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Witnesses:	R. Daffern D. Dickerson R. Fugere S. Menon M. Stark

(U 338-E)

Woolsey Fire Cost Recovery Application – Rebuttal Prudence of Operations – Inspection and Maintenance Testimony

Before the

Public Utilities Commission of the State of California

Rosemead, California
July 15, 2025

SCE-12, Vol. 02: Woolsey Fire Cost Recovery Application – Rebuttal Prudence of Operations – Inspection and Maintenance Testimony

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I.

INTRODUCTION

As set forth in SCE-03, SCE prudently inspected and maintained its transmission, distribution, and telecommunication facilities in the years prior to the Woolsey Fire.[1] In 2004, more than a decade before the fire, SCE developed its industry-leading Distribution Inspection and Maintenance Program (DIMP), which ultimately became the basis for the Commission's General Order (GO) 95 Rule 18. DIMP aligned with and in some cases exceeded regulatory requirements to perform detailed inspections of distribution facilities every five years and basic patrol inspections in interim years. Through these inspection programs, SCE frequently inspected its equipment and identified and prioritized conditions requiring remediation. SCE's other system-wide distribution inspection and maintenance programs at the time of the Woolsey Fire included the infrared (IR) inspection program, the Intrusive Pole Inspections (IPI) program, and the Apparatus Inspections and Maintenance Program.

On the transmission system, SCE assigned the most experienced electrical workers—Senior Patrolmen, all of whom were Qualified Electrical Workers (QEWs)—to circuits or circuit segments. Senior Patrolmen were responsible for routine inspections and maintenance of their circuit as well as responding to emergency issues and reviewing construction. Through this model, SCE's Senior Patrolmen developed deep knowledge of the transmission facilities on their circuit and could monitor conditions over time.

Notwithstanding SCE's prudent practices to maintain its network of distribution and transmission facilities, Cal Advocates and EPUC assert that SCE's inspection and maintenance practices were insufficient. Cal Advocates and EPUC's theories and criticisms, however, do not align with the prudency standard that governs SCE's cost recovery in this case. Under that standard, the appropriate question is whether SCE's inspection and maintenance practices, methods, and acts were consistent with those that a reasonable utility would have undertaken in good faith under similar circumstances, based on the information available at that point in time. SCE's inspection and maintenance practices, both generally and with respect to the Specific Facilities, met this standard.

First, Cal Advocates' criticisms of SCE's transmission patrol inspections prior to its adoption of scheduled detailed inspections in 2018 are unavailing. As a general principle, SCE's revisions of its programs in support of continuous improvement do not render prior versions unreasonable. Moreover,

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[1] SCE's telecommunication maintenance and inspection practices are addressed in SCE-12 Volume 04 (Rebuttal Prudence of Operations – Telecommunications Testimony).

even prior to the adoption of a two-tier scheduled inspection program for transmission facilities, SCE's guidance for patrol inspections provided for a top-to-bottom review of each structure and included an extensive checklist of equipment and conditions to review. SCE's program therefore provided for thorough inspections of transmission facilities in the years prior to the Woolsey Fire. At the same time, SCE's quality control (QC) program provided reasonable coverage of inspections on SCE's transmission system; while SCE had not adopted a QC program for patrol inspections, SCE performed QC on a significant number of IPI and Pole Loading Program (PLP) inspections of SCE's transmission system, including the work of several of the IPI inspectors that worked on the Chatsworth-Thrust Circuit in the years prior to the Woolsey Fire.

On the distribution system, SCE's Annual Grid Patrols (AGPs) were prudent and consistent with GO 165's definition of patrol inspections as "simple visual inspection[s]" designed to identify "obvious structural problems and hazards."[2] While Cal Advocates notes that SCE's Overhead Detail Inspections (ODIs) resulted in more findings than its AGPs, that observation reflects only the distinct purposes of the inspections and the thoroughness of SCE's ODIs. And SCE's backyard inspection program, which allowed inspectors with enough access and visibility to perform an ODI to designate the inspection as "limited access" if unable to physically access the structure, was a reasonable approach to managing access issues for poles across SCE's service area. The last ODI on the Subject Pole prior to the Woolsey Fire was not designated as "limited access," so Cal Advocates' critique has no connection to the cause of the Woolsey Fire in any event.

Cal Advocates further implies that SCE's inspections systematically missed guy wire issues or, alternatively, identified too many guy wire issues, which Cal Advocates asserts indicated system degradation. Cal Advocates unfavorably compares SCE's approach to vegetation in guy wires to that of San Diego Gas & Electric Company (SDG&E) and concludes that the latter was proactive and prudent. But SCE and SDG&E's practices were essentially the same; both utilities identified vegetation in guys only if causing extensive strain or abrasion, using a specific maintenance code, and then remediated those conditions through vegetation trims. Nor does the number of guy-related notifications indicate any imprudence or system degradation. Rather, those notifications indicate that SCE's programs were successful in identifying precisely the types of conditions that maintenance and inspection programs are intended to target. Cal Advocates' reliance on audit findings is also unavailing, as fewer than a dozen

[2] GO 165, Section III.C.

guy wire-related findings out of hundreds of thousands of work orders across 25 audits demonstrates that SCE was consistently identifying those conditions.

