

Application No.: A.23-05-010
Exhibit No.: SCE-04 Vol. 05 Pt. 2
Witnesses: R. Fugere
A. Swisher



(U 338-E)

2025 General Rate Case

Wildfire Management Part 2: Grid Hardening

Before the

Public Utilities Commission of the State of California

Rosemead, California
May 12, 2023

SCE-04 Vol. 05 Pt. 2: Wildfire Management Grid Hardening Table Of Contents

Section	Page	Witness
I. INTRODUCTION	1	R. Fugere
A. Wildfire Mitigation Activities.....	1	
1. Summary of O&M and Capital Request.....	1	
2. Grid Hardening	2	
a) Content and Organization of Chapter	2	
b) Background and Overview	4	
c) Targeted Undergrounding (TUG).....	6	
(1) Work Description and Need.....	7	
(2) Historical Variance Analysis	15	
(3) 2021 Authorized vs. Recorded.....	15	
(4) Capital Expenditure Forecast.....	17	
(5) RAMP Integration.....	27	
d) Wildfire Covered Conductor Program (WCCP).....	28	
(1) Work Description & Need – Covered Conductor Work.....	29	
(2) Work Description & Need: Tree Attachment Remediations.....	57	
(3) Work Description & Need - Vibration Damper Retrofits	63	
(4) Work Description & Need - Fire- Resistant (FR) Wrap Retrofit – Distribution	69	
e) Rapid Earth Fault Current Limiters	71	A. Swisher
(1) Work Description & Need	72	

SCE-04 Vol. 05 Pt. 2: Wildfire Management Grid Hardening

Table Of Contents (Continued)

Section	Page	Witness
(2) Historical Variance Analysis	79	
(3) Comparison of Authorized 2021 to Recorded	80	
(4) Scope Forecast	80	
f) HFRA Sectionalizing Devices	85	R. Fugere
(1) Work Description & Need	86	
(2) Historical Variance Analysis	89	
(3) Comparison of Authorized 2021 to Recorded	91	
(4) Scope Forecast	92	
g) Generation System Hardening Legacy Facilities	98	
(1) Work Description & Need	98	
(2) Historical Variance Analysis	99	
(3) Comparison of Authorized 2021 to Recorded	100	
(4) Scope of Forecast Analysis.....	100	
h) Long Span Initiative.....	102	
(1) Work Description & Need	103	
(2) Historical Variance Analysis	108	
(3) Comparison of Authorized 2021 to Recorded	109	
(4) Scope Forecast	109	
(5) Cost Forecast:.....	110	
(6) RAMP Integration.....	111	

SCE-04 Vol. 05 Pt. 2: Wildfire Management Grid Hardening

Table Of Contents (Continued)

Section	Page	Witness
3. Fusing Mitigation.....	112	A. Swisher
a) SCE’s Actions in Selecting and Installing Potentially-Defective Fuses Were Prudent and Reasonable Based on What SCE Knew at the Time	115	
b) The Cost Impact to Customers of the Defective Fuses Themselves was \$2.03 Million, not the \$24.62 Million SCE is Seeking in Cost Recovery	119	
c) Recovery From Vendor.....	120	

I.

INTRODUCTION

A. **Wildfire Mitigation Activities**

1. **Summary of O&M and Capital Request**

This volume presents SCE’s requests for \$6.979 million (constant 2022 dollars) in O&M expenses for the 2025 Test Year and \$6,338 million (nominal dollars) in capital expenditures for 2023-2028 for the activities listed below in Table I-1 and Table I-2. This funding is crucial to implement effective wildfire mitigation programs and activities designed to reduce the number and likelihood of ignitions associated with SCE equipment as well as to increase resiliency of SCE infrastructure to wildfires.

Table I-1
Wildfire Management O&M Expenses¹
(Constant \$000)

GRC Activity	TY 2025 O&M
Supplemental System Hardening Activities	\$4,963
Grid Hardening	\$501
HFRA Sectionalizing Devices	\$1,515
Totals	\$6,979

Table I-2
Wildfire Management Capital Expenditures 2023 – 2028²
(Total Company Nominal \$000)

GRC Activity	2023 - 2028 Capital Expenditure Forecast
High Fire Risk Inspections and Remediations	\$11,177
Grid Hardening	\$6,292,074
HFRA Sectionalizing Devices	\$33,100
Supplemental System Hardening Activities	\$1,249
Totals	\$6,337,600

2. Grid Hardening

a) Content and Organization of Chapter

In this chapter, SCE presents our forecasts of capital expenditures and Operations and Maintenance (O&M) expenses for Wildfire Management grid hardening activities. SCE summarizes the proposed scope of work, key drivers for the work to mitigate wildfire and PSPS risks, 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 reduce public safety risks by enhancing the resiliency of SCE's electrical system and to minimize the ignition risk of significant wildfires associated with SCE equipment, consistent with state policy.

¹ Refer to WP SCE-04, Vol. 05, Part 2, pp. 1-19 – Grid Hardening O&M Forecast.

² Refer to WP SCE-04, Vol. 05, Part 2, pp. 20-22 – Grid Hardening Capital Forecast.

This chapter is organized by activity as follows:

1. Section c) describes the Targeted Undergrounding (TUG) program, which specifically targets areas with egress constraints, high consequence ignition risks, communities of elevated fire concern, 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;³
2. Section d) describes SCE's Wildfire Covered Conductor Program (WCCP), which includes the installation of covered conductor and fire-resistant poles, removal of tree attachments, retrofit of covered conductor lines with vibration dampers, and retrofit of existing poles in HFRA with fire-resistant wraps;
3. Section e) 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;
4. Section f) describes HFRA Sectionalizing Devices, which are deployed to mitigate fault-related ignition risks and isolate circuit segments to reduce the scope of PSPS events;
5. Section g) describes hardening of legacy generation facilities; and
6. Section h) describes SCE's Long Span Initiative, through which remediations are deployed to mitigate conductor clashes in adverse wind conditions.

³ The specific targeted areas referenced here are the Severe Risk Areas explained in Exhibit SCE-04, Vol. 05, Part 1 – Wildfire Management Overview.

1 In addition to the Grid Hardening activities listed above, in Section 3, SCE
2 provides additional justification to seek recovery of costs for capital expenditures related to Fusing
3 Mitigation that were not approved in D.22-06-032.

4 b) Background and Overview

5 Wildfire mitigation measures have been part of SCE's operational practices for
6 years, as the HFRA accounts for a significant portion of SCE's service area. However, due to increasing
7 risk factors in part driven by accelerating climate change, beginning in 2018 SCE significantly expanded
8 its wildfire mitigation programs as first set forth in its GSRP Application in late 2018. The GSRP
9 proceeding proposed wildfire mitigation measures for the 2018-2020 period (incremental to amounts
10 authorized in the 2018 GRC). In Track 1 of SCE's 2021 GRC, the Commission authorized wildfire
11 mitigation programs (and their associated revenue requirements) for Test Year 2021 and attrition years
12 2022 and 2023. Additionally, Track 2 of SCE's 2021 GRC addressed non-GSRP-related incremental
13 wildfire mitigation costs for 2019, and Track 3 addressed non-GSRP-related incremental wildfire
14 mitigation costs for 2020, as well as GSRP costs for the 2018-2020 period above the amounts authorized
15 in the GSRP Settlement Agreement (D.20-04-013). SCE's GRC Track 4 filing requested wildfire
16 mitigation costs SCE expects to incur in 2024. Because wildfire and PSPS risks persist, although at
17 lower levels, through this 2025 GRC period, SCE's request for wildfire and PSPS mitigation activities in
18 this testimony build upon and advance the objectives of SCE's prior GRC applications, CPUC decisions
19 on those applications, and WMPs to substantially reduce wildfire and PSPS risks. In many cases, SCE's
20 request in this GRC will result in the substantial completion of several prominent wildfire mitigation
21 activities originally proposed in those filings, such as SCE's proactive WCCP, which by the end of 2028
22 will have been deployed to most or all high consequence areas of our HFRA that require proactive
23 hardening with covered conductor.⁴

⁴ Subject to potential expansion of the HFRA over time as SCE continues to evaluate the risks in our service area and take into account factors such as population increases, changing landscapes, and climate change.

1 SCE has further refined its grid hardening approach based on guidance and
2 requirements from OEIS. For example, in the August 2021 Final Action Statement on SCE's 2021
3 WMP, OEIS required SCE to "[r]e-evaluate the scope and pace of its future covered conductor
4 program," with an "explicit consideration of all possible alternative mitigation initiatives," including for
5 the reduction of PSPS events, and to further evaluate the "[e]ffectiveness of covered conductor in the
6 field ..."⁵ In response to SCE's 2022 WMP Update, OEIS provided "areas for continued improvement,"
7 which included discussing SCE's plan and timeline to address the remaining severe risk areas by the end
8 of 2025 and requiring SCE to provide a plan and timeline for moving forward with REFCL.⁶ This GRC
9 forecast includes funding in support of those requirements.

10 In response to this regulatory guidance and in the pursuit of continuous
11 improvement including through SCE's Integrated Wildfire Mitigation Strategy (IWMS),⁷ SCE
12 continued benchmarking with other utilities⁸ and performing updated risk analyses with more
13 sophisticated tools and improved data sets acquired over the past few years. IWMS serves as the primary
14 basis for the grid hardening (and other wildfire mitigations) forecasts and plans in this testimony.
15 Specifically, through IWMS, SCE will continue to deploy covered conductor through the WCCP, further
16 deploy targeted undergrounding in severe risk areas, and continue to deploy a suite of complementary
17 mitigation measures for sections of our overhead distribution facilities where an ignition has the
18 potential of growing into a significant wildfire. These additional measures include deployment of new
19 technologies such as REFCL. As discussed below, SCE's proposed scope of work is driven by the
20 necessity to reduce unacceptable amounts of public safety risk in the event of a wildfire.

⁵ August 18, 2021 Final Action Statement on the 2021 Wildfire Mitigation Plan (WMP) Update of Southern California Edison Company (SCE) at pp. 57-58.

⁶ OEIS's Final Decision on SCE's 2022 WMP Update, pp. 120-121.
<https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=52887&shareable=true>.

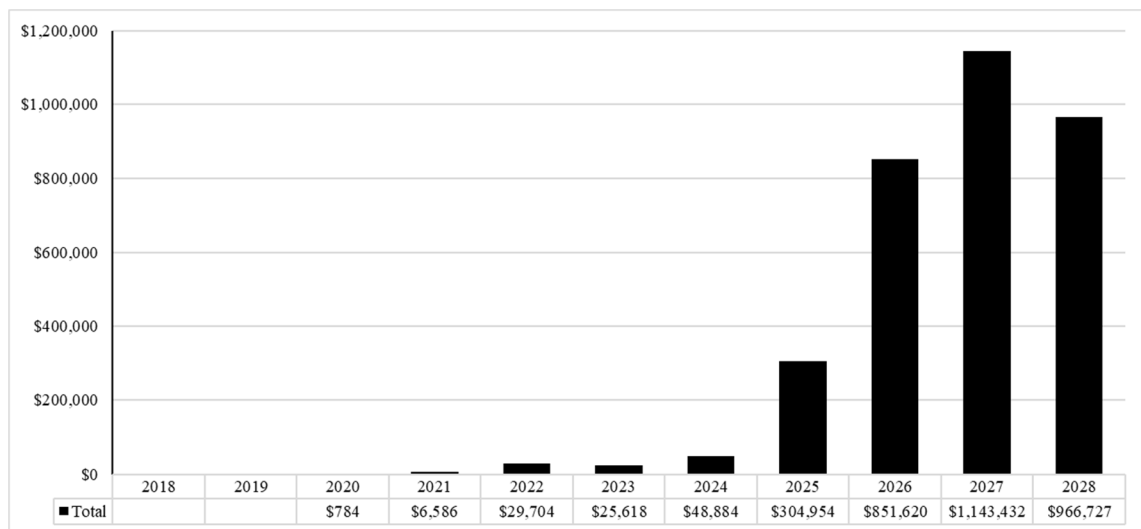
⁷ The IWMS is explained in detail in SCE-04, Vol. 05, Part 1 – Wildfire Management Overview.

⁸ See Appendix A, Joint IOU CC Effectiveness Workstream, of SCE's 2022 WMP Update.

c) Targeted Undergrounding (TUG)

This section discusses the scope and costs associated with SCE's TUG Program in HFRA over the GRC period. The funding request for 2023-2028 capital expenditures for TUG is \$3,341 million (nominal) to convert 611 overhead miles to 716 underground miles (see Figure I-1 and Table I-3 below).

***Figure I-1
Targeted Undergrounding (TUG) Program²
CET-PD-GR-UG-CAT
Recorded (2018 – 2022) / Forecast (2023 – 2028)
(Total Company – Nominal \$000)***



² Refer to WP SCE-04 Vol. 05, Part 2, pp. 23-24 – Capital Detail by WBS Element for Targeted Undergrounding Program.

Table I-3
Targeted Undergrounding Program^{10,11}
Capital Expenditure Forecast (2023 – 2028)
(Total Company - Nominal \$000)

Targeted Undergrounding	2023	2024	2025	2026	2027	2028	Total
Forecast Circuit Miles (OH Miles)	11	20	60	150	200	170	611
Forecast Circuit Miles (UG Miles)	11	20	65	180	240	200	716
Forecast Cost (Nominal \$000s)	\$ 25,618	\$ 48,884	\$ 304,954	\$ 851,620	\$1,143,432	\$ 966,727	\$ 3,341,235

(1) Work Description and Need

Undergrounding refers to the conversion of an existing overhead electric system, which consists of poles, wires, and related equipment, to underground facilities that consist of trenches containing conduit banks that house the wires, vaults, and/or pad mounts for transformers and other equipment. Since the TUG Program is focused on reducing wildfire risk, SCE will only be addressing energized electric conductors (primary, secondary, and services¹²) and will not be including any non-electric facilities in the program. Undergrounding utility systems typically takes between 25 to 48 months from initial scoping to in-field project completion.¹³ This process consists of four phases as shown in Figure I-2 below: Initiate, Plan, Schedule, and Execute. The timeline for each phase, as described below, will vary depending on the size and complexity of each individual undergrounding project.

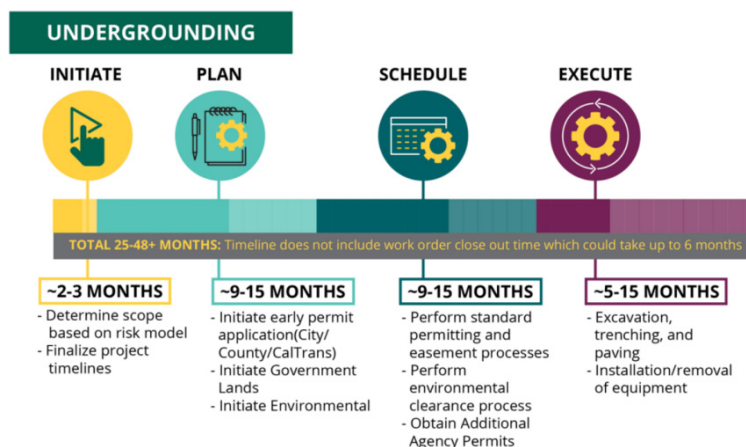
¹⁰ The overhead miles are the measurement of the total overhead circuit miles SCE plans to underground. The underground miles represent the miles required to underground overhead conductors including the rerouting factor, which is explained later in this testimony.

¹¹ SCE's 2023-2025 WMP's strive goal in 2025 is to convert 60 miles of overhead conductor to underground. With the re-routing factor, that matches the 2025 TUG Scope of 65 miles of undergrounding.

¹² SCE will only address services when a wildfire risk exists.

¹³ This estimate does not include the time between in-field project completion to work order close-out.

Figure I-2
Timeline of Undergrounding Work



In the Initiate Phase, scope is determined based on SCE’s current risk model. Once the initial scope is identified, SCE performs a high-level feasibility assessment to determine the level of difficulty of construction based on location and terrain. This feasibility assessment was the first step of review for potential TUG scope and helped determine TUG prioritization for 2024 and 2025 due to shorter cycle times. This step includes manual reviews by SMEs performed on all scoped circuit segments, which will then inform specific work orders, to ensure mitigation is appropriate to the risk. This consists of detailed reviews using SCE’s inspection photos and looking at specific locations with Google’s Street View. Prior to the Plan Phase, the scope is reviewed for operational considerations. On average, this scope review and approval process takes two to three months to complete per project with multiple projects to be reviewed concurrently, assuming there are no competing resources for scoping. For the identified TUG miles planned for execution in 2024-2028, these reviews began in Q1 2022 and are estimated to be complete in Q1 2024.

Once scoping is finalized, work is moved to the Plan Phase. During this phase, a project manager is assigned to oversee the work and design resources are assigned to initiate the work order, design the project, map the circuit miles, procure the materials, and initiate obtaining permits. On average, this process takes nine to 15 months assuming there are no competing demands on resources for planning and no delays in environmental/agency approvals.

1 Once the underground work is fully designed, permitted (including
2 obtainment of easements), and cleared of environmental constraints, it gets authorization to proceed and
3 is provided to SCE's regional districts for the Schedule Phase. In the Schedule Phase, materials are
4 acquired, permits are verified, work is scheduled, and circuit maps are revised if found inconsistent with
5 what is shown in the database. Design resources and project management teams also collaborate with
6 customers, local governments, and state agencies to provide project details to obtain necessary
7 easements prior to the start of construction.¹⁴ Scheduling can take between nine to 15 months.

8 For the Execute Phase of undergrounding, depending on the scope and
9 location of the project, community outreach may be required. There are also numerous other resources
10 that act in support of project execution. Resources will work to schedule outages, when an outage is
11 required to perform the undergrounding work and whether generation is necessary to support the
12 existing customers on the circuit during an outage. Also, SCE develops and schedules alternate traffic
13 plans as needed based on applicable laws of the city where work is taking place. Once the project is
14 ready to start, construction will proceed with necessary monitoring to help ensure adherence to the
15 design standards. Even after construction has started, delays can occur due to weather (e.g., rain/snow,
16 Red Flag Warning (RFW) days, etc.), material delays, permit requirements, and environmental
17 constraints (e.g., nesting birds). SCE estimates the average construction time to be from five to 15
18 months, which assumes no significant delays. To complete the construction, both civil and electrical
19 crews are required to perform the work. There are many factors that may impact the total project

¹⁴ In general, SCE looks to first address those circuit segments which present the greatest risk. However, SCE often bundles work related to multiple and/or contiguous circuit-segments together to achieve operational efficiencies. For example, the risk associated with each circuit may not be uniform along its length. In other words, the risk can vary between a specific mile or segment within a circuit, especially if that circuit traverses various parts of HFRA and is exposed to different probabilities of ignition by contact-from-object, or varying topography and vegetation that can influence fire propagation and consequence. In some cases, it may be operationally efficient and prudent to remediate relatively lower risk segments of a circuit at the same time relatively higher risk segments of the same circuit are addressed, instead of sending multiple crews out at multiple different times, requiring the development of separate work scope packages. Bundling work can also reduce community and environmental impacts by working in a location once versus sending crews to the same area multiple times.

1 lifecycle, including permitting and environmental requirements, easements, geography and terrain,
2 construction resource availability, and other construction-related factors.

3 There are four stages of construction during the Execute Phase: civil
4 infrastructure construction, cable installation, cut-overs, and removal. The civil infrastructure
5 construction stage consists of installing duct banks and underground structures. Duct banks installation
6 could be performed using either open trench methods or trenchless technology.¹⁵ Open trench method
7 consists of digging a continuous trench and installing round plastic conduit below the surface of the
8 roadway. This method entails saw cutting the existing asphalt or concrete street (if the trench is located
9 in the street) and excavating a trench with a backhoe, trencher, or rock wheel. The second method is a
10 trenchless technology called Horizontal Directional Drilling, also known as Directional Boring. This
11 method entails the use of a bore rig that bores a hole in the ground from one point to another for the
12 installation of a conduit(s). The trench size is approximately 24” in width and anywhere from 36” to 62”
13 in depth, depending on number of conduits required. If undergrounding services are needed, during this
14 stage, a separate electrical contractor will be working on the electrical panels of the individual homes
15 and businesses to prepare them to receive the new underground service. Figure I-3 below shows an
16 encasement being poured on a conduit bank.

¹⁵ SCE considers site-specific construction requirements (e.g., number of conduits required which determines if encasement is needed) and subsurface terrain (e.g., rocky soil) when selecting which trenching methodology to pursue.

Figure I-3
Open Trenching Housing a Conduit Bank



In the cable installation stage, electrical crews place new utility lines within the new conduits. Vaults and manholes, installed during the civil stage as needed, accommodate cable pulling and electrical connections as well as any underground equipment being relocated from the overhead system. These structures vary in size from 7’x18’x8’ for the largest vaults to 5’x10’6”x7’ for the smallest standard manhole.

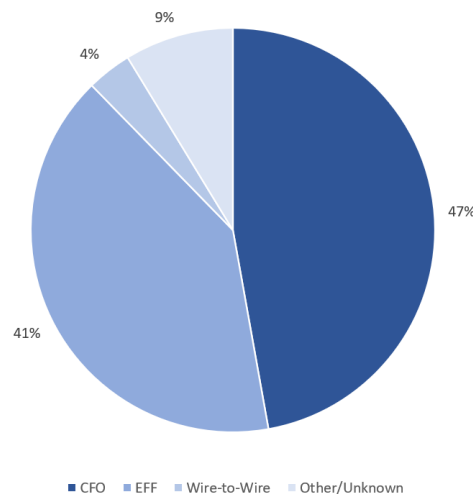
Following the installation of the new equipment, in the cut-over stage, all properties are switched over from the overhead lines to the new underground systems. In the last stage of removal, overhead primary and secondary conductors as well as any SCE-only poles (i.e., not associated with a joint owner) will be removed.¹⁶ If the pole has other non-electric facilities, SCE will top off the pole and transfer ownership rights to the non-electric entity whose equipment remains on the pole.

Undergrounding is a prudent mitigation that addresses the probability of ignition for a select targeted areas that have significant consequences to SCE’s communities and

¹⁶ If the pole has both transmission and distribution equipment, then SCE would leave the pole in place to hold the transmission equipment.

customers in HFRA. An analysis of SCE’s CPUC-reportable ignition events occurring on its distribution primary and secondary conductor from 2018 to 2022 in SCE’s HFRA as shown in Figure I-4 demonstrates that the main drivers of wildfire ignitions associated with SCE’s utility equipment are overhead wire contact from objects (CFO) (e.g., vegetation, metallic balloons, debris, etc.) and equipment and facility failure (EFF). Undergrounding both primary and secondary conductor virtually eliminates the risk of ignitions and outages associated with the risk drivers identified above.¹⁷ 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. Undergrounding virtually eliminates these types of fault conditions as well. While undergrounding by far has the greatest mitigation effectiveness value relative to other mitigations, SCE recognizes that the cost is also relatively high on a per-mile basis and generally applies its use as a wildfire mitigation to Severe Risk Areas.¹⁸

Figure I-4
CPUC-Reportable Ignitions by Risk Driver from 2018-2022



A Re-route Factor Must Be Considered

¹⁷ Underground equipment failure is very limited. If it occurs, it will occur sub-surface and generally would not pose ignition risk.

¹⁸ Severe Risk Areas are defined in Exhibit SCE-04, Vol. 05, Part 1 – Wildfire Management Overview.

1 Generally, when converting existing overhead lines to underground
2 facilities, a line route needs to be determined. Often in urbanized areas this route can be the same as the
3 existing overhead line assuming pre-existing underground utilities (e.g., natural gas, water, sewer, etc.)
4 do not preclude the addition of a new duct and structure system. Routes may also need to be altered to
5 avoid obstructions. For example, this may involve moving a rear property pole line to curbside to avoid
6 swimming pools, block walls, etc. In coastal, mountainous, or more rural communities, topography can
7 present additional challenges to those already mentioned above. Lines may need to be moved to the road
8 to avoid steep terrain, heavy vegetation, water crossings, erosion concerns, and to generally avoid
9 environmental considerations associated with heavy equipment access to construct and/or maintain lines.
10 Because of these topographical challenges with some existing overhead lines, vehicle access required for
11 installing underground cable is not available, which makes undergrounding along the same route
12 impractical. Therefore, overhead lines may need to be brought out to the public right-of-way for
13 undergrounding, increasing the length of the undergrounding needed and increasing the total cost as well
14 as the construction timeline. SCE estimates that for high difficulty miles, underground miles on average
15 are 20% more than overhead miles.¹⁹

¹⁹ The re-route factor is explained in more detail, including visual example, in the Scope Forecast section for the TUG program.

Alternatives to TUG

SCE recognizes that there are some locations within its service area where it is not feasible to underground due to terrain limitation and other operational factors.²⁰ In those cases, SCE would instead install covered conductor in conjunction with REFCL if possible, spacer cable system, or a remote grid as these alternatives can approximate the mitigation effectiveness of TUG. SCE discusses covered conductor and REFCL in Sections d) and e), respectively. A spacer cable system is where the covered conductor is supported by a high-strength messenger through diamond-shaped spacers. This type of cable is typically used in heavily forested areas where tree fall-ins are a risk. In Q4 2022, SCE initiated a spacer cable pilot to examine how covered conductor is supported by a high-strength messenger through diamond-shaped spacers instead of the traditional open crossarm arrangement. The pilot's focus was to analyze the constructability and projected costs of spacer cable.²¹ While the results of this pilot may inform future projects, SCE may conduct other pilots to evaluate additional factors. The pilots in evaluation are planned for completion by December of 2025,²² and portions of the pilot may inform decision-making before planned completion date. If successful, spacer cable would be added as an alternative mitigation. While the mitigation effectiveness of spacer cables is lower than TUG, spacer cables can be a potential alternative in areas where TUG is infeasible due to terrain challenges.

Remote grid is another alternative for TUG. A remote grid is a small, remote collection of customers served entirely by local Distributed Energy Resources (DERs) which are disconnected from the SCE grid. Remote grid reduces wildfire risk by removing the overhead power lines that traverse Severe Risk Areas. In 2023-2025, SCE plans to perform a remote grid feasibility

²⁰ Topographical terrain or other parameters may deem undergrounding construction infeasible (e.g., overhead directly above rocky mountains, not enough room to meet required clearances, etc.).

²¹ The spacer cable pilot encompassed six spans or about 800 feet of covered conductor.

²² See SCE's 2023 WMP Update, p. 231, Table 8-1.

1 study on a dozen locations that are slated for TUG.²³ If proven successful and cost-effective, SCE would
2 install remote grids in lieu of TUG where appropriate.²⁴

3 (2) Historical Variance Analysis

4 TUG projects typically require two to four years to scope, design,
5 schedule, permit, construct, and put into service. Scope for the first year of construction (2021) was
6 initiated in early 2020, and thus no costs were incurred in 2018 and 2019. Subsequently, the projects
7 identified for plan year 2022 were initiated between Q4 2020 and Q1 2021. The capital expenditure of
8 \$0.784 million incurred in 2020 was associated with survey maps and design costs for the plan years
9 2021-2022. Survey maps and design maps helped ensure existing and new electrical equipment and
10 facilities are adequately identified, located, installed, and/or removed and covered under existing or new
11 easements or rights of way. This work also ensured compliance with local and state guidelines and
12 regulations relating to permitting, environmental, traffic control and other regulations. The capital
13 expenditure of \$6.586 million incurred in 2021 was associated with construction costs for the
14 approximately six miles completed in 2021, as well as material and design/planning costs for plan years
15 2022-2023. Similarly, the capital expenditure of \$29.704 million incurred in 2022 was associated with
16 construction costs for the 11 miles completed in 2022 as well as material and design/planning costs for
17 plan years 2023-2024.

18 (3) 2021 Authorized vs. Recorded

19 Table I-4 below shows the recorded and authorized underground miles and
20 costs for the TUG program through 2022.

²³ Remote grids are not feasible for all TUG locations since remote grids usually serve small loads with long lengths of lines.

²⁴ See Exhibit SCE-04, Vol. 05, Part 3 for more details.

Table I-4
TUG Authorized vs. Recorded²⁵

Targeted Undergrounding	UG Miles				Capital Cost (Nominal \$000s)			
	2018-2019	2020	2021	2022	2018-2019	2020	2021	2022
Authorized (Track 1)	N/A	0	6	11	N/A	\$0	\$23,047	\$43,713
Recorded	N/A	0	6	11	N/A	\$784	\$6,586	\$29,704
Variance		0	0	0		\$784	(\$16,461)	(\$14,009)

In 2021 and 2022, SCE recorded \$6.586 million and \$29.704 million, respectively, in capital expenditures for projects within the approximate six and 11 miles completed in 2021 and 2022, compared to the \$23.047 million and \$43.713 million authorized for the six and 11 miles, respectively. There are several reasons for this variance. First, though the actual construction started in 2021, SCE incurred \$0.784 million in capital expenditures in 2020. The costs were associated with survey maps and design costs for the plan years 2021-2022. Second, when SCE's 2021 GRC Track 1 Application was developed in 2019, SCE's initial estimated unit costs were based on completed Rule 20A projects, which include undergrounding overhead equipment such as primaries, secondaries, services and telecommunication wires with various levels of difficulty to construct, e.g., Brea and Fullerton to Lake Elsinore and Mammoth Lakes. However, the completed TUG projects in 2021 and 2022 had a low level of difficulty to construct, e.g., Riverside, which is the primary reason for the cost difference, 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 labor vs. contract resources). The initial miles SCE converted to an underground system in 2021 and 2022 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

²⁵ See WP SCE-07, Vol. 01, Authorized vs. Recorded.

re-routing 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.

