as:

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

Figure SCE 9-27

SDG&E PSPS Decision-Making Framework



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

PacifiCorp

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

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

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

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

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

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

<u>Liberty</u>

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

a. Red Flag Warnings: Issued by the NWS to alert of the onset, or possible onset, of critical weather or dry conditions that would lead to increases in utility-associated ignition probability and rapid rates of fire spread.
b. Low humidity levels: Potential fuels are more likely to ignite when relative humidity is low and vapor pressure deficit is high.
c. Forecast sustained winds and gusts: Fires burning under high winds can increase ember production rates and spotting distances. Winds also can transfer embers from lower fire risk areas into high risk areas, igniting spot fires and increasing wildfire potential.
d. Dry fuel conditions: Trees and other vegetation act as fuel for wildfires. Fuels with low moisture levels easily ignite and can spread rapidly.
e. Observed Energy Release Component (ERC)
f. Observed wind gusts
g. Observed Fosberg Fire Weather Index (FFWI)
h. Observed Burning Index (BI)

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

Figure SCE 9-28

Liberty De-energization Decision Tree (Topaz and Muller 1296 r3 Zones)

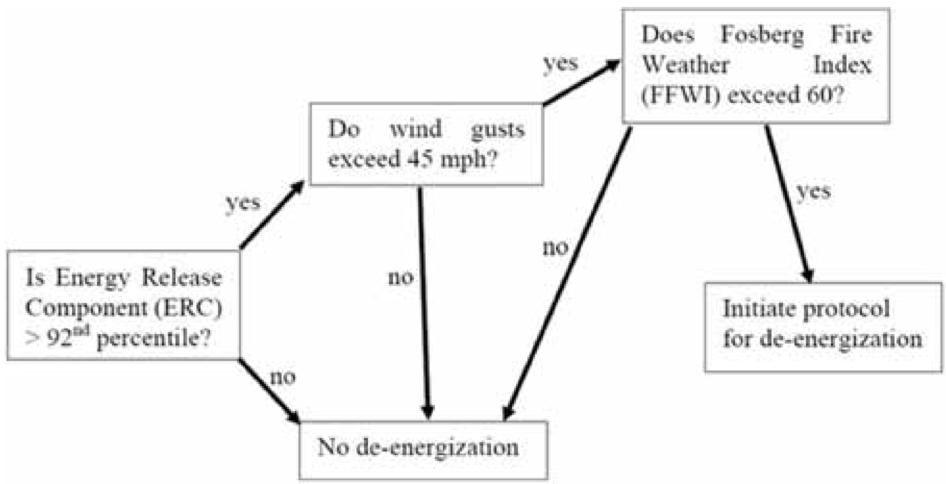
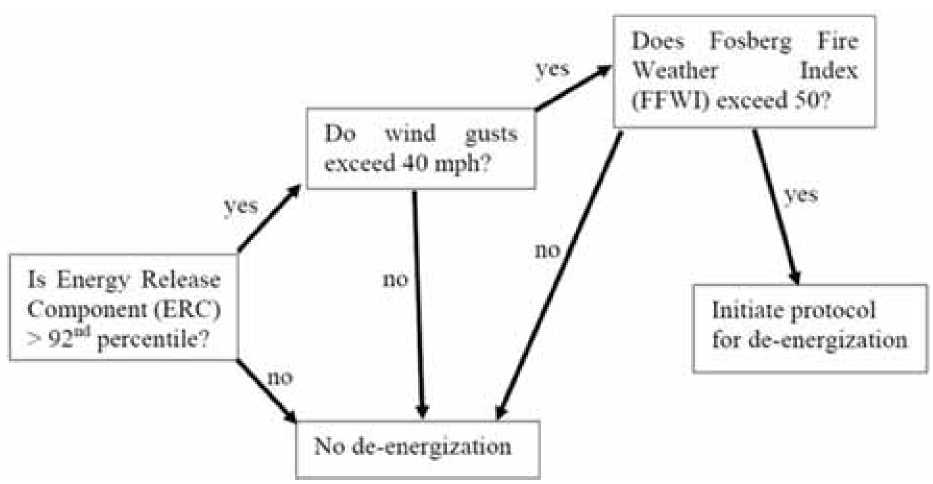


Figure SCE 9-29

Liberty De-energization Decision Tree (All Other Zones)

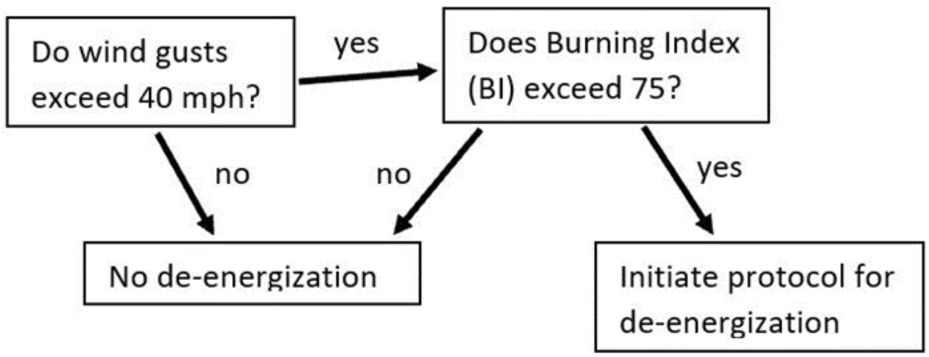


In January 2021, Liberty's Fire and Weather Scientific consultant, Reax Engineering, formulated an enhanced version of its fire weather forecasting tool to include an additional parameter known as Burning Index (BI). BI adds an increased layer of information regarding fire potential to its already robust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

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

Figure SCE 9-30

Liberty's Current Burning Index / Gust De-energization Formulation



BVES

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

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

Covered Conductor Potential to Reduce PSPS Risk:

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

Alternative Comparison:

The utilities conducted workshops over multiple days to discuss and assess whether the alternatives have lower, similar or higher benefits than a covered conductor system in reducing PSPS impacts. The utilities considered three PSPS benefits: 1) reduce PSPS frequency (# of de-energizations), reduce PSPS duration (CMI), and reduce number of customers impacts by PSPS (i.e., customers in scope). The results are shown in Table SCE 9-19 below. A red arrow represents a lower benefit, an orange arrow represents similar benefits, and a green arrow represents a higher benefit.

Table SCE 9-19

PSPS Impact Benefits Comparison of Alternatives to Covered Conductor

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

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

Next Steps:

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

Costs:
The utilities have prepared an initial capital cost per circuit mile comparison of the installation of covered conductor. To construct this unit cost comparison, the utilities organized their capital costs (and/or estimates) into six cost categories. These categories include labor, material, contract, overhead, other, and financing. Labor represents internal utility resources, such as field crews, that charge directly to a project work order. Materials include conductor, poles, etc. that get installed as part of a project. Contract represents all contractors, such as field crews and planners, and consultants utilities use as part of their covered conductor programs. Overhead represents costs, such as engineers, project managers and administrative and general, that get allocated to project work orders. Other represents costs such as land fees, permit fees and costs not assignable to the other categories. Financing represents allowance for funds used during construction (AFUDC) which is the estimated cost of debt and equity funds that finance utility plant construction and is accrued as a carrying charge to work orders. These cost categories are intended to capture the total capital cost per circuit mile of covered conductor installations. For purposes of this report, the utilities obtained recorded and/or estimated costs for construction that occurred during 2021. Table SCE 9-20, below, shows the initial covered conductor capital unit cost per circuit mile comparison across the six utilities.

Table SCE 9-20

Comparison of Covered Conductor Capital Costs Per Circuit Mile

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

As illustrated in Table SCE 9-20, the capital cost per circuit mile ranges from approximately $565,000 to approximately $1.5 million. The capital cost per circuit mile for covered conductor varies due to multiple factors such as type of covered conductor system and components installed, terrain, access limitations, permitting, environmental requirements and restrictions, construction method (e.g., helicopter use), amount of poles/equipment replaced, degree of site clearance and vegetation management needed, and economies of scale. Below, the utilities generally describe the make-up of their covered conductor capital costs and the factors that contribute to the cost differences.

Covered Conductor Capital Costs:

SCE

CC Unit Cost Make Up:

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

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

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

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

Cost Drivers:

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

As seen in Table SCE 9-20 above, SCE's unit cost is the lowest of the six utilities. While SCE has described many factors that affect its covered conductor costs, some of the reasons why SCE's costs may be lower than the other utilities include economies of scale with SCE installing over 1,000 circuit miles per year and its ability to bundle work for its contractors. Bundling work enables multiple projects to be completed in the same general area which minimizes mobilization and demobilization costs and increases contractor productivity. SCE has also not generally observed a steady nor large amount of vegetation management or access road rehabilitation costs across its installations. With thousands of circuit miles installed, these types of incurred costs are low when averaged across SCE's portfolio of completed installations. As noted above, SCE also only replaces, on average, 10 to 12 poles[288] per circuit mile and its WCCP is focused on covered conductor and does not include other major equipment upgrades.

PG&E

CC Unit Cost Make Up:

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

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

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

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

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

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

PG&E's Overhead Hardening (covered conductor installation) scope achieves risk reduction through these foundational elements: bare primary and secondary conductor replacement with covered equivalent, pole replacements, non-exempt equipment replacement, overhead distribution line transformer replacement with transformers that have FR3 fluid, framing (composite crossarms and insulators) and animal protection, and vegetation clearing.

Cost Drivers:

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

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

SDG&E

CC Unit Cost Make Up:

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

Stage 1 – Project Initiation (duration ~1-3 months)

Stage 2 – Preliminary Engineering & Design (duration ~6-9 months)

Stage 3 – Final Design (duration ~3-5 months)

Stage 4 – Pre-Construction (duration ~1-2 months)

Stage 5 – Construction (duration ~3-4 months)

Stage 6 – Close Out (duration 8~-10 months)

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

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

1. Labor (internal) – directs costs associated with SDG&E full-time employees (FTE), including but not limited to individuals from project management, engineering, permitting, environmental, land management, and construction departments. This cost assumes approximately 25% of the electric work is completed by internal SDG&E construction crews.
2. Materials – estimated costs of material used for construction including steel poles, wire, transformers, capacitors, regulators, switches, fuses, crossarms, insulators, guy wire, anchors, hardware (nuts, bolts, and washers), signage, conduit, cable, secondary wire, ground rods, and connectors.
3. Contractor – estimated costs for construction-related services, including civil construction contractors for pole hole digging, anchor digging and substructures, and street/sidewalk repair; electrical construction for pole setting, wire stringing, electric equipment installation and removals; vegetation management where required including tree trimming or removal, and vegetation removal for poles and access paths; environmental support services including biological and cultural monitoring; traffic control; and helicopter support for pole setting, wire stringing, and removals. This cost assumes approximately 75% of the electric work is completed by contract crews.
4. Overheads – estimated costs associated with contracted services not related to construction including engineering, design, project management, scheduling, reporting, document management, GIS services, material management, constructability reviews by Qualified Electrical Worker (QEW), staging yard leases/setup/teardown/maintenance, and permitting support throughout the entire lifecycle of a project, as well as services related to program management including long term planning and risk assessment.
5. Other – estimated costs associated with indirect capital costs. These costs are estimated to be approximately 14.3% of direct capital costs that accumulate on a construction work order. This includes administrative pool accounts that are not directly charged to a specific project, including internal labor vacation, sick, legal, and other expenses.
6. Financing Costs – estimated costs associated with the collection of AFUDC when a construction work order remains active. Most SDG&E jobs are active for approximately 6 to 10 months from the time the job is issued to construction until it is fully completed and the collection of AFUDC charges stop.

Cost Drivers:

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

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

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

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

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

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

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

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

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

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

<u>PacifiCorp</u>

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

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

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

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

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

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

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

6. Financing Costs: AFUDC charges on the projects.

Cost Drivers:

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

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

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

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

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

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

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

<u>BVES</u>

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

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

<u>Cost Drivers:</u>

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

<u>Liberty</u>

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

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

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

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

1. Labor (internal) – Internal Labor represents Project Management, Engineering, Operations, Arborists and Line Crews dedicated to the capital job, and cost of removal.
2. Materials – Materials includes poles, crossarms, insulators, down guys, anchors, transformers, hardware, and covered conductor wire purchased through Liberty supply chain operations.
3. Contractor – Contract charges are for construction contractors and professional services to design and execute project scopes. Contract costs also include line clearance qualified tree crews needed to prune and remove trees along the covered conductor line route.
4. Overheads – Overheads are allocated to active job orders monthly based on capital spend. At Liberty, this could include indirect labor, A&G, capital overheads, fleet, and small tools allocations.
5. Other – Other is reserved for taxes applied to the job.
6. Financing Costs – Financing costs capture AFUDC accumulated costs in the covered conductor job order.

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

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

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

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

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

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

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

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

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

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

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

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

[289] A note about the numbered conditions referenced in this document: "RCP Action-SDGE-[#]" here refers to one of the actions required by the WSD in its evaluation of SDG&E's Remedial Compliance Plan of 2020, issued Dec. 30, 2020. The WSD issued four such orders (RCP Action-SDGE-1 through RCP Action-SDGE-4). There are two other related sets of references in this document: "SDGE-[#]" refers to one of the actions required by the WSD in its evaluation of SDG&E's 2020 WMP issued June 11, 2020 (SDGE-1 through SDGE-16). "QR Action-SDGE-[#]" refers to one of the actions required by the WSD in its evaluation of SDGE's first quarterly report issued Jan. 8, 2021 (QR Action-SDGE-1 through Action-SDGE-49). 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).