On the Specific Facilities in particular, Cal Advocates does not dispute that SCE inspected them numerous times in the years leading up to the Woolsey Fire, consistent with its inspection and maintenance programs. Instead, Cal Advocates relies on certain conditions found at the time of the Woolsey Fire to assert that inspections on the Subject Pole must have been imprudent or ineffective. But Cal Advocates has not demonstrated that any of those conditions were present at the time of the inspections. Indeed, records of high winds following the inspections that did *not* cause a relay or ignition support SCE's position that the transmission guy wire was not loose at the time of those inspections. Moreover, SCE has confirmed through conversations with the individuals involved that an experienced SCE Senior Patrolman inspected the Subject Pole just six weeks prior to the fire and confirmed the guy wires were taut. Other conditions that Cal Advocates asserts SCE should have identified were complex planning requirements that inspectors could not reasonably have been tasked with finding. And SCE's lack of an ODI record for the Subject Pole in 2013, while unfortunate, does not show that the Subject Pole went uninspected for any length of time and, in any event, has no connection to the cause of the Woolsey Fire; SCE completed an ODI, a transmission patrol inspection, and a post-construction inspection of the Subject Pole in the months prior to the fire.

Cal Advocates also relies on selected notification data for the Big Rock Circuit, devoid of context, to challenge the quality of SCE's inspection and maintenance programs and the condition of guy wires on that circuit specifically. Those arguments are unavailing. Cal Advocates' observation that there were outstanding notifications on the Big Rock Circuit at the time of the Woolsey Fire demonstrates only that SCE was frequently inspecting its facilities and identifying conditions for remediation. Cal Advocates also identifies notifications that appear overdue. None of those notifications were on the Specific Facilities, and all but one were either completed timely or related to third-party facilities. And contrary to Cal Advocates' analysis based on three arbitrary keywords, the notifications on the Big Rock Circuit do not indicate any particular guy-related conditions as compared to the system overall.

In that vein, Cal Advocates asserts that SCE's process for linking assets to circuits in its system of record generally inhibited SCE's ability to identify persistent conditions and proactively mitigate risks at the circuit level. But SCE identified and proactively addressed safety and reliability risks on a circuit and local basis through numerous programs and practices that have been identified in multiple

General Rate Cases and actively reviewed by Cal Advocates. For example, through SCE's Overhead Conductor Program (OCP), SCE utilized risk factors, including notification history, to rank circuits for proactive conductor replacement and other mitigation projects. SCE's Worst Circuit Rehabilitation program similarly considered industry standard reliability metrics on a circuit-by-circuit basis and enabled SCE to prioritize grid upgrades accordingly. SCE also had programs for both transmission and distribution that allowed local Grid (for transmission) or District (for distribution) leadership and engineering to identify reliability or asset concerns and submit proposals for targeted asset replacement programs.

Through these programs—and inspection and maintenance programs generally—SCE prudently and effectively maintained and proactively repaired and replaced its facilities in the years prior to the Woolsey Fire.

II.

SCE'S INSPECTION AND MAINTENANCE PROGRAMS FACILITATED PRUDENT MANAGEMENT OF ITS SYSTEM

A. SCE Had Robust Inspection and Maintenance Programs in the Years Prior to the Woolsey Fire

SCE's inspection programs were appropriately designed and executed as described in SCE-03. On the transmission system, SCE's Senior Patrolmen patrolled the circuits or circuit segments they owned on at least an annual basis in the years prior to 2018. Cal Advocates' criticisms of the effectiveness of those patrol inspections are unwarranted; SCE's transmission maintenance guidelines directed inspectors to perform a thorough top-to-bottom visual inspection of each structure and included a detailed checklist of conditions to review. Although SCE did not have a formal QC program for transmission patrols, these inspections were performed by SCE's experienced Senior Patrolmen and documented repairs were subject to review and standardization through the Gatekeeper process.[3] SCE did have QC programs for IPI and PLP inspections on transmission facilities, which provided appropriate coverage to SCE's transmission system. Those QC inspections supported contractor compliance with regulatory requirements and consistent application of SCE's standards.

On the distribution system, Cal Advocates seemingly acknowledges the breadth and effectiveness of SCE's ODIs. It notes that the "extensive deployment" of ODIs shows that they "played a central role in SCE's inspection strategy during 2014-2018."[4] As an example of the comprehensive nature of the ODI program, Cal Advocates notes that SCE "identified over 175,000 notifications potentially related to guy wires" from 2014 to 2018.[5] While Cal Advocates criticizes patrol inspections, AGPs on the distribution system were appropriately designed and implemented to identify obvious structural problems and hazards in between detailed inspections, consistent with GO 165 requirements. Cal Advocates also takes issue with SCE's backyard inspection program, which allowed Electrical System Inspectors (ESIs) to designate inspections as "limited inspection-access." Cal Advocates does not causally connect this critique to ignition of the Woolsey Fire, and the last ODI on the Subject Pole prior to the Woolsey Fire was not designated as "limited access." Moreover, SCE's backyard inspection

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[3] SCE-03, p. 48.