(4) Capital Expenditure Forecast

The funding request for 2023-2028 capital expenditures for TUG is \$3,341 million (nominal dollars) to convert 611 overhead miles to 716 underground miles, which is summarized in Table I-5 below.

***Table I-5
TUG Capital Expenditure Forecast²⁶
(Nominal \$000)***

Targeted Undergrounding	2023	2024	2025-2028	Total
Forecast Circuit Miles (OH Miles)	11	20	580	611
Forecast Circuit Miles (UG Miles)	11	20	685	716
Forecast Cost (Nominal \$000s)	\$ 25,618	\$ 48,884	\$ 3,266,733	\$ 3,341,235

(a) Scope Forecast

SCE stated in its Track 1 proposal, which was filed in late 2019, that “SCE will conduct an assessment to determine if certain areas should be considered for undergrounding. Construction for areas identified for undergrounding will begin in 2021.” SCE’s assessment at that time included an analysis of the top 150 riskiest miles, based on the probability of ignition and consequence scores. Due to this nascent initiative in HFRA and long cycle times for undergrounding, SCE chose to address the top 20% of these 150 riskiest miles, which equates to 30 miles. In the Track 1 proposal, SCE forecasted the pace of the underground work to be six, 11, and 11 miles for 2021, 2022, and 2023, respectively.

SCE’s IWMS analysis, as discussed in SCE-04, Vol. 05, Part 1 demonstrated that 2,950 miles of SCE’s HFRA should be and now have been characterized as Severe Risk Areas. Accounting for the already hardened miles by the end of 2022 and expected to be hardened miles by the end of 2024 (through WCCP and TUG), there will be approximately 550 unhardened miles

²⁶ The 580 OH miles scoped for 2025 – 2028 comprises of 552 miles in Severe Risk Areas, 9 miles in High Consequence Areas, and 19 miles in Other HFRA.

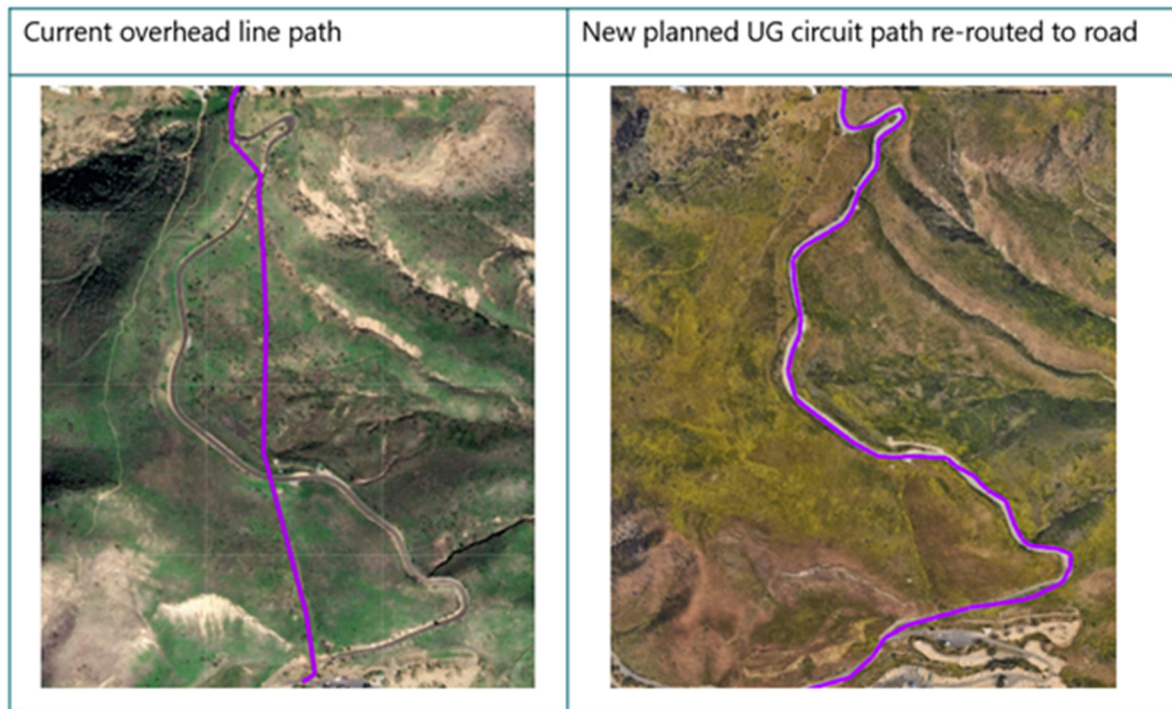
1 remaining at the start of 2025 in Severe Risk Areas and approximately 30 unhardened miles in High
2 Consequence Areas and Other HFRA for a total of 580 miles, which SCE now plans to underground
3 (when feasible) to eliminate most, if not all, of the associated risks.²⁷ Because these areas are the riskiest
4 locations, it is prudent for SCE to utilize the most effective mitigation across most ignition drivers – i.e.,
5 undergrounding – to protect our customers and the communities they live in.

6 As mentioned above, re-routing is necessary to underground a
7 particular line. Due to the relatively easy-to-construct miles in 2023, SCE does not expect 2023 to
8 require a re-route factor. The miles in 2024 are similarly relatively easy-to-construct and require a small
9 amount of re-route. However, starting in 2025, SCE estimates it requires an approximate 20% re-route
10 factor for the remaining 580 overhead miles,²⁸ which equates to 685 underground miles for the 2025-
11 2028 period. Re-routing is necessary at times to underground lines following a road, whereas an
12 overhead line can cross terrain where undergrounding is not feasible or impractical. As described in
13 SCE's approved 2022 WMP Update, obstacles such as buildings/structures, natural barriers, and civil
14 and/or utility obstructions may need to be bypassed in order to underground according to SCE's
15 standards. Additional cable, civil work, sub-surface structures, and/or equipment may be necessary when
16 re-routing is needed for undergrounding. Figure I-5 shows an example of a necessary re-route. The
17 picture on the left shows the current overhead line path, crossing a steep, hilly terrain. The lines may
18 need to be moved to the road to avoid environmental considerations associated with heavy equipment
19 access to construct and/or maintain lines, as shown in the picture on the right. Re-routing requires an
20 additional length of conductor, labor, and materials.

²⁷ The verification of the identified scope is performed through a rigorous SME review process which is explained in detail in Exhibit SCE-04, Vol. 5, Part 1 – Wildfire Management Overview.

²⁸ The re-route factor is an estimated ratio of overhead-to-underground conversion miles based on feasibility reviews of relocating overhead lines to new, acceptable underground paths. This estimated ratio does not reflect final engineering and construction realities.

Figure I-5
Example Showing Why Undergrounding Requires More Conductor Length



(b) Cost Forecast

Table I-6 below shows a breakdown of the total annual costs for SCE’s proposed underground projects in 2023-2028, which largely depend on the level of difficulty of the construction project as well as the level of underground work (primary, secondary, collocated primary and secondary, and services).

Table I-6
Detailed Summary of TUG Capital Expenditure Forecast^{29,30}

	2023	2024	2025	2026	2027	2028	Total
UG Miles	11	20	65	180	240	200	716
Unit Cost (2022\$) (\$000)	\$2,146	\$2,146	\$4,020	\$4,020	\$4,020	\$4,020	N/A
Escalation	1.054	1.106	1.133	1.143	1.151	1.167	N/A
Sub-total	\$24,872	\$47,460	\$296,072	\$826,815	\$1,110,128	\$938,570	\$3,243,917
Environmental 3%	\$746	\$1,424	\$8,882	\$24,804	\$33,304	\$28,157	\$97,318
Total Cost (Nominal \$000)	\$25,618	\$48,884	\$304,954	\$851,620	\$1,143,432	\$966,727	\$3,341,235

The cost forecast starts with determining the level of difficulty of the proposed underground projects. 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 primary cost driver of the underground project lies in the level of difficulty in the terrain and topographical locations. The assessments resulted in a level of difficulty rating of low, medium, high, and not feasible. A low difficulty level is associated with flat and rural areas, requiring less civil construction and minimal paving (even no paving if it is a dirt road). A medium difficulty level is associated with a mix of residential and rural areas. A high difficulty level is associated with rocky and hilly terrain and a high density of population, requiring extensive civil construction and significant re-routing. The cost ranges from \$2.9 million for a medium difficulty level to \$4.5 million for a high difficulty level, with the majority of the forecast scope for 2024 – 2028 in this range. The feasibility 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 to implement and to categorize TUG project duration considerations are shown in Table I-7 and Table I-8 below. The scope in 2024 and

²⁹ Refer to WP SCE-04, Vol. 05, Part 2, pp. 25-28 – TUG Unit Cost Workpaper.

³⁰ SCE's 2023-2025 WMP's strive goal in 2025 is to convert 60 miles of overhead conductor to underground. With the re-routing factor, that matches the 2025 TUG Scope of 65 miles of undergrounding.

2025 are generally associated with easy-to-medium level of difficulty, whereas the scope in 2026-2028 are associated with medium-to-high level of difficulty.³¹

Table I-7
Description for Each Level of Difficulty for an Underground Project

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, etc.)

³¹ The forecast levels of difficulty per year may change due to operational factors such as scoping, permitting, and resource availability.

Table I-8
Underground Project Duration Considerations

Duration	General Description	Additional Details
Short (~25 months)	-Land is all or mostly franchise	-City/County permits -One to two easements
Medium (~36 months)	-Land is a blend of franchise and private property	-Wetlands & Water -Five to ten 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

The next step is to determine the level of work. The TUG level of work for the 2024-2028 period includes undergrounding primary conductor only, collocated primary and secondary conductor, secondary conductor only, and services, if needed. Note that in its funding request, the number of overhead miles reported as completed are associated with primary conductor miles. SCE applies the estimated level of difficulty to the estimated level of work to determine the total costs. Once the total costs are determined, SCE derives a weighted average unit cost, which is \$4.02 million per circuit mile. SCE then uses this weighted unit cost and multiplies it to the annual scope to arrive at the sub-total amount in the TUG capital expenditure forecast as shown in Table I-6 above.³²

The last factor contributing to the total undergrounding costs is an adder of 3% of the annual cost to account for the environmental expenditures necessary for the increased scope of underground work. The work activity is anticipated in urban/developed areas and rural/undeveloped locations, including on public lands (including Inyo and Angeles National Forests, Santa Monica Mountains, CA State Parks & Rec Dept-managed lands, etc.). Public lands approvals require additional time and costs for consultation, submittals, and greater potential environmental field support. Ground disturbance for undergrounding activities can require archaeological surveys and/or monitoring, as well as potential biological or waters resource surveys, monitoring, or permitting. These

³² Refer to WP SCE-04, Vol. 05, Part 2, pp. 25-28 – TUG Unit Cost Workpaper.

factors will not apply to all TUG locations but will be realized for some and thus 3% is an appropriate annual cost adder.³³ Additionally, SCE anticipates the need for a dedicated environmental project manager support as well as environmental consultant resources to efficiently intake, perform resource analysis, and issue Environmental Requirements Docs (or “clearance”) for the program.

(i) Potential Cost Saving Strategies

TUG has a very high level of mitigation effectiveness, however, it is also more costly on a per-mile basis compared to other grid hardening mitigations. Accordingly, SCE is exploring cost saving opportunities to potentially reduce the financial impact to our customers. SCE has currently identified two potential cost saving strategies that may reduce capital and O&M costs. The potential capital saving strategy is related to internal operational and construction efficiencies. The TUG program will be included in the new Grid Hardening Balancing Account (GHBA) for the reasons discussed in SCE-07 Volume 1, and any capital savings will be realized through the operation of the GHBA. The potential O&M cost savings will come from reduced vegetation management and inspection activities avoided by undergrounding overhead conductors. Any resulting vegetation management O&M cost savings will be realized through the operation of the Vegetation Management Balancing Account (VMBA), as discussed in SCE-07 Volume 01.

³³ Based on benchmarking data, across the organization unit’s work activities receiving environmental support, environmental spend ranges from 1 to 15% of direct costs. At the low end, 1% for the covered conductor program, mid-range is Transmission Roads and right-of-way work (TROW) historically at ~5%, and at the high end, major project organization’s (MPO) managed capital projects (highest complexity, CPUC licensing, California Environmental Quality Act/ National Environmental Policy Act (CEQA/NEPA) docs, mitigation, extensive field support) ranging between ~10-15% of total direct costs. Based on these data points, the TUG work is forecast at 3% at the lower end of the 1%-15% range, which is anticipated to involve greater ground disturbance than the covered conductor activities and is anticipated to be less complex in the environmental space than the TROW and MPO Capital project work.

Internal Operational Efficiencies

As SCE develops its internal UG standards, two potential cost saving strategies have been identified to reduce civil construction scope: 1) reducing the conduit depth for installations with primary wire only, and 2) use more padmounted equipment instead of subsurface equipment without affecting operations.

For TUG projects, underground cable systems may be installed at a shallower depth compared to standard overhead to underground conversion projects for county or city roads. The targeted installation depth for the cable shall be 24" wherever possible from the top of conduit to flowline of gutter for residential or commercial circuits 4-33 kV. When main line primary or radial cables are installed in the same trench with secondary cables, minimum depth of cover will be 24" over secondary cables in thoroughfares. For sidewalks or parkways, the minimum cover above secondary cables shall be 18." By reducing the undergrounding depth of the cables, SCE can potentially reduce the cost of underground where applicable.

Traditional overhead construction has transformation equipment mounted on poles connecting primary lines to secondary services. When the conversion of overhead to underground for primary wire requires the secondaries to also be undergrounded, space for the transformation equipment must be accounted for. Padmounted transformers are the preferred option for SCE's updated TUG standards. For padmounted transformers, the benefit is that little to no civil work is required for the pad. Traffic control is typically minimal, if required at all, to install, maintain, and operate a padmounted transformer. Some challenges associated with this approach are finding space on streets/sidewalks and obtaining easement rights on private property. In general, SCE will use padmounted equipment whenever possible to reduce cost and install submersible structures when padmounting is not feasible.

SCE will continue to explore opportunities to reduce capital costs associated with undergrounding, and any viable cost-reducing measures will be reflected in the GHBA.

O&M Cost Savings

SCE has started to analyze the potential O&M cost savings provided by the TUG program. The analysis includes review of the specific structures and spans that SCE plans to underground and estimates of expected savings from reductions in asset inspections and remediations and vegetation management activities. There are several activities in both asset and vegetation inspections programs that apply and require different assumptions. Collectively, these programs can potentially reduce O&M costs by approximately \$22 million (constant 2022\$) over the 2024 – 2028 period.³⁴ These programs are explained in the subsections below and the detailed O&M cost savings analysis is provided in the TUG Workpaper.³⁵ These cost saving amounts are included in the respective activity's forecasts and are contingent upon full approval of SCE's TUG request and will be reduced if SCE's TUG request is not fully authorized.³⁶

Vegetation Remediation Activities

SCE has currently identified three activities in this category: 1) Line Clearing Trims, 2) Hazard, Dead and Dying Tree Removal, and 3) Structure Brushing.³⁷ SCE quantified the O&M cost savings for the Line Clearing Trims Program by overlaying the routine line clearing inventory trees with the forecasted miles for TUG and assumed the overlapping trees would not require trims or removals. SCE quantified the O&M cost savings for the Hazard, Dead and Dying Tree Removal Program by overlaying the subject trees with the forecasted miles for TUG and assumed these trees would not require trims or removals.³⁸ SCE quantified the O&M cost savings for the Structure Brushing Program by identifying the structures that are forecasted to be removed from service due to undergrounding and are part of the structure brushing scope for 2023 and assumed a cost-per-

³⁴ These cost savings do not include potential capital savings, nor does it include cost savings beyond this GRC period.

³⁵ Refer to WP SCE-04 Vol. 05, Part 2, pp. 29-30 – TUG O&M Cost Savings.

³⁶ Final O&M cost savings for TUG Program will need to be recalculated if final authorized amounts differ from SCE's request.

³⁷ These activities are explained in detail in Exhibit SCE-02, Vol. 10 – Vegetation Management.

³⁸ Subject trees are those identified by the Hazard Tree Management Program.

1 inspection and clearing savings. This analysis yielded a total potential savings of approximately \$8
2 million (constant 2022 dollars) over the 2024 – 2028 period for the vegetation remediation activities.

3 **Overhead Distribution Inspection Activities**

4 SCE has currently identified two activities in this category:

5 1) HFRI Inspections (UAS 360) Program and 2) Infrared Inspections Program.³⁹ SCE quantified the
6 O&M cost savings for the HFRI Inspections (UAS 360) Program by identifying the structures that are
7 forecasted to be removed from service due to undergrounding and in scope for the 2023 HFRI
8 Inspections Program and assumed a cost per inspection savings. SCE quantified the O&M cost savings
9 for the Infrared Inspections Program by identifying the number of overhead miles that TUG would
10 convert and allocated the cost per mile of the Infrared Inspection program. This analysis yielded a total
11 potential savings of approximately \$4 million (constant 2022 dollars) over the 2024 – 2028 period for
12 the overhead distribution inspection activities.

13 **Overhead Distribution Remediation Activities**

14 SCE has currently identified one activity in this category:

15 HFRI O&M Remediations (UAS 360) Program and Intrusive Pole Inspections (IPI) related to electric
16 crews.⁴⁰ SCE quantified the O&M cost savings for the HFRI O&M Remediations (UAS 360) and IPI
17 Program by using the O&M only remediations rate from 2022 ground, aerial, and intrusive pole
18 inspections and projected future remediations that would be avoided by poles being removed from
19 service due to TUG. The remediations rate and poles removed from service due to TUG were then
20 combined with average 2022 O&M remediations costs from work that required an electric crew. This
21 analysis yielded a total potential savings of approximately \$10 million (constant 2022 dollars) over the
22 2024 – 2028 period for the overhead distribution remediation activities.

³⁹ These activities are explained in detail in Exhibit SCE-04, Vol. 05, Part 3 – Wildfire Management Emergent Technology and Inspections and Remediations.

⁴⁰ This activity is explained in detail in Exhibit SCE-04, Vol. 05, Part 3 – Wildfire Management Emergent Technology and Inspections and Remediations.

(5) RAMP Integration

SCE's Targeted Undergrounding Program was modeled in SCE's 2022 RAMP Wildfire chapter. Table I-9 below compares the RAMP and GRC capital forecasts for TUG. While the number of underground miles between RAMP and GRC are the same, the increase in cost seen in the GRC is driven by escalation rates and the addition of an environmental cost adder of 3%, which was not expected or analyzed when SCE filed its RAMP Report in May 2022. The RSE for TUG increased since filing our 2022 RAMP for several reasons. First, as noted in SCE-04 Vol. 05 Part 1, SCE included egress into the RSEs calculations. Second, SCE updated the QC factor based on conformance data. Lastly, SCE has an updated scope list for the GRC.

***Table I-9
Targeted Undergrounding
RAMP vs GRC Capital Forecast Comparison - (Nominal \$000)
Risk Spend Efficiencies⁴¹***

RAMP Risk	RAMP ID	RAMP Control / Mitigation Name	Filing	2022	2023	2024	2025	2026	2027	2028	Total 2025 - 2028	2025 - 2028 RSE
Wildfire	M1	Targeted Undergrounding	RAMP	\$51,960	\$42,664	\$45,996	\$283,623	\$798,295	\$1,086,879	\$927,125	\$3,095,923	324
			GRC	\$29,704	\$25,618	\$48,884	\$304,954	\$851,620	\$1,143,432	\$966,727	\$3,266,733	700
			Variance	(\$22,256)	(\$17,046)	\$2,888	\$21,331	\$53,324	\$56,553	\$39,602	\$170,809	376

(a) SPD / Intervenor Comments

In its comments on SCE's 2022 RAMP report,⁴² Safety Policy Division had one specific comment for TUG, stating that, "SCE should remove the additional 173.4 circuit miles (30 percent) in the most recent proposed TUG, as SCE included these to replace duplicated circuit miles without adequate justification." As stated in SCE's opening comments to SPD's Staff Report,⁴³ SCE disagrees with this recommendation. At no point since filing our RAMP application has SCE changed the total circuit miles or the circuit segments that were proposed for our RAMP showing.

⁴¹ Refer to WP SCE-04, Vol. 05, Part 1 – WF/PSPS RAMP to GRC Integration.

⁴² Safety Policy Division's (SPD) November 10, 2022 Staff Evaluation Report (Staff Report).

⁴³ A.22-05-013, SCE's Opening Comments on Safety Policy Division's Evaluation Report on SCE's 2022 RAMP Report, December 9, 2022.

1 There was simply an error in the RSE modeling code that displayed certain duplicate circuit miles in our
2 supplemental workpapers and correspondingly was not showing valid, non-duplicative, originally-
3 proposed miles. There is no basis for removing the 173.4 circuit miles from the RAMP showing or the
4 contemplated GRC scope.

5 d) Wildfire Covered Conductor Program (WCCP)

6 This section discusses the scope and cost forecasts associated with SCE's WCCP
7 in HFRA over the GRC period. As summarized in Table I-10 below, the total funding request for 2023-
8 2028 capital expenditures for WCCP activities, which include covered conductor with fire-resistant
9 poles (FRPs) and secondary conductor (referred together as "covered conductor work"), tree attachment
10 remediation, vibration damper retrofit, and fire-resistant wrap retrofit, is \$2,679 million (nominal \$000).
11 This work entails the installation of 3,650 circuit miles of covered conductor for primary wires plus the
12 installation of fire-resistant poles, replacement of 76 miles of secondary conductor,⁴⁴ remediation of
13 approximately 1,100 tree attachments, vibration damper retrofits of approximately 2,600 structures, and
14 fire-resistant wrap retrofits on 325 structures to further reduce wildfire risks. SCE addresses each
15 activity under WCCP in the sub-headers below.

⁴⁴ SCE only uses the primary conductor length to report miles completed for WCCP work. The 76 miles of second conductor will not be included in the WCCP reported miles as they run parallel to the primary line.

Table I-10
WCCP Capital Expenditure Forecast^{45,46,47,48}
(Nominal \$000)

Wildfire Covered Conductor Program	2023	2024	2025	Forecast			2028	Total
Covered Conductor w/ FRPs (Circuit Miles)	1,200	1,200	850	300	50	50		3,650
Secondary Conductor (Circuit Miles)	-	37	26	9	2	2		76
Total Conductor w/ FRPs Cost (Nominal \$000s)	\$ 840,531	\$ 879,801	\$ 638,519	\$ 222,930	\$ 29,735	\$ 29,970		\$ 2,641,485
Tree Attachment Remediation (Structures)	500	500	61	-	-	-		1,061
Tree Attachment Remediation Cost (Nominal \$000s)	\$ 16,697	\$ 17,484	\$ 2,276	\$ -	\$ -	\$ -		\$ 36,457
Vibration Damper Retrofit (Structures)	392	594	829	829	-	-		2,644
Vibration Damper Retrofit (Nominal \$000s)	\$ 107	\$ 171	\$ 244	\$ 246	\$ -	\$ -		\$ 769
FR Wrap Retrofit (Structures)	-	325	-	-	-	-		325
FR Wrap Retrofit Cost (Nominal \$000s)	\$ -	\$ 719	\$ -	\$ -	\$ -	\$ -		\$ 719
Total Capital (\$000 Nominal)	\$ 857,336	\$ 898,174	\$ 641,039	\$ 223,176	\$ 29,735	\$ 29,970		\$ 2,679,430

(1) Work Description & Need – Covered Conductor Work

SCE plans to replace overhead bare conductor with covered conductor for a total of 3,650 circuit miles over the 2023-2028 period at a cost of \$2,641 million, provided in Figure I-6.

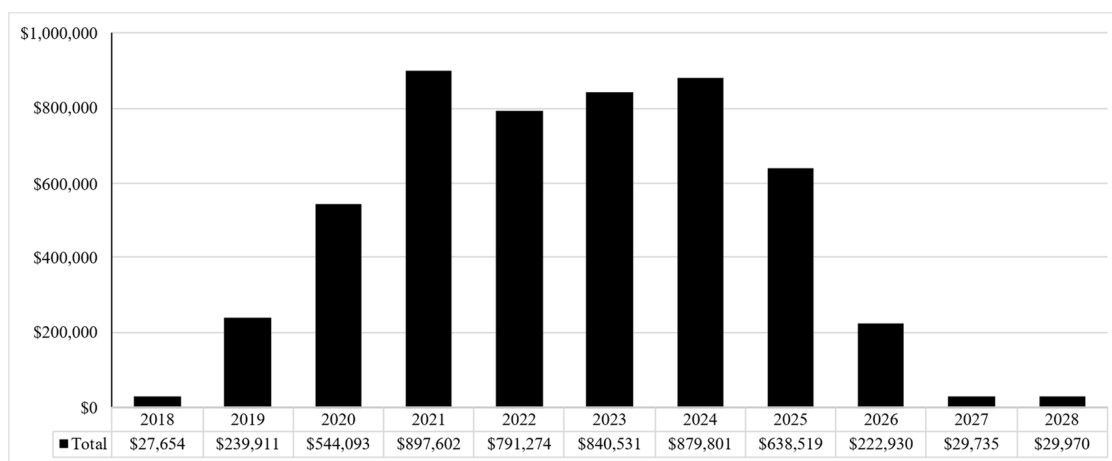
⁴⁵ Total slightly impacted due to rounding.

⁴⁶ An error was identified subsequent to the finalization of financial data. Therefore, the intended financial number that is stated here in testimony does not align with the financial numbers in standardized workpapers and the RO model. An errata will be submitted to align the financial numbers in testimony, standardized workpapers, and the RO model at a future date.

⁴⁷ Refer to WP SCE-04, Vol. 05, Part 2, pp. 31-38 - Capital Detail by WBS Element for WCCP.

⁴⁸ WBS: CETPDGRFPMTEMTB, CETPDGRFPMTW, CETPDGROCMTW, CETPDGRTRMTW, CETPDGRTAMTW, CETPDWMVD822400, CETPDWMFR822400.

Figure I-6
Covered Conductor⁴⁹
Multiple WBS Elements⁵⁰
Recorded (2018 – 2022) / Forecast (2023 – 2028)⁵¹
(Total Company – Nominal \$000)



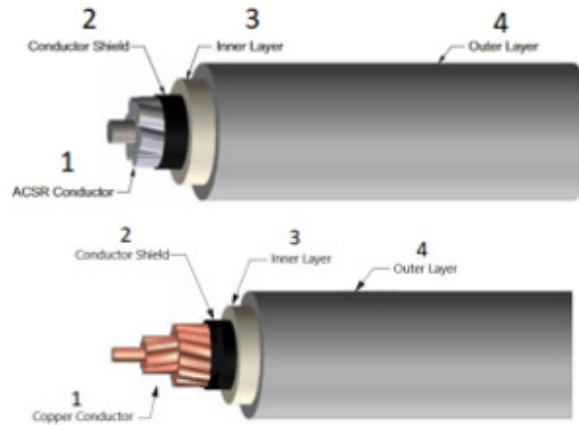
Covered conductor refers to the primary conductor being “covered” with insulating materials to protect against the impacts of incidental contact. There are four components that comprise this type of covered conductor: the conductor, the conductor shield, the inner layer, and outer layer. This is illustrated in Figure I-7 below.

⁴⁹ Refer to WP SCE-04 Vol. 05, Part 2, pp. 31-38 – Capital Detail by WBS Element for WCCP.

⁵⁰ WBS: CETPDGRFPMTEMTB; CETPDGRFPMTW; CETPDGROCMTW; CETPDGRTRMTW.

⁵¹ Recorded 2018 costs for Covered Conductor are shown in this table for presentation of total program costs as Covered Conductor costs were recorded to Plant Betterment when work began in late 2018 prior to when new WCCP accounting was created. Refer to Exhibit SCE-02, Vol. 07 for further discussion on Plant Betterment.

Figure I-7
Cross-section of ACSR (Top) and Copper (Bottom) Covered Conductor



Descriptions of the four components are as follows:

1. *Conductor*: Either Aluminum Conductor Steel-Reinforced (ACSR) or Hard Drawn Copper (HDCU). Copper covered conductor is primarily used for coastal applications due to copper being more resistant to corrosion than aluminum.