9.8.1 Appendix A

Covered Conductor Benchmarking Survey Results

Joint IOU CC Effectiveness Workstream

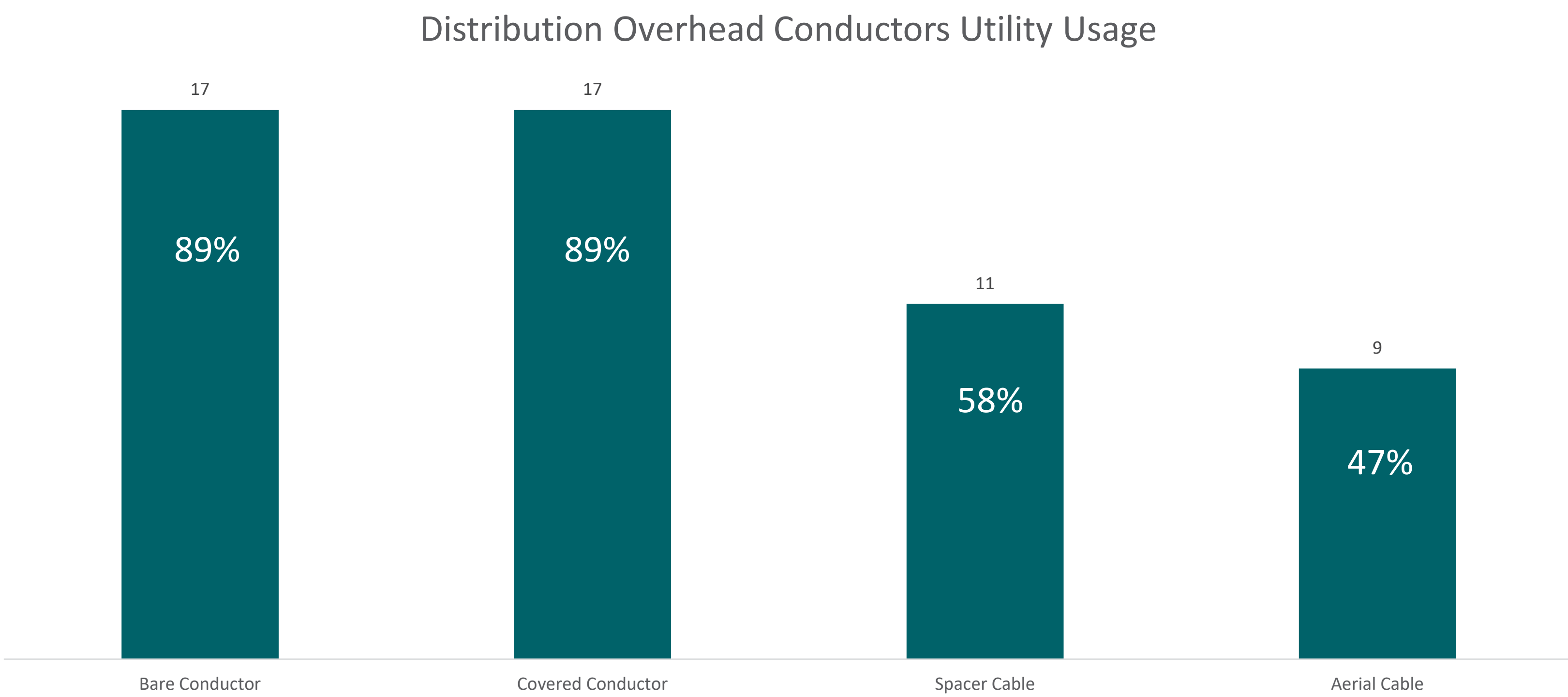
Energy for What's Ahead®

SOUTHERN CALIFORNIA EDISON®

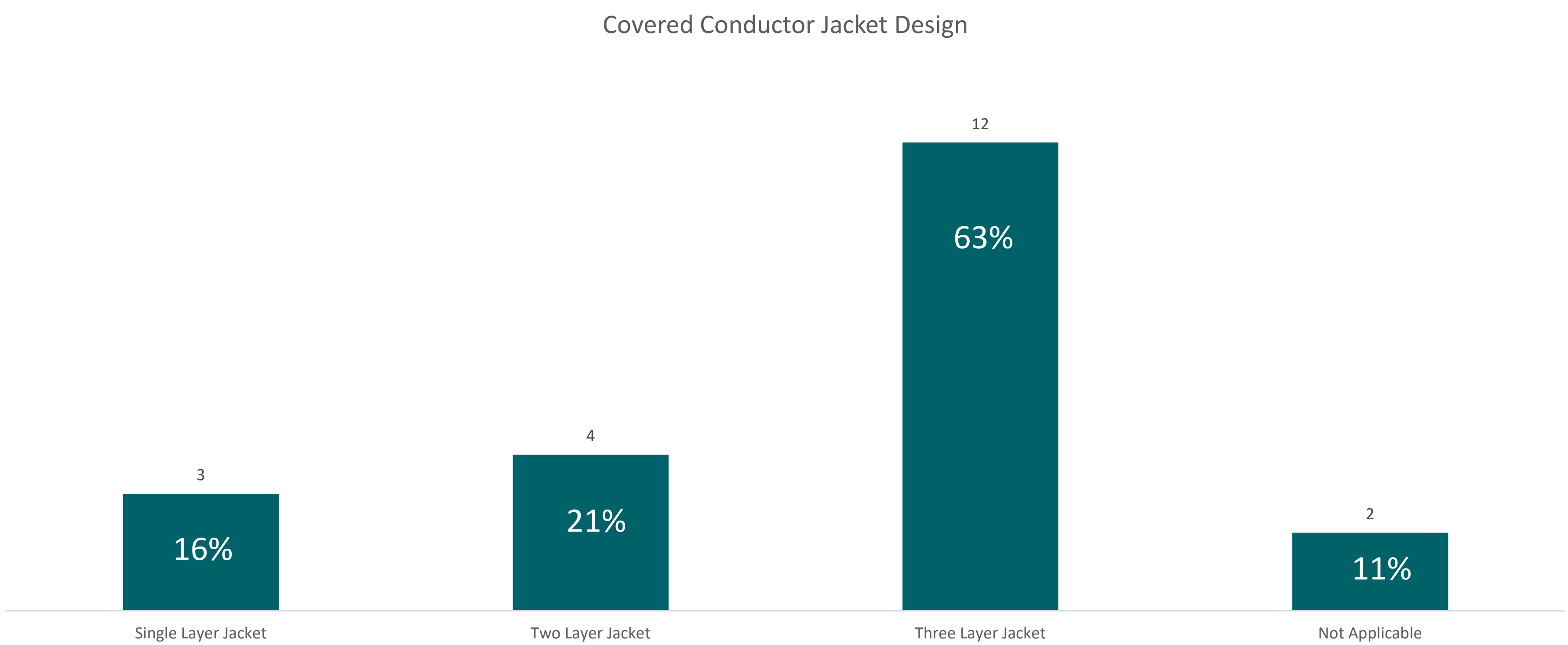
Participants

1. American Electric Power
2. Ausnet Services
3. Bear Valley Electric Service, Inc.
4. Duke Energy
5. Essential Energy
6. Eversource Energy (CT)
7. Korean Electric Power Corporation
8. Liberty
9. National Grid
10. Pacific Gas and Electric Company
11. PacifiCorp
12. Portland General
13. Powercor
14. Puget Sound Energy
15. San Diego Gas & Electric
16. Southern California Edison
17. TasNetworks
18. Tokyo Electric Power Company
19. Xcel Energy

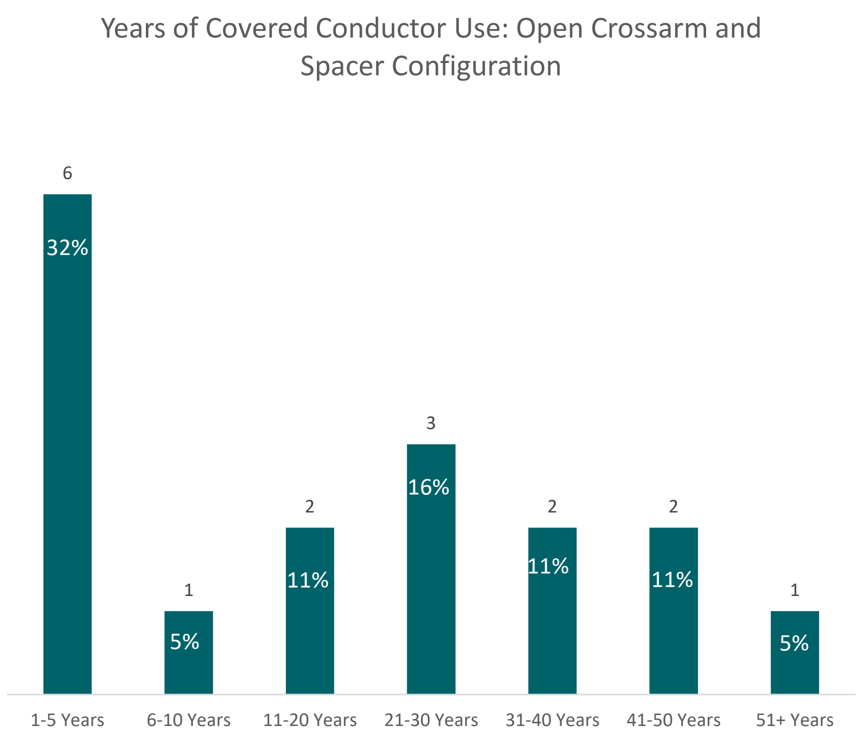
What types of overhead conductors does the utility utilize in its distribution system?

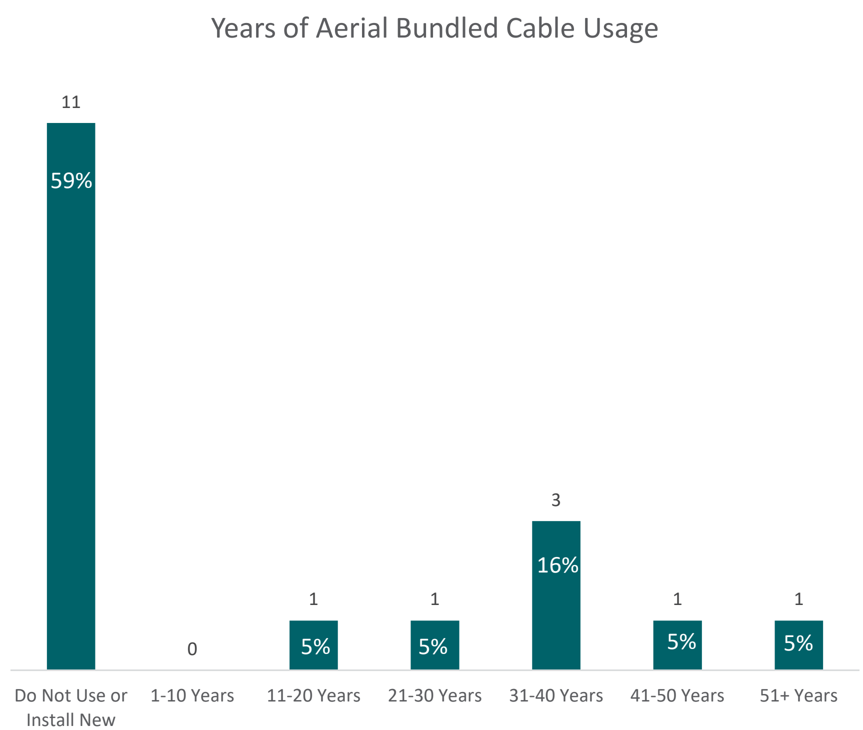


What type of covered conductor design does the utility utilize?



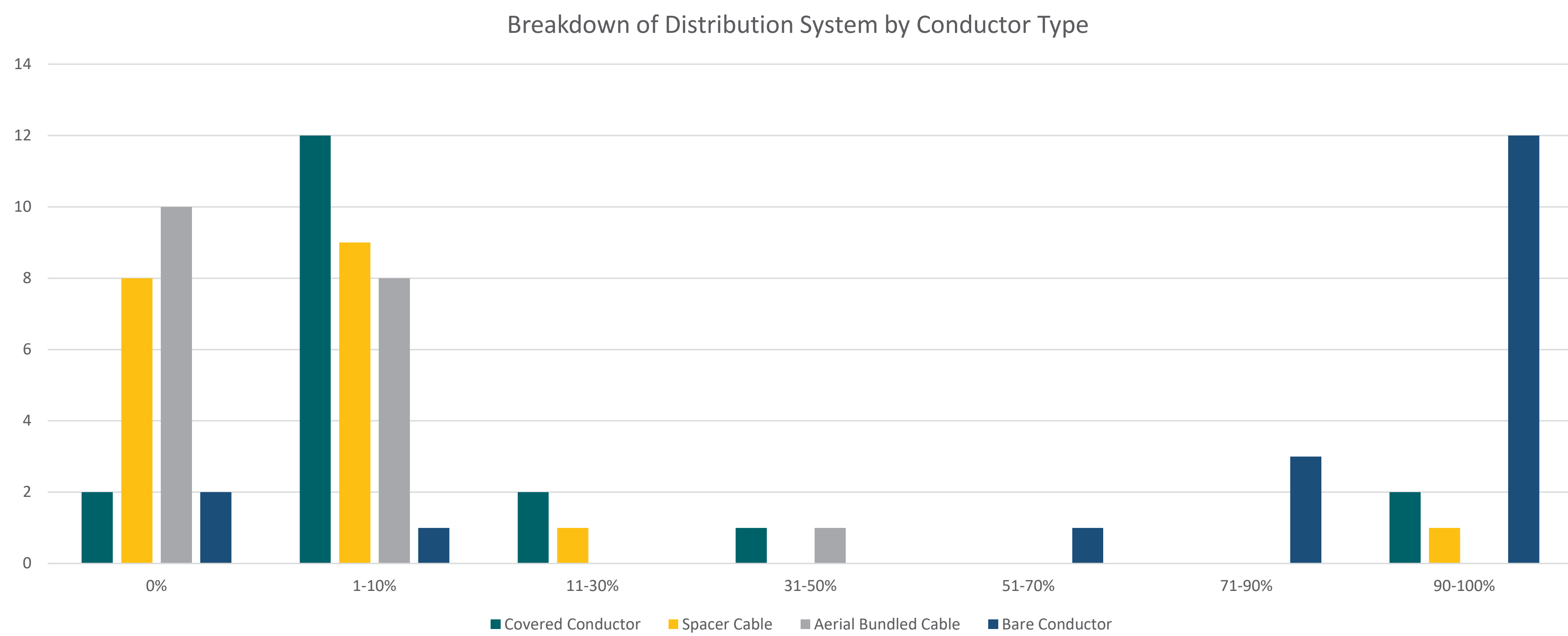
Years of Covered Conductor and Aerial Bundled Cable Usage





Energy for What's Ahead®

What percent of the primary distribution system is covered conductor vs. spacer cable vs. ABC vs. bare conductor?