[4] CA-09, p. 17.

[5] CA-06, p. 6.

program was a reasonable approach to managing the inevitable access issues that arise across SCE's service area, and SCE appropriately directed its inspectors to use that designation only if they could complete the inspection notwithstanding the access impairment.

1. Transmission Patrol Inspections Prior to 2018 Were In Many Cases Thorough Visual Inspections of Each Structure

Cal Advocates asserts that prior to 2018 SCE "had no policy or practice of conducting comprehensive, structure-by-structure evaluations on transmission circuits."[6] Cal Advocates' criticism is without merit; SCE reasonably and prudently conducted annual patrols in the years prior to the Woolsey Fire that, as discussed below, provided for a thorough visual inspection of each structure. Cal Advocates implicitly acknowledges the efficacy of those inspections by highlighting the number of notifications arising from the program for conditions concerning "clearance conditions or structural integrity components" and conceding that those inspections were "detecting more and more structural issues over time."[7]

In February 2018, SCE updated its Maintenance Practices for Transmission Facilities under the Operational Control of the California Independent System Operator (ISO) (ISO FMP) to identify a separate "detailed inspection" to be performed every 36 months. This revision was intended to distinguish two different types of inspections—detailed inspections to be performed on a regular cadence and a more basic visual inspection to be performed in interim years—and to provide a framework around each type of inspection.[8] But even prior to adoption of these separate detailed inspections, SCE's ISO FMP provided for comprehensive, structure-by-structure evaluations. Indeed, the definition of "patrol inspection" in Revision 5 of the ISO FMP[9]—in effect from January 2013 to

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[6] CA-09, pp. 21–22.

[7] CA-09, pp. 10–12. Cal Advocates asserts that the increase in guy-related notifications on the transmission system reflected "emerging patterns of degradation," while the decrease in notifications arising from annual patrols overall suggested a shortcoming in SCE's approach to inspections. *See* CA-09, pp. 14–15. These conflicting positions suggest that Cal Advocates views any movement in the number of notifications—up or down—as a sign of imprudence. Notification numbers are likely to vary across years for a variety of reasons, but the number of guy and clearance-related notifications arising from annual patrols is a positive indicator that SCE's Senior Patrolmen were actively identifying those conditions for remediation, consistent with the purpose of SCE's maintenance and inspection programs.

[8] GO 165 did not contain requirements for frequency of detailed inspections for transmission facilities, nor does Cal Advocates cite any standard industry practice for detailed transmission inspections.

[9] *See* Appendix A, p. A-6.

February 2018—was similar to the definition of "detailed inspection" in Revision 6 of the ISO-FMP adopted in February 2018[10] as shown in Table II-1 below.

Table II-1
Comparison of Pre-2018 Routine Patrols to Post-2018 Detailed Inspections

Revision 5, definition of "Routine Patrol"*	**Revision 6, definition of "Detailed Inspection"****
A visual assessment (typically scheduled) performed at ground level or via aircraft, for the purpose of identifying, priorities [sic] and recording discrepancies. This activity may include effecting minor or temporary repairs.	A careful visual assessment performed in close proximity to or while upon a structure for the purpose of identifying, prioritizing, and recording discrepancies. This activity includes performing minor or temporary repairs during the inspection and special technical evaluation as needed.

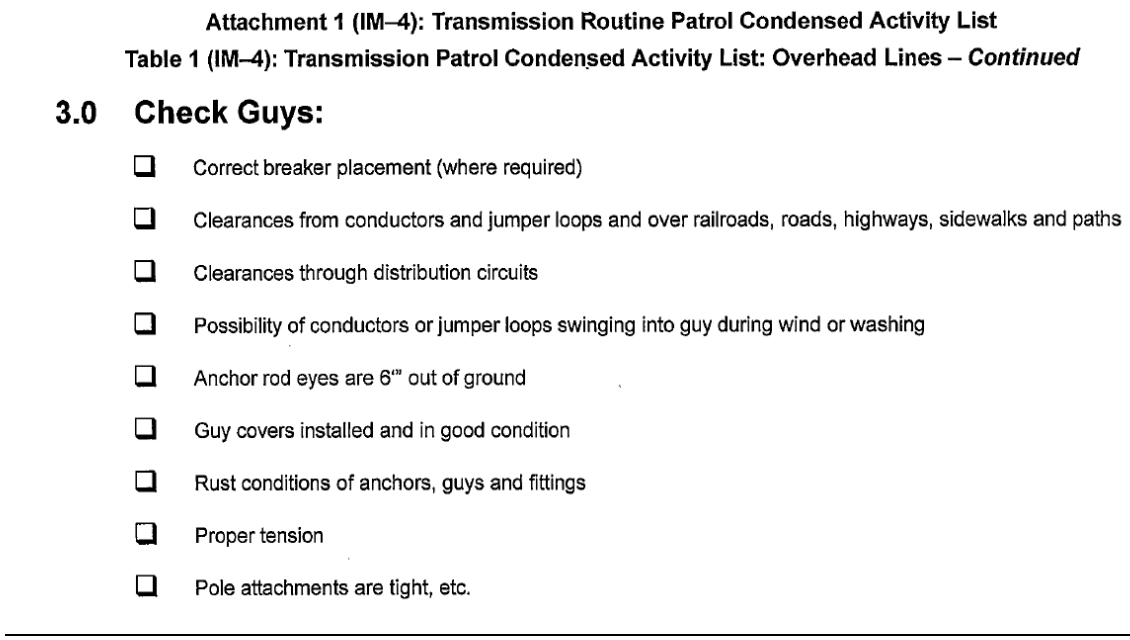
* ISO FMP, Revision 5, Section 3.10.
** ISO FMP, Revision 6, Section 3.5.