2. *Conductor Shield*: The conductor shield is a semi-conducting thermoset polymer that is designed to reduce electrical stress should any object make contact with the covered conductor, making the covered conductor more robust.

3. *Inner Layer*: The inner layer is Crosslinked Low Density Polyethylene (XL-LDPE), an insulating material that helps protect the conductor from phase-to-phase or phase-to-ground contact faults.

4. *Outer Layer*: The outer layer is Crosslinked High Density Polyethylene (XL-HDPE), which is also an insulating material, but because it is high density, it is a tougher layer that provides abrasion and impact resistance. Additional additives, such as UV resistance and track resistance, are included in the outer layer to prevent the degradation of the covering.

SCE installs covered conductor in open-crossarm configuration as shown in the left image in Figure I-8 below, which is the same configuration that is used in SCE's bare wire

1 systems. In this configuration, the conductor is self-supporting and attached to insulators on crossarms at
2 the structure. An open-crossarm is different from a spacer cable system shown in the right image in
3 Figure I-8 below, where the covered conductor is supported by a high strength messenger through
4 diamond shaped spacers. SCE is in the process of piloting the spacer cable system, and plans to add it as
5 a mitigation option, if proven successful and cost-effective.⁵² The spacer cable system could be
6 considered for deployment in the following areas: locations with an accessible right of way, areas where
7 there is an enhanced risk of heavy tree fall, and areas where covered conductor would not provide
8 sufficient risk mitigation and where undergrounding would be infeasible due to constructability
9 constraints.

***Figure I-8
Covered Conductor in Open-Crossarm Configuration (Left) and Spacer Cable
Configuration (Right)***



10 SCE's covered conductor system also includes the installation of
11 composite or fire-resistant wrapped poles (together, referred to as fire-resistant poles (FRP)), composite
12 crossarms, wildlife covers, surge arresters, polymer insulators, and vibration dampers.

13 Prior to the installation of the covered conductor system, SCE performs
14 pole loading calculations (PLC) to determine if the pole can withstand the additional load of the covered

⁵² A spacer cable system is more expensive than the traditional open-crossarm configuration for covered conductor due to the additional required material (i.e., diamond-shaped spacers) and labor since spacers are installed every 50 feet. Spacer cable system is a feasible option only in areas that are bucket truck accessible.

conductor system. If the pole fails PLC, then SCE replaces the pole with an FRP.⁵³ Otherwise, the pole remains a bare wood structure and will be updated over time to a fire-resistant structure as needed through other programs per SCE's engineering standards in HFRA.⁵⁴ Composite poles are fiber-reinforced polymer utility structures. They are resistant to corrosion, chemicals, and rot. The fire-resistant wrap is an intumescent (swelling up when heated) grid made of 23-gauge galvanized steel grid coated with a durable intumescent polymer. When exposed to elevated temperatures (greater than 300° F), either from direct flame contact or radiant heat, the wire mesh will expand via its intumescent properties and form a barrier that protects the wood pole. Once a direct flame is removed, the fire-resistant wrap will self-extinguish. Figure I-9 shows an example of a composite and fire-resistant pole.

***Figure I-9
Composite Pole (Left) and Fire-Resistant Pole (Right)***



An analysis of SCE's CPUC-reportable ignitions occurring between 2018-2022 shows that approximately 30% of ignitions in HFRA are related to secondary conductor. As part of the future scope of the covered conductor system, SCE will also address the secondary conductors that are co-located with the primary conductor. Secondary conductor is a conductor that branches off transformers fed by the primary conductor to service lower voltages such as residential loads as shown

⁵³ If the FRP replacement is a fire-resistant wrapped pole, the electrical crews use poles that come already wrapped by the manufacturer. No wrapping is performed on site.

⁵⁴ SCE's FRP retrofit program is discussed below.

1 in Figure I-10 below. Currently, a significant majority (90%) of SCE's secondary conductors are already
2 upgraded with multiplex conductors, which are more effective at mitigating ignition risk than a small
3 remaining portion (10%) of open wire secondary (OWS) or weather-resistant aluminum (WAL) (see left
4 picture of Figure I-11). SCE plans to replace these with multiplex conductors (see right picture of Figure
5 I-11). This work should also address OEIS's concern in its comments to SCE's 2022 WMP requiring
6 SCE to provide a plan to reduce secondary ignitions in the future.⁵⁵ This standard update, however, will
7 only affect covered conductor installations starting in 2024, and is not planned for 2022 and 2023 work,
8 as those are already in the design phase.⁵⁶ This 2025 GRC funding request includes the replacement of
9 76 circuit miles of secondary conductors for the 2024-2028 period.

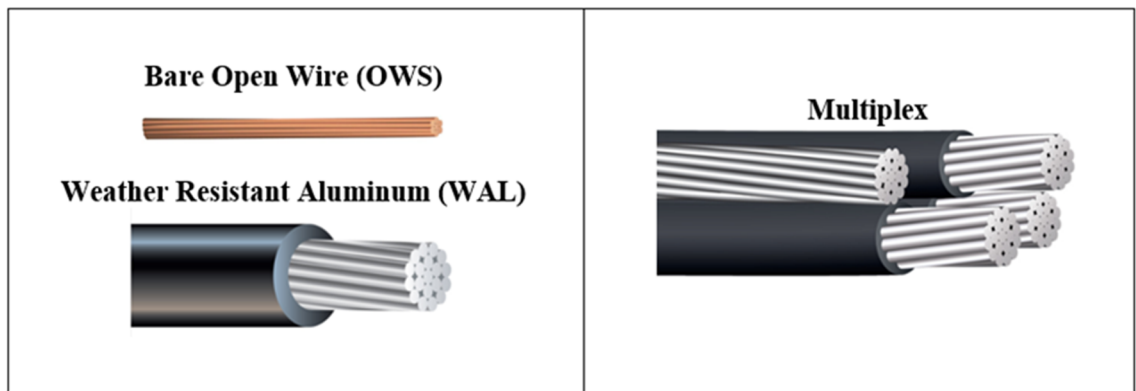
Figure I-10
Example of Co-located Primary and Secondary Conductor Configuration



⁵⁵ OEIS 2023-2025 Wildfire Mitigation Plan Guidelines, SCE-22-17.

⁵⁶ In the future, SCE may consider upgrading a small subset of secondary conductors to multiplex conductors on previously installed covered conductor system.

Figure I-11
Vintage Secondary Conductor (Left) and Updated Secondary Conductor (Right)

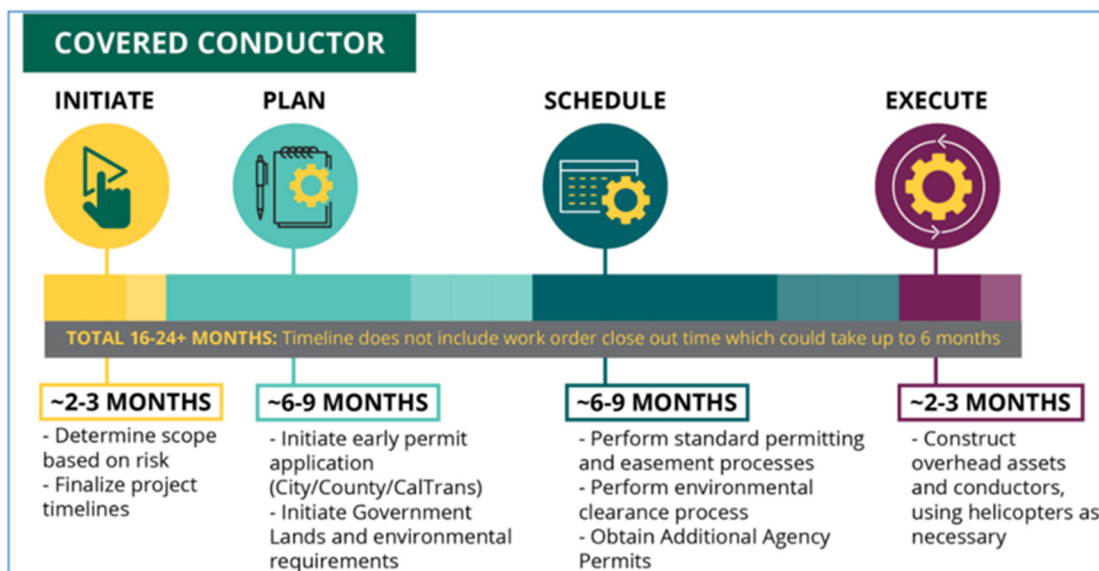


Similar to the implementation of the Targeted Undergrounding Program above, the covered conductor system undergoes the same phases of work -- Initiate, Plan, Schedule, and Execute. However, the covered conductor system installation has a shorter estimated timeframe than TUG (i.e., 16 to 24 months from initial scoping to in-field project completion).⁵⁷ The tasks within each phase of covered conductor work are also similar to what is described for the TUG Program. For example, SCE determines scope in the Initiate phase, obtains early permits in the Plan phase, and performs environmental clearance processes in the Schedule phase. Similarly, in the Execute phase, there are many factors that may affect the construction timeline including, for example, the size of the project, location of the project, terrain, environmental restrictions, weather (e.g., rain/snow, RFW days, etc.), resource availability and ensuring adherence to city requirements. Every project will have unique factors that impact project timelines. Qualified Electrical Workers (QEWs) are required to perform the electrical construction work. SCE uses a combination of SCE and external contractor crews to perform this work. The determination of which workforce to utilize is based on crew availability, work priorities, location, and other factors. Because there are numerous factors that can impact the Execute Phase, the average timeline in Figure I-12 below includes 2-3 months for the execution phase that assumes relatively good conditions, e.g., minimal agency requirements, no environmental restrictions, no RFW

⁵⁷ This estimate does not include the time between in-field project completion to work order close-out.

days, etc. Under challenging conditions, e.g., access issues, difficult terrain, environmental constraints, significant agency requirements, etc., the execution phase can take up to 6-12 months.

Figure I-12
Timeline of Covered Conductor Work



Covered conductor is a prudent and cost-effective mitigation that mitigates the risk of ignition in areas that have a high level of consequences to SCE's communities and customers in HFRA. An analysis of CPUC-reportable ignition events from 2018 to 2022 in SCE's HFRA demonstrates that the main drivers of wildfire ignitions associated with utility equipment are as follows: (a) overhead wire contact from objects or CFO (e.g., vegetation, metallic balloons, debris, etc.); (b) equipment and facility failure (EFF); and (c) wire-to-wire faults. Because covered conductor has three protective layers as outlined above, covered conductor is most effective at preventing overhead wire CFO and wire-to-wire faults. And covered conductor is also effective at mitigating EFF drivers for conductor-related components (e.g., conductor, connectors, insulators) and/or those components that get replaced during the covered conductor work (e.g., FRPs, composite crossarms, wildlife covers, and surge arresters).

SCE's IWMS analysis, as discussed in SCE-04, Vol. 05, Part 1, demonstrated that 4,400 miles of SCE's HFRA should be and now have been characterized as High

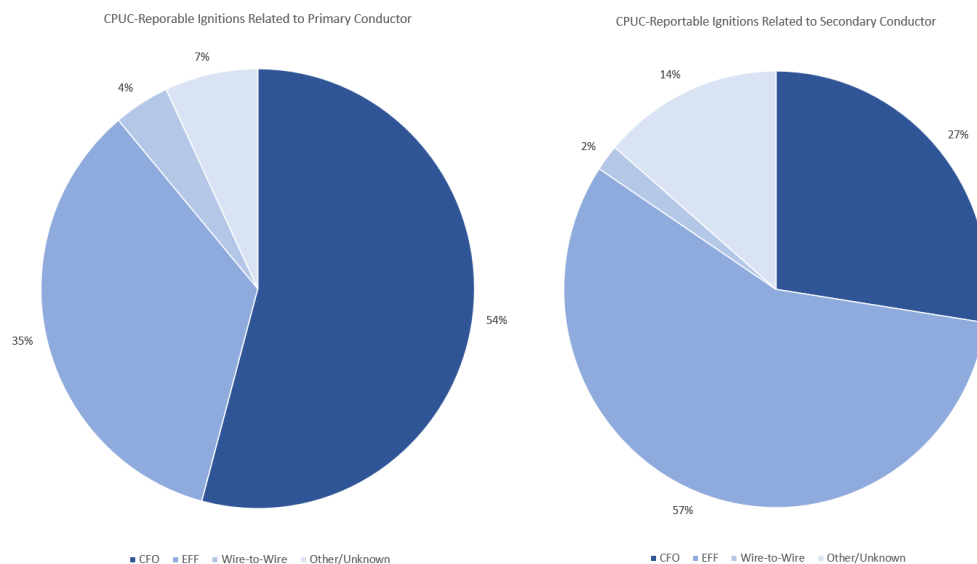
Consequence Areas⁵⁸ and 2,250 miles as Other HFRA. Accounting for the hardened miles completed by the end of 2022 and hardened miles forecast by the end of 2024 (through WCCP and TUG), there are approximately 1,250 unhardened miles remaining at the start of 2025 (some High Consequence Areas and remaining Other HFRA), which SCE needs to harden with covered conductor to reduce wildfire risks for its customers. Since covered conductor has a mitigation effectiveness value of 72% (and higher when complemented by other mitigations), is cost-effective, and can buy down risk in a relatively short amount of time, SCE prudently deploys it in areas with high wildfire consequences. This scope forms the basis of SCE's funding request for WCCP in the upcoming GRC period.

Additionally, SCE recently performed a similar analysis on secondary ignition events from 2019-2022⁵⁹ in SCE's HFRA. SCE observes an increasing trend in the number of secondary ignition events, where the main drivers are EFF and CFO (see Figure I-13 below). SCE estimates that approximately 90% of secondary conductors have already been upgraded to multiplex conductor. Thus, 10% of secondary conductors are still bare open wire or weather-resistant aluminum (WAL) with a thin sleeve which have been in service since over 50 years ago. In Q3 2022, SCE updated its Distribution Design Standards to upgrade these bare open wire or WAL secondary conductors to multiplex conductors, consisting of either two (duplex), three (triplex), or four (quadraplex) individual conductors twisted around each other (see picture of the multiplex conductor on the right of Figure I-11 above). Since the multiplex conductors are "covered" and bundled together, they can withstand CFO much better than the bare open wire or WAL can. Through WCCP, SCE plans to replace any identified bare open wire or WAL secondary conductors that are co-located with the primary lines with multiplex conductors to reduce the EFF and CFO drivers. Replacements will begin in 2024.

⁵⁸ SCE identifies the majority of its HFRA as High Consequence Areas with one or more of the following characteristics: 1) 300 – 10,000 acres burned at 8 hours (exclusive of locations that are classified as Severe Risk Areas), and 2) circuits that experience high winds that may be frequently impacted by PSPS.

⁵⁹ Secondary ignition event data was collected for part of 2019, and 2020 was the first year with a full year of data available.

Figure I-13
Primary and Secondary Distribution Ignition Drivers in 2018-2022



Further Validation of Covered Conductor Effectiveness

SCE performed benchmarking, testing, and developed standards for the deployment of covered conductor. In 2022, in collaboration with PG&E and SDG&E, SCE engaged an independent third-party to perform lab testing to further validate the effectiveness of covered conductor known as the “Joint IOU Covered Conductor Working Group”. Testing was completed at Kinetrics, a nationally recognized independent laboratory and testing facilities.⁶⁰ The testing was independently facilitated and reviewed by Exponent⁶¹ and Kinetrics. The testing matrix was also reviewed by engineering and risk management SMEs as well as external stakeholders such as PG&E, SDG&E, and Filsinger.⁶² Different potential events were tested, including arc testing, ignition testing, and mechanical strength testing. Results from this third-party testing further validated the effectiveness of covered conductor at preventing phase-to-phase (wire-to-wire) and phase-to-ground (wire-down) faults.⁶³

⁶⁰ Kinetrics was selected from a group of 37 different companies.

⁶¹ Exponent is an independent third-party engineering and scientific consulting firm.

⁶² Filsinger Energy Partners, Inc. is an independent energy advising firm.

⁶³ Refer to Effectiveness and Implementation Considerations of Covered Conductors: Testing and Analysis. Exponent, December 22, 2022. https://www.sce.com/sites/default/files/AEM/Supporting Documents/2023-2025/Joint IOU Covered Conductor Testing Cumulative Report 12-22-22_Redacted.pdf.

1 The information compiled and assessments completed in 2022 continue to
2 indicate covered conductor effectiveness between approximately 60 to 90 percent in reducing the drivers
3 of wildfire risk, consistent with benchmarking, testing and utility estimates.

4 The Exponent study found a number of things including:

5 1. CC effectiveness was evaluated by phase-to-phase contact and
6 simulated wire-down testing. CCs were 100% effective at preventing arcing and ignition in tested
7 scenarios at rated voltages.

8 2. CCs prevented arcing and ignition and limited current flow to less than
9 2.5 mA in 100% of tested phase-to-phase contact scenarios at rated conductor voltages, which included
10 different types of vegetation, balloons, simulated animals, and conductor slapping.

11 3. CCs prevented arcing and ignition in 100% of simulated wire-down
12 events in dry brush. Broken conductors and conductors with damage that exposed the underlying metal
13 showed potential for ignition.

14 Figure I-14 below shows the ignition testing scenario of a foreign object
15 (in this case, a tree branch) laying across two conductors. No ignitions were observed on the two
16 covered conductor lines (left picture in Figure I-14). However, ignitions were observed on the two bare
17 conductor lines in most simulations (right picture in Figure I-14). The test results supported an increase
18 in the mitigation effectiveness level of covered conductor by 5% from 67% to 72% due to effectiveness
19 seen in vegetation, vehicle, and CFO sub-drivers including fall-in risk.

Figure I-14
Example of Ignition Testing Simulations with Covered Conductor and Bare Conductor



Covered conductor performs well not only in lab settings, but also in real-world applications as intended. For instance, the inspection photos shown in Figure I-15 below were taken on November 25, 2021 (during Thanksgiving weekend) in the Idyllwild area of Riverside County. Several branches landed on the covered conductor, but because the wires are insulated, these strikes did not cause a fault or sparking on the circuit. Power remained safely on for customers. To date, no ignitions have occurred from risk drivers that covered conductor directly mitigates.⁶⁴

⁶⁴ For additional information on recorded effectiveness of covered conductor see the “Recorded Effectiveness” section of the Joint IOU Covered Conductor Working Report contained in SCE’s 2023-2025 WMP. pp. 886-888.

Figure I-15
Two Real-World Instances Showing Covered Conductor Efficacy



1 **Operational Realities and PSPS Benefits of Deploying Covered**
2 **Conductor Must Be Considered**

3 SCE deploys covered conductor beyond the scope of miles indicated by
4 risk modelling to account for operational realities and PSPS benefits to customers. In the field, when
5 SCE installs covered conductor, it does not necessarily limit deployment strictly to the particular circuit
6 segment identified by the risk model. Instead, SCE prudently extends that covered conductor installation
7 to the next contiguous structure with equipment or the next structure that is a dead-end, even if those
8 structures are outside of the range of the initial scoping predicted by the risk model (e.g., in Other HFRA
9 category).

10 SCE factors in other operational considerations as well when deploying
11 covered conductor that may result in deployment beyond what the model indicates. Pole loading is one
12 such consideration: the extra weight and associated wind loading of covered conductor must be taken
13 into account. The imbalance of pull on a pole requires guying⁶⁵ but in many cases locations for guying
14 are limited by easement requirements or other operational challenges. Often, it is most operationally
15 feasible to extend the installation of covered conductor to a point where there is sufficient space for a
16 guy wire or extend the installation to an already existing dead-end location. As another example, in
17 some cases the model indicates installation of covered conductor on a particular circuit in a location
18 where there are multiple circuits on the same structures and these circuits have different risk rankings.
19 This occurs when circuits have different probabilities of ignition, but the same wildfire consequence. It
20 is often more cost-effective and makes more operational sense to cover the circuit segments of all
21 circuits along the same path. As an additional benefit, this also lessens the impact to the surrounding
22 customers, who would otherwise experience a second set of outages if SCE were to return to deploy
23 covered conductor on the adjacent circuit segment at a later time.

24 Covered conductor also has additional benefits beyond reducing wildfire
25 risk – when deployed effectively, it can reduce the activation of Public Safety Power Shutoff (PSPS)

⁶⁵ Guying is a process of attaching a pole to a stabilizing structure, such as the ground.

1 events. PSPS refers to the proactive power turn-off by the utility during potentially dangerous weather
2 conditions in fire-prone areas to reduce the threat of wildfires. Having circuits that meet current high fire
3 risk area construction standards, with covered conductor installed, will increase the threshold for that
4 circuit's de-energization criteria and reduce the need and impact of PSPS.⁶⁶ However, a circuit segment
5 with covered conductor cannot meaningfully reduce PSPS impacts if SCE is not able to electrically
6 isolate that circuit segment from contiguous circuit segments with bare conductor. Thus, SCE must
7 install covered conductor to the next structure that will allow SCE to isolate the covered portion of the
8 circuit from the bare portion of the circuit. In order to achieve this PSPS benefit for any isolatable
9 portion of a circuit, additional circuit miles will be required. These circuit miles will be determined on a
10 case-by-case basis during scoping & design based on the feasibility to operationalize this benefit.

11 SCE estimates that on average this "operational buffer" equates to
12 approximately 20% additional circuit miles that are inside HFRA in addition to those miles scoped
13 based solely on the risk model output.⁶⁷ SCE made a similar proposal in its 2021 GRC Track 1 funding
14 request, and the CPUC acknowledged and agreed with SCE on this matter: "Regarding SCE's assertion
15 that the operational realities of deploying covered conductor require additional circuit miles, since the
16 Wildfire Risk Model is focused on evaluating risk at the circuit level, as opposed to operational design
17 considerations, we find it reasonable to expect some additional operational miles to be installed during
18 actual design and deployment."⁶⁸

19 **2021 GRC Track 1 CPUC Compliance Requirement on PSPS Benefit**
20 **with Covered Conductor Work**

21 In D.21-08-036, the Commission stated, "In requesting the 20 percent
22 adder, SCE broadly states that covered conductor circuits will benefit from increased PSPS event

⁶⁶ There have been a few instances in recent years where some circuits experienced extremely high wind conditions that exceed even the increased covered conductor windspeed threshold. In these cases, SCE is considering undergrounding the covered conductor to further reduce ignition risks and need for PSPS.

⁶⁷ Refer to WP SCE-04, Vol. 05, Part 2, pp. 39-40, Covered Conductor Operational Buffer Miles.

⁶⁸ D.21-08-036 at 204, *Decision on Test Year 2021 General Rate Case for Southern California Edison* (Aug. 20, 2021).

1 thresholds. As part of its next GRC application, we direct SCE to present a quantitative evaluation of
2 how covered conductor has resulted in higher thresholds for initiating a PSPS event, broken down by
3 Tier 2 and Tier 3 HFTDs, as well as an evaluation of how covered conductor has contributed to
4 reductions in SCE's historic PSPS frequency, scope, or duration."⁶⁹

5 SCE's targeted PSPS mitigation efforts helped reduce PSPS customer
6 impacts in 2022. In 2022, SCE expedited grid hardening activities on 70 of its Frequently Impacted
7 Circuits (FICs). These 70 circuits had cumulative impacts of 60 de-energizations, 180,000 customer
8 outages and 50 million customer minutes of interruption in 2020 and 2021. Due to this proactive
9 hardening, in 2022 SCE only had four de-energizations impacting approximately 1,900 customers and
10 approximately 800,000 CMI.⁷⁰

11 Covered conductor was the principal mitigation deployed in 2022. Due to
12 covered conductor's ability to reduce risk of contact from foreign objects, SCE was able to raise wind
13 speed de-energization thresholds from the National Weather Service Wind Advisory levels (at 31 mph
14 sustained wind speed and 46 mph gust wind speed) to the National Weather Service High Wind
15 Warning levels (at 40 mph sustained and 58 mph gusts) on portions of overhead circuitry that had
16 covered conductor installed. In fact, through 2022, SCE was able to raise wind speed de-energization
17 thresholds for nearly 2,300 circuit miles where covered conductor had been installed (more than half of
18 SCE's total covered conductor deployment to date). Covered conductor reduced the need for PSPS on
19 some circuits in lower wind areas and reduced the duration of PSPS de-energizations on circuits in
20 higher wind areas where the higher thresholds were still breached.⁷¹

⁶⁹ D.21-08-036 at p. 204, *Decision on Test Year 2021 General Rate Case for Southern California Edison* (Aug. 20, 2021).

⁷⁰ Table I-13: *2022 PSPS Actual vs. Hypothetical 2022 Backcast* below shows a comparison of 2022 actual PSPS events and a hypothetical scenario where SCE did not proactively implement the wildfire mitigations. Had SCE not been proactive in our mitigations, the 2022 PSPS season could have necessitated more de-energizations than observed.

⁷¹ In some cases, other factors such as particularly high fire potential, can lower the thresholds for specific events.

As Table I-11 shows, as of year-end 2022, SCE installed covered conductor on 4,395 circuit miles of overhead circuitry in the HFRA. Of those 4,395 miles, approximately 71% have been installed in HFTD Tier 3 and approximately 29% have installed in HFTD Tier 2. The table below shows the percentage of that covered conductor work that has been installed on fully-isolatable segments or is associated with other circumstances that allow SCE to raise the wind speed thresholds to call a PSPS event.

***Table I-11
Installed Covered Conductor & Resulting Wind Speed Threshold Increases in
Tier 2 and Tier 3 HFRA***

Covered Conductor Miles Installed through YE 2022	PSPS Wind Speed Threshold Change Eligible	Percentage
Tier 3 – 3,134 miles	2,003 miles	64%
Tier 2 – 1,261 miles	286 miles	23%

Note installed miles do not automatically translate to allowing those miles to see windspeed threshold increases as sometimes covered conductor is first installed on high-risk ignition areas, but other portions of wire on the same isolatable segment can be prioritized differently. Thus, PSPS may remain necessary in HFRA, at thresholds under what covered conductor can address, until a fully isolatable segment is completely covered, or an exception is made as described below. Alternatively, SCE deploys new covered conductor from dead-end to dead-end, meaning that some spans may be covered beyond a sectionalizing device, leading to more miles covered than have raised thresholds.

In addition to covered conductor, other important and at times complementary measures are taken to reduce PSPS including installation of new automated switches or sectionalizing devices. Sectionalizing devices help to reduce the size of the areas that are de-energized during PSPS events. Redundancy in SCE’s electrical grid allows for transfer of load from one circuit to another through a circuit tie, which means that, even on a radial line, SCE can leave upstream segments of a circuit energized while de-energizing areas downstream that are experiencing high fire threat

1 conditions. Using these devices and operating in this way allows for reducing the number of customers
2 impacted by PSPS events.

3 SCE also conducted circuit exception reviews in 2022 to either raise PSPS
4 thresholds or eliminate the circuits from PSPS consideration altogether. SCE's circuit exception process
5 entails a detailed periodic review of the wildfire risk of circuits in the HFRA. If the risk is sufficiently
6 low at the time based on a thorough review based on fire science, engineering, and risk analysis, an
7 approved exception allows a circuit that would otherwise have a lower PSPS windspeed threshold to be
8 increased to the National Weather Service High Wind Warning level, or to take it out of PSPS
9 consideration altogether, depending on the specifics of the circumstances. In this way, the circuit
10 exception process can reduce the frequency, scale/scope, and duration of PSPS events on circuits for
11 which exceptions are approved. In the exception review process, wildfire risk is determined by
12 consideration of localized fuel conditions, topography, proximity to wildland areas, and other criteria.
13 Exceptions are reviewed annually since these criteria can change with time due to processes like
14 urbanization or a recent burn scar.

15 Table I-12, below compares the 2022 PSPS season with the 2021 PSPS
16 season and shows the marked improvement as shown as percent decreases in the frequency, scale, scope,
17 and duration of 2022 PSPS events relative to the preceding year.⁷²

⁷² Weather and fuel conditions are large drivers of the magnitude of PSPS impacts experienced each year. 2022 was a relatively mild fire weather year, compared to the preceding two years, due to the combination of a persistent monsoon across mountain areas, the remnants of Hurricane Kay in September, and a strong winter storm in early November. These events brought appreciable amounts of precipitation to much of the region, which helped to mitigate fire activity. In addition, the lack of Santa Ana winds early in the season resulted in fewer PSPS activations than what we anticipate going forward.

Table I-12
2021 versus 2022 PSPS Season

Frequency Circuit De-energizations	Scope/Scale Customer Outages	Duration Customer Minutes of Interruption (CMI)
↓89%	↓81%	↓94%

SCE also performed a backcasting analysis comparing actual 2022 PSPS outcomes against 2022 weather and fuels modeled with previous years protocols (Table I-13), which helps evaluate the effectiveness of SCE’s PSPS mitigation activities described above. In other words, SCE sought to model what the 2022 season could have looked like if no grid hardening measures or risk modeling changes had been undertaken to date. While it is difficult to recreate all the complex decision-making factors to determine how much longer and more widespread an outage could have been, SCE was able to attribute savings to mitigations (e.g., raised thresholds from covered conductor installation, scope changes from switching protocols and exceptions) and model likely PSPS reductions.