Energy for What's Ahead®

Circuit Miles of Covered Conductor, Spacer Cable, and ABC Installed

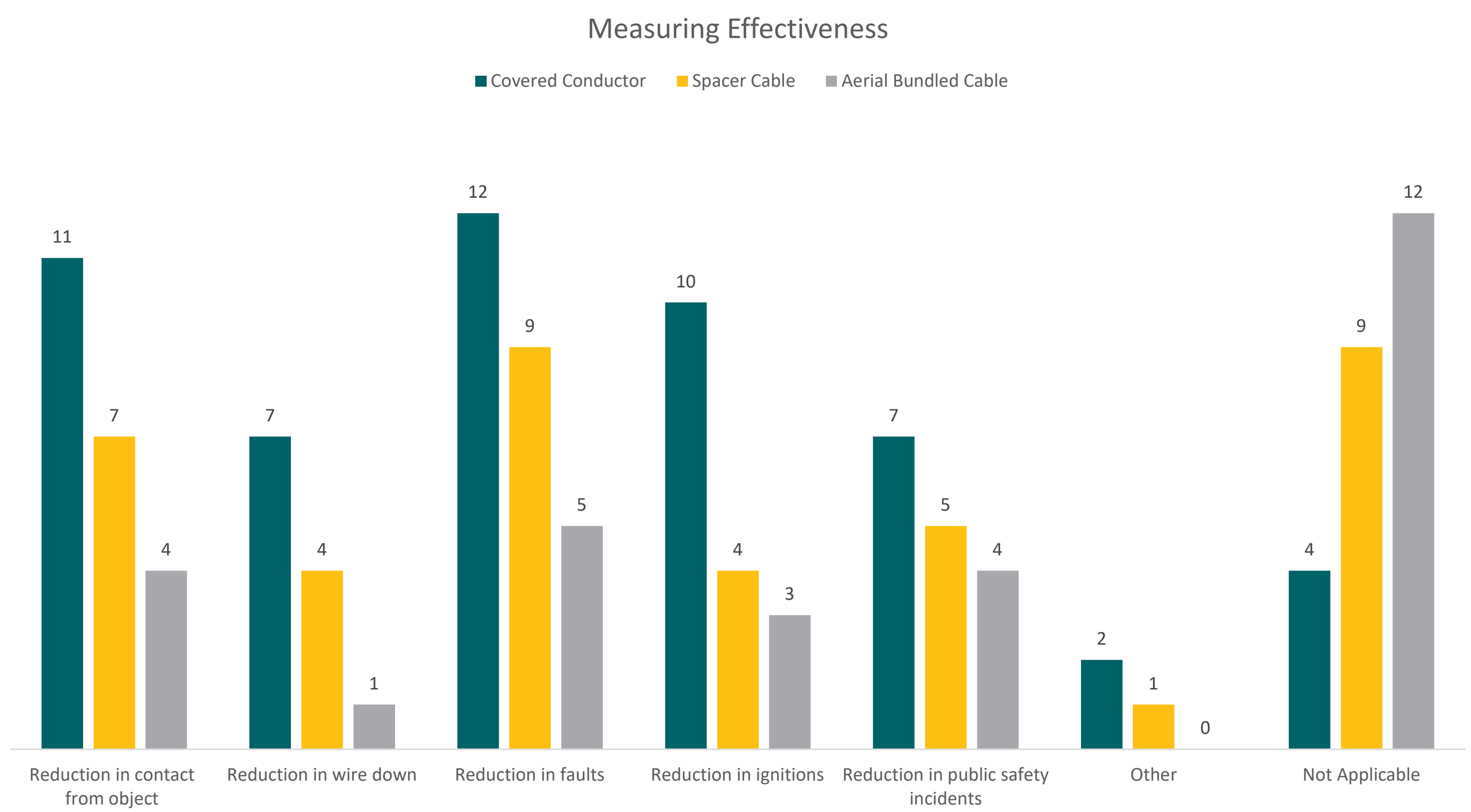
Utility	Covered Conductor Circuit Miles	Spacer Cable Circuit Miles	Aerial Bundled Cable Circuit Miles
American Electric Power	156	137	0
AusNet Services	5	25	125
Bear Valley Electric Service, Inc.	22	0	0
Duke Energy	0	0	0
Essential Energy	2,500	0	1500
Eversource Energy (CT)	8,000	520	200
Korean Electric Power Corporation[1]	120,485		
Liberty	5	2	0
National Grid	4,000	3,000	1,000
Pacific Gas and Electric Company	820	0	3
PacifiCorp	0	60	0
Portland General	243	9	0
Powercor	6	1	60
Puget Sound Energy	1,500	1	0
San Diego Gas & Electric	22	2	0
Southern California Edison	2,187	0	64
TasNetworks	2	0	10
Tokyo Electric Power Company[2]	267,190		16,156
Xcel Energy	0	50	0

1. Korean Electric Power Corporation uses Covered Conductor and Aerial Bundled Cable. Value represents total circuit miles of Covered Conductor and Aerial Bundled Cable. Circuit mile data is based on information provided from previous benchmarking
2. Tokyo Electric Power Corporation uses Covered Conductor and Spacer Cable. Value represents total circuit miles of Covered Conductor and Spacer Cable.

Outage and Ignition Tracking

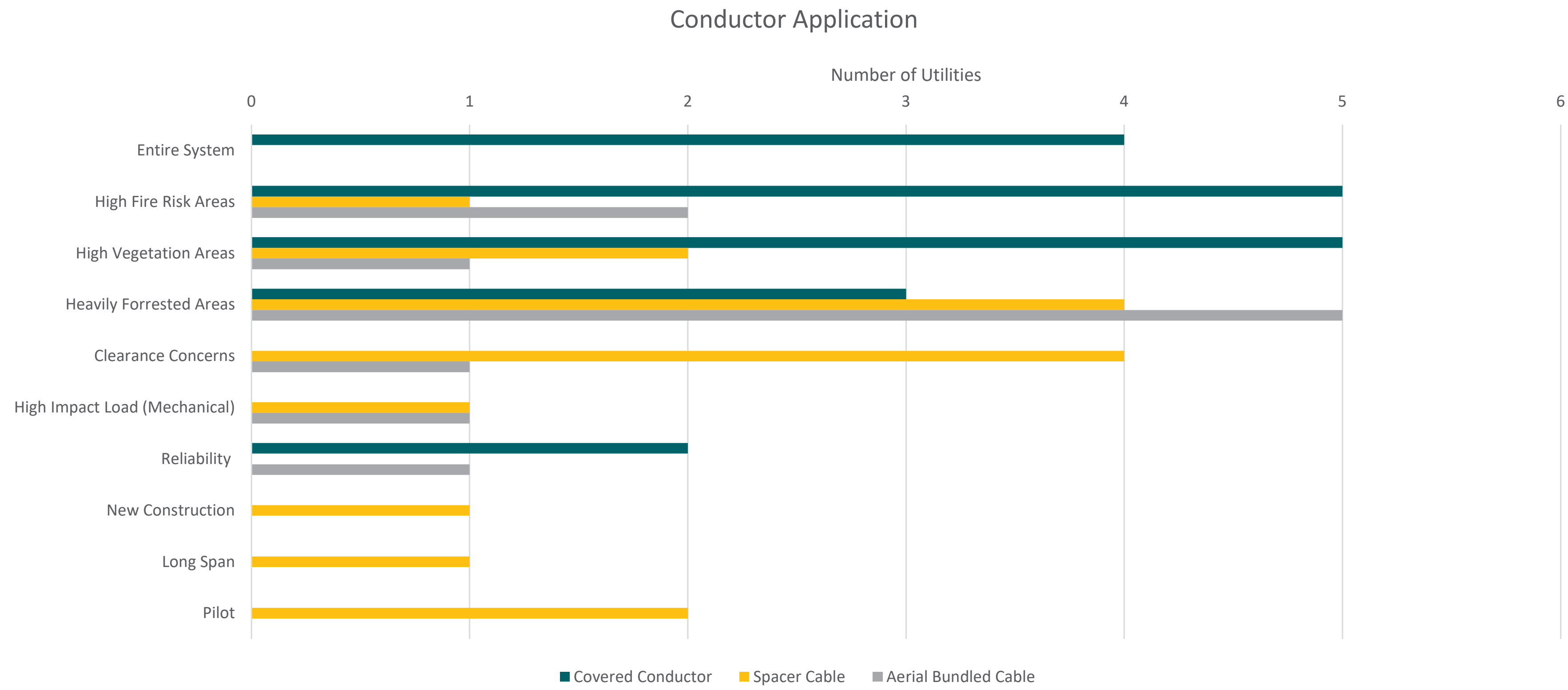
Utility[1]	Track Outage Counts for Bare vs. CC?	Has use of CC, Spacer Cable, or ABC reduced faults?	Track ignition Counts for Bare vs. CC?	Has use of CC, Spacer Cable, or ABC reduced ignitions/ignition drivers?	If no ignition reduction, why?
American Electric Power	No	Yes	No	Yes	
AusNet Services	No	Yes	No	Yes	
Bear Valley Electric Service, Inc.	Yes	Yes	Yes	No	No prior ignitions
Duke Energy	NA	NA	NA	NA	Does not use CC
Essential Energy	Yes	Yes	Yes	Yes	
Eversource Energy (CT)	Yes	Yes	No	No	Data not tracked
Korean Electric Power Corporation	Yes	Yes	No	Yes	
Liberty	No	No	No	No	Data not tracked
National Grid	Yes	Yes	No	No	Data not tracked
Pacific Gas and Electric Company	No	Yes	No	No	Data not tracked
PacifiCorp	Yes	Yes	Yes	Yes	
Portland General	No	Yes	No	No	Data not tracked
Powercor	No	No	No	Yes	
Puget Sound Energy	No	Yes	No	No	Data not tracked
San Diego Gas & Electric	Yes	Yes	Yes	Yes	
Southern California Edison	Yes	Yes	Yes	Yes	
TasNetworks	No	Yes	Yes	Yes	
Tokyo Electric Power Company	No	Yes	No	Yes	
Xcel Energy	No	Yes	No	No	Data not tracked

Measuring Effectiveness of Covered Conductor, Spacer Cable, and ABC

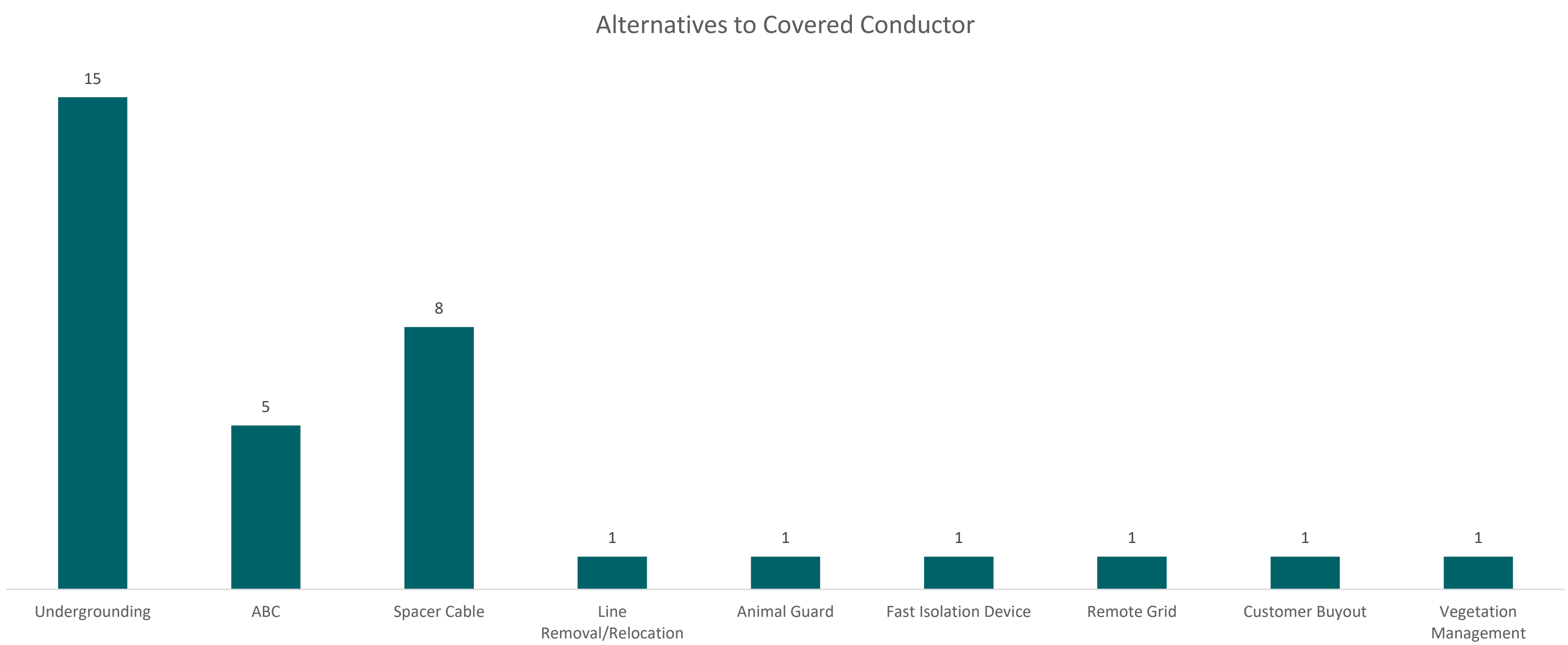


Energy for What's Ahead®

Covered Conductor, Spacer Cable, and Aerial Bundled Cable Application



Alternatives



Energy for What's Ahead®

Protection

- **Existing** fault detection methodologies
  - Overcurrent protection
    - Circuit breaker & Relay
    - Fuses
    - Reclosers
    - TripSavers
  - SCADA connected devices
  - Smart Meters
  - High voltage DC pulse with directional tracking
  - High impedance fault detection
  - Distribution automation system monitoring
  - Distance to fault algorithm