Revision 5 also included a "Transmission Routine Patrol Condensed Activity List" that directed inspectors on routine patrols to "Check each Structure Top to Bottom" for an extensive list of conditions.[11] In addition to the "top-to-bottom" structure assessment, this five-page long checklist included several other categories of conditions to inspect during a patrol, including insulators, hardware, conductors, guys, the natural conditions of the surrounding area, and construction or activities that affect the line. The specific section on guys directed inspectors to check for various conditions including clearances and guy tension as shown in Figure II-1 below.

[10] *See* CA09-SA-1518 (ISO FMP, Revision 6).

[11] *See* Appendix A, pp. A-23–A-27.

Figure II-1
ISO FMP Revision 5 Transmission Routine Patrol Condensed Activity List



Attachment 1 (IM–4): Transmission Routine Patrol Condensed Activity List
Table 1 (IM–4): Transmission Patrol Condensed Activity List: Overhead Lines – *Continued*

3.0 Check Guys:

- ❑ Correct breaker placement (where required)
- ❑ Clearances from conductors and jumper loops and over railroads, roads, highways, sidewalks and paths
- ❑ Clearances through distribution circuits
- ❑ Possibility of conductors or jumper loops swinging into guy during wind or washing
- ❑ Anchor rod eyes are 6" out of ground
- ❑ Guy covers installed and in good condition
- ❑ Rust conditions of anchors, guys and fittings
- ❑ Proper tension
- ❑ Pole attachments are tight, etc.

In the years prior to the Woolsey Fire, SCE's Senior Patrolmen identified a significant number of conditions on the transmission system through their annual patrols: as set forth in SCE-03, SCE identified approximately 1,600 Priority 1, 30,000 Priority 2, and 28,000 Priority 3 conditions on its transmission system from 2013 to 2018.[12]

2. SCE's QC Programs Provided Appropriate Oversight of Contractors Performing Inspections on the Transmission System

Cal Advocates' assertions that SCE's QC program did not adequately review inspections on SCE's transmission system in general, and the Chatsworth-Thrust Circuit in particular, are also without merit.

First, Cal Advocates observes that SCE did not have a formal QC program for transmission patrol inspections in the years prior to the Woolsey Fire, and therefore concludes that SCE "has not provided evidence on the quality, thoroughness, or reliability of SCE's transmission patrol inspections in the years prior to the Woolsey Fire."[13] SCE reasonably elected to focus its QC resources on programs executed by contractors. Grid patrols, by contrast, were performed by SCE's Senior

[12] SCE-03, p. 46.

[13] CA-09, p. 33.

Linemen, all of whom were QEWs with significant field experience and familiarity with regulatory requirements and SCE's standards. Moreover, transmission inspections were subject to review and standardization through the Gatekeeper process, through which Transmission Grid leadership would review documented repairs arising from patrols.[14]

Second, while Cal Advocates acknowledges that SCE had formal QC inspections for its PLP inspections and IPIs, including on the transmission system, it notes that SCE did not identify any QC inspections for poles on the Chatsworth-Thrust Circuit in 2014-2018.[15] Cal Advocates' implication that inspection programs should be audited at the circuit level is unreasonable. Individual circuits are not relevant from a QC perspective. SCE's QC programs are instead designed to provide a statistically valid sample of inspections at the program level, while ensuring that (depending on the relevant QC program) samples include various geographic areas and the work of individual inspectors and contractors.

Further, as Cal Advocates recognizes, between 2014 and 2018 SCE conducted 23 IPIs and no PLP inspections on the Chatsworth-Thrust Circuit. Because SCE's samples drew from IPI and PLP inspections system-wide, it is reasonable that no QC inspections were performed on the relatively small number of inspections under these programs on the Chatsworth-Thrust Circuit. SCE did perform QC inspections for several of the inspectors who performed the IPIs on the Chatsworth-Thrust Circuit during this period.[16] Moreover, SCE's QC programs overall provided robust coverage of the transmission system; between 2016 and 2018, SCE performed more than 900 IPI QC inspections and more than 1,800 PLP QC inspections on transmission facilities. The conformance rate for PLPs on transmission facilities remained relatively stable between 2016 and 2018 (between 89.0 percent and 92.8 percent), while SCE's conformance rate for IPIs on transmission facilities increased from 84.5 percent in 2016 to 98.8 percent in 2018.[17] These numbers reflect the consistency and quality of these programs.