This analysis shows that, had SCE not been proactive in our mitigations, the 2022 PSPS season could have necessitated de-energization of roughly 49,000 customers on 60 circuits, for a total of approximately 47 million minutes of interruption (compared to actual de-energization of approximately 16,000 customers on 13 circuits, for a total of 7 million minutes of interruption). Table I-13, below shows these hypothetical reductions as a percentage of actual outcomes.

Table I-13
2022 PSPS Actual vs. Hypothetical 2022 Backcast

Frequency Circuit De-energizations	Scope/Scale Customer Outages	Duration Customer Minutes of Interruption (CMI)
↓78%	↓67%	↓85%

Additional SME Review of CC Miles Recommended by the Risk Model

In 2022, SCE began additional engineering SME review of covered conductor scope submitted for execution beginning in 2024. This includes visually inspecting segments

1 using Google Street View to confirm that covered conductor is appropriate. Additionally, SCE is also
2 reviewing already submitted work orders that was based on older risk models and have not been
3 constructed to see if the scope aligns with the new model. During these reviews, SCE determines
4 whether to continue with covered conductor, convert covered conductor to TUG, cancel covered
5 conductor, or if other alternatives may be more appropriate. In most cases, the SME review agrees with
6 what was prescribed by the model or that the older model's recommendation aligns with the new model.
7 Figure I-16 shows a photo of a location, confirming that covered conductor is the appropriate mitigation
8 given the surrounding dry vegetation.

Figure I-16
Photo of Location Confirms Covered Conductor as Appropriate Mitigation



9 Figure I-17 shows an example of a deviation between the consequence
10 risk model (left picture) and detailed SME review (right picture). The model recommended covered
11 conductor on Portion 1 and to leave Portion 2 bare. However, upon SME review, as was seen with the
12 left picture Figure I-18, Portion 1 runs along a residential area with little to no dry vegetation that could
13 spread, and, as with the right picture in Figure I-18, Portion 2 is in areas with low-laying bushes and dry

1 vegetation that could spread. The recommendation from the SME review is to leave Portion 1 bare and
2 cover Portion 2.

3 SCE expects to complete this review in Q1 2024. The type of miles may
4 shift from covered conductor to TUG or vice versa, but SCE does not anticipate significant deviation
5 from the initial covered conductor scope in this GRC.

Figure I-17
Example of Deviation Between Risk Model and Review for Covered Conductor

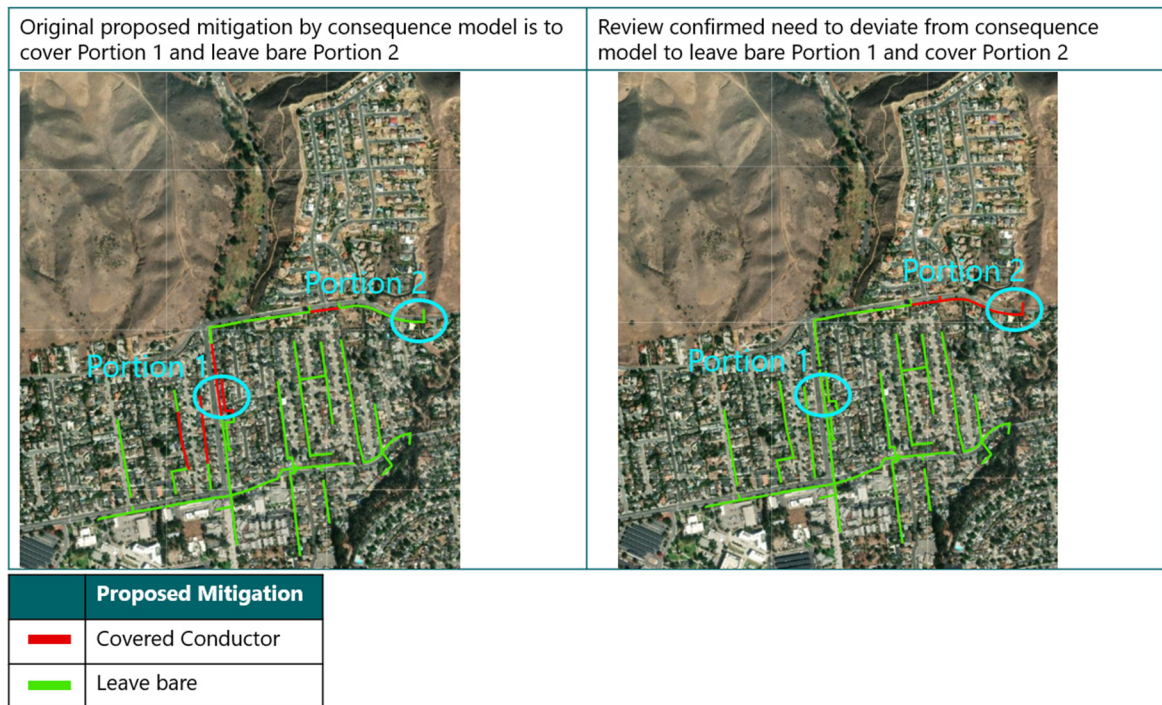


Figure I-18
Photos of Locations Confirms Need to Deviate from Consequence Model

Image from Portion 1 (CC to bare)



Image from Portion 2 (Bare to CC)



Alternatives or Complementary Mitigations to Covered Conductor

Some mitigations can be used as an alternative or are complementary to covered conductor, depending on how they compare to covered conductor with respect to feasibility, cost, mitigation effectiveness, and/or speed of deployment. For instance, spacer cable system or aerial bundled cable are preferred over covered conductor in areas of dense vegetation although these systems are more costly and take longer to install than covered conductor.

Undergrounding is more effective than covered conductor in preventing ignition risks and could be used as an alternative, but covered conductor mitigates the risk drivers that tend to cause the largest fires. Further, undergrounding takes longer to implement and is more expensive than covered conductor on a per-mile basis. However, TUG is a necessary complement to SCE's overall wildfire mitigation efforts and is strategically implemented in Severe Risk Areas in SCE's HFRA to mitigate unacceptable ignition risks, as described in detail above.

Rapid Earth Fault Current Limiters (REFCL) are systems that are widely used in Australia to reduce ignition risks. REFCL can rapidly reduce the current if a powerline comes in contact with the ground or a tree limb and is therefore effective at reducing energy phase-to-ground faults. However, unlike covered conductor, REFCL cannot reduce energy from wire-to-wire contact without ground contact, or from contact between falling tree branches and multiple wires. REFCL is also limited primarily to use on three-wire systems, although it can be economically applied to 4-wire systems in select cases. Therefore, REFCL should not be viewed as an alternative to covered conductor, but rather as a complementary mitigation to covered conductor, where both are feasible to deploy. REFCL is also a new technology to North America. It is complex and there are few utilities to benchmark against, and it will take time to fully evaluate the technology in the field and appropriately scale the mitigation. For more details on SCE's REFCL deployment proposals, please refer to section e) below.

(a) Historical Variance Analysis

This section provides a year-over-year comparison of the number of completed covered conductor circuit miles and associated recorded capital expenditures (see Table I-14 below).⁷³

Table I-14
Historical Analysis for Covered Conductor in 2018-2022 (Nominal \$000)⁷⁴

Covered Conductor w/ FRPs	Recorded					Total
	2018	2019	2020	2021	2022	
Completed Circuit Miles	57	277	797	1,426	1,356	3,913
Capital Expenditures (Nominal \$000s)	\$ 27,654	\$ 239,911	\$ 544,093	\$ 897,602	\$ 791,274	\$ 2,500,534

In 2018, SCE first introduced the use of covered conductor to prudently and cost-effectively reduce wildfire ignition risks associated with its overhead equipment. SCE was able to successfully install 57 circuit miles of covered conductor at the cost of approximately \$28 million (nominal) in 2018. 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 of covered conductor and spent approximately \$544 million. In 2021, SCE nearly doubled the circuit miles compared to the prior year, completing 1,426 circuit miles with an associated spend of approximately \$898 million. In 2022, SCE completed 1,356 circuit miles with an associated spend of approximately \$791 million. It should be noted that 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 since incurred costs for covered conductor projects often span multiple years.

(b) 2021 Authorized vs. Recorded

The 2021 GRC Track 1 Decision authorized a total revenue requirement amount and total circuit miles for 2019-2023 for WCCP.⁷⁵ Therefore, to the extent that

⁷³ SCE completed an additional 480 miles of covered conductor under non-WCCP programs such as OCP, 4 kV cutover, storm restorations, etc. These miles were not counted as part of the WCCP programs.

⁷⁴ Recorded 2018 costs for Covered Conductor are shown in this table for presentation of total program costs as Covered Conductor costs were recorded to Plant Betterment when work began in late 2018 prior to new WCCP accounting was created. Refer to SCE-02, Vol. 07 for more discussion on Plant Betterment.

⁷⁵ D21-08-036, p. 204.

SCE's cumulative final costs and scope for that time period exceed 110% of 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. Table I-15 below shows the annual authorized and recorded amounts for 2021. It should be noted that D.21-08-036 authorized the dollar amount and total circuit miles on a cumulative basis for the 2019-2023 period. The annual authorized circuit miles seen in Table I-15 were calculated and derived from the total authorized amount.

Table I-15
Authorized vs. Recorded Miles and Capital Expenditures for Covered Conductor
w/ FRPs⁷⁶

Covered Conductor (\$000)	2021	Miles
Authorized	\$ 535,036	1,043
Recorded	\$ 897,602	1,426
Variance	\$ 362,566	383

(c) Capital Expenditure Forecast

Table I-16 below summarizes the funding request for 2023-2028 capital expenditures of \$2,641 million (nominal dollars) for installing 3,650 circuit miles of covered conductor with fire-resistant poles (FRPs) and 76 miles of secondary conductor. It is important to note that 2023 WCCP installations fall within the scope of the 2021 GRC Track 1 Final Decision authorization and 2024 WCCP installations are currently being litigated in Track 4 of the 2021 GRC.

⁷⁶ See WP SCE-07, Vol. 01, Authorized vs. Recorded.

Table I-16
Capital Expenditure Forecast for Covered Conductor Work

	Forecast			Total
	2023	2024	2025-2028	
Covered Conductor w/ FRPs (Circuit Miles)	1,200	1,200	1,250	3,650
Secondary Conductor (Circuit Miles)	-	37	39	76
Total Conductor w/ FRPs Cost (Nominal \$000s)	\$ 840,531	\$ 879,801	\$ 921,154	\$2,641,485

(i) Scope Forecast

As described in Part 1 of this volume, High Consequence areas are locations in SCE's HFRA that have the potential to burn between 300 and 10,000 acres in 8 hours or are subject to potential PSPS events due to high winds. As further described in Part 1 of this volume, ignitions in High Consequence Areas have a high probability of growing into very large fires. SCE plans to mitigate the wildfire risk in its High Consequence Areas with covered conductor due to its ability to greatly reduce the likelihood of ignitions. Based on the IWMS framework, SCE has 2,950 circuit miles of Severe Risk Areas, 4,400 circuit miles of High Consequence Areas, and 2,250 circuit miles of Other HFRA for a total of 9,600 circuit miles as presented in Table I-17 below. Given that SCE's current covered conductor installation rate is approximately 1,200 miles per year, SCE believes it is prudent to propose installing covered conductor on 1,200 circuit miles for each year in 2023 and 2024 for a total of 2,400 miles. However, by the end of 2024, there *still* remains 2,754 unmitigated miles in the respective risk tranches as shown in Table I-17. In the TUG section above, SCE proposes to address 580 miles of mostly Severe Risk Areas with undergrounding for the 2025-2028 period. SCE proposes to install 1,250 miles of covered conductor in High Consequence Areas and Other HFRA in the 2025 – 2028 period.^{77,78} The remaining miles in Other HFRA will be hardened via traditional infrastructure replacement over time.

⁷⁷ For those Severe Risk Areas where undergrounding is infeasible, SCE will also consider REFCL, remote grids, spacer cable, and aerial bundled cable in addition to, or in lieu of, covered conductor.

⁷⁸ The proposed pace of work for WCCP would be 850, 300, 50, 50 miles for 2025, 2026, 2027, 2028, respectively. The ramp-down of WCCP is to balance the on-ramp of TUG work, which is higher-risk work.

Table I-17
CC and TUG Scope Planned for 2023-2028⁷⁹

Risk Category	Total Miles in HFRA	Expected to be Hardened by end of 2024	Expected to be Unhardened by end of 2024	TUG Planned for 2025-2028	CC Planned for 2025-2028	Remaining Unhardened Miles by end of 2028
Severe Risk Areas	2,950	2,398	552	552	-	-
High Consequence Areas	4,400	4,081	319	9	310	-
Other HFRA	2,250	367	1,883	19	940	924
Total Miles in HFRA	9,600	6,846	2,754	580	1,250	924

(ii) Cost Forecast

Table I-18 below shows the annual forecast costs for installing covered conductor with FRPs and secondary conductor. The total annual costs also include an environmental cost adder for the anticipated increase in environmental requirements.

Table I-18
Cost Breakdown of Covered Conductor Work^{80,81,82}
(Nominal \$000)

	2023	2024	2025	2026	2027	2028	Total
(1) Covered Conductor Circuit Miles	1,200	1,200	850	300	50	50	3,650
(2) Covered Conductor Unit Cost (2022\$) (\$000)	\$663	\$663	\$663	\$663	\$663	\$663	N/A
(3) Secondary Conductor Circuit Miles	-	37	26	9	2	2	76
(4) Secondary Conductor Unit Cost (2022\$) (\$000)	\$63	\$63	\$63	\$63	\$63	\$63	N/A
(5) Escalation	1.054	1.106	1.133	1.143	1.151	1.167	N/A
(6) Sub-total	\$839,026	\$883,126	\$640,790	\$228,071	\$38,278	\$38,835	\$2,668,125
(7) Environmental (Nominal \$000)	\$1,897	\$1,991	\$2,039	\$2,057	\$288	\$292	\$8,563
(8) Total (Nominal \$000)	\$840,922	\$885,116	\$642,830	\$230,128	\$38,565	\$39,127	\$2,676,688
Accounting Adjustments	\$3,537	\$4,554	\$5,836	\$3,161	\$1,706	\$1,493	\$20,287
Covered Conductor Cost Savings	(\$3,928)	(\$9,869)	(\$10,146)	(\$10,359)	(\$10,536)	(\$10,650)	(\$55,490)
Total Forecast (Nominal \$000)	\$840,531	\$879,801	\$638,519	\$222,930	\$29,735	\$29,970	\$2,641,485

Row (1) in the table above shows the forecast number of miles for each year in the 2023-2028 period as discussed in the Scope Forecast section immediately above. Row (2) shows the average covered conductor unit cost, which includes the cost of fire-resistant

⁷⁹ Hardened miles as of 05/01/2023 for all risk tranches. SCE may revise this data to reflect adjustments based on comparing completed work orders to mapping data, and also pending completion of SCE's Review & Revise stage of IWMS.

⁸⁰ Refer to WP SCE-04, Vol. 05, Part 2, pp. 41-42 – Covered Conductor Unit Cost Workpaper.

⁸¹ Accounting Adjustments reflect changes made to SCE's employee compensation program. Please refer to SCE-06, Vol. 04.

⁸² "Covered Conductor Cost Savings" discussed below.

poles. This average unit cost was estimated using completed work orders in 2022. The last-year-recorded amounts are reasonable because they reflect costs that are representative of future trends. Row (3) is the forecast number of secondary conductor miles starting in 2024. SCE estimates that the ratio between primary and secondary conductor in HFRA is 0.31, meaning that for every 100 primary conductor miles, there are 31 secondary miles. SCE expects the replacement rate to be 10%, since it is estimated that 3% of SCE's secondary conductors are bare open wire and 7% are weather-resistant aluminum conductor. Hence, the number of secondary conductor miles is the product of 0.31, 0.1, and number of primary conductor miles. For example, for 2024, the secondary conductor miles are $0.31 \times 0.1 \times 1,200 = 37.2$ miles. Row (4) is the average secondary conductor unit cost, which was based on our system average cost for this type of material/cable.

Row (5) shows the escalation rates for distribution system capital. Row (6) is the sub-total amount of the covered conductor and secondary conductor costs. Row (7) is an environmental adder for the anticipated increase in environmental requirements. Typically, the recorded cost for environmental work for covered conductor is \$12 million per year and is charged as part of the work order. Starting in 2023, SCE expects that amount to increase by 15% to account for known costs such as Wetlands and Construction Storm Water permitting reviews and agency fees, and unknown costs such as unforeseen regulatory changes, additional surveys and permitting for resources, emergent agency and species of concerns, and non-compliance follow-ups. The \$1.8 million (constant \$) is 15% of the \$12 million, which was added to each year of work between 2023-2026. In 2027-2028, this amount is reduced to \$250,000 due to a reduction in covered conductor scope. Row (8) is the total costs in nominal dollars.

Included in this forecast are cost savings measures from a variety of activities where SCE has determined it can save approximately \$10 million per year during the GRC period. These activities include various process improvements or implementation of time-saving measures to improve project time and costs. Procurement and purchasing processes and practice improvements can reduce time to order as well as reduce work, safety risks and potential errors, such as procuring fiberglass cross arms with pre-drilled holes instead of requiring SCE to complete such work.

The savings are net of any investments made to enable the savings including the hiring of one junior engineer to activate savings of approximately \$0.3 million per year and the purchase of generators instead of renting generators at premium prices for site work.⁸³

(d) RAMP Integration

Table I-19 below shows the RAMP and 2025 GRC comparison for the scope and total costs of covered conductor work. Although the scope between RAMP and 2025 GRC was unchanged in the 2025-2028 period, SCE expects the cost in the 2025 GRC to exceed what was estimated in RAMP due to several factors: higher average unit cost and escalation rates to reflect current market conditions, incremental cost of environmental permits, and inclusion of secondary conductor replacement costs. The RSE for WCCP decreased since filing our 2022 RAMP for several reasons. First, the unit costs increased from the RAMP as discussed above. Second, SCE updated the QC factor from 3% to 8% based on conformance data. Lastly, SCE has an updated scope list for the GRC.

Table I-19
Covered Conductor
RAMP vs GRC Capital Forecast Comparison - (Nominal \$000)
Risk Spend Efficiencies^{84,85}

RAMP Risk	RAMP ID	RAMP Control / Mitigation Name	Filing	2022	2023	2024	2025	2026	2027	2028	Total 2025 - 2028	2025 - 2028 RSE
Wildfire	C1 and C1a	WCCP	RAMP	\$697,957	\$723,601	\$752,979	\$538,239	\$192,810	\$32,784	\$33,657	\$797,490	1,520
			GRC	\$791,274	\$844,460	\$889,670	\$648,665	\$233,289	\$40,271	\$40,620	\$962,845	865
			Variance	\$93,317	\$120,859	\$136,691	\$110,426	\$40,480	\$7,487	\$6,963	\$165,356	(656)

(2) Work Description & Need: Tree Attachment Remediations

This section discusses SCE's funding request for tree attachment remediations, which is summarized in Figure I-19 below. SCE plans to remediate approximately 1,100

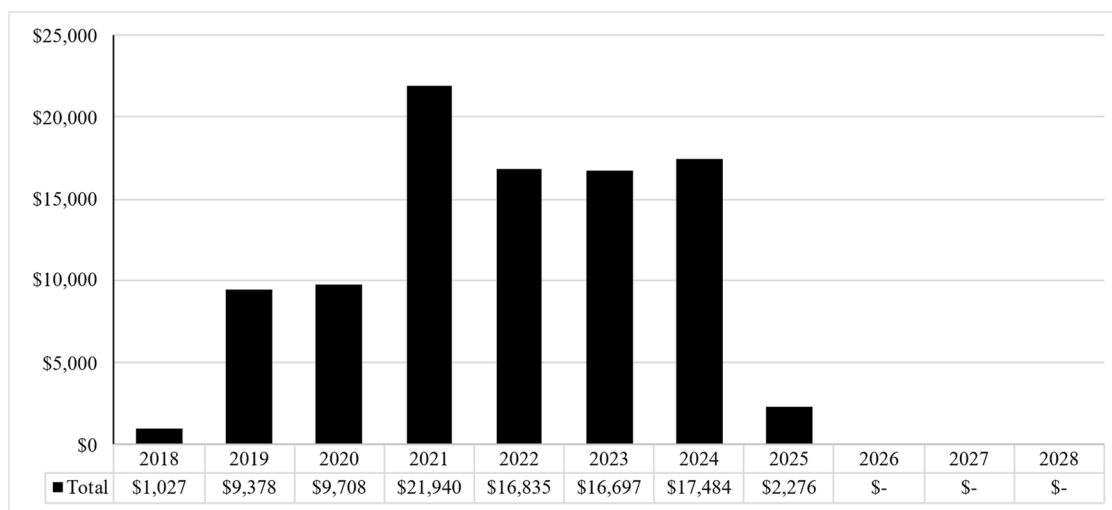
⁸³ WCCP also includes \$0.901 million in O&M in 2025 for Construction Standards Remediation. WP SCE-04, Vol. 05, Part 2, pp. 1-7 – Grid Hardening O&M Forecast.

⁸⁴ Refer to WP SCE-04, Vol. 05, Part 1 – WF/PSPS RAMP to GRC Integration.

⁸⁵ GRC forecasts in this table exclude accounting adjustments and cost savings related to covered conductor, which is consistent with the RAMP forecast.

tree attachments at the cost of \$36.457 million (nominal) over the next three years, completing this program by the end of 2025.

Figure I-19
Tree Attachment Remediations^{86,87}
CET-PD-GR-TA-MTW
Recorded (2018 – 2022) / Forecast (2023 – 2028)⁸⁸
(Total Company – Nominal \$000)



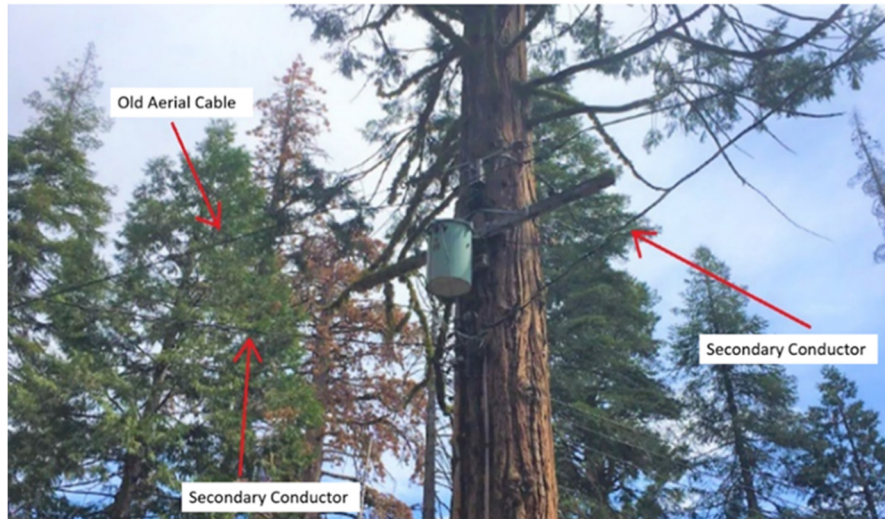
Tree attachment remediation refers to the installation of new poles in order to eliminate instances where existing electrical equipment, including overhead conductor, are attached to trees (see Figure I-20 below).

⁸⁶ Refer to WP SCE-04, Vol. 05, Part 2, pp. 31-38 – Capital Detail by WBS Element for WCCP.

⁸⁷ An error was identified subsequent to the finalization of financial data. Therefore, the intended financial number that is stated here in testimony does not align with the financial numbers in standardized workpapers and the RO model. An errata will be submitted to align the financial numbers in testimony, standardized workpapers, and the RO model at a future date.

⁸⁸ Recorded 2018 costs for Tree Attachments are shown in this table for presentation of total program costs as Tree Attachment costs were recorded to Plant Betterment when work began in late 2018 prior to new WCCP accounting was created. Refer to SCE-02, Vol. 07 for further discussion on Plant Betterment.

Figure I-20
An Example of a Tree Attachment Where Electrical Equipment
Was Attached to a Live Tree



Older construction methods used in SCE’s forested service area leveraged existing trees to support overhead conductors instead of installing utility poles. These “tree attachments” do not meet SCE’s current design standards since the integrity of the trees cannot be verified using inspections and assessment techniques for poles. In addition, tree attachments increase the probability of faults and damages from vegetation contact and “fall-ins.” The Commission has agreed with SCE 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.⁸⁹ Removing the electrical equipment and installing them on a new pole reduces ignition driver risks.

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, i.e., to address the contact from object and equipment/facility failure risk drivers. Note that most tree attachment work is completed with aerial cable as that is the design standard for areas with dense vegetation. Aerial cable is a fully insulated conductor, equivalent to underground cable, and can withstand permanent phase-to-phase and phase-to-

⁸⁹ See D.21-08-036 at p. 205.

1 ground contact. An alternative to relocating tree attachments to a utility pole is to underground the
2 overhead equipment. However, the terrain where these tree attachments exist most likely make
3 undergrounding infeasible or very costly. SCE intends to replace all tree attachments remaining in
4 HFRA by the end of 2025.

5 (a) Historical Variance Analysis

6 SCE began tree attachment remediation work in 2018 and recorded
7 \$1.027 million to gain experience and inform future work.⁹⁰ In 2019 SCE proactively remediated 101
8 tree attachments. Subsequently, in 2020 SCE proactively remediated an additional 44 tree attachments in
9 areas not affected by the 2020 wildfires.⁹¹ Similarly, in 2021 SCE proactively remediated 358 tree
10 attachments.⁹² In 2022, SCE proactively remediated 931 tree attachments.⁹³ Thus, in total, from 2019-
11 2022 SCE proactively replaced 1,434 tree attachments.⁹⁴

12 (b) 2021 Authorized vs. Recorded

13 The 2021 GRC Track 1 Decision authorized capital expenditures
14 of \$22.458 million in 2021. SCE recorded \$21.940 million in 2021 as shown in Table I-20 below. For
15 2021, SCE completed 358 tree replacements compared to 674 authorized tree replacements.

⁹⁰ 2018 tree attachment remediation work was performed in Dinkey Creek circuit.

⁹¹ 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 total, SCE proactively and reactively remediated 501 (i.e., 44+457) structures in 2020.

⁹² In 2021, SCE reactively remediated another 180 tree attachments that were destroyed by storm conditions. In total, SCE proactively and reactively remediated 538 (i.e., 358+180) structures in 2021.

⁹³ In 2022, SCE reactively remediated another 68 tree attachments that were destroyed by storm conditions. In total, SCE proactively and reactively remediated 999 (i.e., 931+68) structures in 2022.

⁹⁴ In total, SCE completed approximately 2,139 replacements (1,434 proactive replacements + 705 reactive replacements).

Table I-20
Authorized vs. Recorded Capital Expenditures for Tree Attachment Remediation⁹⁵
(Nominal \$000)

Tree Attachments (\$000)	2021
Authorized	22,458
Recorded	21,940
Variance	\$ (518)

In 2021, SCE completed fewer scope than what was authorized because there were several storms that occurred during this period and SCE had to shift resources from the proactive replacement work to finish the restoration work based on prioritization. On a per-structure basis, the recorded cost was higher than the authorized due to several factors. First, tree attachments were in areas of very rough terrain that required most helicopter sets, which increased the cost on the structures. Additionally, these areas were in environmentally sensitive locations (e.g., bird nesting), therefore, environmental monitors were required to oversee the work. The time and effort to change scope in the field to accommodate these environmentally sensitive areas also increased the cost. In addition, since we are working with several agencies such as forest, national parks, Bureau of Land Management (BLM) and/or California Department of Fish and Wildlife (CDFW), environmental costs on these projects also increased due to the inability to access these structures by traditional overland travel. Foot access as compared to truck access caused additional time to complete work and increased costs. Furthermore, due to OSHA requirements, there are work restrictions if the cases in COVID surge in a district. This caused schedule delays and increased overtime hours.

(c) Capital Expenditure Forecast

Accounting for the completed 2,139 proactive and reactive replacements, there are approximately 1,100 tree attachments remaining to be remediated in the 2023-2025 period at a cost of \$36.457 million (nominal \$). SCE expects to complete this activity by the end of 2025.

⁹⁵ See WP SCE-07, Vol. 01, Authorized vs. Recorded.

(i) Scope and Cost Forecast

SCE estimates the tree attachment scope for the next three years is approximately 1,100 tree attachments. 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, anticipated to be completed in 2025. The forecast tree attachment remediation cost is \$36.457 million as shown below in Table I-21, which is derived by taking the product of the unit cost of \$31,151 (constant dollars) and quantity of 1,061 remaining tree attachments.⁹⁶ The cost-per-structure is calculated from the 2021 and 2022 recorded costs to reflect current market conditions for this type of work. The cost drivers are explained in the historical year-over-year analysis section above. SCE used 2021 and 2022 recorded costs because 2021 consisted of primary conductor work and 2022 included more tree attachment work at the secondary level, which is typically less complex (with relatively lower costs) than work at the primary level. SCE expects that tree attachment remediations in 2023 and beyond will consist of a mix of primaries and secondaries such that the selection of 2021 and 2022 recorded costs to derive unit costs is appropriate.