- **Potential** fault detection methodologies
  - Early Fault/Failure Detection
  - Distribution Fault Anticipation
  - Open Phase Detection
  - High impedance fault detection
  - Sensitive Ground Fault
  - Rapid Earth Fault Current Limiter
  - Downed Conductor Detection
  - LR controllers
  - Fault indicators
  - Sensing insulators
  - Zero phase voltage measurement
  - AMI meter loss of voltage detection
  - Working with vendors to develop communication aided protection to detect faulted or broken CC
  - Inspection

Patrol Protocols

- Patrol conductors after storm before energization
  - Require visual observation
  - Same as bare conductor
- Drone usage

Other Comments

Utility	Comment
SDG&E	Primarily using covered conductor, but have the option for spacer cable.
PacifiCorp	Spacer cable has been highly effective
Liberty	Piloting on a case-by-case basis, targeting highest-risk areas, based on Risk-Based Decision model.
Duke Energy	Installed covered conductor and spacer cable on our system in the past. There is a miniscule amount on our system. Our current construction standards do not call for covered or spacer cable installation for the following reasons: 1) Require additional installation procedures and maintenance compared to bare conductors. 2) Require proper Installation to prevent BIL and deterioration failures. 3) Designed to prevent intermittent vegetation contact. Should NOT be used for sustained contact of vegetation. 4) Must coincide with continual Vegetation Maintenance.
Xcel Energy	Using a strengthened neutral shield wire to protect crossarm construction from tree impacts.
TEPCO	• Use of bare wires for MV line is prohibited in Japan. For MV line, covered electric wires are basically used. • Spacer cables used when it is necessary to move the electric wire position away or change routes between utility poles. • Aerial bundled cables are used when connecting the MV line of the third route on the utility pole.
Portland General	• Developing the application strategy to mitigate wildfire in high-risk zones using these conductor types. Until now, these systems were primarily used for reliability purposes.

9.8.2 Appendix B

Exponent®

Effectiveness of Covered Conductors: Failure Mode Identification and Literature Review

Exponent®

Effectiveness of Covered Conductors: Failure Mode Identification and Literature Review

Exponent, Inc.
149 Commonwealth Dr.
Menlo Park, CA 94025

December 22, 2021

Doc. no. 2103590.000 - 6880

Contents

Executive Summary

Exponent, Inc. (Exponent) was jointly retained by the California investor-owned utilities (IOUs) to assess the effectiveness and reliability of covered conductors (CCs) for overhead distribution system hardening. Our investigation included a literature review, discussions with subject matter experts, a failure mode identification workshop, and a gap analysis comparing expected failure modes to currently available test and field data. Based on our investigation to date, we offer the following conclusions:

1. Covered conductors are a mature technology (in use since the 1970s) and have the potential to mitigate several safety, reliability, and wildfire risks inherent to bare conductors. This is due to the reduced vulnerability to arcing/faults afforded by the multi-layered polymeric insulating sheath material.

2. A subject matter expert workshop, composed of six California IOUs and Exponent, was conducted, and identified hazards and failure modes affecting bare conductors and CCs. Of the 10 hazards that affect bare conductors, CCs have the potential to mitigate six. Mitigated hazards include tree/vegetation contact, wind-induced contact (such as conductor slapping), third-party damage, animal-related damage, public/worker impact, and moisture.

3. The primary failure mode of bare conductors is arcing due to external contact. Laboratory studies and field experience have shown that arcing due to external contact was largely mitigated with CCs. Therefore, a corresponding reduction in ignition potential would be expected.

4. Field experience from around the world, including North America, South America, Europe, Asia, and Australia, consistently report improvements in reliability, decreases in public safety incidents, and decreases in wildfire-related events that correlate with increased conversion to CC.

5. While high-level field experience–based evidence of CC effectiveness is plentiful, relatively few lab-based studies exist that address specific failure modes or quantify risk reduction relative to bare conductors. For some failure modes, further testing is recommended to bolster industry knowledge and to enable more effective risk assessment.

6. Several CC-specific failure modes exist that require operators to consider additional personnel training, augmented installation practices, and adoption of new mitigation strategies (e.g., additional lightning arrestors, conductor washing programs, etc.).

Note that this Executive Summary does not contain all of Exponent's technical evaluations, analyses, conclusions, and recommendations. Hence, the main body of this report is at all times the controlling document.

Motivation and Scope

California investor-owned utilities (IOUs) Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E) engaged Exponent to summarize the effectiveness of CCs for hardening of overhead distribution electric lines. During the project, three additional California IOUs joined the effort: Liberty, PacifiCorp, and Bear Valley Electric Service. CCs have gained industry attention due to their potential for mitigating risks associated with public safety, reliability, and wildfire ignition. The current study was undertaken to better understand the advantages, operative failure modes, and current state of knowledge regarding CCs. The objectives of this study were to:

1. Summarize the effectiveness of CCs.
2. Summarize the implementation and design considerations of CCs.
3. Identify gaps in current testing/knowledge and practices/implementation.

To meet these objectives, we performed a comprehensive review of publicly available literature, utility-provided data, and manufacturer information. Additionally, a high-level failure mode identification workshop was conducted with input from technical subject matter experts representing the California IOUs and Exponent. The workshop output was compared against the available literature and test data to identify any gaps between the current state of knowledge and the identified failure modes.

Covered Conductor Technology

History and Motivation for Development

The term “covered conductor” refers to a variety of conductor cable designs that incorporate an external polymer sheath to protect against incidental contact with other conductors or grounded objects such as tree branches. This technology has several advantages over traditional bare conductors, and the key drivers for adoption have been to improve overall system reliability, to enhance public safety in high-population areas, to decrease required right-of-way in densely forested areas, to decrease the scope and frequency of vegetation management, and to reduce the probability of ignition from conductor heating/arcing in fire-prone areas.

Construction and Types

CCs were first adopted in the United States and Europe in the 1970s for medium-voltage distribution lines (35 kV and below) and were later implemented for high-voltage overhead lines in the 1990s [Leskinen 2004]. Early iterations had various technical challenges that led to the development of the modern CC design that will be discussed throughout this report. Modern CCs consist of an all-aluminum conductor (AAC), aluminum conductor with steel reinforcement (ACSR), or copper (CU) conductor, enclosed in a multi-layer polymer sheath. The number of layers and their composition largely depend on the specified voltage rating, as multi-layered variants have a higher impulse strength than the single-layer design and often include a semiconducting conductor shield. This report focuses on CC use in the “medium voltage” range (6–35 kV), though the technology can also be used for higher or lower voltage.

Figure 1 shows a three-layer CC design, which is commonly used for distribution-level voltages. A high-density polyethylene (HDPE) outer jacket provides strength, abrasion resistance, and weather resistance. This layer may be cross-linked to increase its high temperature strength and dimensional stability. A low-density polyethylene (LDPE) inner jacket provides dielectric strength to protect the underlying conductor and may also be cross-linked to enhance high temperature properties. Finally, a semiconducting thermoset “shield” layer is wrapped around the conductor, which equalizes the electric field around the conductor to reduce voltage stress and preserve the insulation [Wareing 2005].

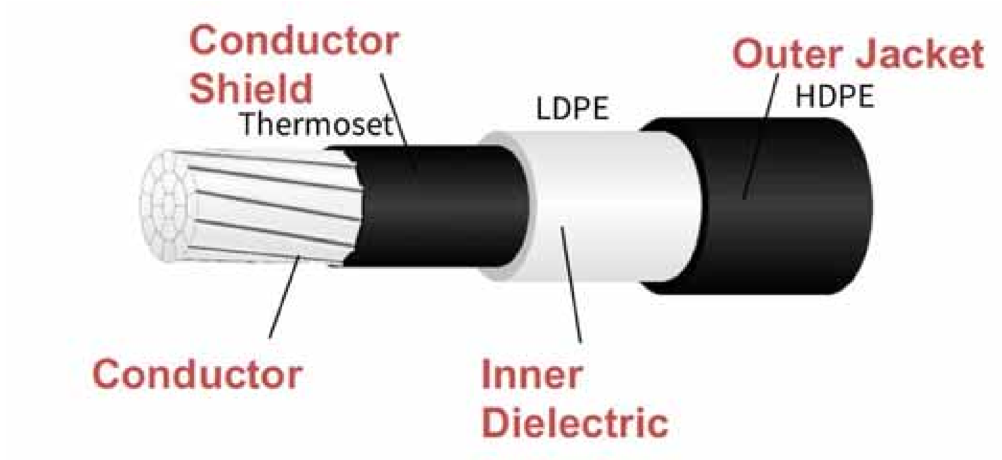


Figure 1. A schematic illustration of a three-layer CC. Diagram modified from Hendrix Aerial Cable Systems [Trager].

Overhead Configurations

One common configuration for CCs used in overhead distribution systems is the standard crossarm-mounted construction. This configuration, sometimes referred to as "tree wire," is often seen where CCs are installed on pre-existing infrastructure designed for bare conductors. This method can leverage legacy hardware, construction and maintenance practices, and pole structures if the weight, diameter, and modified tensioning are considered. Conductors are typically attached to polyethylene pin-type insulators in this configuration. A reduced crossarm structure can also be used in narrow rights-of-way. One disadvantage to this method of installation is that it requires stripping of the conductor sheath at dead-end attachments, creating a length of unprotected bare conductor. Figure 2 shows an example of tree wire construction.

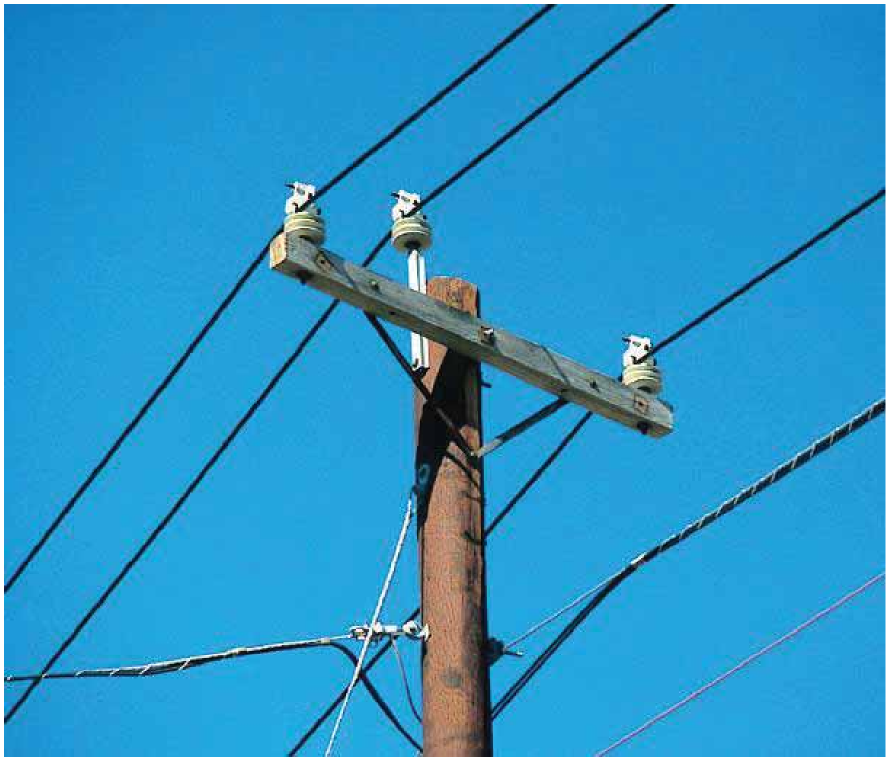


Figure 2. An example of crossarm-mounted CC, or “tree wire,” construction. Photo from Hendrix Aerial Cable Systems [Trager].

CCs are also often constructed in a “spacer cable” configuration. Spacer cable takes advantage of the reduced clearance required of CCs by closely spacing adjacent conductor phases with rigid spacer hardware. This configuration is advantageous in tight corridors where right-of-way may be limited and can reduce wind-related impact on individual conductors [Trager]. No stripping of the conductor sheath is required for this installation method, resulting in a completely covered system except for tap, transformer/capacitor, surge arrester, and protective device locations. A notable feature of spacer cable is that the conductor is not self-supporting, but rather, a steel cable or “messenger cable” is used to support multiple conductors. The messenger cable can also shield the conductors somewhat from fallen branches and lightning strikes. Figure 3 shows an example of spacer cable construction.

Figure 3. An example of spacer cable CC construction. Photo from Hendrix Aerial Cable Systems [Trager].

Field Experience

Finland

Finland started adopting CCs for medium-voltage lines in the 1970s and high-voltage lines in the 1990s to increase reliability. While only 4% of the total medium-voltage network, CCs accounted for 90% of the total average medium-voltage length increase during the early 2000s [Leskinen 2004].