3. Distribution Patrol Inspections Were Appropriately Focused on Obvious Defects

On the distribution system, Cal Advocates questions the efficacy of AGPs based on a comparison of the number of notifications potentially related to guy wires found through ODIs to the

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[14] SCE-03, p. 48.

[15] CA-09, p. 33.

[16] *See* Appendix B, p. B-3. Two of the five inspectors had relatively small numbers of IPI inspections and so had not yet undergone QC inspections. However, three of the inspectors had been subject to between 37 and 95 QC inspections each.

[17] *See* Appendix B, pp. B-1–B-2.

number found through AGPs. Specifically, Cal Advocates observes that SCE's ODIs found "more than a thousand times as many" conditions potentially related to guy wires as AGPs from 2014 to 2018.[18]

That AGPs resulted in fewer notifications of any type than ODIs is entirely consistent with the distinct nature and purpose of each type of inspection. As set forth in GO 165, a patrol inspection is a "simple visual inspection" designed to identify "*obvious* structural problems and hazards."[19] A detailed inspection, by contrast, requires individual pieces of equipment and structures to be "carefully examined" and the condition of each "rated and recorded."[20] SCE's DIMP in effect as of 2018 similarly defined an AGP as a "simple visual inspection," typically performed by vehicle, and an ODI as "a close in-depth visual inspection of all the overhead electrical distribution facilities within the assigned inspection area."[21] Per the DIMP, Priority 3 conditions were generally not identified or documented as part of a grid patrol.[22] This distinction alone is significant, as nearly half of the more than 175,000 notifications Cal Advocates identifies as potentially relating to guy wires were P3 conditions.[23]

Cal Advocates further observes that there were no findings through AGPs on the Big Rock Circuit during this period. The lack of any findings through AGPs does not show that these patrols were ineffective or reflect any imprudence on SCE's part. Rather, it simply reflects the lack of any obvious conditions during the relevant time period.

4. SCE Reasonably Used Limited Access Designations to Document Access Issues

Cal Advocates raises various concerns with ODIs designated as "limited inspection-access," including the number of such inspections, inspector discretion to use the designation, and that those inspections were potentially "not as effective in reducing risks."[24] These assertions do not demonstrate imprudence in SCE's ODI program generally or in connection with the Woolsey Fire specifically. The last ODI on the Subject Pole prior to the Woolsey Fire was not designated as limited access.

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[18] CA-06, p. 6.

[19] GO 165, Section III.A.3 (emphasis added).

[20] GO 165, Section III.A.4.

[21] CA09SA-0497, CA09SA-0505 (DIMP 2018-Third Quarter Issue (July 27, 2018), IN-1 Section 2.0 and IN-2 Section 2.0).

[22] CA09SA-0505 (DIMP 2018-Third Quarter Issue (July 27, 2018), IN-2 Section 3.1).

[23] 84,192 out of 175,242 total notifications.

[24] CA-09, pp. 19–20.

SCE's use of the limited access designation was a reasonable approach to managing access issues that understandably arose in inspecting the nearly 1.4 million poles across its service area. SCE adopted the limited access inspection designation in 2014 as a modification to its backyard inspection program. SCE identified this program modification in its 2018 GRC testimony in September 2016,[25] and the Office of Ratepayer Advocates (ORA) did not oppose the estimated costs.[26]

SCE directed ESIs to use the limited access designation in situations where access to the pole was limited but the ESI had sufficient visibility to perform an inspection and determine the safety and reliability of SCE equipment. Limited access designations were distinct from "obstruction exceptions" or "access exceptions," which SCE directed ESIs to use if the pole was inaccessible or surrounded by dense vegetation or customer debris such that the inspection could *not* be performed and which did require follow-up. SCE provided specific training to ESIs on the backyard inspection program with sample photos of situations where the limited access designation would be appropriate. ESIs were expected to use their training and judgment to designate an inspection as "limited access" within these guidelines. Like other ODIs, limited access inspections were subject to review by ODI supervisors and SCE's T&D QC group to help ensure those inspections were appropriately capturing conditions requiring remediation.

Limited access inspections on the Big Rock Circuit identified numerous conditions requiring remediation in the years prior to the Woolsey Fire. The "find rate" for Priority 2 and Priority 3 notifications for non-limited access ODIs on the Big Rock Circuit from 2014-2018 was 29.6 percent, while the find rate for Priority 2 and Priority 3 notifications for limited access ODIs during the same period was 28.2 percent.[27]

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[25] A.16-09-001, SCE-02 V04, p. 8 ("In the 2015 GRC, additional funding was authorized for an ODI program enhancement requiring inspectors to gain access to obstructed or historically difficult to access structures in customer backyards. . . . SCE continued to refine the program, and in August 2014 implemented a modified backyard inspection program that allows the inspectors to inspect poles with limited access. Where the inspector has limited access to the pole, but can still perform the inspection, the inspector can complete the inspection with a limited inspection designation. . . . This modified approach results in less time and expense than originally forecast in SCE's 2015 GRC, and SCE has controlled recorded costs at level slower than previously forecast.").