Table I-21
Tree Attachments Capital Forecast (Nominal \$000)⁹⁷

Tree Attachments (\$000)	2023	2024	2025
Units	500	500	61
Escalated Unit Costs	\$ 32.828	\$ 34.453	\$ 35.292
Total	\$ 16,414	\$ 17,226	\$ 2,153
Accounting Adjustments	\$ 282.75	\$ 257.13	\$ 122.98
Total Forecast	\$ 16,697	\$ 17,484	\$ 2,276

(d) RAMP Integration

Table I-22 below shows a RAMP and 2025 GRC comparison for the scope and total costs of tree attachment remediations. In 2022 SCE completed additional tree attachment remediations which resulted in the reduction of scope and dollars in 2025.

⁹⁶ The forecast incorporates accounting adjustments to reflect certain changes made to SCE's employee compensation program. Please refer to SCE-06, Vol. 04.

⁹⁷ Refer to WP SCE-04, Vol. 05, Part 2, pp. 43-44 –Tree Attachment Remediations Unit Cost Workpaper.

Table I-22
Tree Attachment Remediation
RAMP vs GRC Capital Forecast Comparison - (Nominal \$000)
Risk Spend Efficiencies⁹⁸

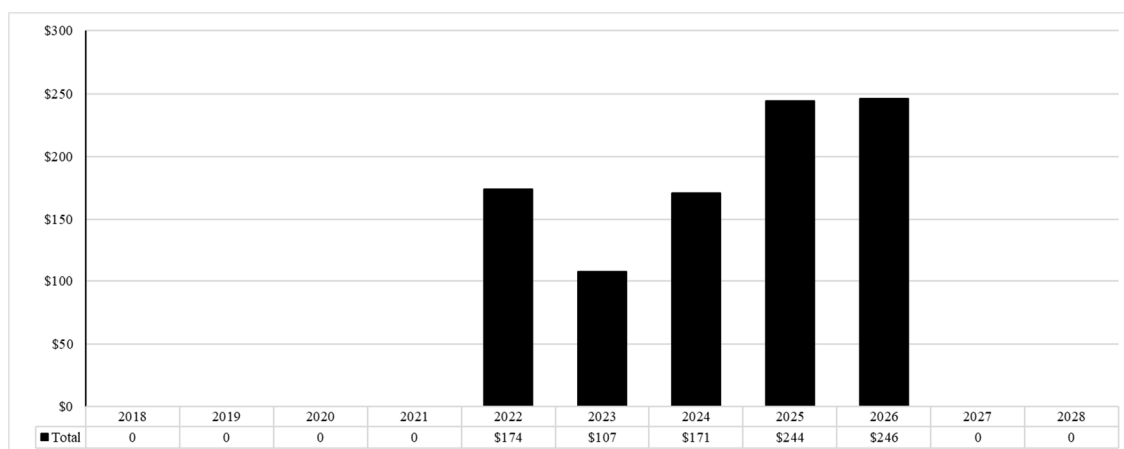
RAMP Risk	RAMP ID	RAMP Control / Mitigation Name	Filing	2022	2023	2024	2025	2026	2027	2028	Total 2025 - 2028	2025 - 2028 RSE
Wildfire	C6	Tree Attachment Remediation	RAMP	\$16,552	\$16,265	\$16,819	\$27,479	\$0	\$0	\$0	\$27,479	6,449
			GRC	\$16,835	\$16,697	\$17,484	\$10,570	\$0	\$0	\$0	\$10,570	878
			Variance	\$283	\$431	\$665	(\$16,909)	\$0	\$0	\$0	(\$16,909)	(5,571)

(3) Work Description & Need - Vibration Damper Retrofits

This section discusses SCE's funding request for vibration damper retrofits, which is summarized in Figure I-21 below. SCE plans to install vibration dampers on 2,644 structures at a total cost of \$769,000 (nominal) over the next four years, completing this program by the end of 2026.

⁹⁸ Refer to WP SCE-04, Vol. 05, Part 1 – WF/PSPS RAMP to GRC Integration.

Figure I-21
Vibration Damper Retrofits⁹⁹
CET-PD-WM-VD-822400
Recorded (2018 – 2022) / Forecast (2023 – 2028)
(Total Company – Nominal \$000)



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.¹⁰⁰ If this vibration is not mitigated, long-term degradation may reduce the covered conductor's useful life. The impacts will not occur immediately, but if left unmitigated, over time vibration can reduce the covered conductor's expected 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.¹⁰¹ The purpose of the study was to determine the level of Aeolian vibration on

⁹⁹ Refer to WP SCE-04, Vol. 05, Part 2, pp. 31-38 – Capital Detail by WBS Element for WCCP.

¹⁰⁰ 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 wire. If the areas differ, then there are cases where bare wire can be more susceptible to vibration 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 to vibration than covered conductor installed in a hilly terrain with plenty of trees.

¹⁰¹ Refer to WP SCE-04, Vol. 05, Part 2, pp. 45-46 – Vibration Susceptibility Study.

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. Based on the results of the field study and additional analysis, SCE concluded that vibration dampers on covered conductors that meet certain tension criteria mitigate wear and tear over the life of the conductor. In October 2020, SCE published vibration damper design and construction standards for future covered conductor installations.¹⁰²

SCE also evaluated the covered conductor installations constructed prior to the publication of the October 2020 vibration damper standards to assess their susceptibility to vibration. Previous installations were categorized into high-susceptibility, medium-susceptibility, or low-susceptibility areas.¹⁰³ SCE's analysis indicated that targeting high- and medium-susceptibility areas is most prudent because low-susceptibility areas are unlikely to experience Aeolian vibration.¹⁰⁴ 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

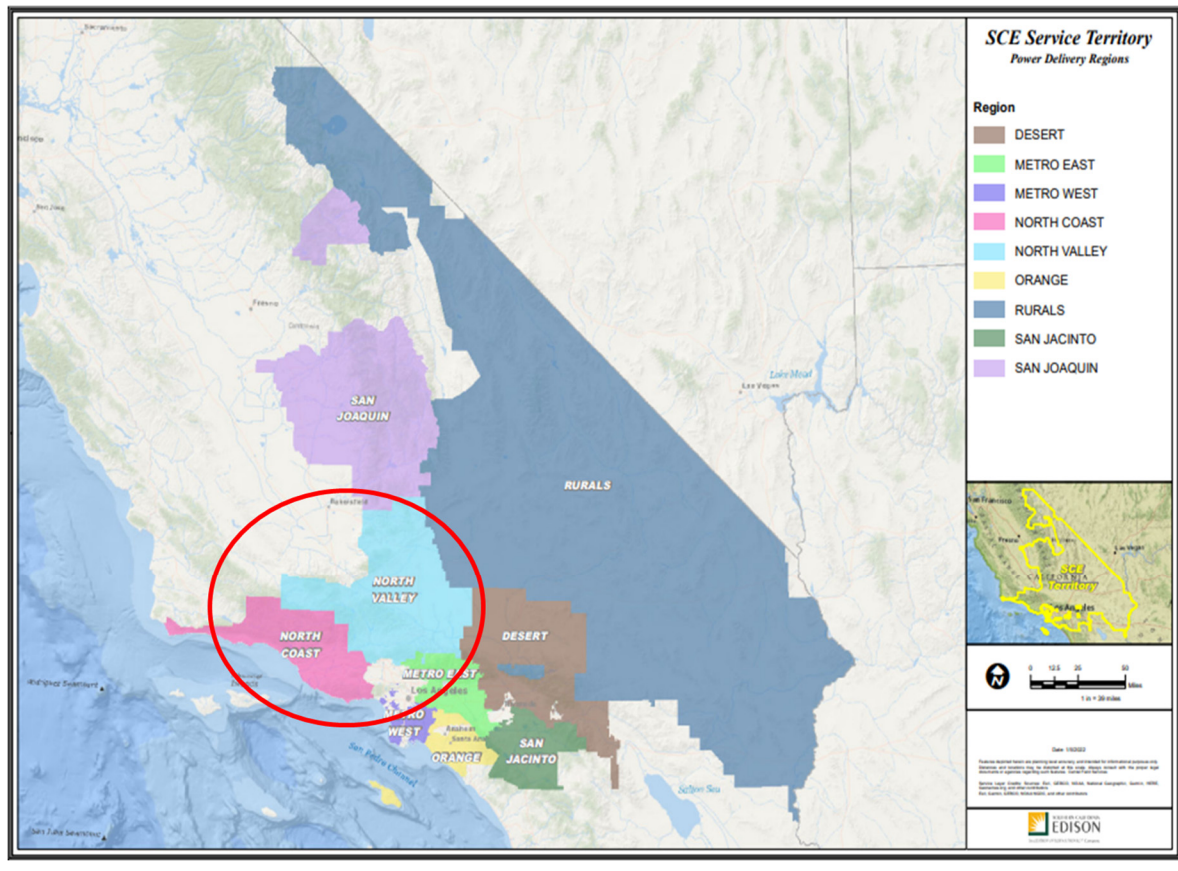
¹⁰² However, on May 18, 2021, SCE issued an interim deviation from standards on vibration damper for covered conductor due to the temporary shortage of dampers caused by the COVID-19 related supply constraints, labor issues, and shipping delays experienced by SCE's main vibration damper supplier. This 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 dampers are still required to be installed for the work locations that have inventory on hand.

¹⁰³ 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.

¹⁰⁴ Note that SCE only focused on installations that were considered light loading areas (i.e., 3,000 ft. and below in elevation), which is consistent with SCE's standard vibration damper installation requirements.

across SCE's HFRA, with the majority of the work focused in the North Coast and North Valley regions where susceptibility to Aeolian vibration is higher (see Figure I-22 below).¹⁰⁵

Figure I-22
SCE Service Area Regional Map - Highlighted North Coast & North Valley



SCE uses two types of vibration dampers as shown in Figure I-23 below: Stockbridge and Spiral, as they maintain the useful life of covered conductor. Stockbridge dampers are

¹⁰⁵ For new installations and if supply is available, SCE installs vibration dampers on full tension spans in areas that are 3,000 ft. and below in elevation. In areas above 3,000 ft. in elevation, SCE installs vibration dampers when the 336 (30/7) ACSR covered conductor is used or if vibration on the conductor is observed through inspections. Due to supply constraints caused by the global supply chain issue in 2021, SCE permitted an interim deviation from the standards that allows installation of covered conductor without dampers. SCE asked crews to self-report installations that followed this interim deviation and has tracked installations constructed as early as February 2021. SCE plans to perform another vibration susceptibility study at these locations for retrofit work.

used for covered conductor with a larger outer diameter whereas spiral dampers are used for covered conductor with a smaller outer diameter.¹⁰⁶

Figure I-23
Types of Vibration Dampers:
Stockbridge Damper (left) and Spiral Damper (right)



(a) Historical Variance Analysis

SCE performed the wind susceptibility analysis in 2020 to 2021 and identified approximately 2,800 structures in high and medium susceptibility areas that require a vibration damper retrofit. In light of resource constraints, SCE began retrofitting approximately 100 structures in 2022 at a cost of \$0.174 million.

(b) 2021 Authorized vs. Recorded

This activity was not included in SCE's 2021 GRC Track 1, therefore there were no 2021 authorized vs. recorded costs. SCE introduced this activity in its Track 4 application which was filed in May 2022.

(c) Capital Cost Forecast

(i) 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 I-23 shows the forecast scope of the vibration damper retrofit in these areas from 2023 to

¹⁰⁶ Spiral vibration dampers are not effective for larger-sized conductors.

2026. SCE is prioritizing structures in the riskiest vibration susceptibility areas and prioritizing structures with a lower theoretical useful life. SCE already completed 100 structures in 2022 and plans to complete approximately 2,700 structures in the next four years (2023-2026). SCE estimates the forecast cost of vibration damper retrofit for approximately 2,700 structures to be \$0.769 million. This estimate is based on a cost of \$260 per structure using 2022 recorded data.¹⁰⁷

Table I-23
Capital Expenditure Forecast for Vibration Damper Retrofit (Nominal \$000)¹⁰⁸

Vibration Dampers (\$000)	2023	2024	2025	2026
Units	392	594	829	829
Escalated Unit Costs	\$274	\$287	\$294	\$297
Total Forecast	\$ 107	\$ 171	\$ 244	\$ 246

(d) RAMP Integration

Table I-24 below shows a 2022 RAMP and 2025 GRC comparison for the scope and total costs for vibration damper retrofit. While the scope forecast in RAMP and the 2025 GRC are the same, the cost forecast used in RAMP was an estimate at that time whereas the cost forecast used in the 2025 GRC is based on 2022 recorded data.

¹⁰⁷ The forecast incorporates accounting adjustments to reflect certain changes made to SCE's employee compensation program. Please refer to Exhibit SCE-06, Vol. 04.

¹⁰⁸ Refer to WP SCE-04, Vol. 05, Part 2, pp. 47-48 –Vibration Dampers Unit Cost Workpaper.

Table I-24
Vibration Damper
RAMP vs GRC Capital Forecast Comparison - (Nominal \$000)
Risk Spend Efficiencies¹⁰⁹

RAMP Risk	RAMP ID	RAMP Control / Mitigation Name	Filing	2022	2023	2024	2025	2026	2027	2028	Total 2025 - 2028	2025 - 2028 RSE
Wildfire	M3	Vibration Damper	RAMP	\$108	\$369	\$555	\$839	\$856	\$0	\$0	\$1,695	106
			GRC	\$174	\$107	\$171	\$244	\$246	\$0	\$0	\$490	1,314
			Variance	\$66	(\$261)	(\$384)	(\$595)	(\$610)	\$0	\$0	(\$1,205)	1,208

(4) Work Description & Need - Fire-Resistant (FR) Wrap Retrofit – Distribution

As explained in the WCCP section above, prior to the installation of a covered conductor project, SCE performs pole-loading calculations (PLC) to determine if the pole can withstand the additional load of the covered conductor system. If the pole fails PLC, then SCE replaces the pole with a fire-resistant pole (FRP). If the FRP replacement is a fire-resistant wrapped pole, the electrical crews use a pole that is pre-wrapped by the manufacturer and no wrapping is performed on site. If the pole passes PLC, the pole remains a bare wood structure and will be updated over time to a fire-resistant structure, as needed through other programs per SCE’s engineering standards in HFRA. However, in 2024, SCE proposes to perform a pilot called Fire Resistant (FR) Wrap Retrofit to assess the feasibility of performing the wrap on site to proactively protect those bare wood structures that passed PLC instead of waiting to update the structures at a later time. This pilot is prompted by a simulation study which shows that if a wood dead-end¹¹⁰ or tangent¹¹¹ pole fails in a large fire, it can result in cascading failures such as the collapse of the adjacent poles/wires in a distribution line (if it is a tangent pole, then one on each side of the failed structure; if it is a dead-end pole, then on one side of the failed structure).

¹⁰⁹ Refer to WP SCE-04, Vol. 05, Part 1 – WF/PSPS RAMP to GRC Integration.

¹¹⁰ A dead-end pole is a pole that supports the end of a conductor run spanning multiple poles.

¹¹¹ A tangent pole supports the conductor in the middle of a conductor run.

Figure I-24
Dead-end Structure (left) and Tangent Structure (right)



Although wood poles themselves are generally not the source of ignition, dead-end and tangent structures carry significant amounts of weight and tension from supporting sections of overhead wire. Installing a FR wrap on dead-end and tangent poles can help the poles maintain structural integrity after a fire, which can prevent cascading failures of other poles, and shorten the restoration time. This pilot will focus on installing FR wraps on dead-end and tangent poles for the top riskiest circuits/circuit segments in HFRA that are located within areas experiencing the highest frequency of burns.¹¹²

(a) Historical Year-over-Year Analysis

This activity is new and thus not applicable for evaluation of historical variance.

(b) 2021 Authorized vs. Recorded

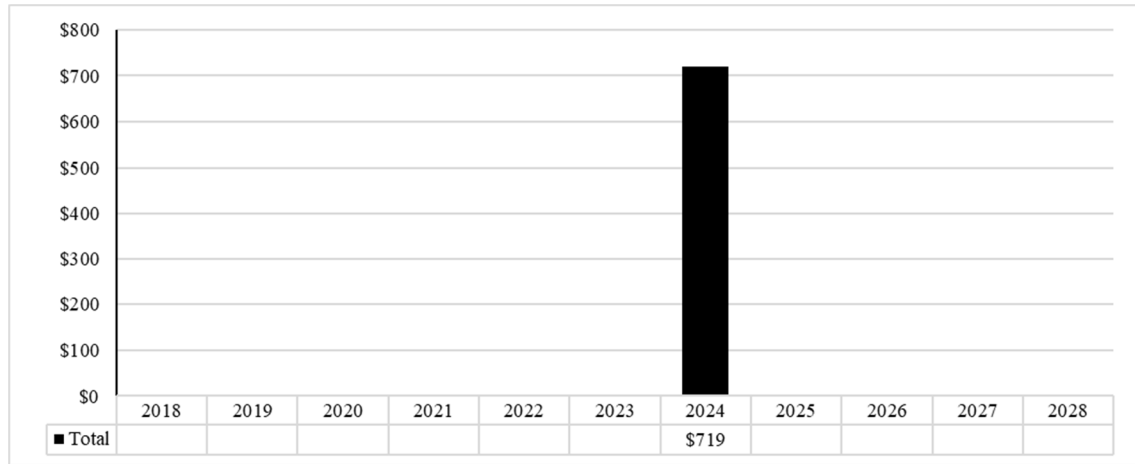
This activity is new and thus no authorized and recorded costs are available.

(c) Capital Cost Forecast

Figure I-25 below provides the capital expenditure forecast for Fire-Resistant (FR) Wrap Retrofits.

¹¹² Based on fire scar count in Severe Risk Areas.

Figure I-25
FR Wrap Retrofit of Dead-end Poles¹¹³
CET-PD-WM-FR-822400
Recorded (2018-2022) / Forecast (2023 -2028)
(Total Company – Nominal \$000)



(i) Scope and Cost Forecast

This work is estimated to cost \$0.719 million in 2024 at cost of \$1,809 per pole.¹¹⁴ The cost estimate for this activity was developed based on an assessment conducted by SCE to determine how long it would take a two-person electrical crew to install FR wrap. SCE forecasts the need to complete 325 poles in 2024.

e) Rapid Earth Fault Current Limiters

Rapid Earth Fault Current Limiter (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, thereby reducing the possibility of ignitions from faults. Between 2023 and 2028, SCE forecasts a cost of approximately \$240 million for REFCL projects, provided in Figure I-26.

¹¹³ Refer to WP SCE-04, Vol. 05, Part 2, pp. 31-38 – Capital Detail by WBS Element for WCCP.

¹¹⁴ Refer to WP SCE-04, Vol. 05, Part 2, pp. 49-50 – FR Wrap Retrofit Unit Cost Workpaper.

Figure I-26
Rapid Earth Fault Current Limiters (REFCL)¹¹⁵
CETPDWMDT822400, CETPDWMDT822401
Recorded (2018 – 2022) / Forecast (2023 – 2028)
(Total Company – Nominal \$000)

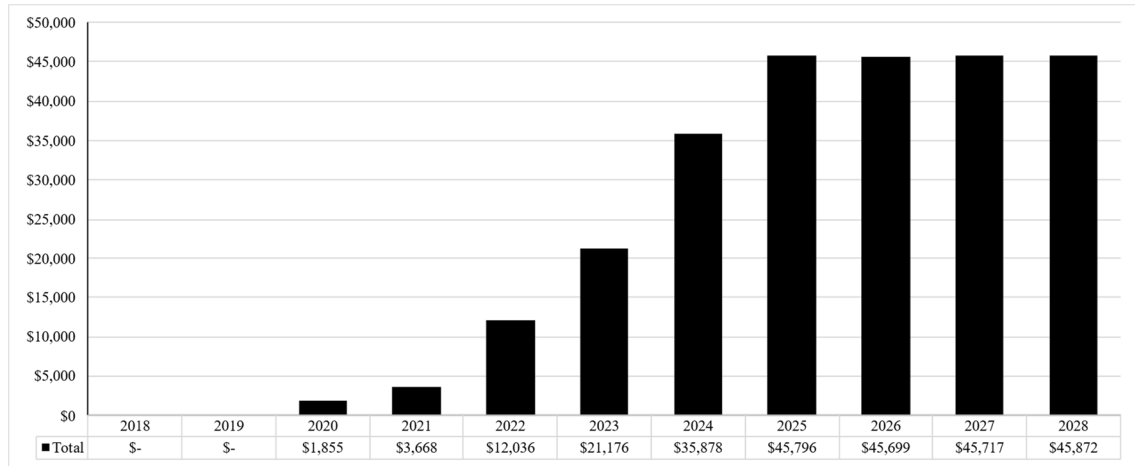


Table I-25
Rapid Earth Fault Current Limiters (REFCL)¹¹⁶
Forecast (2023 – 2028)
(O&M – Constant \$000)

		2025	2026	2027	2028	Total
Rapid Earth Fault Current Limiter	L	\$ -	\$ -	\$ -	\$ -	\$ -
Rapid Earth Fault Current Limiter	NL	\$ 501	\$ 745	\$ 882	\$ 1,012	\$ 3,140
Total		\$ 501	\$ 745	\$ 882	\$ 1,012	\$ 3,140
Test Year 2025 Normalized		L	\$ -			
		NL	\$ 785			
Normalized Total			\$ 785			

(1) Work Description & Need

REFCL devices can detect ground faults as small as a half ampere on one phase in a three-phase powerline. These devices almost instantly reduce the voltage on the faulted line while boosting the voltage on the two remaining phases to maintain service for customers while

¹¹⁵ Refer to WP SCE-04, Vol. 05, Part 2, pp. 51-54 – Capital Detail by WBS Element for Rapid Earth Fault Current Limiters.

¹¹⁶ Refer to WP SCE-04, Vol. 05, Part 2, pp. 55-61 – O&M Detail for Rapid Earth Fault Current Limiters.

1 extinguishing arcs. REFCL technology has been widely deployed in Europe and Asia for purposes of
2 improving reliability and reducing shock hazards, as well as in the Australian state of Victoria for the
3 purpose of wildfire mitigation.

4 A substantial number of public safety hazards from high-voltage electrical
5 equipment, including downed-wire incidents, energized-conductor contacts, events involving
6 underground equipment failures, arc flashes, and fire ignitions come from ground faults. REFCL
7 technology has been found to substantially reduce the energy released in ground faults, and therefore has
8 the potential to significantly reduce ignition risks.

9 If deployed with covered conductor, the risk reduction potential of REFCL
10 may be similar to that of undergrounding. In addition to SCE's own pilot work detailed below, testing
11 from the Australian state of Victoria showed that REFCL has a 90% chance of preventing an ignition
12 from a ground fault even if there is direct contact of energized conductor with dry grass or vegetation
13 (Figure I-27, below).¹¹⁷ Regulatory guidance has encouraged SCE and other California IOUs to
14 accelerate REFCL pilot programs, as they have provided promising initial results to address ignition risk
15 associated with vegetation contact and wire downs.¹¹⁸

16 As part of SCE's WMPs beginning in 2019, SCE evaluated the utility of
17 REFCL technologies to reduce fire ignition risks associated with the electric system. Multiple variations
18 of REFCL technologies were piloted to better understand how the available alternatives apply to the
19 wide variety of circuit designs on the SCE system. The diversity of SCE circuit types means that no
20 single variation can be cost-effectively applied across the entire system. For example, for large
21 substations feeding tens to hundreds of miles of high fire risk circuitry, Ground Fault Neutralizer
22 projects modeled on the Australian REFCL program may be a good choice. However, the Ground Fault
23 Neutralizer is neither economically feasible nor necessary for fire-risk reduction for smaller distribution

¹¹⁷ See Energy Safe Victoria's "REFCL Functional Performance Review" dated October 14, 2020
<https://www.esv.vic.gov.au/sites/default/files/2022-12/REFCL-Functional-Performance-Review.pdf>.

¹¹⁸ 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.

1 systems. For these smaller facilities, grounding conversion projects to either operate ungrounded or
2 resonant grounding can achieve a similar risk reduction at a much lower cost.

3 SCE utilizes two different forms of REFCL technology: (1) Ground Fault
4 Neutralizer (GFN) and (2) Grounding Conversions.

Figure I-27
Arcing from a Downed Power Line Test With (left) and Without REFCL (right)



5 The CPUC's Resolution to SCE's 2020 WMP directed SCE to develop
6 learnings from pilot REFCL installs. SCE created a detailed report on its REFCL pilot work with the
7 following four projects:¹¹⁹

- 8 1. An overhead isolation transformer installed in 2020 covering 2.5
9 miles of the Calstate 12kV circuit.
- 10 2. A GFN in Neenach substation installed in 2021 covering
11 approximately 170 miles of circuitry.
- 12 3. An ASC to resonant ground Arrowhead substation installed in
13 2021 covering 40 miles of circuitry.
- 14 4. A padmounted isolation transformer covering 12 miles of the
15 Stetson 12kV circuit in 2021.

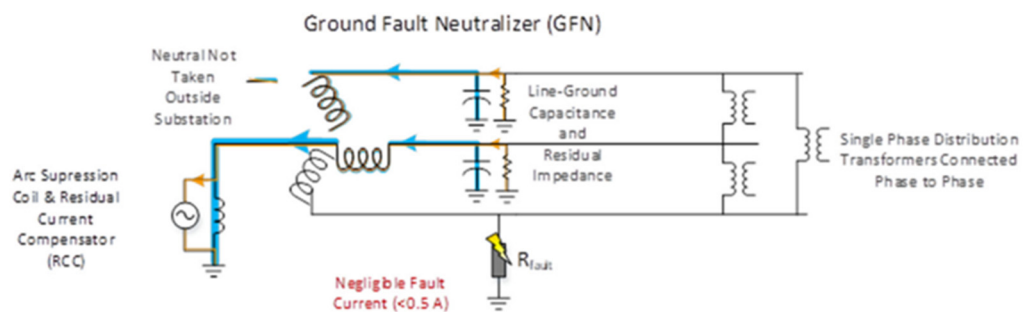
¹¹⁹ See Office of Energy Infrastructure Safety's "Final Evaluation of 2021 Wildfire Mitigation Plan Update Southern California Edison," dated August 18, 2021. p. 26. https://energysafety.ca.gov/wp-content/uploads/sce_2021wmp_finalactionstmt.pdf.

The pilot programs were designed to determine the feasibility of these technologies for wide-scale deployment on SCE's system. These pilots demonstrated the capability to increase the sensitivity to detect ground faults by more than a factor of 100 and reduce the energy release from ground faults by more than 99.9%. The pilots also helped refine the design requirements and standards development, which can be applied in further deployments. The details of each type of REFCL technology and associated benefits are discussed below.

(a) Ground Fault Neutralizer (GFN)

The most widely deployed variant of REFCL technology for wildfire application is the GFN, consisting of an ASC, which cancels out most of the fault current in parallel with a residual current compensator (RCC) inverter to cancel out the remaining fault current. This is the technology applied by Australian utility companies as part of their REFCL programs. Figure I-28 below shows a schematic of the GFN technology.

Figure I-28
Schematic of Ground Fault Neutralizer



SCE installed, tested, and put a GFN in service at one substation in 2021 in accordance with the plans submitted in SCE's 2020-2022 WMPs.¹²⁰ This GFN covers approximately 170 circuit miles. The GFN is the preferred REFCL design for large substations because those systems produce higher fault currents that require the additional inverter to limit the fault energy.

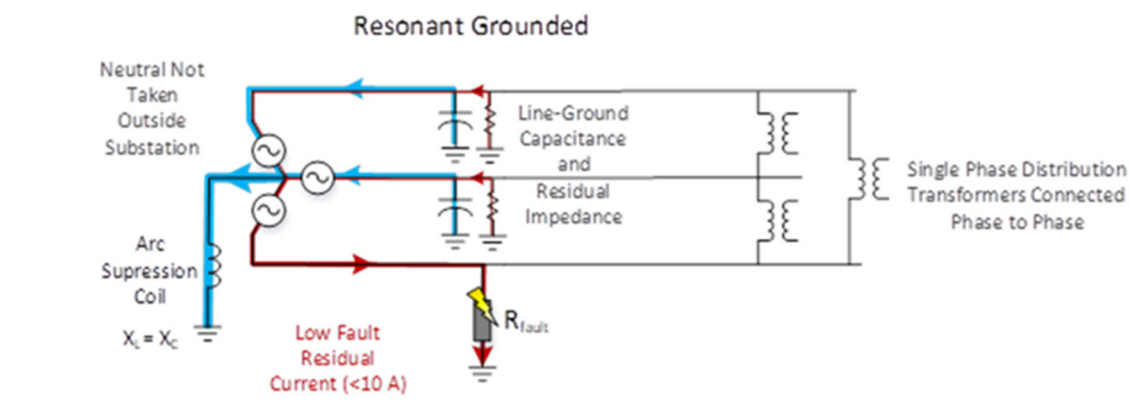
¹²⁰ SCE's 2020-2022 WMP, pp. 115-117.