The annual outage rate per 100 km from Finland is shown in Figure 4 and is valid for rural areas. As the figure shows, the number of faults has steadily decreased since the 1970s to around five faults per 100 km. This likely corresponds to the increased number of CC lines in the network [Leskinen 2004].

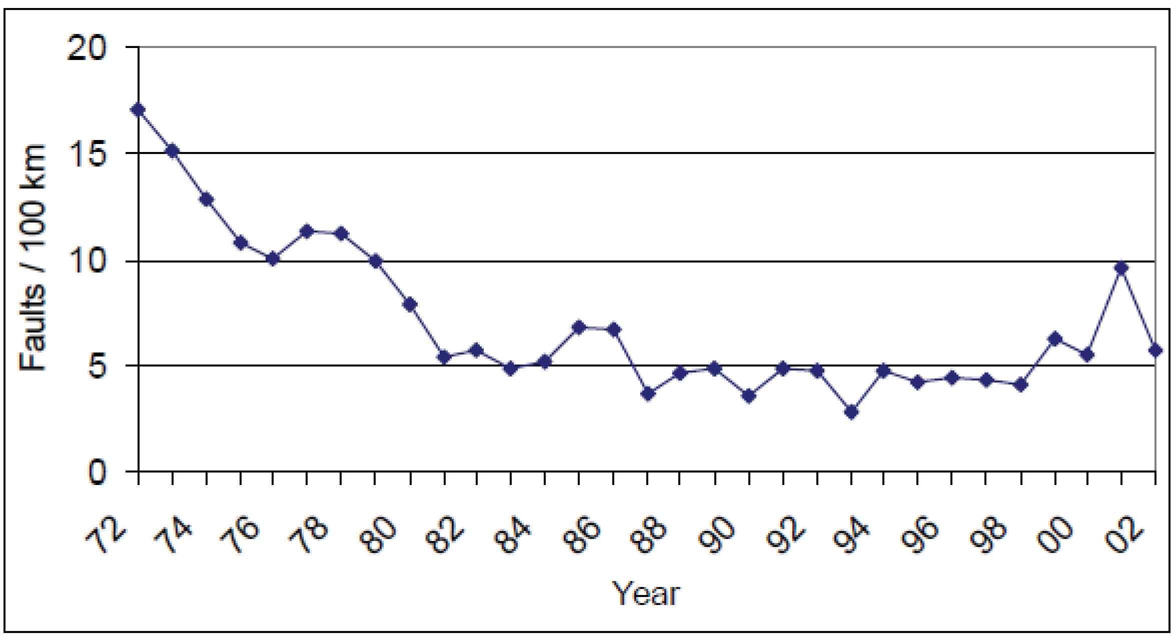


Figure 4. Annual number of faults per 100 km in rural areas of Finland from 1972 to 2002 for medium-voltage lines. Image from [Leskinen 2004].

This study also analyzed previous literature that suggested CC installation also affects the number of high-speed and delayed automatic reclosings. Based on the field data-derived empirical equations from Heine, *et. al*., as shown in Figure 5, the number of high-speed autoreclosings decreases by one third when the percentage of CC lines increases from 10% to 50% [Heine 2003, Leskinen 2004]. The number of autoreclosings is indicative of the number of faults; therefore, these data suggest that the number of faults decreased with increased use of CCs. More recent studies show that the number of permanent faults in CC lines is 20% of the number associated with bare conductor overhead lines and gives an annual fault number of one per 100 km [Leskinen 2004].

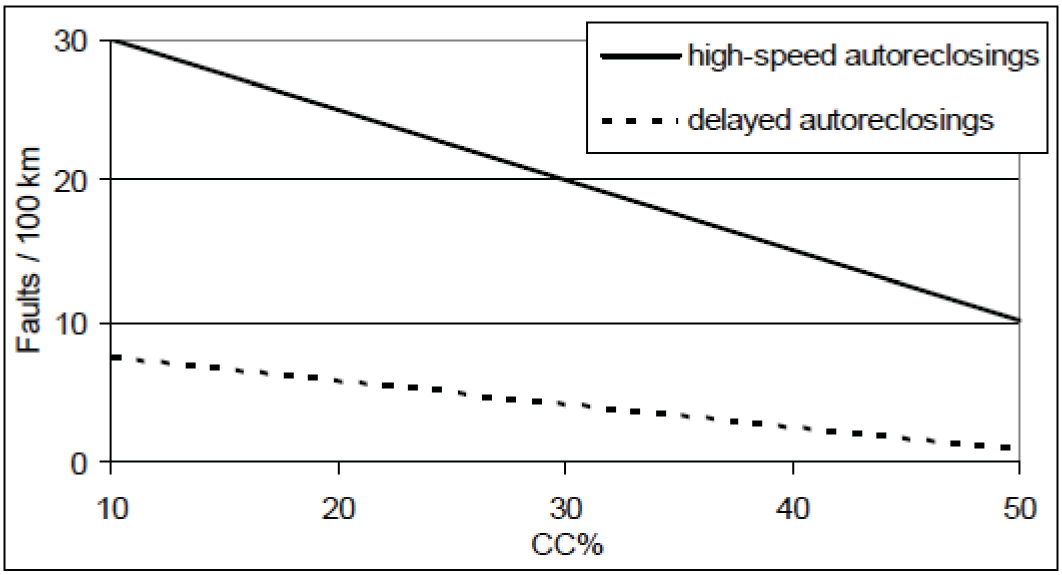


Figure 5. Fault frequency as a function of CC network share in Finland. Image from [Leskinen 2004].

Slovenia

The Slovenian utility Elektro Ljubljana began building CC lines in 1993 to improve reliability, and within ten years CC lines comprised 8% of all Slovenian medium-voltage overhead lines [Leskinen 2004]. The annual medium-voltage outage rate in rural Slovenia was between 15 and 25 per 100 km prior to the introduction of CCs. After the adoption of CC lines and other new technology such as remote-controlled load breakers and shunt circuit breakers, the annual outage rate reduced to less than two faults per 100 km. This rate is nearly double the most recent annual outage rate of Finland, as discussed in the prior section. The higher fault rate in Slovenia compared to Finland has been attributed to the higher level of lightning and a lack of standards [Leskinen 2004].

Taiwan

The Taiwan Power Company invested the equivalent of over $360 million between 1996 and 2000 to replace 11.4 kV overhead lines with 15 kV cross-linked polyethylene (XLPE) weatherproof wires (a type of CC) [Li 2010]. Figure 6 shows the impact of CC lines on the Taiwan Power Company distribution system. (The ratio of covered line length using XLPE weatherproof wire in the distribution system to the total line length of the system is given by the variable r_c.) The distribution system reliability is assessed using the system average interruption frequency index (SAIFI) and the system average interruption duration index (SAIDI). Figure 6 shows the variation of r_c, SAIFI, and SAIDI during 1985 to 2005. Installation of CC lines from 1985 to 2005 resulted in lower fault frequency and interruption duration.

As distribution systems in Taiwan are near highly populated areas, endangered-life indices (ELIs) were used for statistical data with regard to people who experience electric shocks. The following ELI values were used: the annual number of people who receive electric shocks (N_p), the annual number of people injured by electric shocks (N_{pi}), and the annual number of people electrocuted (N_{pe}). The ELI rates and r_c values from 1985 to 2005 are shown in Figure 6. As r_c increased, all ELIs decreased annually from 1995 to 2005 as more CC lines were incorporated into the distribution system.

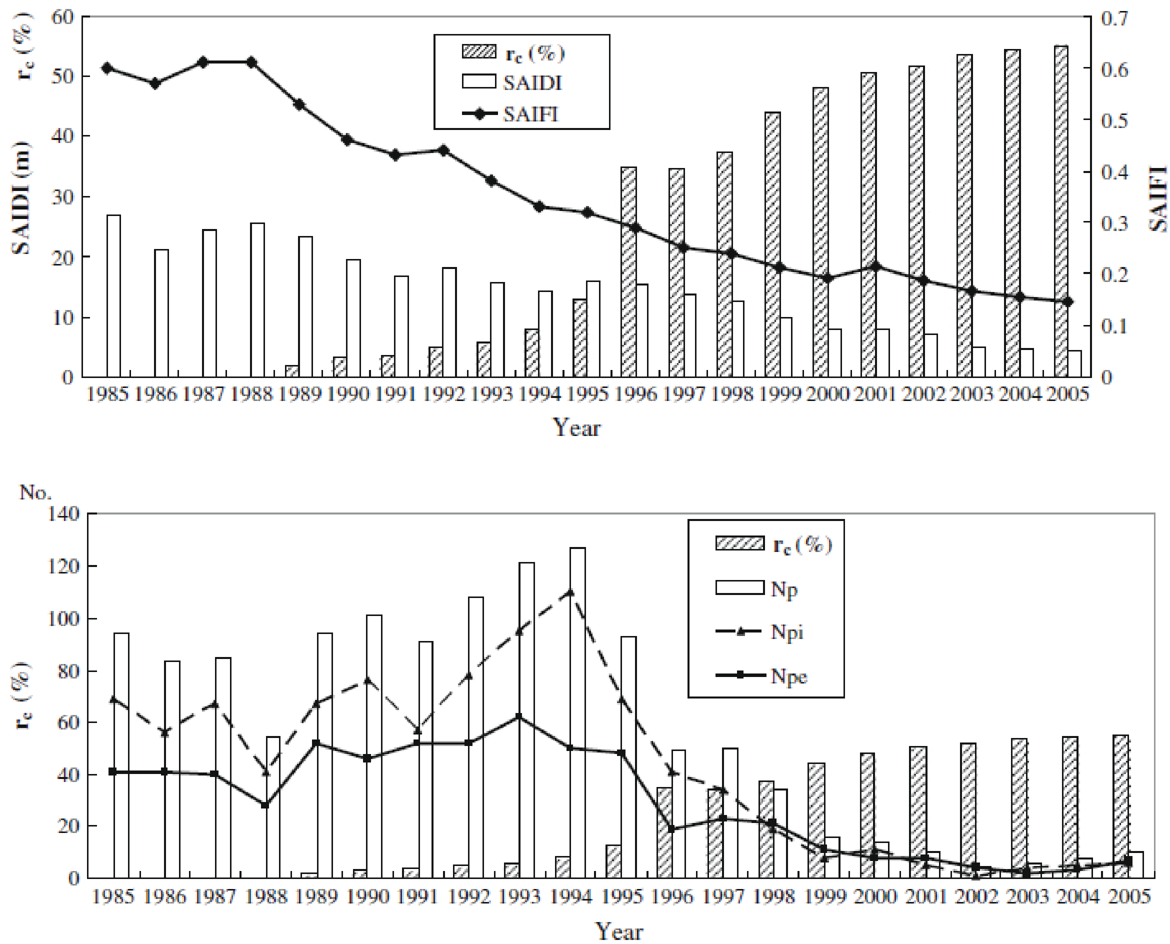


Figure 6. (Top) Taiwan Power Company results from 1985 to 2005 for the ratio of covered line length using XLPE weatherproof wire in a distribution system to the total line length of the system (r_c), system average interruption frequency index (SAIFI), and the system average interruption duration index (SAIDI). (Bottom) Taiwan Power Company results from 1985 to 2005 r_c and endangered-life indices (ELIs). The following ELI values are shown: annual number of people who receive electric shocks (N_p), annual number of people injured by electric shocks (N_{pi}), and annual number of people electrocuted (N_{pe}). Image from [Li 2010].

Australia

CCs have been used in Australia for more than 50 years, primarily motivated by wildfire risk reduction. Early CCs had limited lifetimes due to surface degradation, tracking, radio frequency (RF) emissions, and lightning damage [Wareing 2005]. In the mid-2000s, the Australian Strategic Technology Program determined that technological advancements may help solve historical issues with CCs to allow for their widespread adoption. After the Black Saturday bushfires, the Victorian Bushfires Royal Commission (VBRC) recommended the existing power lines be replaced with aerial bundled cables or other technology that reduced the risk of bushfires. The VBRC estimated a 90% reduction in the likelihood of a bushfire starting by installing CCs [SCE 2019]. Additionally, a study by the Commonwealth Scientific and Industrial Research Organization (CSIRO) found that a 98% reduction in the risk of bush fires due to CCs could be expected [SCE 2019, Electrical Connection 2021]. Although it is unclear how these specific metrics were determined, this shows high confidence by the VBRC and the CSIRO in the effectiveness of CC for wildfire mitigation.

Malaysia

The Tengag Nasional Berhad (TNB) distribution network in Malaysia includes 5,300 km of 33 kV, 22 kV, and 11 kV medium-voltage bare overhead conductor lines and 2,700 km of 33 kV and 11 kV medium-voltage aerial-bundled cables (ABC) lines [Ariffin 2012]. Malaysia has reliability challenges caused by above-average lightning activity, small-animal damage, and vegetation damage, which motivated the use of CCs to improve reliability. TNB started installing medium-voltage ABC lines in the 1990s. Early versions of ABCs had inferior fault rates and failed to deliver on the expected benefits. A redesign was undertaken to change from the single-layer copper screen with HDPE outer sheath to a double-layer copper screen. Additionally, improved construction standards were followed, and compatible accessories were used that resulted in improved performance.

TNB found that the medium-voltage bare conductor lines had a higher number of recorded failures compared with medium-voltage ABC lines from 2001 to 2007. The newly designed medium-voltage ABCs had a failure rate five times lower than that of the original medium-voltage ABCs used in the Malaysian system. In this study, a specific definition for the word "failure" was not provided.