[26] A.16-09-001, ORA-07, p. 10 ("SCE's 2015 recorded adjusted expenses of $161.491 million are $11 million less than that it was authorized in its 2015 GRC of $172 million. ORA does not oppose SCE's TY forecast of $159.968 million.").

[27] 128 Priority 2 and Priority 3 notifications were found out of 432 non-limited access inspections, while 50 Priority 2 and Priority 3 notifications were found out of 177 limited access inspections. SCE did not identify any Priority 1 conditions on the Big Rock Circuit during this timeframe.

B. SCE Appropriately Identified and Remediated Guy-Related Conditions

Cal Advocates asserts that SCE's inspection and maintenance programs did not sufficiently identify and address conditions requiring remediation relating to guy wires. This assertion is mistaken.

First, Cal Advocates is incorrect that SCE's practices with respect to vegetation in guy wires were less proactive than those of SDG&E. SCE understands that its practices in this regard were not materially different from those of SDG&E. Neither SDG&E nor SCE had a specific vegetation clearance requirement for guy wires generally—nor was one provided in GO 95. Instead, like SDG&E, SCE had problem codes that allowed inspectors to create a notification for vegetation causing strain or abrasion on a guy wire, and such issues would typically be remediated by trimming the vegetation causing the issue.

To argue that SCE purportedly failed to timely identify and remediate guy-related issues on its system, Cal Advocates points to the number of guy-related notifications across SCE's system and on the Big Rock Circuit in particular, outstanding guy-related notifications as of 2024, and guy-related audit findings. However, none of these metrics suggests that SCE's inspection and maintenance programs did not appropriately identify and remediate guy-related conditions. Rather, the number of guy-related notifications overall and the existence of open notifications demonstrate that SCE actively identifies guy-related conditions across its system. And the minimal audit findings related to guy wires represent an exceedingly small fraction of the work orders reviewed in those audits and demonstrate that SCE was consistently identifying those conditions.

1. SCE's Approach to Vegetation Causing Strain or Abrasion on Guy Wires Aligned with SDG&E's Approach

While Cal Advocates acknowledges that GO 95, Rule 35 "did not specify requirements for clearance between overhead guy wires and vegetation,"[28] it criticizes SCE for not having a clearance requirement for guy wires. Cal Advocates bases this criticism on its representation that SDG&E's programs and policies "required it to maintain clearances between vegetation clearance [sic] and guy wires,"[29] which Cal Advocates deems an "example of proactive and prudent vegetation management practices."[30]

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[28] CA-09, p. 34.

[29] CA-09, p. 35.

[30] CA-09, p. 37.

In reality, SCE and SDG&E's approaches to vegetation contacting guy wires were essentially the same. Contrary to Cal Advocates' representation, SDG&E's Code 332 did not require it to maintain clearances between vegetation and guy wires generally; indeed, SDG&E explained that "[v]egetation may come into contact with the guy wire; an infraction occurs when the vegetation contact causes a significant strain, abrasion, or damage to the guy wire."[31] Instead, Code 332 was used for "vegetation in the guy causing heavy strain or abrasion."[32] Once this condition was identified, SDG&E's pruning specifications provided for two feet of post-trim clearance.[33]

SCE used a similar code and standard to identify and address vegetation contact issues for guy wires. As SCE explained to Cal Advocates in data request responses, vegetation causing strain or abrasion to a guy wire would be addressed through SCE's transmission and distribution inspection and maintenance programs.[34] While the DIMP Overhead Detailed Inspection Guidelines and Transmission Routine Patrol Condensed Activity List did not specifically identify vegetation in guys as a condition to review, those lists were not exhaustive. Rather, in completing their inspections, ESIs and Senior Patrolmen could select from a list of specific problem statements applicable to each equipment component. Inspectors could therefore utilize one of several problem statements to indicate "Vegetation/Tree" as the condition, "Guy" as the equipment component, and "Trim" as the action required.[35] Those notifications would be referred to vegetation management, which would arrange for a contractor to complete the trim work. Given that there were no regulatory clearance requirements, tree vendors were required when practical to ensure the trim met ANSI A300 Tree Pruning Standards, which meant cutting to the parent lateral of the branch causing the conflict. If there was no lateral branch, crews would typically obtain one to two feet of clearance. For bushes, crews would cut back as much as required to release the strain and potential for abrasion.

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31 CA09SA-2179 (SDG&E's response to CALPA-SDGE-A2410002-002A, Question 5).

32 CA09SA-2177 (SDG&E's response to CALPA-SDGE-A2410002-002A, Question 3); CA09SA-2159 (SDG&E Vegetation Management Audit Procedures, p. 12) (describing code 332 as "Vegetation in service line causing heavy strain or abrasion").