The GFN at Neenach substation was commissioned in June 2021. This commissioning process included placing 45 ground faults on the system to confirm it was functioning as expected. This testing demonstrated both the expected increase in sensitivity to be able to detect half-ampere ground faults and the resulting reduction in energy release.

(b) Grounding Conversions

Changes to the electric system grounding is one of the key approaches for the application of REFCL technology. Grounding conversion projects typically transition from traditional solidly grounded systems to resonant and ungrounded systems, which reduce fault energy and increase fault detection sensitivity. Resonant grounding has been used by European utilities for reliability and safety benefits for many years. These grounding conversions, which are done by ungrounding a transformer neutral or installing an ASC, involve less equipment and fewer complexities compared to a GFN. However, the reduction in fault current is also less, only reaching the desired levels for ignition reduction if applied on small systems. Figure I-29 below shows a schematic of the resonant grounding technology.

Figure I-29
Resonant Grounding Schematic



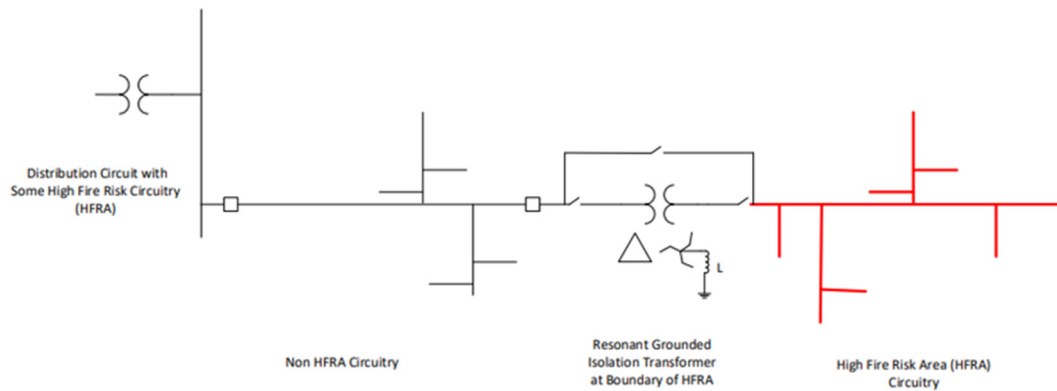
SCE expects to target this technology for use on small distribution systems. For the purposes of REFCL systems, the distinction between “large” and “small” substations primarily depends on the length of overhead and underground circuitry. The systems may be located at a

1 substation or could also be situated as a portion of a distribution circuit. Small substations would
2 typically use an ASC to achieve the resonant grounding conversions. Distribution circuit grounding
3 conversion applications require transformation at the grounding site. This is typically either
4 accomplished with small step-down transformer banks (e.g., 33/12kV transformer installations called
5 pole top installations), or with the use of isolation transformers where system voltage is the same on
6 both sides of the bank (e.g., 12kV/12kV). On these small systems, fault current can be reduced to meet
7 the same voltage reduction targets during a ground fault that the GFN achieves on larger systems. These
8 systems also often lack space for the additional equipment required for a GFN, making a grounding
9 conversion the best available practice.

10 In 2020, SCE initiated design for an ASC field installation to
11 convert a small substation in HFRA to resonant grounding. This design included substation site
12 selection, material specifications, development of operating policies, development of engineering design
13 documents and construction requirements, identification of industry vendors for ASC devices, and
14 development of remediations to expected challenges learned from Australian utility installations. SCE
15 installed, tested, and put the ASC in service at Arrowhead substation in 2021, which covers
16 approximately 40 circuit miles. In 2022, SCE monitored this installation, and made minor setting
17 changes based on equipment performance during ground faults.

18 Smaller systems can also be created by splitting off a few miles of
19 circuitry with an isolation transformer. This allows for targeting of REFCL technology to align with
20 HFRA circuitry, reducing costs related to conversion of the entire substation system, which may consist
21 of both HFRA and non-HFRA circuitry. Figure I-30 depicts an example of a resonant grounded system
22 with the use of an isolation transformer applied to serve the HFRA circuitry.

Figure I-30
Isolation Transformer Schematic



The use of ungrounded or resonant grounded isolation transformers in small systems has been shown to meet REFCL requirements. SCE determined, through testing¹²¹ and review of the Australian REFCL program, that the isolation transformer REFCL scheme is expected to reduce the probability of ignition from single phase-to-ground faults by at least 90%.¹²² The above Figure I-30 shows a schematic of the typical application for isolation transformer technology.

In 2020, SCE completed a pilot isolation transformer installation at one location and developed the operating practices and construction requirements associated with the application of these systems. The pilot allowed SCE to fine tune the hardware, and the transformer has continued to operate without experiencing any faults or encountering other issues. The initial installation applied an overhead isolation transformer for the REFCL grounding conversion. In 2021, a second pilot with a larger pad-mounted isolation transformer was developed and installed, increasing the amount of circuit loads which could be converted to the REFCL system. In 2022, SCE focused on optimizing the pad-mounted isolation transformer design and related resonant grounding conversion equipment for

¹²¹ SCE's engineers published a paper on the Institute of Electrical and Electronics Engineers (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. Additionally, U.S. Patent Number 11,398,725, titled "Circuit for reducing fire hazard risk in a power distribution network," covers this technology.

¹²² See SCE's 2021 WMP, p. 173.

deployment in future years. An additional grounding conversion project is scheduled to be completed in 2023. Additional engineering and design work will ramp-up in 2023 to support scope for future years.

(2) Historical Variance Analysis

REFCL Pilot Project:

SCE incurred \$1.855 million in capital expenditures during 2020 on the GFN pilot project at Neenach. 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 with capital expenditures totaling approximately \$3.668¹²³ million as shown in Table I-26.

Table I-26
Capital – Pilot Project (Nominal \$000)

REFCL Pilot Program	2020	2021
Recorded	\$1,855	\$3,668

In 2022, SCE spent \$11.972 million to procure all major equipment for Acton and Phelan substations. In addition, SCE began to install the foundation at Phelan substation and capacitive balancing units to stabilize the system, allowing for the increase in sensitivity for the REFCL system.

In 2022, SCE spent \$0.063 million to install an ASC at Stetson substation to be a resonant grounded system instead of an ungrounded system, bringing the fault current down.

¹²³ \$0.620 million and \$0.342 million for Early Fault Detection technology and High Impedance Relays, respectively, were erroneously attributed to the REFCL Pilot budget in 2021. These activities are discussed further in Exhibit SCE-04, Vol. 05, Part 3.

Table I-27
REFCL Projects – Capital Recorded (Nominal \$000)

Recorded	2022
Ground Fault Neutralizer	\$ 11,972
Grounding Conversions	\$ 63

(3) Comparison of Authorized 2021 to Recorded

This activity is new and thus no authorized and recorded costs are available.

(4) Scope Forecast

As described above, SCE has determined that REFCL has significant potential risk reduction benefits per dollar and plans to expand the deployment of REFCL technologies during the GRC period in an effort to continue to evaluate and understand construction and operational complexities. If REFCL continues to work and provide risk reduction benefits as anticipated, SCE is proposing to scale up its deployment of REFCL projects in a risk-informed manner. This expansion strikes a balance between the wildfire mitigation effectiveness of the technology and a measured deployment that allows SCE to validate the mitigation effectiveness assumptions and learn and develop best practices for installation and operation.

SCE is expanding its REFCL GFN program in 2023, focusing on installations at two substations. SCE will incorporate lessons learned from those projects to plan and forecast future projects. SCE has also initiated the engineering and material procurement for Ground Fault Neutralizers to be installed at Acton and Phelan Substations in 2023, which will cover 675 miles of circuitry and at Banducci and Del Sur Substations in 2024, which will cover 475 miles of circuitry. By the end of the GRC period in 2028, SCE seeks to have installed REFCL protections to cover 20% of HFRA (approximately 2,000 miles) with REFCL GFN technology. This assumes four installations per year over the GRC period, with a total of 21 stations to be completed by the end of 2028. While the miles covered for each station will vary, SCE estimates an average of approximately 100 miles of HFRA are protected per station.

1 SCE assumes completing six grounding conversion installations per year
2 of the GRC period, with a total of 33 locations to be completed by the end of 2028. While the miles
3 protected per location will vary, SCE estimates an average of approximately 8 miles of HFRA are
4 protected per location.

5 (a) Basis of O&M Forecast

6 REFCL drops voltage when a phase-to-ground fault occurs so the
7 current is lowered, thereby reducing the possibility of ignitions. When these events occur, the GFNs act
8 to prevent consequences. However, crews are called to investigate the cause of the event, remediate the
9 event, and/or reset or rebalance settings of equipment. SCE requests \$0.785 million (normalized) in Test
10 Year 2025, as shown in Table I-28 below. Distribution includes pole top, grounding, and isolation bank-
11 related work. The substation share includes GFN-related work. SCE anticipates costs to increase from
12 this investigation and remediation activity as more equipment will be deployed each year. Table I-28
13 forecasts are current estimates from SCE's engineering teams and will be further refined as SCE gains
14 experience with REFCL.

Table I-28
REFCL O&M Forecast (2023 -2028)
(Constant 2022 \$000)^{124, 125, 126}

		2023	2024	2025	2026	2027	2028	Total
Rapid Earth Fault Current Limiter	L	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Rapid Earth Fault Current Limiter	NL	\$ 250	\$ 351	\$ 501	\$ 745	\$ 882	\$ 1,012	\$ 3,140
Total		\$ 250	\$ 351	\$ 501	\$ 745	\$ 882	\$ 1,012	\$ 3,140
Test Year 2025 Normalized	L	\$ -						
	NL	\$ 785						
Normalized Total		\$ 785						

(b) Basis of Capital Forecast

SCE requests a total of approximately \$240 million for REFCL capital upgrades between 2023 and 2028. SCE’s capital forecast for REFCL projects reflects SCE’s plans for a measured deployment of REFCL as a wildfire mitigation technology while SCE continues to validate the technology’s mitigation effectiveness.

As shown below in Table I-29, SCE requests approximately \$211 million in capital for 21 GFN projects. Costs per project can vary between approximately \$5 million and \$25 million per substation due to a number of variables, including the scope and complexity of each project, land availability, material availability, and related expenses. Although the scope and complexity of REFCL projects can vary widely, SCE’s forecast is based on a conservative estimate of \$10 million per GFN project between 2023 and 2028. In 2023, SCE plans to complete GFN installations at the Acton and Phelan substations. SCE has also determined the Del Sur and Banducci substations will be engineered and materials will be procured for installation in 2024. SCE’s estimate of approximately \$40 million per year to complete four GFN projects per year is based on an estimate of approximately \$10 million in costs per project. Each year, SCE will incur costs for the construction of stations as well as

¹²⁴ An error was identified subsequent to the finalization of financial data. Therefore, the intended financial number that is stated here in testimony does not align with the financial numbers in standardized workpapers and the RO model. An errata will be submitted to align the financial numbers in testimony, standardized workpapers, and the RO model at a future date.

¹²⁵ SCE assumes distribution and substation related work each account for 50% of the total forecast.

¹²⁶ Refer to WP SCE-04 Vol. 05, Part 2, pp. 62-63 –Rapid Earth Fault Current Limiters O&M Cost Forecast.

advanced planning and material procurement for future projects. SCE estimates incurring \$6 million in construction costs and \$4 million for engineering work and material procurement for each project.

Table I-29
Ground Fault Neutralizer¹²⁷
CETPDWMDT822400
Forecast (2023 – 2028)
(Total Company – Nominal \$000)¹²⁸

Capital - GFN	2023	2024	2025	2026	2027	2028
REFCL GFN Units	2	3	4	4	4	4
REFCL GFN Capital	\$ 20,000	\$ 30,000	\$ 40,000	\$ 40,000	\$ 40,000	\$ 40,000
Accounting Adjustments	\$ 152	\$ 164	\$ 90	\$ (1)	\$ 16	\$ 162
Total Forecast	\$ 20,152	\$ 30,164	\$ 40,090	\$ 39,999	\$ 40,016	\$ 40,162

As shown below in Table I-30, SCE requests a total of \$29.556 million in capital for 31 Grounding Conversion projects between 2023 and 2028. SCE estimates a weighted-average project cost of approximately \$0.95 million per unit based on the costs of isolation bank transformers and pole-top grounding. Isolation bank transformers are estimated to cost approximately \$1.075 million each, and pole-top grounding conversion projects are estimated to have a base unit cost of \$0.32 million. The difference in costs for each is largely due to the need to acquire land and complete pad mount construction for isolation transformers, where pole-top installations can utilize existing poles and generally requires a smaller ground-based footprint.

¹²⁷ Refer to WP SCE-04, Vol. 05, Part 2, pp. 64-65 – Rapid Earth Fault Current Limiters Unit Cost Workpaper.

¹²⁸ The forecast incorporates accounting adjustments to reflect certain changes made to SCE's employee compensation program. See Exhibit SCE-06, Vol. 04.

Table I-30
Grounding Conversions¹²⁹
CETPDWMDT822401
Forecast (2023 – 2028)
(Total Company – Nominal \$000)¹³⁰

CAPITAL - Grounding Conversions (\$000)	2023	2024	2025	2026	2027	2028
REFCL Grounding Conversion Units	1	6	6	6	6	6
REFCL GC Capital	\$ 1,075	\$ 5,695	\$ 5,695	\$ 5,695	\$ 5,695	\$ 5,695
Accounting Adjustments	\$ (51)	\$ 19	\$ 11	\$ 5	\$ 6	\$ 16
Total Forecast	\$ 1,024	\$ 5,714	\$ 5,706	\$ 5,700	\$ 5,701	\$ 5,711

SCE has developed these capital cost forecasts using a bottoms-up analysis of time, labor rates, equipment, and land cost assumptions. The main drivers of potential cost variances for both GFN and Grounding Conversions include the ability for SCE to acquire land for the required equipment installations, and material and equipment availability, which SCE has experienced delays with in 2022.

(c) RAMP Integration

As noted in Table I-31 below, SCE had previously forecast \$204.688 million for a total of 2,900 *total* circuit miles in its RAMP for the 2025 to 2028 period. At the time, this assumed each GFN project would cover approximately 175 miles of HFRA and non-HFRA circuitry. SCE's revised forecast is approximately \$183 million, to cover approximately 2,000 *HFRA* circuit miles as described above. This is due to SCE's updated estimates based on more recent experience with REFCL.

¹²⁹ Refer to WP SCE-04, Vol. 05, Part 2, pp. 51-54 – Capital Detail by WBS Element for Rapid Earth Fault Current Limiters.

¹³⁰ The forecast incorporates accounting adjustments to reflect certain changes made to SCE's employee compensation program. *See* Exhibit SCE-06, Vol. 04.

Table I-31
REFCL
RAMP vs GRC Capital Forecast Comparison - (Nominal \$000)
Risk Spend Efficiencies¹³¹

RAMP Risk	RAMP ID	RAMP Control / Mitigation Name	Filing	2022	2023	2024	2025	2026	2027	2028	Total 2025 - 2028	2025 - 2028 RSE
Wildfire	M2	Rapid Earth Fault Current Limiter	RAMP	\$10,596	\$23,917	\$28,836	\$49,523	\$50,585	\$51,676	\$52,904	\$204,688	13,483
			GRC	\$12,035	\$21,176	\$35,878	\$45,796	\$45,699	\$45,717	\$45,872	\$183,084	20,708
			Variance	\$1,439	(\$2,741)	\$7,042	(\$3,727)	(\$4,886)	(\$5,960)	(\$7,031)	(\$21,604)	7,225

f) HFRA Sectionalizing Devices

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 for various benefits, including to mitigate fault-related ignition risks and minimize customer outages.¹³² The Sectionalizing Devices activity also includes performing upgrades to Circuit Breaker (CB) relay hardware to accommodate Fast Curve (FC) Settings, which reduce fault energy by increasing the speed with which a relay reacts to most fault currents. Fast Curve settings were initially installed in 2018 to provide fast operation on high-risk circuits. Since then, SCE’s strategy has been further refined to provide for more sensitive pickup operation. This provides for a greater amount of circuit miles protected by FCs, along with installation of strategically placed RARs and fuses to improve circuit reliability. In some cases, adding strategically placed RARs allows for upstream devices to not enable FC, improving the customer experience by reducing the number of customers impacted by an outage when a fault occurs. SCE’s efforts to evaluate and update settings along with deploying additional devices allows for quicker operation of circuit protection when enabled. SCE’s program to enhance setting sensitivity and install additional devices will be completed after detailed engineering reviews determine the appropriate setting levels and location of devices to reduce customer overall impacts.

¹³¹ Refer to WP SCE-04, Vol. 05, Part 1 – WF/PSPS RAMP to GRC Integration.

¹³² HFRA Sectionalizing devices also includes Vertical Switches, which have a cost of approximately \$0.530 million in 2023.

Figure I-31
HFRA Sectionalizing Devices
CETPDGRARMTECOV
Recorded (2018 – 2022) / Forecast (2023 – 2028)¹³³
(Total Company – Nominal \$000)

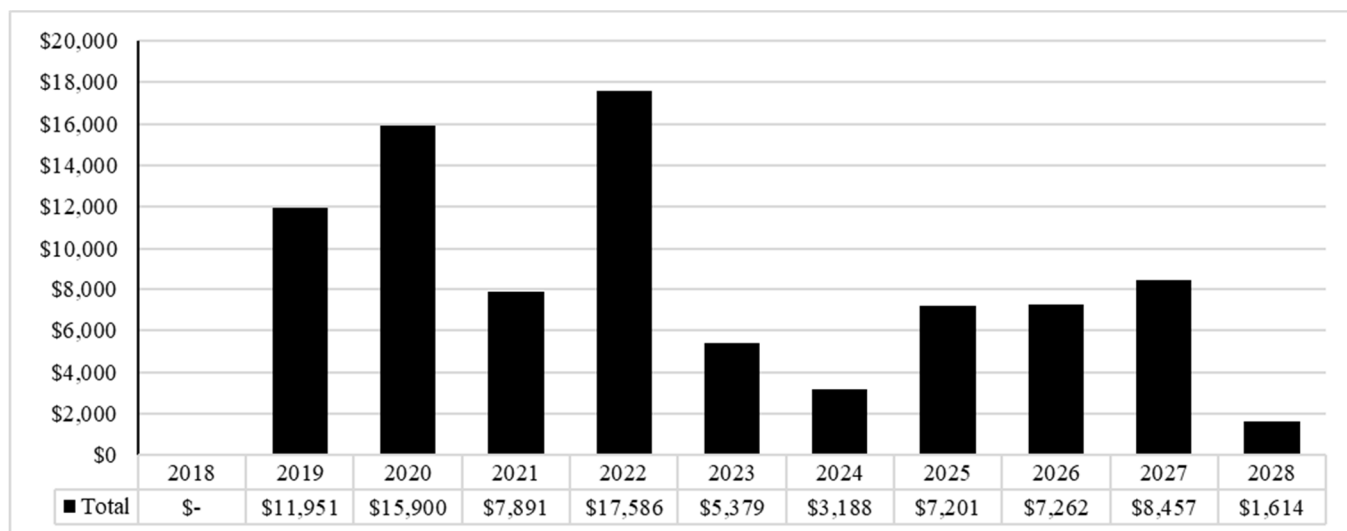


Table I-32
RAR & CB Relay Fast Curve Settings¹³⁴
Forecast (2023 – 2028)¹³⁵
(O&M – Constant 2022 \$000)

		2023	2024	2025	2026	2027	2028
RAR & CB Relay Fast Curve Settings	L	\$ 2,286	\$ 1,542	\$ 1,723	\$ -	\$ -	\$ -
RAR & CB Relay Fast Curve Settings	NL	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total		\$ 2,286	\$ 1,542	\$ 1,723	\$ -	\$ -	\$ -
Test Year 2025 Normalized	L	\$ 431					
	NL	\$ -					
Normalized Total		\$ 431					

(1) Work Description & Need

Distribution circuits span many miles and can cross multiple risk consequence zones, contain assets at various levels of resiliency, and are subject to varying weather

¹³³ Refer to WP SCE-04, Vol. 05, Part 2, pp. 66-68 – Capital Detail by WBS Elements for HFRA Sectionalizing Devices.

1 conditions based on specific asset locations. During PSPS events, portions of circuits or circuit segments
2 that have reduced ignition risks also have to be de-energized along with portions that present ignition
3 risks if there is no available means of isolating these segments from each other. Having manual switches
4 to segment circuits increases the time and resources needed for de-energization, testing, and re-
5 energization. The remote-control capabilities associated with RARs and RCSs are necessary to enable
6 SCE to quickly respond to emergent fire danger conditions to reduce ignition driver risks and minimize
7 the impacts of PSPS events. A RAR device and RCS device are similar in that they can remotely
8 segment circuits, but a RAR device also includes the capability to automatically detect and respond to
9 faults, or an electrical disturbance in the power system accompanied by a sudden increase in current

10 A CB relay is a device designed to trip a circuit breaker when it detects a
11 fault. The CB then interrupts the current flow, cutting off the power supply to minimize damage to the
12 circuit. In 2018 SCE deployed FC settings at substation CB relays and RARs. Relays with conventional
13 settings take a certain amount of time to detect and respond to a fault while FC settings increase the
14 speed in which the relay detects and responds to a fault. Some HFRA circuits have older style
15 electromechanical CB relays which are incapable of enabling these enhanced FC settings. To reduce
16 ignition risk, SCE has actively been upgrading outdated electromechanical relays with new
17 microprocessor relays to enable FC settings for the remaining HFRA feeder circuits.

18 These sectionalizing assets assist SCE in four important ways:¹³⁶

- 19 1. Public Safety Power Shutoff (PSPS) – When SCE proactively de-
20 energizes circuitry due to elevated fire conditions, SCE will be able to
21 utilize sectionalizing devices (RARs and RCSs) to further limit the
22 number of customers impacted;

¹³⁴ An error was identified subsequent to the finalization of financial data. Therefore, the intended financial number that is stated here in testimony does not align with the financial numbers in standardized workpapers and the RO model. An errata will be submitted to align the financial numbers in testimony, standardized workpapers, and the RO model at a future date.

¹³⁵ Refer to WP SCE-04, Vol. 05, Part 2, pp. 69-75 – O&M Detail by WBS Element for HFRA Sectionalizing Devices.

¹³⁶ RCSs do not interrupt faults and therefore do not provide benefits (2) through (4).

2. Fault Interruptions - RARs will be applied to automatically interrupt faults increasing fault detection sensitivity on the HFRA circuit and will minimize the amount of circuitry, and thereby customers, de-energized;
3. Targeted Fast Curve Enablement - during Red Flag Warnings and other elevated fire danger conditions, selected RARs and CBs will have their Fast Curves remotely enabled to operate with Fast Curve Settings, thereby isolating many faults faster, reducing fault energy, and ignition risks; and
4. Reclose Relay Blocking - permits SCE to remotely block automatic reclosing of RARs and CBs in SCE's HFRA during Red Flag Warnings and other elevated fire danger conditions while permitting reclosing in non-HFRA, thus enabling a lesser degree of outages and public impacts in the event of a fault.

The remote-control capabilities associated with RARs, RCSs, and replacement of relays and associated equipment to enable group control are necessary to allow SCE to quickly respond to emergent fire danger conditions. Without the remote-control capabilities, a field employee would be required to manually toggle settings at the physical location of each device every time conditions warrant such action, which would reduce SCE's ability to quickly activate these settings when needed. Additionally, due to the large number of devices that may potentially be enabled at a given time, the group control capabilities enable SCE operators to quickly activate the desired protection settings. 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.

SCE continues to perform circuit evaluation for PSPS-driven grid hardening work after PSPS events. These post-PSPS evaluations are used to develop targeted plans for grid hardening and circuit modifications to reduce PSPS impact. These ongoing evaluations may result

in the installation of HFRA sectionalizing devices or settings to reduce the PSPS frequency, duration, and the number of customers impacted. With the completion of these evaluations, SCE can determine the appropriate scope for this activity. Adding these automated sectionalization devices helps SCE limit PSPS de-energization to fewer and smaller circuit segments. In addition to minimizing the effects of PSPS events, RARs also minimize outage impacts to customers by isolating or restoring power quickly to circuit segments not impacted by weather conditions. Where fault interruption is not required, lower cost RCS devices are scoped to provide customer electric service benefits associated with PSPS.

(2) Historical Variance Analysis

As shown below Table I-33 in SCE spent \$3.177 million and \$0.484 million updating device settings for 807 devices and 156 devices in 2018 and 2019, respectively.

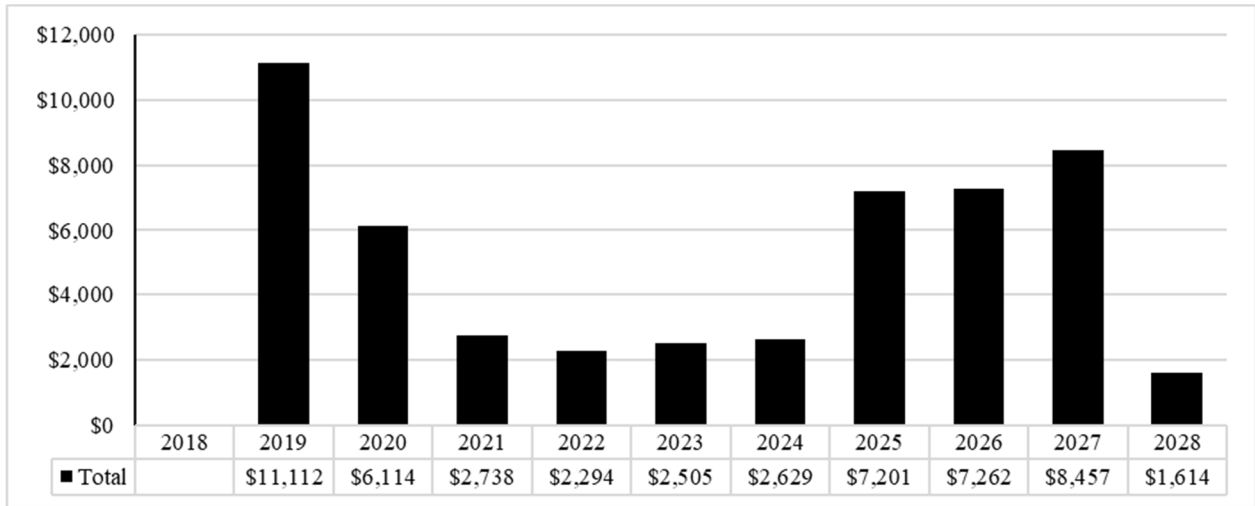
***Table I-33
RAR and CB Fast Curve Settings
Recorded (2018-2022) O&M
(Constant 2022 \$000)¹³⁷***

	2018	2019	2020	2021	2022
CB Fast Curve Settings Enhance	\$ 3,177	\$ 484	\$ (20)	\$ 14	\$ 1,027
Units	807	156	0	0	413

In 2019, SCE installed 71 new RAR devices at a cost of \$11.1 million in capital. In 2020, SCE installed 49 new RAR and RCS devices with a capital cost of \$6.1 million. In 2021, SCE installed 23 new RAR and RCS devices at a cost of \$2.7 million. In 2022, SCE installed 17 RAR and RCS devices at a capital cost of \$2.3 million.

¹³⁷ Negative charges in 2020 are reflective of an accounting accrual adjustment for charges expected to close in 2019, but did not, thus the reversal. SCE determined charges for 2021 should be considered erroneous and will work to appropriately categorize.

Figure I-32
HFRA Sectionalizing Devices¹³⁸
CETPDGRARMTECOV
Recorded (2018 – 2022) / Forecast (2023 – 2028)
(Total Company – Nominal \$000)



The decreasing number of RAR replacements between 2019 and 2022 was due to the desire to quickly deploy RARs in early years to achieve the overall circuit protection benefits described above. Approximately 33% of SCE’s 2022 scope targeted the remaining top 25% riskiest circuits compared to 2021. By the end of 2022, 76% of the remaining top 25% riskiest circuits were addressed. The top 25% riskiest circuits relate to the program circuit risk rankings based on probability of ignitions and potential consequences.

In 2019, SCE developed plans for CB Relay updates at a cost of \$0.838 million in capital. In 2020, 109 CB relay units were installed with a cost of \$9.8 million. In 2021, 95 relay units were replaced costing \$5.2 million. In 2022, SCE installed 117 new CB Relays at a cost of \$15.1 million. The annual costs also include design and planning costs for deployment the following year with costs in 2022 accounting for planning and design for years 2023 and 2024. Costs in 2022 are also higher as projects from 2021 may have closed worked orders in 2022.