Brazil

CEMIG, one of the four biggest power companies in Brazil, adopted spacer cables in urban areas starting in 1998 to improve reliability [Rocha 2000]. CEMIG's annual work plan was to rebuild the urban distribution system by building 1,400 km of medium-voltage lines and 2,800 km of low-voltage lines using spacer cables. CEMIG completed periodic field inspections during the first nine years of energizing the initial pilot lines. The following observations were made during the field inspections:

- Outages due to atmospheric discharges were observed where the cables had been peeled to create a metallic tie. Changes were made to how ties, polymeric rings, and polymeric anchoring clamps were installed, which resulted in improved performance.
- In areas with permanent tree contact, no signs of electrical tracking were observed.
- Minimal outages were observed in areas with vandalism (insulator breakage) and pole collisions. No outages were recorded on spacer cable lines with vandalism incidents, whereas four to five outages occurred on bare cable lines.
- Outages caused by material failures were practically eliminated.

Overall, CEMIG found a 33% reduction in the average duration and frequency of outages per customer due to the expansion of spacer cable lines [Nishimura 2001].

Failure Modes and Effectiveness

Failure Modes

A high-level failure mode identification workshop was conducted to identify operative failure modes relevant to overhead distribution systems for both bare conductors and CCs. The list of failure modes was developed during a day-long workshop with technical subject matter experts representing Exponent, PG&E, SCE, SDG&E, PacifiCorp, Liberty, and Bear Valley Electric Service. This exercise leveraged the technical knowledge from the seven different organizations and the combined experience and shared operator experiences from the six utilities. This workshop was not a full risk assessment, as other factors such as severity / consequence of an event, likelihood, and ability to detect each failure mode were outside the scope of this exercise.

The output of the failure mode workshop was a list of failure modes applicable to bare conductors and/or CCs and is presented in Table 1. The failure modes are organized into three descriptive categories: external events, human factors, and operations/maintenance. Each line item is further differentiated by the operative hazard within each category. External events primarily include hazards related to weather, vegetation, or fire. Human factors include human-induced hazards such as vehicle/equipment contact, gunshots, and Mylar balloons. The operations/maintenance category encompasses hazards related to the design, installation, and maintenance of overhead distribution lines. Within each hazard, specific scenarios that can result in failure are listed. For example, a phase-to-phase fault (failure mode) resulting from a Mylar balloon (hazard) is differentiated from a phase-to-phase fault (failure mode) resulting from a fallen tree branch (hazard). Failure modes that apply to bare conductors but are largely mitigated by using CCs are marked with a green checkmark.

Table 1. List of failure modes for bare and covered conductors.

Category	Hazard	Scenario	Bare	Covered	#	Failure Mode
External Events	Fire	External fire (wildfire)		X	1	Potential damage to sheath, reducing effectiveness
				X	2	Potential flammability of CC sheath
			X	X	3	Annealing of metal conductor due to fire exposure
External Events	Extreme heat	Extreme temperatures cause sag and clearance issues	X	✓	4	Phase-to-phase or phase-to-ground fault
External Events	UV exposure / solar exposure	Aging / exposure of conductor covering		X	5	Embrittlement and/or cracking of conductor covering
External Events	Sheath contamination	Moisture / salt contamination		X	6	Tracking/insulation failure due to moisture/salt (corona)
		Smoke during fire		X	7	Tracking/insulation failure due to smoke/ash
External Events	Ice/snow	Mechanical loading / stress on conductors	X	X	8	Excessive mechanical loading leading to conductor failure/wire down
		Unloading / dynamic shedding of ice	X	X	9	Dynamic forces leading to conductor failure and wire down
		Combined wind/ice	X	X	10	Galloping (see wind hazard)
External Events	Lightning	Atmospheric lightning	X*	X	11	Arc damage / melting of conductor, possible wire down. Short circuit duty exceeds conductor damage curve.
External Events	Animal	Animal contact		X	12	Phase-to-phase fault due to animal-damaged sheath (chewing)
				X	13	Bird dropping degradation of polymer sheath
			X	✓	14	Large bird contact of multiple conductors (phase-to-phase)

Category	Hazard	Scenario	Bare	Covered	#	Failure Mode
External Events	Moisture	Moisture/salt/ oceanic exposure	X	✓	15	Atmospheric corrosion of span leading to decreased mechanical strength or increased electrical resistance
			X	X	16	Atmospheric corrosion near hardware/dead-end leading to decreased mechanical strength or increased electrical resistance
				X	17	Freeze/thaw cycles leading to sheath damage
			X	X	18	Lack of corrosion inhibitors (on splices) leading to corrosion
				X	19	Migration of water within the sheath layer
			X	✓	20	Stress corrosion cracking of span
			X	X	21	Stress corrosion cracking near hardware/dead-end
External Events	Wind	Winds (within the natural frequency of structure)	X	X	22	Aeolian vibration-induced fatigue cracking
			X	X	23	Mechanical overload of tie wire during galloping (ice/ or lashing of spacer /messenger wires)
			X	X	24	Swinging leading to wear
			X	X	25	Vortex shedding impact / contact of adjacent conductors leading to fatigue of downstream conductors
			X	✓	26	Line slapping (intermittent conductor contact)
		Transmission / distribution line contact	X	✓	27	Differential wind-driven blowout leading to contact of distribution / transmission lines
		Pole damage		X	28	Damage due to potential for increased loading when new covered conductors replace existing bare conductors on the same poles / crossarms / guys

Category	Hazard	Scenario	Bare	Covered	#	Failure Mode
External Events	Tree damage	Tree falls, breaks conductor	X	✓	29	Conductor failure / wire down resulting in loss of service, potential for ignition (along the entire length of bare conductor or exposed section of CC)
			X	X	30	Live conductor down with no outage
		Tree branch bridges various lines (conductors do not break)	X	✓	31	Phase-to-phase fault, potential ignition
			X	X	32	Delayed fault due to long-term contact (dielectric breakdown / reduction in dielectric strength), potential phase-to-phase fault
				X	33	Abrasion of sheath
				X	34	Cracking of CC sheath
				X	35	Heating damage to sheath
				X	36	Corrosion of conductor due to compromised sheath
		Tree falls and pulls entire system to ground	X	X	37	Surrounding structure fails (broken conductor)
			X	X	38	Surrounding structure fails (conductor intact)
Human Factors	Public/worker impact	Agricultural equipment / third-party workers / under-build workers (cable/telephone)	X	✓	39	Potential for shock or electrocution
		Vehicle impact to pole / guy wire	X	✓	40	Potential for guy wire whip to create contact to conductor
			X	✓	41	Phase-to-phase contact
			X	✓	42	Phase-to-ground contact
		Gunshots	X	X	43	Conductor damage

Category	Hazard	Scenario	Bare	Covered	#	Failure Mode
Human Factors	Third-party damage	Tarps under high wind conditions	X	✓	44	Phase-to-phase contact
		Balloons	X	✓	45	Phase-to-phase contact
		Kites	X	✓	46	Phase-to-phase contact
		Palm fronds	X	✓	47	Phase-to-phase contact
Operations & Maintenance	Maintenance / Installation	Conductor damage due to incorrect hardware tool or incorrect stripping		X	48	Mechanical damage to sheath (dent/gouge)
		Poor splicing or poor connection	X	X	49	Poor contact leading to localized heating and connection failure
		Over-tensioning	X	X	50	Incorrect tensioning leading to conductor failure (due to vibration, increased stress)
		Under-tensioning	X	X	51	Increased sway leading to wear
			X	✓	52	Clearance issues due to increased sway
		Excessive angles	X	X	53	Insulator breaks off due to mechanical overload (for excessive angles). Conductor may break off or float, contacting pole.
		Broken tie wires	X	X	54	Poorly installed tie wires could break, leading to conductors separating from insulators and contacting pole.
		Improper installation	X	X	55	Bird caging—conductor strands separate

* Direct lightning strikes resulting in concentrated heating of the bare conductor and a wire down event are relatively infrequent.

Effectiveness of Covered Conductors

Failure Mode Discussion

In total, 58 unique failure mode / hazard scenario combinations were identified through the failure mode workshop. These failure modes can be categorized into three basic types:

1. Failure modes that affect both bare *and* CCs.
   Example: Aeolian vibration-induced fatigue cracking of the metal conductor (Table 1, No. 23).
2. Failure modes that affect bare conductors but are reduced or effectively eliminated by CCs.
   Example: Phase-to-phase fault due to tree branch bridging conductor phases (Table 1, No. 32).
3. Failure modes that are unique to CCs that do *not* affect bare conductors.
   Example: Lightning-induced melting of conductor sheath (Table 1, No. 12).

Failure modes that apply to bare and covered conductors

Failure modes that apply to both bare and covered conductors are well known due to historic use of bare conductors and are generally expected to be effectively managed through existing mitigations and controls. However, there are instances in which these failure modes may be *more* prevalent with CCs than with bare conductors. For instance, some wind-related phenomena such as Aeolian vibration may, in certain circumstances, be exacerbated with CCs due to their smooth surface, increased weight, and larger overall diameter [Leskinen 2004]. For similar reasons, CCs may also be more prone to ice loading than bare conductors. Ice loading may result in mechanical overload of the conductor, or increased susceptibility to galloping. A full list of failure modes that apply to both bare and covered conductors derived from the failure mode workshop is given in Table 2.

Table 2. Failure modes that affect both bare and covered conductors.

Hazard	#	Failure Mode	Potential risk relative to bare
Fire	3	Annealing of metal conductor due to fire exposure	Reduced
Ice/snow	8	Excessive mechanical loading leading to conductor failure / wire down	Increased
	9	Dynamic forces (ice shedding) leading to conductor failure and wire down	Needs study
	10	Galloping damage (see wind scenario)	Needs study
Lightning	11	Arc damage / melting of conductor, possible wire down	Increased
Moisture	16	Atmospheric corrosion near hardware/dead-end leading to decreased mechanical strength or increased electrical resistance	Comparable
	18	Lack of corrosion inhibitors (on splices) leading to corrosion	Comparable
	21	Stress corrosion cracking near hardware/dead-end	Comparable
Wind	22	Aeolian vibration induced fatigue cracking	Needs study
	23	Mechanical overload of tie wire during galloping (ice/ or lashing of spacer /messenger wires)	Needs study
	24	Swinging leading to wear	Increased
	25	Vortex shedding impact / contact of adjacent conductors leading to fatigue of downstream conductors	Needs study
Tree damage	30	Live conductor down with no outage	Increased
	32	Delayed fault due to long-term contact	Reduced
	37	Surrounding structure fails (broken conductor)	Needs study
	38	Surrounding structure fails (conductor intact)	Needs study
Third-party damage	43	Conductor damage from gunshot	Comparable
Maintenance/ installation	49	Poor contact leading to localized heating and connection failure	Comparable
	50	Incorrect tensioning leading to conductor failure (due to vibration, increased stress)	Comparable
	51	Increased sway leading to increased wear	Needs study
	53	Insulator breaks off due to mechanical overload (for excessive angles). Conductor may break off or float contacting pole.	Comparable
	54	Poorly installed tie wires could break, leading to conductors separating from insulators and contacting pole.	Comparable
	55	Bird caging—conductor strands separate	Comparable

These failure modes that can affect both bare and covered conductors are of particular importance to operators, as risk assessments may need to be updated to reflect the increased likelihood of certain events when switching to CCs. Since no studies were found that directly compared the frequency or severity of these failure modes between covered and bare conductors, the impact on mitigation and maintenance practices has not been quantified.

Despite the dearth of test data on the likelihood and severity of these failure modes for CCs relative to bare conductors, insight can be gained from a first-principles analysis of these failure modes. For example, the vulnerability to fatigue from Aeolian vibration is expected to be different for CCs for several reasons. The Aeolian vortex shedding frequency is inversely proportional to transverse wind speed, and therefore the shedding frequency will be lower for CCs because of the increase in conductor diameter due to the insulation. However, this lower cycle count could be offset by differences in the wind power input of self-damping, which define the vibration amplitude. In addition, Aeolian fatigue failure typically manifests at attachments (clamps), and it is not known whether typical CC connectors are more susceptible to the strain concentrations that lead to failure. Similarly, ice gravity loading and dynamic loads from ice and snow shedding can be expected to differ due to different conductor diameter, surface roughness, weight, and surface temperature. Additional analysis is required to better understand these failure modes.

Failure modes mitigated by covered conductors

The next group of failure modes are those that are largely mitigated by the use of covered conductors. These failure modes are the primary drivers for adoption of CCs, as they represent the risk reduction potential compared to traditional bare conductors. A total of 17 failure modes largely mitigated through the use of CC were identified through the workshop exercise, and are marked with a green checkmark in Table 1. The common theme among these failure modes is that they are created through contact with third-party objects, vegetation, or other conductors that create phase-to-ground or phase-to-phase faults. The available literature, industry testing, and field experiences from utilities around the world suggest that modern CCs can prevent arcing in the medium-voltage range over short time scales, thereby increasing system reliability and public safety, and reducing the potential for wildfire ignition. A full list of failure modes addressed by CCs derived from the failure mode workshop is given in Table 3.

Table 3. Failure modes that affect bare conductors but are largely mitigated by covered conductors.