33 CA09SA-2163 (SDG&E Vegetation Management Audit Procedures, p. 13).

34 CA09SA-2125 (SCE's response to CalAdvocates-SCE-A2410002-025, Question 1).

35 E.g., "TRIM VEG TREE COMM GUY POLE," "TRIM VEG TREE PUBLIC GUY POLE," "TRIM VEG TREE SEC GUY POLE," "TRIM VEG TREE PRI GUY POLE, "TRIM TRANS CLEAR TCOMM GUY POLE," and "TRIM VEG TREE TCOND GUY POLE."

SCE's inspectors frequently utilized these problem codes in the years prior to Woolsey Fire. As Cal Advocates notes, SCE created two such notifications on the Big Rock Circuit between 2014 and 2018.[36] Most recently before the Woolsey Fire, an ODI on March 5, 2018 resulted in a "TRIM VEG TREE COMM GUY POLE" notification, with the description providing "Tree limb has grown around down guy and is deflecting it."[37] SCE assigned a due date within six months. A contractor completed the trim less than two months later on April 30, 2018, indicating that it "cut back two large limbs to free guy wires from heavy tension."[38] Notably, the inspector who issued this notification was also the last inspector to perform an ODI on the Subject Pole, indicating that he was well aware of this problem code and would have issued a notification had vegetation been causing strain or abrasion on any of the guys on the Subject Pole. The Senior Patrolman who last inspected the Subject Pole in September 2018 had also issued a notification with this problem code (unrelated to the Specific Facilities) just months earlier in June 2018.

The table below identifies how many notifications SCE created for vegetation in guy wires in the years prior to the Woolsey Fire.

Table II-2
SCE Notifications Using Vegetation Interfering with Guy Problem Codes[39]

Year	Number of Notifications
2015	333
2016	274
2017	298
2018	194

Accordingly, in the years prior to the Woolsey Fire both SDG&E and SCE appropriately identified vegetation causing heavy strain or abrasion on guy wires and, if such conditions were present,

[36] CA-09, p. 7, Fig. 2; *see also* CA08SA-0219–CA08SA-0223 (SCE's response to CalAdvocates-SCE-A2410002-045, Question 1) (explaining the problem statements "TRIM VEG TREE COMM GUY POLE" and "TRIM VEG TREE SEC GUY POLE").

[37] *See* CA08SA-0023 (SCE's response to CalAdvocates-SCE-A2410002-001, Question 4, CalAdvocates-SCE-A2410002-001 Q 4 ODI.xlsx).

[38] *See* Appendix C.

[39] Excluding notifications that were deleted.

trimmed vegetation accordingly. SCE's approach to vegetation in guy wires was therefore reasonable and prudent and ensured that vegetation did not impair the structural integrity of its system.

2. Notification Data Demonstrates that SCE Actively Identified Guy Wire Conditions Requiring Remediation

Cal Advocates' critique of SCE's management of guy wire conditions is not borne out by the data. As Cal Advocates acknowledges, SCE was identifying and remediating significant numbers of guy-related issues through both its ODIs and its transmission patrol inspections in the years prior to the Woolsey Fire.[40] These notifications do not show any imprudence on SCE's part; on the contrary, they show that SCE's inspection and maintenance programs were working as intended to identify and address conditions requiring remediation.

Cal Advocates also references SCE's "growing backlog" of guy-related issues as evidence of SCE's purported "asset management failures" given that there were more than 6,000 asset notifications created between 2014 and 2018 that remained pending as of 2024.[41] None of the pending notifications are on the Specific Facilities or have any connection to the Woolsey Fire ignition. Moreover, all but four of those notifications are Priority 3 notifications, which means that they had a low potential impact to safety and reliability and, under SCE's practice at that time, were not typically assigned a due date.[42] Of the remaining four Priority 2 notifications:

- Two were resolved timely under other work orders but not closed in SAP;[43]
- One concerning a Communications Infrastructure Provider (CIP) guy wire was completed in 2020, which was delayed due to an inability to contact the CIP;[44]

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[40] *See* CA-08, pp. 10–15 and CA-09, p. 8 (noting that SCE identified 108 conditions (or 100 conditions excluding those that were subsequently deleted) containing the words "Clear," "Guy," or "Loose" on the Big Rock Circuit from 2014-2018); CA-09, pp. 10–14 (noting that transmission notifications containing the words "Clear" "Guy," and "Loose" nearly doubled between 2014 and 2018); CA-06, p. 6 (noting that ODIs identified over 175,000 notifications potentially related to guy wires—i.e., containing the words "Clear," "Guy," or "Loose"—from 2014-2018).

[41] CA-09, p. 15.

[42] Three of the Priority 3 notifications did have due dates assigned. Those three notifications have been resolved as of the date of this testimony.

[43] Notifications 408709791 for "REPAIR LOOSE PRI GUY POLE" (pole replaced on March 18, 2019, prior to August 2, 2019 due date) and 407714631 for "REPAIR LOOSE PRI GUY POLE" (equipment removed on November 12, 2017, prior to April 6, 2018 due date).