¹³⁸ Refer to WP SCE-04, Vol. 05, Part 2, pp. 66-68 – Capital Detail by WBS Element for HFRA Sectionalizing Devices.

Table I-34
Historical Capital (Nominal \$000)

	2019	2020	2021	2022
CB Relay & Hardware	\$ 839	\$ 9,786	\$ 5,153	\$ 15,292
Units	-	109	95	117

The total historical capital for all HFRA between RAR and CB hardware from above is as follows:

Table I-35
Total HFRA Historical Capital (Nominal \$000)

	2019	2020	2021	2022
CB Relay & Hardware	\$ 839	\$ 9,786	\$ 5,153	\$ 15,292
New RARs	\$ 11,112	\$ 6,114	\$ 2,738	\$ 2,294
Total	\$ 11,951	\$ 15,900	\$ 7,891	\$ 17,586

(3) Comparison of Authorized 2021 to Recorded

Prior to 2021, SCE targeted updates to circuits serving HFRA that had CBs with existing microprocessor-based relays. These activities concentrated on relay settings-only updates and not relay hardware replacements, which are most costly to complete. In 2021, SCE upgraded hardware on 95 circuits, which allowed FC settings to be programmed. By upgrading the hardware to provide FC settings, SCE's system was able to increase the speed in which the relay detects and responds to a fault, further reducing the probability of ignition. As part of the 95 circuits in 2021, SCE installed 23 RAR/RCS devices on 15 HFRA circuits at a cost of \$2.738 million. These devices enable more granular operational capability at the circuit segment level and allows for higher windspeed thresholds for calling PSPS events on those segments where covered conductor has been fully installed on an isolatable portion of a circuit, even if other segments of a circuit still contain bare overhead conductor. This activity was part of SCE's expedited grid hardening effort explained in the 2020 PSPS Action Plan.

SCE was authorized \$5.33 million for CB relay hardware and spent \$5.15 million, a difference of \$0.18 million. However, SCE increased the number of units from 34 to 95 units installed in an effort to expand coverage.

Table I-36
2021 Recorded vs Authorized Capital (Nominal \$000)¹³⁹

New CB Relay Hardware	Spend	Units
Recorded	\$ 5,153	95
Authorized	\$ 5,334	34
Variance	\$ (181)	61

(4) Scope Forecast

SCE breaks this work into three activity categories:

1. Updating settings
2. New RAR and RCS devices
3. New CB Relay devices

Approximately 900 circuits have been set with the original FC settings strategy since 2018. One hundred of the highest risk circuits were reviewed and reset with the enhanced FC settings in 2022. The strategy is to review and implement the new FC settings on the remaining 800 circuits between 2023 and 2026. SCE forecasts the 800 remaining circuits will total 2,484 devices that require setting enhancements. The work will consist of circuit reviews and settings updates starting in 2023 and concluding in 2025. With approximately three protective devices per circuit, approximately 300-500 CB and RAR devices will be enhanced with updated settings per year with the assumed breakdown below. SCE plans to replace older relay equipment with newer equipment capable of utilizing FC settings. This program plans to add new CB relays to 84 circuits by 2024, 79 in 2023 and 5 in 2024. These 84 “New CB Relay Setting Installations” would be the first time FC programing would be installed on relay devices, while “setting enhancements” are updates to the programing of CBs and RARs that have older fast curve settings that are determined to be outdated.

¹³⁹ Refer to WP SCE-07, Vol. 01, Authorized vs. Recorded.

Table I-37
Settings Upgrades Forecast O&M Units

Units	2023	2024	2025
New CB Relay Setting Installation	79	5	-
CB Relay Setting Enhancements	312	437	499
RAR Setting Enhancements	288	403	461
Total	679	845	960

RARs and RCSs are located on distribution lines and are sectionalization devices that help SCE limit PSPS de-energization to fewer and smaller circuit segments. SCE has traditionally installed automation equipment to improve reliability and provide operational flexibility and has expanded its distribution automation activities as part of wildfire and PSPS mitigation strategy. SCE estimates 20% of the circuit devices scoped for setting enhancements will require new RAR devices, which can accommodate new settings. SCE anticipates completing 10 per year in 2023 and 2024 as SCE requires time to ramp up replacement efforts. In 2025 and 2026, SCE plans to replace 50 devices and plans to replace 60 devices in 2027.

In addition, due to previous year PSPS activities, SCE plans to add additional devices to limit future PSPS events. In total, between 2023 and 2028, SCE forecasts the need to install 282 of these units, inclusive of the 180 “RARs for Enhanced Settings,” described above. Those with the ‘PSPS’ note are new units assumed to be scoped based on circuit evaluation after PSPS events from 2021 and 2022- approximately 4 to 7 devices per year depending on the equipment type. This forecast is for PSPS-driven projects based on circuit evaluations after PSPS events from 2021 and 2022. If after PSPS events it was determined switches could have reduced the number of customers impacted by an outage, SCE proposes to install RAR and RCS devices.

Table I-38
Number of New RAR & RCS Capital Units

	2023	2024	2025	2026	2027	2028
RARs (For Enhanced Settings)	10	10	50	50	60	0
RARs (PSPS)	6	6	6	6	6	6
OH RCSs (PSPS)	7	7	7	7	7	7
UG RCSs (PSPS)	4	4	4	4	4	4

SCE initiated a program to deploy Fast Curve (FC) settings at substation CB relays and developed a plan for upgrading non-compatible and/or older vintage electrochemical and microprocessor relays for HFRA feeder circuits between 2020-2022. The program calls for the installation of Substation microprocessor relays and RTU equipment, and relay settings updates and assists in the coordination of planned outages and planning around any environmental challenges. Between 2023 and 2024, SCE plans to install a total of 32 new Capital relay units, 27 in 2023 and 5 in 2024, which can accommodate new FC settings. This is in addition to the 84” New Relay Settings” resulting in a total of 116 impacted relays.

***Table I-39
Number of New Relay Capital Units***

	2023	2024
Relay Units	27	5

(a) Basis of O&M Forecast

As shown in Table I-37 above, SCE forecasts 679, 845, and 960 units of new CB relay upgrades for 2023, 2024, and 2025, respectively for an overall total of 2,484 devices to cover all HFRA circuits. SCE estimates a unit cost of \$16,000 for each new CB Relay Setting using the average cost of these projects between 2020 and 2022, bringing the forecast to \$1.264 million in 2023 and \$0.08 million in 2024. SCE estimates a unit cost of approximately \$1,700 for CB Relay Setting Enhancements and \$1500 for RAR Setting Enhancements.¹⁴⁰ The combined forecast for RAR and CB Setting Enhancements are \$0.960 million in 2023, \$1.344 million in 2024, and \$1.536 million in 2025. See Table I-40 and Table I-41 below for an overall O&M forecast summary for HFRA Sectionalizing Setting Enhancements.

¹⁴⁰ Both unit costs were derived from an analysis of labor time and cost. The CB Relay enhancement unit cost is the sum of protection engineering labor and substation test labor. The RAR enhancement unit cost is the sum of protection engineering labor, distribution automation labor and apparatus labor.

Table I-40
RAR & CB Relay Setting Enhancements Breakdown O&M¹⁴¹
 (Constant 2022 \$000)

	2023	2024	2025
New CB Relay Setting Installations	\$ 1,264	\$ 80	\$ -
CB Relay Setting Enhancements	\$ 530	\$ 743	\$ 848
RAR Setting Enhancements	\$ 430	\$ 601	\$ 688
Subtotal (Constant \$000)	\$ 2,224	\$ 1,424	\$ 1,536
Forecast Adjustments	\$ 62	\$ 118	\$ 187
Total Forecast (Constant \$000)	\$ 2,286	\$ 1,542	\$ 1,723

Table I-41
HFRA Sectionalizing Setting Enhancements O&M
 Setting Enhancement Forecast Costs (Constant 2022 \$000)^{142, 143}

		2023	2024	2025	2026	2027	2028
RAR & CB Relay Fast Curve Settings	L	\$ 2,286	\$ 1,542	\$ 1,723	\$ -	\$ -	\$ -
RAR & CB Relay Fast Curve Settings	NL	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total		\$ 2,286	\$ 1,542	\$ 1,723	\$ -	\$ -	\$ -
Test Year 2025 Normalized	L	\$ 431					
	NL	\$ -					
Normalized Total		\$ 431					

(b) Basis of Capital Forecast

Between 2023 and 2028, SCE forecasts the need to install new additional RAR and RCS units at 282 locations at a total cost of \$29.7 million.

¹⁴¹ The forecast incorporates accounting adjustments to reflect certain changes made to SCE's employee compensation program. See Exhibit SCE-06, Vol. 04.

¹⁴² Refer to WP SCE-04, Vol. 05, Part 2, pp. 69-75 – O&M Detail for HFRA Sectionalizing Devices.

¹⁴³ SCE is not forecasting any O&M expenses in 2026 – 2028 for RAR & CB Relay Setting Enhancements. Therefore, SCE is normalizing the test year 2025 forecast as shown in Table I-41.

Table I-42
Number of New RAR & RCS Units (Nominal \$000)¹⁴⁴

	2023	2024	2025	2026	2027	2028
RARs - Enhanced Settings	\$1,048	\$1,100	\$5,634	\$5,682	\$6,866	-
RARs (PSPS)	\$629	\$696	\$788	\$900	\$1,036	\$1,209
OH RCSs (PSPS)	\$372	\$391	\$400	\$404	\$406	\$412
UG RCSs (PSPS)	\$456	\$479	\$490	\$495	\$498	\$505
Total for all New RAR	\$2,505	\$2,665	\$7,313	\$7,480	\$8,806	\$2,127
Accounting Adjustments	\$0	(\$36)	(\$112)	(\$219)	(\$349)	(\$512)
Total RAR Capital	\$2,505	\$2,629	\$7,201	\$7,262	\$8,457	\$1,614

The new RAR unit cost of \$99,461 and \$50,453 per overhead (OH) RCS devices was derived by examining 2021 work orders for similar devices and escalating to 2022 values. The unit cost for underground (UG) RCS devices was derived by examining 2020 unit costs and escalating to 2022.¹⁴⁵

The cost for the 32 new relay units for 2023 and 2024 is forecast to be a total of \$3.433 million with \$2.874 million in 2023 and \$0.559 million in 2024 for 27 and 5 devices, respectively.

Table I-43
Capital Expenditure Forecast for CB Relays (Nominal \$000)

CB Relay Hardware	2023	2024
Units	27	5
Total	\$ 2,874	\$ 559

The estimated \$101,000 per CB Relay unit was derived by examining the average cost of similar replacements between 2020 and 2022. New relay cost per calculation was derived by dividing the \$21.9 million in recorded costs between 2020 and September 2022 by 216 relays.¹⁴⁶

(c) RAMP Integration

As shown below in Table I-44, SCE's RAMP estimated \$9.5 million for RAR and RCS setting upgrades, compared to this updated request of approximately \$24.5

¹⁴⁴ The forecast incorporates accounting adjustments to reflect certain changes made to SCE's employee compensation program. See Exhibit SCE-06, Vol. 04.

¹⁴⁵ Refer to WP SCE-04, Vol. 05, Part 2, pp. 76-77 –HFRA Sectionalizing Devices Unit Cost Capital Detail.

¹⁴⁶ Refer to WP SCE-04, Vol. 05, Part 2, pp. 76-77 –HFRA Sectionalizing Devices Unit Cost Capital Detail.

million. Since the RAMP filing SCE has increased the overall number of RAR and RCS devices that we plan on installing in 2023 – 2028. As discussed above, RARs and RCSs help SCE limit PSPS de-energization to fewer and smaller circuit segments. The increased number of devices will allow SCE to install new fast curve settings. SCE estimates 20% of the circuit devices scoped for setting enhancements will require new RAR devices, which can accommodate new settings.

Table I-44
RARs and Circuit Breaker Relays
RAMP vs GRC Capital Forecast Comparison - (Nominal \$000)
Risk Spend Efficiencies¹⁴⁷

RAMP Risk	RAMP ID	RAMP Control / Mitigation Name	Filing	2022	2023	2024	2025	2026	2027	2028	Total 2025 - 2028	2025 - 2028 RSE
Wildfire	C3	Remote Controlled Automatic Reclosers Settings (RAR/RCS)	RAMP	\$3,615	\$0	\$0	\$3,830	\$3,913	\$3,997	\$4,092	\$15,832	2,539
			GRC	\$2,294	\$2,505	\$2,629	\$7,201	\$7,262	\$8,457	\$1,614	\$24,533	2,662
			Variance	(\$1,321)	\$2,505	\$2,629	\$3,370	\$3,349	\$4,460	(\$2,478)	\$8,701	123
Wildfire	C4	Circuit Breaker Relay Hardware for Fast Curve	RAMP	\$10,193	\$3,312	\$0	\$0	\$0	\$0	\$0	\$0	N/A
			GRC	\$15,292	\$2,874	\$559	\$0	\$0	\$0	\$0	\$0	N/A
			Variance	\$5,099	(\$438)	\$559	\$0	\$0	\$0	\$0	\$0	N/A

Table I-45
Circuit Breaker Relays
RAMP vs GRC O&M Forecast Comparison - (Nominal \$000)
Risk Spend Efficiencies¹⁴⁸

RAMP Risk	RAMP ID	RAMP Control / Mitigation Name	Filing	2022	2023	2024	2025	2025 - 2028 RSE
Wildfire	C4	Circuit Breaker Relay Hardware for Fast Curve	RAMP	\$0	\$3,523	\$0	\$0	N/A
			GRC	\$1,027	\$5,084	\$1,631	\$1,700	N/A
			Variance	\$1,027	\$1,561	\$1,631	\$1,700	N/A

¹⁴⁷ Refer to WP SCE-04, Vol. 05 Part 1 – WF/PSPS RAMP to GRC Integration.

¹⁴⁸ Refer to WP SCE-04, Vol. 05 Part 1 – WF/PSPS RAMP to GRC Integration.

1 g) Generation System Hardening Legacy Facilities

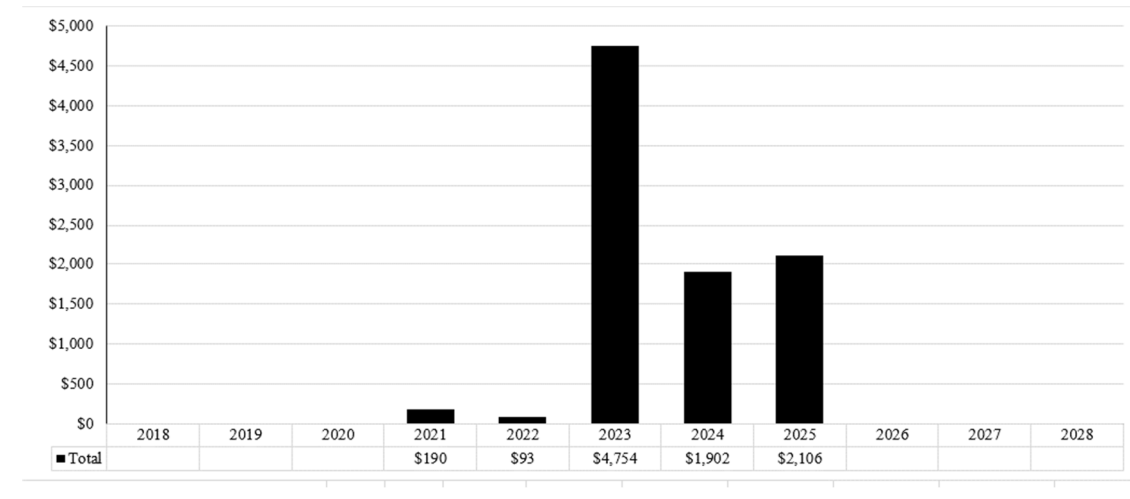
2 (1) Work Description & Need

3 In 2020, SCE began to study and evaluate risks and identify remediation
4 work on certain legacy utility-owned hydroelectric generation assets located within HFRA, such as
5 powerhouses. This program was intended to sunset in 2023, but due to permitting processes and the
6 scope of work involved in the required remediations from assessments, SCE anticipates the work may
7 continue through 2025. The mitigation options recommended in the assessments were site-specific and
8 included a combination of the installment of grounding rods, crushed rock and lightning arresters.
9 Assessments in 2021 identified four legacy sites to be remediated and remediation projects were
10 completed in 2022. The remaining 17 legacy facilities assessments were completed in 2022. Resulting
11 remediations for the 14 facilities identified for mitigations will be implemented in 2023-2025.

12 There are three sub-activities associated with this work:

- 13 1. Low Voltage site hardening, which assesses a variety of low voltage
14 sites in HFRA for opportunities to reduce wildfire risk. This can be
15 done by changing the site to solar/battery and removing secondary
16 lines. The risk can also be mitigated by re-routing or installing
17 covered conductor to reduce risk.
- 18 2. Updating hydro control circuits, which involves an assessment of
19 distribution lines that feed hydroelectric generation facilities
20 exclusively. Hardening projects include covering conductor and
21 updating control circuits with updated protections.
- 22 3. Assessing and updating grounding grids and lightning arrestors help
23 ensure that in the event of a lightning strike or electrical incident,
24 equipment can handle the voltage and release safely instead of causing
25 additional wildfire risk.

Figure I-33
Legacy Facilities^{149, 150}
CG000WMHE000100
Recorded (2018-2022) / Forecast (2023 – 2028)
(Total Company – Nominal \$000)



(2) Historical Variance Analysis

In 2020, SCE conducted studies to evaluate risk, scope, and alternatives for identified circuits; evaluation of additional system hardening mitigation for wildlife fault protection and Grounding and Lightning Arresters, spending \$0.866 million in O&M. In 2021, SCE completed 12 grounding study assessments to continue its assessments in advance of breaking ground on projects and completed five Hydro Control Circuits assessments, and two Low Voltage Site Hardening project plans based on 2020 engineering assessments, as well as additional Grounding Studies and Lightning Arrestor assessments for a total cost of \$0.150 million in O&M. In 2022, SCE completed 13 Grounding Studies and grounding remediations project work at four sites with a total O&M spend of \$0.343 million.

¹⁴⁹ Refer to WP SCE-04, Vol. 05, Part 2, pp. 78-79 – Capital Detail by WBS Element for Legacy Facilities.

¹⁵⁰ An error was identified subsequent to the finalization of financial data. Therefore, the intended financial number that is stated here in testimony does not align with the financial numbers in standardized workpapers and the RO model. An errata will be submitted to align the financial numbers in testimony, standardized workpapers, and the RO model at a future date.

Table I-46
Legacy Facilities – O&M Expenditures (Constant 2022 \$000)

O&M (\$000)	2020	2021	2022
Legacy Facilities	\$ 87	\$ 150	\$ 343

In 2021 SCE spent \$0.190 million in capital to complete covered conductor projects at two sites. In 2022, SCE performed grid hardening at four sites. Two were completed on two control circuits at two legacy facility sites, one grid hardening project and grounding assessment and lightning arrestor remediation projects for a total capital cost of \$0.093 million.

Table I-47
Legacy Facilities – Capital Expenditures (Nominal \$000)

Capital (\$000)	2021	2022
Legacy Facilities	\$ 190	\$ 93

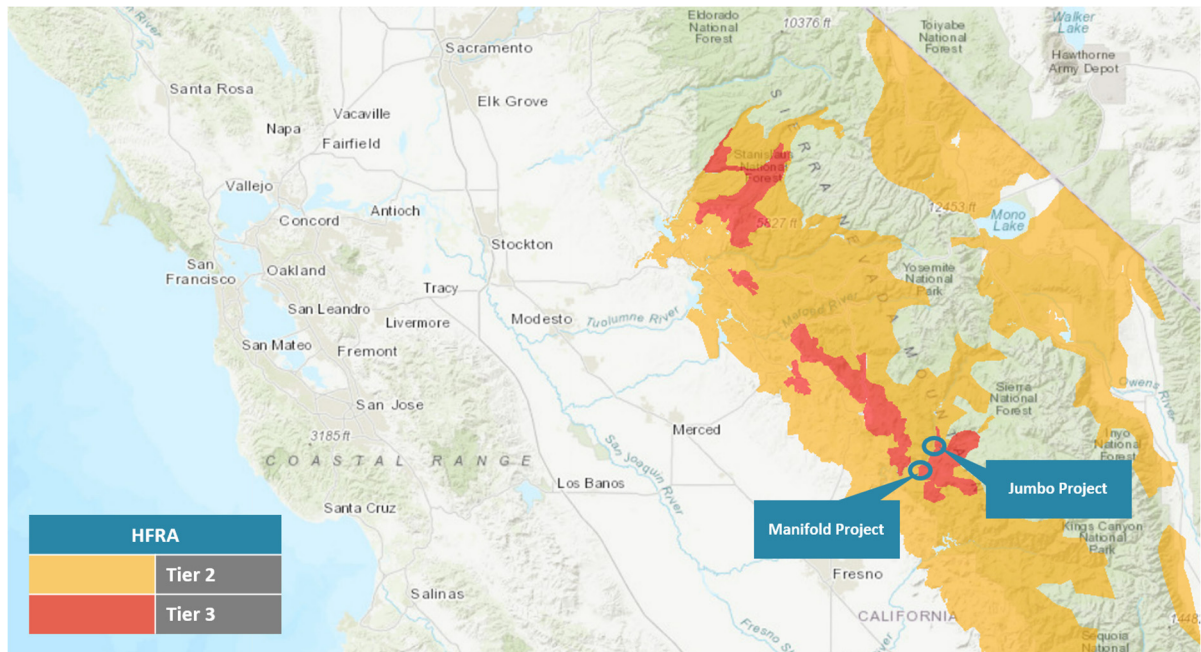
(3) Comparison of Authorized 2021 to Recorded

This initiative did not have authorized dollars as it began work after SCE's 2021 Test Year GRC application.

(4) Scope of Forecast Analysis

SCE has determined three sites require hydro control circuit upgrades at Jumbo, Manifold and Siphon, with covered conductor work at Siphon scheduled to be completed at the end of 2023. Work at Jumbo and Manifold is in Tier 2 and Tier 3 HFTDs and is scoped to eliminate bare wire circuits and cut over to existing nearby covered conductors. These two remaining hydro control circuit projects are expected to be completed in 2024.

Figure I-34
Jumbo and Manifold Project Locations within Tier 2 and 3 HFTD



In 2023, SCE aims to perform grounding studies and lightning arrestor remediations at two generation facilities and one grid hardening project at a hydro control circuit. In 2024, SCE aims to complete grounding studies and lightning arrestor remediations at four generation facilities and grid hardening at two hydro control circuits. In 2025, SCE aims to complete grounding studies and lightning arrestor remediations at five generation facilities.

Assessments for 17 remaining legacy facilities that had not been previously assessed were completed in 2022. The mitigations from the assessments were site specific and included a combination of the installment of grounding rods, crushed rock and lightning arresters. Out of the 17 facilities assessed, it was determined grounding grid remediations are needed at 14 facilities. This work will be completed between 2023 and 2025.

Table I-48
Legacy Facilities – Number of Capital Projects

Legacy Facilities - Capital	2023	2024	2025
Hydro Control Circuits (Units)	1	2	
Grounding Grid Upgrades (Units)	2	4	5

(a) Capital Forecast:

Table I-49
Legacy Facilities Capital Expenditures (Nominal \$000)^{151, 152, 153}

Legacy Facilities - Capital (\$000)	2023	2024	2025
Hydro Control Circuits	\$ 4,254	\$ 1,000	\$ -
Grounding Grid Upgrades	\$ 500	\$ 902	\$ 2,106
Sub Total	\$ 4,754	\$ 1,902	\$ 2,106
Accounting Adjustments	\$ 0.045	\$ 0.001	\$ 0.030
Total	\$ 4,754	\$ 1,902	\$ 2,106

In 2023, SCE plans to upgrade one hydro control circuit and two grounding grids for a total of \$4.754 million. In 2024, SCE plans to upgrade two hydro control circuits and three grounding grids for a total of \$1.902 million. In 2025, SCE forecasts that the five grounding grid upgrades will cost a total of \$2.106 million.¹⁵⁴

h) Long Span Initiative

SCE requests \$23.697 million in capital (2023 – 2028) and \$9.671 million in O&M (2023 – 2025) for long-span remediation activities, as shown in Table I-50 and Table I-51 below.

¹⁵¹ An error was identified subsequent to the finalization of financial data. Therefore, the intended financial number that is stated here in testimony does not align with the financial numbers in standardized workpapers and the RO model. An errata will be submitted to align the financial numbers in testimony, standardized workpapers, and the RO model at a future date.

¹⁵² Refer to WP SCE-04, Vol. 05, Part 2, pp. 80-83 –Legacy Facilities Unit Cost Workpaper.

¹⁵³ The forecast incorporates accounting adjustments to reflect certain changes made to SCE’s employee compensation program. *See* Exhibit SCE-06, Vol. 04.

¹⁵⁴ In 2023 and 2024, SCE plans to spend a total of \$1.8 million in O&M to revise existing facility engineering drawings and update documentation to reflect grid hardening upgrades with respect to each facility. Additionally, O&M will be used for facilities where crushed rock already exists but does not meet the three-inch depth minimum standard which requires a reduced amount of crushed rock to fill. Refer to WP SCE-04 Vol. 05, Part 2, pp. 84-90 – O&M Detail for Legacy Facilities.

Table I-50
Long Span Initiative¹⁵⁵
CET-PD-WM-LS-822400
Recorded (2018 – 2022) / Forecast (2023 – 2028)
(Total Company – Nominal \$000)

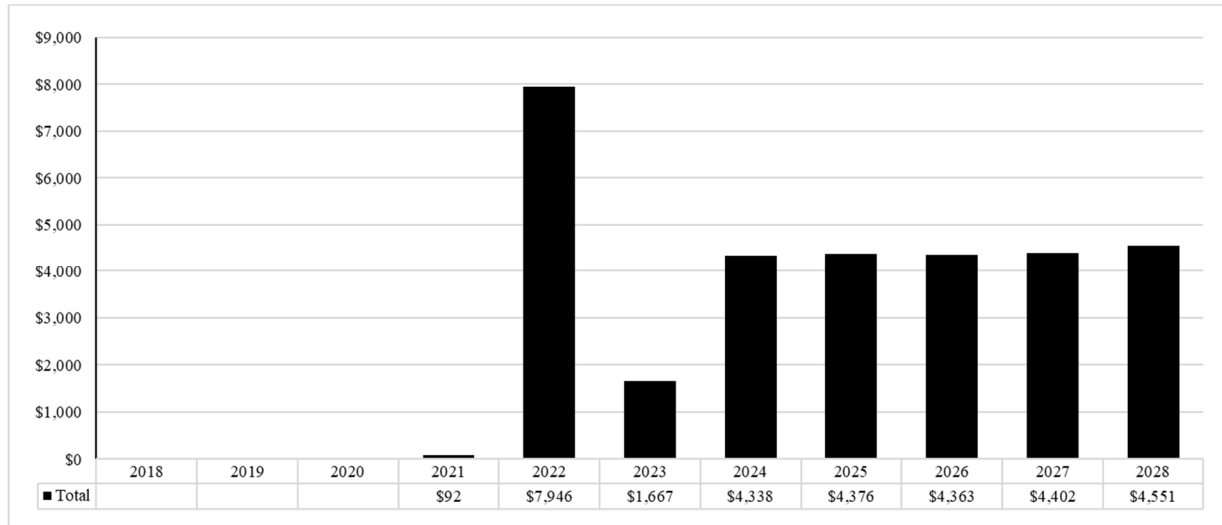


Table I-51
Long Span Initiative¹⁵⁶
O&M Forecast (2023 – 2025)
(Constant \$000)

		2023	2024	2025
Long Span Initiative	L	\$ 260	\$ 650	\$ 650
Long Span Initiative	NL	\$ 1,375	\$ 3,324	\$ 3,413
Total		\$ 1,635	\$ 3,974	\$ 4,062

(1) Work Description & Need

Long span remediations involve spans of wire exceeding 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 in adverse wind conditions. The timing of remediations is being reassessed as many spans have been or

¹⁵⁵ Refer to WP SCE-04, Vol. 05, Part 2, pp. 91-92 – Capital Detail by WBS Element for Long Span Initiative.

¹⁵⁶ Refer to WP SCE-04, Vol. 05, Part 2, pp. 1-7 – Grid Hardening O&M Forecast.

1 are planned to be remediated by covered conductor installations. LSI may serve as an interim mitigation
2 to prevent ignition due to conductor clashing until the span is completely hardened with covered
3 conductor or has been undergrounded. Specifically, SCE is evaluating remediations for higher-risk spans
4 not being addressed in the near-term by other hardening initiatives such as WCCP or TUG.