Hazard	#	Failure Mode
Extreme heat	4	Fault due to sag/clearance issues
Animal	14	Large bird contact of multiple conductors (phase-to-phase contact)
Moisture	15	Atmospheric corrosion of span leading to decreased mechanical strength or increased electrical resistance
	20	Stress corrosion cracking of span
Wind	26	Line slapping (intermittent conductor contact)
	27	Differential wind driven blowout leading to contact of distribution / transmission lines
Tree damage	29	Conductor failure/wire down resulting in loss of service, potential for ignition (along the entire length of bare conductor or exposed section of CC)
	31	Phase-to-phase fault. Potential ignition.
Public/worker impact	39	Potential for shock or electrocution
	40	Potential for guy wire whip to create contact to conductor
	41	Phase-to-phase contact (vehicle)
	42	Phase-to-ground contact (vehicle)
Third-party damage	44	Phase-to-phase contact (tarp)
	45	Phase-to-phase contact (balloon)
	46	Phase-to-phase contact (kite)
	47	Phase-to-phase contact (palm frond)
Maintenance/ Installation	52	Clearance issues due to increased sway

As stated above, these failure modes generally consist of arcing between phases or objects. The primary and secondary effects of these failure modes have implications for system reliability, public safety, and wildfire prevention. For example, arcing between phases due to conductor slapping can create sparks, conductor melting, and/or a possible wire-down scenario. This not only creates an outage risk but also creates potential for a wildfire ignition if dry brush exists below the lines. As will be discussed, available literature indicates that CCs prevent arcing during line slap, such that sparks and melting never occur. In another example, windstorms can blow debris and vegetation into the conductors. While this may not result in a wire-down event, it can create arcing between phases, and the vegetation (e.g., palm fronds) can ignite and fall to the ground. CCs prevent arcing when vegetation is blown into the lines and, therefore, ignition cannot occur.

The extent to which existing information supports the effectiveness of CCs to address these failure modes was considered. For example, it is generally accepted that CCs largely eliminate the risk of vegetation-caused phase-to-phase faults. However, the literature and existing data were analyzed to understand the extent to which this has been proved and whether there are situations that have not been studied. Testing performed by SCE found that CCs prevented phase-to-phase and phase-to-ground faults in field tests that simulated common scenarios such as branch contact, Mylar balloon contact, and conductor slapping (simulating sustained contact) when energized at 12 kV [SCE 2019]. This is relevant and useful testing, though similar laboratory studies to further bolster these conclusions were not found in the available literature.

Most of the available literature consists of high-level observations that correlate system reliability and safety metrics to increases in CC line installation [Leskinen 2004, Li 2010, SCE 2019, Electrical Connection 2021, Ariffin 2012, Rocha 2000, Nishimura 2001]. These studies suggest that the purported benefits of CCs are effective. However, the benefits are not attributed to specific failure modes, but rather overall system reliability and safety metrics. Further, the true technical limits, i.e., to what extent, and over what time scale arcing is mitigated, still lack concrete data. Few publicly available studies were found that directly test the arcing characteristics of CCs. While the SCE testing provides systematic fault testing of CCs, one limitation of the testing performed by SCE is that it was focused on short-term incidental contact and did not test long-term effects such as a tree branch growing into conductor spans. Second, while the success of these tests at 12 kV provides useful data for many distribution-level applications, an effective steady-state breakdown voltage (upper limit) at which arcing eventually occurs was not identified.

Failure modes unique to covered conductors

Failure modes unique to CCs primarily involve damage or degradation to the insulating polymer sheath. These may not be addressed by mitigations that currently exist under asset management plans geared toward bare conductor use. Therefore, Exponent recommends to better understand these failure modes through available literature and targeted testing. When addressing CC-specific failure modes, it is important to consider that some failure modes may simply reduce the benefits of the covering (i.e., return to bare conductor risk level) while others may create a situation that has a unique and independent risk profile relative to a typical bare conductor installation. These factors will be the focus of the Covered Conductor Risks section below. As will be shown later in the report, some of these failure modes have been largely addressed by advances in technology (e.g., UV stabilizers that reduce embrittlement of conductor covering) or are unlikely to occur (e.g., animal chewing the same spot on two adjacent phases). A full list of the CC-specific failure modes derived from the failure mode workshop is given in Table 4.

Table 4. Failure modes that affect *only* covered conductors.

Hazard	#	Failure Mode
Fire	1	Potential damage to sheath, reducing effectiveness
	2	Potential flammability of CC sheath
UV exposure / solar exposure	5	Embrittlement and/or cracking of conductor covering
Contamination	6	Tracking/insulation failure due to moisture/salt (corona)
	7	Tracking/insulation failure due to smoke/ash
Animal	12	Phase-to-phase fault due to animal-damaged sheath (chewing)
	13	Bird dropping degradation of polymer sheath
Ice/snow	17	Freeze/thaw cycles leading to sheath damage
	19	Migration of water within the sheath layer
Wind	28	Damage due to potential for increased loading when new covered conductors replace existing bare conductors on the same poles / crossarms / guys
Tree damage	33	Abrasion of sheath
	34	Cracking of CC sheaths
	35	Heating damage to sheath
	36	Corrosion of conductor due to compromised sheath

Hazard	#	Failure Mode
Maintenance / installation	48	Mechanical damage to sheath (dent/gouge)

Few published studies were found that analyze specific CC-specific failure modes. However, some data have been obtained from CC manufacturers that assists in understanding the limitations of the technology. Hendrix Wire & Cable has performed several tests on the properties and durability of its CC products. These tests include tracking resistance, ultraviolet (UV) resistance, environmental stress cracking, hot creep tests, and performance of CCs in high-contamination environments [Hendrix 2019, Trager 2006]. These test results suggest that modern CC sheathing is resistant to many forms of environmental degradation. However, since these tests were designed to isolate individual variables in a controlled environment, they do not account for all possible variables in a real-world scenario. The failure modes addressed by the Hendrix testing are likely to reduce the effectiveness of covered conductors but, in most circumstances, would not result in a new, higher-risk profile.

Another consideration that is not represented in the failure mode table is the possibility of undetected wire-down events. The CC sheath provides protection from immediate phase-to-ground faults, and therefore may not trigger fault detection systems. This may lead to high-impedance faults and delay necessary field repairs. Downed bare conductors can also result in high-impedance faults, but the situation will be different for CCs since there will be reduced conductor contact with the ground. The potential for these high-impedance fault events that evade detection is the subject of current research, and new early fault detection systems are in development. Operators transitioning to covered conductors may benefit from further research into early fault detection solutions [SCE 2019, Kistler 2019]. These CC-specific failure modes will be the focus of the Covered Conductor Risks section below.

The failure modes discussed thus far are important for understanding the benefits and tradeoffs of implementing CC technology. The next sections will focus on three broad categories of system performance: reliability, public safety, and wildfire ignition. These sections are structured as such because of the available literature, much of which is not specific to individual failure modes but is broader in nature. Available knowledge in these areas from field experience and lab testing will be highlighted, as well as any deficiencies that may warrant further study.

System Reliability

Industry experience has demonstrated an improvement in system reliability when using CCs [EPRI 2014, Leskinen 2004, Li 2010, Nishimura 2001, Rocha 2000, Ariffin 2012]. The primary driver of this improvement in reliability was the decreased probability of fault events, which resulted in fewer system outages. Finland saw a steady decrease in recorded faults in rural areas in the years after 1972, which corresponded to an expansion of CC use. Finland also found that the number of automatic reclosing events decreased to one third as the percentage of CC lines increased from 10% to 50% [Leskinen 2004]. A Taiwanese study similarly found that SAIFI was reduced by approximately 75% and SAIDI was reduced by approximately 86% as the percentage of CCs was increased from 0% to ~55% [Li 2010]. The Electric Power Research Institute (EPRI) also stated that CCs have the potential to reduce tree-caused outages by 40% based on an analysis of data from Duke Energy and Xcel Energy [EPRI 2015].

Public Safety

Public safety is a driver of CC adoption in high population density areas. The Taiwan Power Company observed a ~92% decrease in the number of people experiencing an electric shock from overhead powerlines from 1994 to 2005, when CCs became nearly 60% of their total distribution network [Li 2010]. Operators in Japan observed a similar correlation between accidents and CC installation, noting a factor of 50% reduction in accidents per year from 1965 to 1984 after converting their entire 74 km 6.6 kV network to CCs [Kyushu 1997]. The National Electric Energy Testing, Research and Applications Center (NEETRAC) at Georgia Tech performed a study on the touch current characteristics of CCs vs. bare conductors [NEETRAC 2018]. Both laboratory testing and computer simulations were performed to investigate the results of human bare-hand contact on a two-mile 12 kV distribution system. These tests demonstrated that the contact current for bare conductor was as high as 7 amperes (A), while the maximum contact current for CCs was in the micro-ampere (µA) range. The increased protection against electric shock incidents is significant. However, damage to the conductor sheath or intentional stripping at hardware or dead-end connections will predictably negate or reduce these benefits.

Wildfire Ignition

Utilities in dry climates such as Australia and the western United States are subject to increased risk of wildfire ignition from powerline failures. The reduced propensity for arcing events with CCs is a distinct advantage for minimizing this risk. The Powerline Bushfire Safety Program of the Victoria, Australia, government commissioned a study that examined the fire performance of CCs in "wire down" ignition tests [Marxsen 2015]. Both covered and bare conductors were tested in "wire on ground" faults under severe fire risk conditions. The authors concluded that intact CCs effectively mitigate ignition risk, stating that "the leakage current through the outer plastic covering with the conductor lying on the ground is not sufficient to create thermal runaway so it does not create fire risk."

However, tests on damaged CCs, i.e., conductors with existing through-thickness coating loss, found that the probability of ignition for CCs can be higher than with bare conductors due to the concentration of arcing at the damage location. On flat ground with uniform dry grass coverage, the estimated probability of fire ignition for a damaged CC was 67% vs. only 37% for bare conductor [Marxsen 2015]. An important limitation of this test is that it assumes direct contact of the fuel source with the bare portion of the damaged conductor. The probability of fire would likely be much lower in areas with non-uniform vegetation cover or uneven ground, reducing the likelihood that coating holidays or stripped connection points would contact dry brush. Further, the study investigated the effects of through-thickness coating holidays but did not address the potential negative effects of partial coating loss from sources such as abrasion.

Summary of Covered Conductor Effectiveness

The prior sections outline field experience and laboratory studies that suggest a significant risk reduction with CC use. Although not all bare conductor failure modes are addressed by specific laboratory studies in controlled environments, sufficient high-level evidence exists to suggest that selected hazards affecting bare conductor are addressed by CC use. As shown in Table 5, there are six hazards that are largely mitigated by CC use, including animal, moisture, wind, tree/vegetation, public/ worker impact, and third-party damage. However, as discussed in the prior sections, this does not suggest that additional work is not required to address these hazards. In many cases, specific test scenarios may still add value to better understand CC use. Such tests scenarios are discussed in the Recommendations section of this report.

Table 5. Hazards that are largely addressed by use of covered conductors are shown in green.

	Hazard	Potential to Mitigate Failures		
		Bare Conductor	Covered Conductor	Sources
Primary Hazards	Tree/vegetation		Reduced risk of tree/veg contact-induced fault	Li 2010; Leskinen 2004; Ariffin 2012
Primary Hazards	Wind		Reduced risk of phase-to-phase faulting from slapping or blowout	Leskinen 2004
Primary Hazards	Third-party damage		Reduced risk of phase-to-phase faults from contact with kites, balloons, palm fronds, etc.	SCE 2019
Primary Hazards	Animal		Reduced risk of animal contact-induced fault	Ariffin 2012
Primary Hazards	Public/worker impact		Reduced risk of faults from worker contact or vehicle impact	Li 2010
Secondary Hazards	Moisture		Provides environmental protection except near hardware/dead-ends	
Secondary Hazards	Ice/snow			
Secondary Hazards	Fire			
Secondary Hazards	Extreme heat			
Secondary Hazards	Maintenance/ installation			
Secondary Hazards	UV exposure	N/A		
Secondary Hazards	Contamination	N/A		
Secondary Hazards	Lightning	N/A		

Comparison to Underground Cabling

The above-referenced literature and case studies demonstrate the advantages of CCs relative to bare conductors. The insulating polymer sheath mitigates several failure modes related to phase-to-phase and phase-to-ground faulting such as conductor slapping, animal contact, tree contact, and downed-conductor scenarios. While these benefits are critical to distribution system reliability and safety, there are additional hazards associated with overhead line constructions that cannot be reduced or eliminated by CCs. For example, CCs are exposed to ice/snow loading, contamination from salt, industrial pollutants, wildfire smoke, and conductor burndown from lightning strikes.

The third option typically considered for distribution system hardening is underground cabling. This method of construction has the potential to mitigate the same failure modes as CCs while also mitigating failure modes related to several other hazards, as shown in Table 6. By routing distribution lines underground, the conductors are protected from weather, fire, and other above-ground hazards that affect both bare and covered overhead conductors.

While there are benefits of underground distribution lines, there are also several economic and logistical challenges associated with their implementation. While economic considerations were largely out of scope for this work, a study conducted by SCE found that the cost per mile for undergrounding an existing overhead line ($3 million per mile) is roughly an order of magnitude more expensive than reconductoring with CCs ($430,000 per mile) [SCE 2019]. Underground conversions also may not be possible in all circumstances due to limitations of the terrain and local geology. For example, underground lines may not be practical or possible in mountainous areas or regions with high earthquake risk. Another consideration is the time required for implementation. Underground conversions are time-intensive projects, so a system hardening program based on undergrounding will take more time to realize any tangible benefits to system reliability/safety. Repairs to underground lines are more expensive and time-consuming due to access difficulties. Finally, there are environmental impacts from underground conversion that do not exist for reconductoring of existing infrastructure. These challenges are not reflected in Table 6 but require consideration in any mitigation implementation strategy.

Table 6. Mitigation potential of distribution line constructions.