5 SCE has updated its risk-informed approach to inspect and remediate
6 remaining long spans, which includes proactively installing line spacers, covered conductor, or using
7 alternate construction. In 2022, SCE enhanced its risk methodology and prioritization by incorporating
8 the IWMS and using LiDAR measurements, conductor POI, and wind-related features to better target
9 conductor clash scenarios for scoping long span remediations in 2023 and beyond. SCE is looking to
10 further update the risk-informed approach to remediate remaining long spans, which could be bundled
11 with locations already planned for covered conductor installations or proactively remediated with line
12 spacers.

13 The Long Span Initiative activity resulted from studies to evaluate risk
14 factors and determine worse case conditions that could lead to wire-to-wire contact (sparks or ignition)
15 on over-sagged conductors. Long spans that pose a high risk for conductor clashing and that fall within
16 locations that are largely consequential in the case of an ignition are prioritized for remediation.

17 There are three types of remediations that are carried out with the purpose
18 of reducing clashing risks and potential ignitions stemming from long spans:

- 19 1. Line spacers – Insulated equipment that separates the lines to reduce
20 the possibility of wire-to-wire contact. It is the preferred remediation
21 type due to the speed of deployment and its effectiveness against
22 clashing. They are utilized during instances where there is bucket truck
23 accessibility.

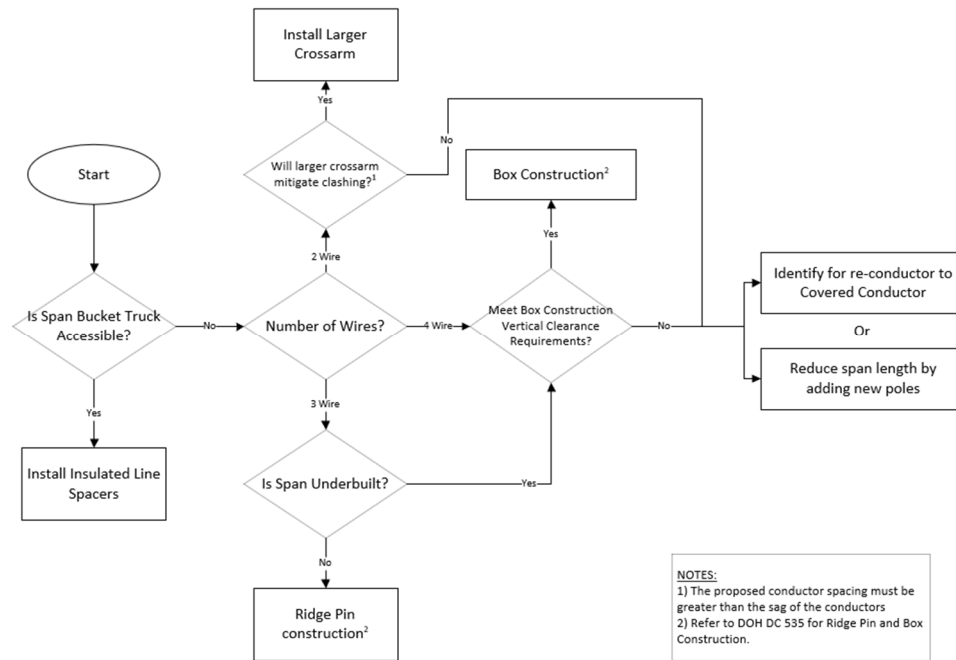
Figure I-35
A Line Spacer Installed on a Long Span to Mitigate Wire-to-Wire Contact (Left), Close-Up Line Spacer View (Right)



2. Alternate Construction – This includes ridge pin, box construction, wider crossarms, and interset poles. These construction configurations increase phase spacing or reduce sag, which minimizes the probability of wire-to-wire contact. This type of remediation is typically utilized when there is no bucket truck accessibility for line spacers.
3. Covered Conductor - The wires are covered to ensure the lines are protected in the event that clashing occurs. Covered conductor will be installed in instances where there is no bucket truck access and either a 3-wire span is underbuilt or a 4-wire span does not have sufficient space for box construction. However, although covered conductor may be the remediation selected, the work will be appropriately considered a LSI activity unless it is part of a larger covered conductor installation, where it will then be budgeted as covered conductor. A capital covered conductor LSI project is also defined as a span, which is typically $\frac{1}{4}$ of a mile covered conductor.

Figure I-36, below, provides SCE's process for determining a remediation type based on the above alternatives:

Figure I-36
Long Span Initiative Remediation Decision Tree



Below is an example of a 1.26 mile-long span across a canyon in SCE's service area. The significant length and sag mixed with high wind conditions could lead to wire-to-wire clashing, which could lead to ignitions.

Figure I-37
Single 1.26 Mile Long Span – Aerial View



Figure I-38
Single 1.26 Mile-Long Span – Ground View (Lines Highlighted to Show Length)



(2) Historical Variance Analysis

LSI Capital projects are projects where covered conductor is the selected remediation. Considering covered conductor was typically deployed as a last resort mitigation under this program, it has historically only accounted for 6.5% of all LSI remediations. In 2021 SCE spent approximately \$0.092 million in capital to remediate one span with covered conductor and remediated 116 capital projects, costing a total of \$7.9 million in 2022.

Table I-52
Long Span Initiative – Capital Expenditures (Nominal \$000)

	2021	2022
LSI Capital	\$ 92	\$ 7,946
Number of Projects	1	116

LSI O&M expenses include line spacers, ridge pin construction, box construction, wider crossarms, and interset poles. Historically, about 93.5% of all remediations carried out for LSI have fallen under O&M. In 2021 SCE completed 51 O&M projects and at a cost of \$0.089 million. However, these costs for 2021 were recorded in an account called HFRI Remediations as the LSI activity was new. Remediation efforts significantly increased in 2022 with SCE remediating 1,014 O&M projects with a total cost of approximately \$4 million.¹⁵⁷

The higher average cost in 2022 was a result of inflationary pressures. Resource constraints also played a factor in the O&M expenditures considering the increase in contractors and the utilization of SCE premium time labor.

¹⁵⁷ This includes \$0.08 million of O&M expenses in 2022 to perform inspections on approximately 1,000 spans.

Table I-53
Long Span Initiative- O&M Expenditures (Constant 2022 \$000)

	2022
LSI O&M - Labor	\$ 3,976
Number of Projects	1,014

(3) Comparison of Authorized 2021 to Recorded

There were no authorized costs for the Long Span Initiative in 2021.

(4) Scope Forecast

SCE has currently targeted 9,944 long spans that are planned to be remediated over the next several years to be determined based on a risk-assessment model. While some of these long spans may be remediated by other measures such as WCCP or TUG projects, SCE has determined it can and should inspect approximately 2,000 spans per year and complete 1,000 LSI remediation projects per-year based on resource availability. Based on analysis of previous LSI remediations, covered conductor is the remediation selected for approximately 6.5% of projects. Thus, for every 1,000 projects in each year, 65 would be capital and the remaining 935 projects per year would be alternative construction or line spacers.

In 2023, SCE forecasts only 400 projects as it continues to conduct field inspections to determine remediations. However, SCE believes 1,000 projects per-year for a total of 5,000 projects between 2024-2028 is reasonable and attainable based off a projected level of field inspections and resources to complete remediations each year. This number is subject to change depending on future covered conductor work and other mitigations.

Table I-54
Forecast Number of Capital Projects

Capital LSI Projects	2023	2024	2025	2026	2027	2028
Units	26	65	65	65	65	65

Table I-55
Forecast Number of O&M Projects

O&M LSI Projects	2023	2024	2025	2026	2027	2028
Units	374	935	935	935	935	935

(5) Cost Forecast:

The Long Span Initiative activity consists of both Capital and O&M expenditures. O&M remediations consist of all the LSI remediations, except for covered conductor, which is Capital.

(a) Capital Expenditure Forecast

SCE is requesting \$23.697 million in capital to remediate 351 spans between 2023 and 2028. LSI Capital is limited to installing covered conductor on each span.¹⁵⁸

Table I-56
Long Span Initiative- Forecast Capital (Nominal \$000)¹⁵⁹

LSI Capital (\$000)	2023	2024	2025	2026	2027	2028
Units	26	65	65	65	65	65
Total Forecast (\$000)	\$ 1,667	\$ 4,338	\$ 4,376	\$ 4,363	\$ 4,402	\$ 4,551

(i) Basis for Capital Forecast

Long Span Initiative activity cost per budgeted for 2023 used costs of 109 units recorded through October 2022. The 2023 LSI Cost Per is \$58,622 with a 1.05 escalation to account for anticipated contractor rate increase in Q2 2023.

¹⁵⁸ This is incremental to and separate from the WCCP forecast, as these projects are selected specifically for their long-span nature. However, any project that would qualify for LSI but that is also scoped for WCCP or TUG in the near future will be removed from consideration for LSI.

¹⁵⁹ Refer to WP SCE-04, Vol. 05, Part 2, pp. 93-94 – Long Span Initiative Unit Cost Workpaper.

(b) O&M Expenditure Forecast

SCE is requesting approximately \$4 million per year in O&M to inspect long spans and remediate approximately 1,000 spans per year between 2024 and 2025. This O&M requests covers all the anticipated LSI remediations that are not covered conductor, at a unit cost of \$3,862 per unit.¹⁶⁰ In addition, approximately \$0.160 million per year is forecast to complete approximately 2,000 inspections per year.

Table I-57
Long Span Initiative- Forecast O&M (Constant 2022 \$000)¹⁶¹

			2023	2024	2025
Inspections	Long Span Initiative	L	\$ -	\$ -	\$ -
Inspections	Long Span Initiative	NL	\$ 152	\$ 160	\$ 164
Preventive Maintenance	Long Span Initiative	L	\$ 260	\$ 650	\$ 650
Preventive Maintenance	Long Span Initiative	NL	\$ 1,223	\$ 3,164	\$ 3,249
Total			\$ 1,635	\$ 3,974	\$ 4,062

(i) Basis for O&M Forecast

This LSI cost per estimate was developed using actual cost pers from 958 units through July 2022. The 2023 estimated cost per LSI is \$3,862.¹⁶²

(6) RAMP Integration

SCE's GRC capital forecast is approximately \$9.7 million higher than forecast in the RAMP between 2025 and 2028, offset by a larger decrease of \$17.9 million in O&M in 2025. A significant portion of the capital increase between years 2025 and 2028 is due to the shift of scope anticipated in the RAMP to be completed in 2023 into future years due to resource constraints discussed above.

¹⁶⁰ Note LSI O&M forecast expenditures are captured in the High Fire Risk Inspections and Remediations account.

¹⁶¹ Refer to WP SCE-04, Vol. 05, Part 2, pp. 95-96 – Long Span Initiative O&M Forecast.

¹⁶² Total O&M includes approximately \$0.160 million per year for approximately 2,000 inspections per year.

Table I-58
LSI Control
RAMP vs GRC Capital Forecast Comparison - (Nominal \$000)
Risk Spend Efficiencies¹⁶³

RAMP Risk	RAMP ID	RAMP Control / Mitigation Name	Filing	2022	2023	2024	2025	2026	2027	2028	Total 2025 - 2028	2025 - 2028 RSE
Wildfire	C8	Long Span Initiative (LSI)	RAMP	\$4,931	\$7,617	\$7,839	\$8,032	\$0	\$0	\$0	\$8,032	1,619
			GRC	\$7,946	\$1,667	\$4,338	\$4,376	\$4,363	\$4,402	\$4,551	\$17,692	286
			Variance	\$3,015	(\$5,950)	(\$3,501)	(\$3,656)	\$4,363	\$4,402	\$4,551	\$9,660	(1,332)

SCE's O&M forecast is significantly less than RAMP due to the reduction in scope from RAMP to the GRC as the RAMP assumed a total of over 7,000 units would be remediated in 2025, while the GRC forecast assumes 1,000 units per year through 2028.

Table I-59
LSI Control
RAMP vs GRC O&M Forecast Comparison - (Nominal \$000)
Risk Spend Efficiencies¹⁶⁴

RAMP Risk	RAMP ID	RAMP Control / Mitigation Name	Filing	2022	2023	2024	2025	2025 - 2028 RSE
Wildfire	C8	Long Span Initiative (LSI)	RAMP	\$5,815	\$10,479	\$21,482	\$22,020	1,619
			GRC	\$3,976	\$1,676	\$4,166	\$4,350	286
			Variance	(\$1,839)	(\$8,803)	(\$17,316)	(\$17,669)	(1,332)

3. Fusing Mitigation

Fuses are safety devices consisting of a filament that melts and breaks an electric circuit or “blows” if the current exceeds the fuse’s rating to minimize the impact of faults and damage to other equipment including conductors. SCE’s fusing mitigation program installs and replaces existing fuses on smaller branch distribution lines within high fire risk areas (HFRA). The installation of fuses to non-fused circuitry presents a large benefit for reducing fault energy and increasing fault detection sensitivity

¹⁶³ Refer to WP SCE-04, Vol. 05, Part 1 – WF/PSPS RAMP to GRC Integration.

¹⁶⁴ Refer to WP SCE-04, Vol. 05, Part 1 – WF/PSPS RAMP to GRC Integration.

1 for the branch line applications to help minimize ignition risks. Additionally, fuses installed on branch
2 lines sectionalize faulted circuitry quickly minimizing the number of customers affected by resulting
3 outages. SCE's fusing mitigation program was one of the Grid Hardening activities introduced in the
4 GSRP Application in 2018 that could be deployed relatively quickly in SCE's HFRA to reduce the
5 potential for ignition events from faults. As part of the GSRP settlement, the Commission approved
6 capital expenditures of \$71.47 million for the installation of new fuses and O&M costs of \$13.07 million
7 for upgrading existing fuses on branch lines serving the HFRA.¹⁶⁵

8 For decades, SCE has applied both conventional expulsion and current limiting fuses
9 (CLFs) for branch line circuitry protection. Both fuse technologies functionally limit fault energy by
10 reducing the fault event duration and in turn reducing the potential for equipment damage should a fault
11 occur. Although CLFs can lower the current magnitude of a fault (hence the "current limiting" name)
12 and also have higher fault current interrupting ratings, CLF applications were historically limited to
13 branch lines that were characterized by relatively high fault current, e.g., branch lines close to a
14 substation. Lower cost conventional expulsion fuses were applied on branch lines in lower fault current
15 applications.

16 Beginning in 2018, SCE's fusing mitigation program identified and requested in the
17 GSRP included the initial efforts to predominately install CLFs on branch lines in HFRA that lacked
18 fusing, and later efforts to replace existing non-CLF fuses in the HFRA with either CLFs or other "Cal
19 Fire exempt" conventional expulsion fuses.¹⁶⁶ In December 2018, following the failure of a few CLFs,
20 SCE commenced discussions with the manufacturer to troubleshoot issues observed with CLFs. In
21 August of 2019, as soon as SCE understood the systemic nature of the potential fusing issues related to
22 CLFs installed as part of the fusing mitigation program, SCE began to take the prudent and necessary
23 steps to first quarantine the potentially defective fuses and later determine the locations where such fuses
24 potentially had been installed so the fuses could be replaced in a risk-informed manner. Ultimately,

¹⁶⁵ D.20-04-013, Appendix A to Appendix 1 at A-1.

¹⁶⁶ A fuse that is "Cal Fire exempt," has been determined to have a low risk of ignition, exempting SCE from clearing brush around the pole.

1 SCE learned that approximately 5,300 locations were identified to have been constructed with
2 potentially defective CLFs manufactured from approximately October 2018 to July 2019 and later
3 replaced by SCE. That replacement process began in 2020 and is ongoing.

4 In its 2021 GRC Track 3 request, SCE sought reasonableness review of the \$24.62
5 million (nominal \$) incremental to amounts authorized in the GSRP settlement for fusing mitigation
6 program capital expenditures from 2018-2020. In Track 3, the Commission did not approve cost
7 recovery of \$24.62 million incremental costs related to SCE's fusing mitigation program in the HFRA,
8 noting that "SCE does not provide adequate information regarding how it selected or installed the
9 potentially defective fuses that would enable us to make a finding that SCE acted prudently."¹⁶⁷ The
10 Commission considered SCE's argument that, if any disallowance is warranted, it should be
11 proportionate to the costs incurred as a result of the defective fuse itself, but concluded that "SCE does
12 not present any information in the record [of Track 3] that would enable the Commission to determine
13 what percentage of the recorded costs are for the fuse itself as opposed to the other components.
14 Therefore, SCE has failed to meet its burden of demonstrating what portion of the incremental costs
15 would be reasonable."¹⁶⁸ Finally, in recognition of the defect, the Track 3 Decision¹⁶⁹ ordered that "SCE
16 shall in its next GRC provide an accounting of the amounts of the recovery, as well as the number and
17 costs of the defective units. To the extent ratepayers have funded some of these fuses, ratepayers should
18 be credited their fair share of any recovery."¹⁷⁰

19 Notably, the Track 3 Decision did not in any way disallow SCE's fusing mitigation
20 program cost recovery request, much less subject the capital costs to a permanent disallowance.¹⁷¹ The
21 Decision merely held that based on the record in Track 3 it was unable to find that SCE had acted

¹⁶⁷ D.22-06-032, pp. 30-31.

¹⁶⁸ D.22-06-032, p. 32.

¹⁶⁹ D.22-06-032.

¹⁷⁰ D.22-06-032, p. 33 and p. 108 (Conclusion of Law 11).

¹⁷¹ SCE notes that with respect to other aspects of SCE's Track 3 request, the Decision uses the term "disallowed" in other areas of the Decision, but with respect to SCE's fusing mitigation costs, simply notes that the record is insufficient to determine that the costs are reasonable and eligible for recovery from ratepayers (*compare* D.22-06-032, p. 109, Conclusion of Law 18 and p. 110, Conclusion of Law 28; p. 108, Conclusion of Law 10).

1 prudently. Moreover, because these costs are tracked in a memorandum account,¹⁷² there is no
2 retroactive ratemaking issue with authorizing recovery as part of this proceeding.

3 Accordingly, herein SCE includes additional evidence to clarify that it was not aware of
4 the potential fuse defect or impact created by the manufacturing/design changes and issues when it
5 installed the aforementioned fuses in connection with the fusing mitigation program. Furthermore, there
6 was no basis for pilot testing the CLF batches installed because SCE has been successfully installing
7 these CLF designs across its system for 20 to 30 years. When SCE discovered the potential defects in
8 the CLFs, we moved expeditiously and prudently to mitigate the impacts to customers. SCE quickly
9 quarantined the population of potentially defective fuses that had not yet been installed and identified
10 the locations which had been previously installed. SCE then replaced potentially defective fuses to
11 study which fuses were the most susceptible to in-field failure. SCE acted prudently and should be able
12 to recover all costs associated with the fusing mitigation program. SCE provides a breakdown of costs
13 related to the defective fuse installation. In the event that the Commission concludes that SCE was
14 imprudent in selecting or installing the particular CLFs, at least \$22.60 million of the \$24.62 million
15 (constant 2020 dollars) request should be authorized for recovery (which omits only the costs of the
16 CLFs that potentially were defective). Finally, SCE describes its efforts, to date, to recover costs from its
17 fusing vendor.

18 a) SCE's Actions in Selecting and Installing Potentially-Defective Fuses Were
19 Prudent and Reasonable Based on What SCE Knew at the Time

20 The Track 3 Decision notes that “SCE states the potential defect was due to
21 design or manufacturing changes but does not explain the circumstances and timing of SCE discovering
22 the design or manufacturing changes. Depending on the circumstances, further testing may have been
23 warranted prior to installation.”¹⁷³ The following timeline demonstrates the circumstances and timing of

¹⁷² These costs are currently tracked in the Wildfire Mitigation Plan Memorandum Account (WMPMA).

¹⁷³ D.22-06-032, p. 31 (internal citation omitted).

1 SCE discovering the design or manufacturing changes and issues in selecting and installing the CLFs in
2 its fusing mitigation program:

- 3 • Concurrent with scaling up our procurement of fuses from SCE's existing fusing
4 manufacturer in connection with the fusing mitigation program, SCE performed a
5 quality process inspection of the manufacturer's facility
- 6 • SCE began installing CLFs on branch lines as part of the fusing mitigation
7 program in October 2018
- 8 • In mid-December 2018, SCE initiated a failure analysis with the manufacturer
9 following two field reports of a few CLFs not operating as expected; the
10 manufacturer could not identify the cause(s) for the issues at this time
- 11 • Between October 2018 and February 2019, SCE installed CLFs at around 4,800
12 locations (approximately 2-3 CLFs at each location) and was still unaware of
13 systemic issues with the CLFs
- 14 • In February 2019, SCE experienced fusing supply issues from the supplier and
15 shipment delays. At this time, SCE learned that the delays were part of a
16 manufacturer hold to redesign the CLFs, though it was unclear what changes had
17 been made or whether the changes would address the potential fusing issues that
18 SCE had observed
- 19 • In April 2019, the CLF manufacturer updated SCE on design changes to the CLFs
- 20 • In May 2019, SCE communicated to the supplier and manufacturer that CLFs
21 purchased were non-conforming, listing the issues SCE had observed (including
22 that CLFs were prone to moisture ingress) and requesting further information
23 about non-conforming materials, analyses of potential impacts to the operation of
24 CLFs, the root cause analyses, and additional testing
- 25 • In June 2019, SCE released an internal bulletin to provide broader awareness of
26 the CLF failures, including reminders to save and return failed material for further

1 analysis as the root cause of the fusing failures had not been identified by SCE or
2 the supplier

- 3 • In August 2019, SCE issued another bulletin, initiating a material quarantine of
4 the fuse products through August 2019; however, the scope and potential impact
5 of the defects and non-conformances were still not fully understood
- 6 • In January 2020, SCE replaced fuses at 385 locations with replacements
7 confirmed to be conforming and was working with the manufacturer to test the
8 removed CLFs under circumstances that replicated conditions in the field where
9 SCE had observed failures
- 10 • In August 2020, SCE communicated the specific manufacturing dates for the
11 CLFs impacted by the manufacturing and design defects, clarifying the precise
12 CLFs that should be quarantined and the CLFs that could be used for replacement
13 and new installations
- 14 • Once SCE fully understood the systemic nature of the fusing issues in 2021, SCE
15 acted promptly to develop a plan to proactively replace potentially defective
16 fuses, in a risk-informed manner. After SCE determined the issues with the CLFs,
17 SCE also was able to confirm that the CLFs currently being purchased conformed
18 with SCE's requirements.

19 As this timeline demonstrates, when SCE first encountered the CLF failures in
20 late 2018, SCE did not know why these fuses had failed. As SCE learned more information about the
21 manufacturing and design defects of the CLFs and the scope, nature, and impact of each defect, SCE
22 took steps, each guided by the information known at the time, to address the issues – first, engaging with
23 the manufacturer, and then analyzing and testing CLFs that failed, later sending out internal alerts to
24 make sure SCE learned of any additional issues and failures and in turn learned from each of those
25 failures, and quarantining the supply of to-be-installed CLFs. SCE plans to replace additional remaining

1 potentially defective CLF units in a cost-effective and risk-informed manner over the next five to seven
2 years.¹⁷⁴

3 The Track 3 Decision states that “[d]epending on the circumstances, further
4 testing may have been warranted prior to installation.”¹⁷⁵ But under these circumstances, further testing
5 of the CLFs before installing them in connection with the fuse mitigation program would not have been
6 warranted. While it is typical for SCE to perform “pilot” or “trial” installations of new equipment prior
7 to approval and initial deployment, it is not reasonable to expect SCE to perform pilot installations for
8 every batch of fuses received from the manufacturer. A standard that would require SCE to test fuses
9 (or other materials) wherever SCE uses them, without any indication of an issue warranting testing,
10 would be prohibitively expensive, time-intensive, and unwarranted.

11 In D.22-06-032, the Commission noted that “[a]lthough SCE states it has used the
12 same type of fuses for 20-30 years, the extent to which SCE used the same type of fuses is unclear given
13 SCE’s assertions that it has traditionally used conventional fuses (as opposed to CLF) for branch line
14 fuse (BLF) applications.”¹⁷⁶ CLFs *have* been installed on SCE’s system for 20-30 years, particularly on
15 high-current branch lines, such as those connected to substations. Although the installation of CLFs on
16 branch line fuses as part of SCE’s fusing mitigation program was new, the use of these fuse types on
17 other parts of SCE’s system, including branch lines, was not. The application of CLFs to branch lines
18 was neither the cause nor contributed to the fusing defect.

19 Moreover, SCE was unaware of the design and/or manufacturing defects when it
20 installed the potentially defective CLFs, and was not aware of the nature or timing of the manufacturing
21 changes made by the manufacturer until long after the fact. It would not have made sense to test these
22 fuses prior to installation because there was no indication at the time that the design/manufacturing had
23 changed or that the fuses were potentially defective. As noted above, when SCE experienced issues
24 with the CLFs, it immediately explored and examined those issues, and later discovered the potential

¹⁷⁴ Exhibit SCE Tr. 3 Vol.1, n. 72.

¹⁷⁵ D.22-06-032, p. 31 (internal citation omitted).

¹⁷⁶ D.22-06-032, p. 31 (internal citation omitted).

1 manufacturing defects in the CLFs, and thereafter moved expeditiously and prudently to mitigate the
2 impacts to customers. For all of these reasons, the Commission should authorize SCE to recover its
3 fusing mitigation costs in full.

4 b) The Cost Impact to Customers of the Defective Fuses Themselves was \$2.03
5 Million, not the \$24.62 Million SCE is Seeking in Cost Recovery

6 As SCE stated in Track 3, most of the fusing mitigation program costs incurred
7 were not for the fuse itself, but for the installation of other components that hold the fuse, which will
8 remain useful and continue to benefit customers for many years to come. The material costs for the
9 fuses themselves made up \$2.03 million of the \$24.62 million fusing mitigation program costs.¹⁷⁷ These
10 other critical component parts of fusing mitigation remain in the field as fuses are replaced at each
11 installation. The initial installation costs related to fusing mitigation include costs of materials, such as
12 crossarms, fuse holders, and wildlife cover. None of these components is impacted by SCE's fuse
13 replacement efforts, and notwithstanding the potential fuse issue, they continue to provide service to
14 customers even if the associated fuse at the location is eventually switched out.¹⁷⁸ For example, when a
15 fuse detects an overcurrent condition (generally a fault), it operates and opens (in other words it stops
16 the flow of electricity) and clears the "faulted" condition, protecting the equipment and system from
17 being damaged. After such an event, the fuse needs to be replaced but the fuse holder can still be used
18 again. While there may be a reduced service life for some of the potentially defective fuses, the larger
19 set of material that was applied for these installations will continue to be used and useful and function
20 beyond the initial fuse deployment.

21 Replacing certain of the fuses does involve labor costs. SCE can take the
22 opportunity to replace some potentially defective fuses proactively, bundling replacement with other

¹⁷⁷ The \$2.03 million in constant 2020 dollars is based on recorded material cost of the fuse of an average of approximately \$166 per fuse, with 5,300 locations that required, on average, 2.3 fuses replaced per location (5,300 x 2.3 x \$166 = \$2.03 million).

¹⁷⁸ Even if all evidence for the added value of the capital fuse work and that most replacements will be bundled with other work and not cost much more than the cost of the fuse, the max cost per location on a proactive basis is \$1,715 per D.22-06-032.

1 work activities and minimizing labor costs related to fuse replacements. These proactively scheduled
2 replacements are in fact O&M expenses, not capital expenditures. Thus, even if the Commission were
3 to find that SCE was imprudent in its procurement and installation of the fuses (which as described
4 above, SCE was not), the appropriate remedy is to record the actual costs of the fuse *replacements*
5 (approximately \$2.03 million) plus incremental installation-related O&M for those replacements
6 (conservatively estimated at \$9.09 million)¹⁷⁹ “below the line,” so that customers are made whole.
7 Imposing a disallowance for new installations that will continue to be used and useful would act as an
8 impermissible penalty to SCE.¹⁸⁰

9 c) Recovery From Vendor

10 As of the date of this filing, SCE has taken action to preserve all legal rights and
11 is pursuing reimbursement from the vendor.

¹⁷⁹ \$1,715 per location x 5,300 locations in 2020 constant dollars equals approximately \$9.09 million.

¹⁸⁰ The Commission has repeatedly applied Section 451 by disallowing costs specifically found to be the result of unreasonable conduct, yet allowing other costs at issue in the same proceeding. *See, e.g.*, D.94-03-048 (disallowing “incremental costs stemming from the 1985 accident” at SCE’s Mohave generating station, and making clear that “dollars at risk for disallowance shall include only costs in excess of what the company would have incurred ... had Edison followed a reasonable reheat pipe inspection program and taken the necessary steps to correct weld and metal fatigue problems”); *see also* D.12-12-030 at pp. 60-61 (“Shareholders should not be excused from their duty to pay the costs of re-testing, and ratepayers should not receive a new pipeline at no cost.”) and D.86-10-069 at p. 66 (excluding certain costs from the disallowance calculation “to avoid counting disallowances for imprudently incurred direct costs twice.”).