	Hazard	Potential to Mitigate Failures		
		Bare Conductor	Covered Conductor	Underground
Primary Hazards	Tree/vegetation			
	Wind			
	Third-party damage			
	Animal			
	Public/worker impact			
Secondary Hazards	Moisture			
	Ice/snow			
	Fire			
	Extreme heat			
	Maintenance/installation			
	UV exposure	N/A		
	Contamination	N/A		
	Lightning	N/A		

Covered Conductor Risks

To understand all potential implications of implementing CCs, failure modes unique to CCs were assessed relative to available literature and testing information. The goal of this comparison was to understand the extent to which the identified CC-specific failure modes represent risks to operators that implement CCs. CC-specific failure modes fall into one of two categories: failure modes that may reduce the effectiveness of the insulating sheath, and failure modes that have a unique and independent risk profile relative to bare conductors (i.e., there is a potential for the risk to be higher than for bare conductors). Table 7 presents the potential consequence of the failure mode relative to bare conductors. The consequences for each failure mode were assigned based on whether the CC failure mode, should it occur, would be likely to decrease, increase, or have comparable risk relative to bare conductors, based on literature review and industry best practices. For example, contamination from salt may result in tracking on the surface of the insulation and may significantly reduce the insulating capacity of the sheath. In this scenario, the CC would have reduced effectiveness relative to a new CC but would still not exhibit a risk profile that is comparable or higher than that of a bare conductor. Complete failure of the CC insulation was considered in this analysis. For simplicity, localized (holiday) or partial failure was not considered. A detailed description of the rationale for each status can be found in the body of this section. Table 7 also lists literature sources and recommendations on whether additional testing is recommended for a given failure mode. As shown in Table 7, several effective mitigations were identified in literature for the CC-specific failure modes. However, there are still failure modes without known or proven mitigations that likely require further testing, research, and/or analysis.

Table 7. Risk of covered conductors relative to bare conductors and knowledge gaps.

Hazard	Scenario	Failure Mode	Consequence of Failure	Mitigation Notes	Selected Literature/ Testing	More Investigation Recommended
Fire	External fire	Potential damage to sheath, reducing effectiveness	Reduced effectiveness of CC	No mitigation effective against extreme temps	No testing or field experience found*	Yes
	Wildfire	Potential flammability of CC sheath	Reduced effectiveness of CC	No mitigation effective against extreme temps	SCE 2019	Yes
UV exposure / solar exposure	Aging / exposure of conductor covering	Embrittlement and/or cracking of conductor covering	Reduced effectiveness of CC	UV inhibitors commonly used to prolong polymer lifetime	Hendrix 2010; Ariffin 2012	No
Contamination	Moisture/ salt	Tracking insulation failure due moisture/salt (corona)	Reduced effectiveness of CC	Tracking and erosion issues are documented for 1-, 2-, and 3-layer CC under polluted conditions	Yousuf 2019: Cardoso 2011; Espino-Cortes 2014	No
	Smoke during fire	Tracking/insulation failure due to smoke/ash	Reduced effectiveness of CC	Tracking and erosion issues are documented for 1-, 2-, and 3-layer systems under polluted conditions	Yousuf 2019: Cardoso 2011; Espino-Cortes 2014	No
Animal	Animal contact	Phase-to-phase fault due to animal-damaged sheath (chewing)	Potentially higher consequence than bare	Redesign of coating to include a two-layer copper screen and use non-HDPE as the sheath material**	Ariffin 2012	No

Hazard	Scenario	Failure Mode	Consequence of Failure	Mitigation Notes	Selected Literature/ Testing	More Investigation Recommended
		Bird dropping degradation of polymer sheath	Reduced effectiveness of CC	Washing conductors may be effective to prevent degradation	No testing or field experience found*	Yes
Moisture	Moisture/salt/ oceanic exposure	Freeze/thaw cycles leading to sheath damage if CC is not co-extruded	Reduced effectiveness of CC	No mitigation identified in literature	No testing or field experience found*	Yes
		Migration of water within the sheath layer	Reduced effectiveness of CC	Proper installation hardware and procedures needed	No testing or field experience found*	Yes
Wind	Pole damage	Increased potential for pole damage (due to heavier conductor and larger wind area)	Potentially higher consequence than bare	Proper standards and procedures needed when retrofitting	Leskinen 2004	Yes
Tree damage	Tree falls, breaks conductor	Live conductor down with no outage	Reduced effectiveness of CC	Literature shows fewer ELIs as CC were introduced into system (see Taiwan section)	Li 2010	Yes
	Tree branch bridges various lines (conductors do not break)	Abrasion of sheath	Reduced effectiveness of CC	Literature shows CC reduced outages due to tree contact	Li 2010; Leskinen 2004; Ariffin 2012	Yes
		Cracking of CC sheaths	Reduced effectiveness of CC	Literature shows CC reduced outages due to tree contact	Li 2010; Leskinen 2004; Ariffin 2012	Yes

Hazard	Scenario	Failure Mode	Consequence of Failure	Mitigation Notes	Selected Literature/ Testing	More Investigation Recommended
		Heating damage to sheath following coating damage	Reduced effectiveness of CC	Literature shows CC reduced outages due to tree contact	Li 2010; Leskinen 2004; Ariffin 2012	Yes
		Corrosion of conductor due to compromised sheath	Reduced effectiveness of CC	Literature shows CC reduced outages due to tree contact	Li 2010; Leskinen 2004; Ariffin 2012	Yes
Maintenance / installation	Sheath damage due to incorrect hardware tool or incorrect stripping	Mechanical damage to sheath (dent/gouge)	Potentially higher consequence than bare	Proper standards and procedures needed	Rocha 2000	No

* Based on a thorough literature review. However, sources may exist that were not found through this effort.

** HDPE may be beneficial for other failure modes.

Risk Discussion

In total, 24 failure modes that are unique to CCs were assessed for their risk relative to bare conductors. The failure modes presented in Table 7 were identified through the joint IOU workshop. However, the frequency of these events (as well as consequence) was not within scope for this effort, and, as such, not all failure modes may present measurable risks to operators. Further, only a portion of these failure modes may result in an elevated risk profile relative to bare conductors, whereas others may only reduce the effectiveness of the covering. The following section discusses special cases from Table 7 in more detail.

Two fire-related failure modes were identified, including damage to, and flammability of, the sheath. In a "worst-case" scenario, if the sheath becomes damaged by fire or heat from a nearby fire, only the metallic conductor will remain. In this case, the effectiveness of CCs is greatly reduced, but no elevated risk relative to bare conductor would result. If, however, the sheath was only damaged in a localized area (versus extensive damage across the entire sheath), then a fault event could have the potential to concentrate heat and arcing in the area of the coating damage in a more severe manner than a bare conductor. In this case, a new, unique risk profile may exist beyond a simple reduction in CC effectiveness. In both cases, no mitigation, testing, or field experience was found in the literature reviewed. For this reason, further research, and possibly testing of these failure modes is recommended to determine the effect of sheath damage due to fire.

UV or solar exposure may accelerate the conductor sheath aging by causing embrittlement and/or cracking. Damage to the sheath may reduce the effectiveness of the CC. UV inhibitors are commonly incorporated in the conductor coating to prolong polymer lifetime [Hendrix 2010, Ariffin 2012].

Contamination from moisture/salt and smoke during fires was considered, as tracking could reduce the effectiveness of the insulation. Tracking of single-, dual-, and triple-layer CCs in heavily polluted areas and coastal areas is well documented in literature [Cardoso 2011, Yousuf

2019, Espino-Cortes 2014]. Similar to the fire hazard discussed above, if the insulation or sheath experiences significant tracking, then the CC effectiveness will be reduced.

Lightning may cause arc damage or melting of the CC that results in a down wire. Reports in the literature indicate CCs help to reduce the number of outages due to lightning, though the mechanism for failure prevention is unclear [Ariffin 2012, Leskinen 2004]. However, the presence of the CC insulation may create an increased risk during a lightning strike. For bare conductors during a lightning event, the electrical arc is more easily dissipated across the metallic surface. In the case of CCs, the insulation may concentrate the electrical arc at a single point during a lightning event, which may cause burndown [Lima 2016, Leal 2021]. Pinholes in the CC insulation may also result in a small reduction of the breakdown voltage. Although lightning arrestors help to mitigate this failure mode, additional testing or research could still be helpful in better understanding the effects of lightning strikes on CCs.

Animal chewing on the conductor coating may cause a localized area of damage such that arcing/heating may be concentrated during a fault. Therefore, this type of damage may present an elevated risk profile relative to bare conductors. Literature sources recommend use of a two-layer copper screen and non-HDPE as the sheath material to deter animals from chewing on the conductors. However, using non-HDPE coatings for the sheath material must be weighed against the benefits of using HDPE materials, especially in areas where animal chewing may not pose a significant risk. No further testing is recommended at this point, as this mitigation is well documented in literature [Ariffin 2012].

Moisture may result in sheath damage due to freeze/thaw cycles or water migration. In the case of water migration, sealing the ends of the conductor may help prevent damage. Few literature sources were found that addressed this specific failure mode or potential mitigation strategies. Additional research, analysis, or testing is recommended to address moisture ingress that could change the breakdown voltage potential of CCs.

Wind damage to poles due to the heavier weight of CCs and larger wind sway is potentially an increased risk compared to bare conductors. This risk can be mitigated by using proper standards and procedures, especially when retrofitting CCs onto existing structures. Additional analysis is recommended to understand potential pole damage due to CC weight.

Tree damage may result in multiple failure modes, as shown in Table 7. On a high level, field experience shows that the number of outages caused by tree contact is reduced when CCs are used [Leskinen 2004, Li 2010, Ariffin 2012, Rocha 2000]. CCs likely decrease the risk of tree-related failure modes. However, the literature studies reviewed do not detail the specific failure modes that are mitigated. Additional research and testing may be needed to determine the extent to which CCs reduce the risk of certain failure modes. Testing focused on long-term tree contact and mechanical testing of the polymer sheath is recommended.

Maintenance and installation considerations are different for CCs compared with bare conductors. Due to the CC sheath, care should be taken while installing CCs to minimize damage from incorrect hardware, stripping, or installation. Additionally, the span sag levels must be adjusted due to increased weight of CCs. Specialized training, standards, and procedures must be followed to account for the additional considerations for CC installation and maintenance. These standards and procedures should help minimize the CC risks and make them comparable to those of bare conductors. However, the additional training, standards, and procedures introduce the potential to increase the risk of CCs compared to bare conductors if not properly followed. No further testing is recommended at this time for this hazard, as long as proper procedures and standards are established for maintenance and installation.

Implementation and Design Considerations

In addition to new failure modes and risks that may be introduced by CCs, there also exist several special considerations for effective design and implementation of CC systems.

Hardware specific to CCs is recommended to ensure consistent and safe installation and reduce the risk of damaging the conductor insulation. This hardware may include insulation-piercing connectors (IPCs), spacers, tangent brackets, and messenger cable. If IPCs are not used, manual stripping of conductor insulation is required at hardware connection points. This creates a risk for local arcing/faults as well as the potential for conductor sheath damage and environmental ingress if not properly executed.

Replacement of bare conductors with equivalent CCs can potentially cause increased sag and can overload the poles, crossarms, or guys because they can increase both gravity and wind loads. The capacity of existing structures needs to be checked before reconductoring is considered. The span length for new lines is typically shorter than bare conductors due to the heavier weight of CCs. However, this can be overcome if a larger messenger wire with greater ultimate tensile strength is used [Cardoso 2011]. Span lengths of 40 meters are common for distribution systems but can be increased up to 400 meters with proper installation [Cardoso 2011].

Installation and maintenance procedures are necessary for CCs due to the special requirements listed above. Proper handling of CCs and considerations when retrofitting CCs onto existing infrastructure is needed. This includes but is not limited to minimizing the amount of coating stripped or removed, covering any exposed conductor, increasing line sag to account for the additional CC weight, and installing proper accessories for lighting arrestors, dead-end covers, composite poles, and crossarms [EPRI 2009 Crudele]. This requires additional personnel training to address unique aspects of CC care, special equipment requirements, and handling during installation and maintenance.

Recommendations

1. Line Tension Study

Several failure modes that affect both bare and covered conductors have the potential to be exacerbated with CCs relative to bare conductors. These are primarily related to the physical differences between the conductors such as diameter, weight, and surface characteristics, leading to potential differences in susceptibility to Aeolian vibrations, galloping, line sway, mechanical overload due to ice accretion, and others (Table 2). Therefore, a thorough understanding of these differences from an analytical perspective is recommended. Specifically, a study investigating the most appropriate line tension considering the size and weight of covered conductor is recommended, which would aid in mitigation of the identified failure modes.

2. Additional Arc Testing

The available literature was found to be promising and suggests that many of the identified failure modes are largely addressed by use of CCs. However, a few key scenarios have yet to be addressed. Further arc testing is recommended to investigate the effects of long-term contact with vegetation, ground, or other objects to better understand delayed high-impedance fault behavior. The effects of wet vs. dry conditions on arcing behavior also warrants further investigation.

3. Covered Conductor–Specific Failure Mode Testing

An understanding of CC-specific failure modes is critical to effective asset management. While implementing CCs will mitigate some risks associated with bare conductor use, there are new failure modes introduced through the use of CCs. The available literature focuses on the benefits of CCs and is relatively lacking with respect to these failure modes. Further research (and potentially testing) is recommended to better understand the following phenomena:

a. Sheath damage and flammability due to nearby fire
b. Tracking due to contamination from salt or smoke
c. Moisture ingress
d. CC sway behavior and the potential for pole damage

4. Early Fault Detection Research

Due to the insulation provided by CCs, a fallen intact conductor may be difficult to quickly detect with existing fault protection systems. Early fault detection schemes are a subject of current research, and additional investigation of this technology is recommended.

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Limitations

At the request of PG&E, SCE, and SDG&E, Exponent has conducted an investigation into the effectiveness of covered conductors for overhead distribution system hardening. Exponent investigated specific issues relevant to this technology, as requested by PG&E, SCE, and SDG&E. The scope of services performed during this investigation may not adequately address the needs of other users of this report, and any reuse of this report or its findings, conclusions, or recommendations presented herein is at the sole risk of the user. The opinions and comments formulated during this assessment are based on observations and information available at the time of the investigation. No guarantee or warranty as to future life or performance of any reviewed condition is expressed or implied.

The findings presented herein are made to a reasonable degree of engineering certainty. We have made every effort to accurately and completely investigate all areas of concern identified during our investigation. Exponent may supplement this report should new data become available.