[44] Notification 405943799.

- One remains pending; SCE has obtained a railroad permit for the work.[45]

Accordingly, of the 6,772 pending records that Cal Advocates identifies, only one is currently overdue.

Cal Advocates also cites certain guy and clearance-related conditions identified through Safety and Enforcement Division (SED) audit reports from February 2013 through May 2018.[46] But those guy-related findings represent an exceedingly small percentage of the notifications and conditions reviewed through the audits. In the eight audits cited by Cal Advocates, SED reviewed more than 325,000 work orders closed and identified 10 guy-related finding not previously documented. And as Cal Advocates acknowledges, it identified guy wire-related findings in only eight of the 25 audits it reviewed. Moreover, as SCE noted in certain of its audit responses, the conditions identified could have developed after SCE's last inspection. Accordingly, SED's limited findings do not indicate that SCE was systematically missing or failing to address guy-related issues on its system; to the contrary, they show that SED regularly reviewed SCE's inspection and maintenance practices across its service area and did not identify any systematic or widespread issues.

C. SCE Prudently Inspected and Maintained the Specific Facilities

Cal Advocates' assertions that SCE's inspections were insufficient with respect to the Subject Pole are unsupported by evidence. As set forth in SCE-03 and as undisputed by Cal Advocates, SCE inspected the Subject Pole multiple times in the years prior to the Woolsey Fire pursuant to the utility's inspection and maintenance programs. Cal Advocates claims the inspections were deficient because they did not identify slack guying at the Subject Pole. Yet Cal Advocates has not shown that the Subject Pole's guys were in fact slack at the time of the inspections. Cal Advocates' critique of SCE inspectors for not identifying the lack of a fault return conductor and testimony regarding the lack of a 2013 ODI record also do not show that SCE acted imprudently in connection with its inspections of the Subject Pole.

Cal Advocates first claims that SCE's inspections were deficient because none of the inspections, including a transmission patrol inspection on January 6, 2017, identified a problem with the subtransmission guy prior to January 20, 2017, when a slack subtransmission guy caused the Big Rock

[45] Notification 409403435.

[46] CA-09, pp. 29–30.

Circuit to relay.[47] Cal Advocates' claim presupposes that the guy was actually slack on or before January 6, 2017. Yet Cal Advocates acknowledges that "it is possible that the down-guy became slack in the two-week period between the [January 6, 2017] inspection and the [January 20, 2017] outage," while asserting that the "available evidence" does not support that conclusion.[48] But the only evidence Cal Advocates presents to support its contention that the guy was slack on January 6, 2017, is (1) that SCE's patrol inspections did not adequately identify slack guys; and (2) that only a "narrow window" of time occurred between January 6 and 20, 2017. The first argument, which is also addressed at Section II.A, is circular; whether SCE's transmission patrol inspections adequately identify slack subtransmission guys is not probative of whether the subtransmission guy was slack in this instance. The second argument is circumstantial and contradicted by other evidence. For instance, available weather data suggests that had the guy been loose during the January 6, 2017, transmission patrol, the circuit likely would have relayed on January 14, 2017, when a Wind Advisory was issued for the area, predicting gusty winds. No such relay occurred until January 20, 2017.[49]

Cal Advocates likewise suggests that because SCE inspections between January and September 2018 did not identify any issues with the subtransmission down guy at the Subject Pole, those inspections were deficient. Again, Cal Advocates' argument is circular and presents no evidence that the subtransmission down guy was slack during any of these inspections (let alone on all three). Moreover, as with the January 6, 2017, transmission patrol, available weather data suggests that had the subtransmission down guy been loose in September 2018 or prior, the circuit would have relayed on October 15 and/or 30, 2018, when Wind Advisories were issued for the area. No such relay operation was recorded until November 8, 2017.[50] Finally, had the subtransmission down guy been slack during the ODI on January 23, 2018, or the transmission patrol inspection performed on September 10, 2018, SCE's September 24, 2018, post-construction inspection would have identified the condition. As discussed in SCE-11, no slack subtransmission guy was identified on September 24, 2018, even after

[47] CA-05, p. 15; CA-06, p. 7.

[48] CA-06, p. 24.

[49] A Wind Advisory was also issued for the area on January 20, 2017.

[50] A Wind Advisory was also issued for the area on November 8, 2018.

both a contractor foreman and an SCE Senior Patrolman examined the Subject Pole and specifically checked for loose guying.[51]

Cal Advocates also speculates that the density of the tree likely impeded SCE's ability to adequately inspect the subtransmission down guy. But only a small section toward the bottom of the guy wire was located adjacent to tree branches, not including the section closest to the ground anchor. Cal Advocates does not dispute, however, that inspectors' view of the clearance between the guy wires and the distribution facilities, and of the guys' attachments to the pole and at the anchors, was unimpeded.

As discussed in SCE-02 and SCE-03, SCE also had no notice that the lower distribution down guy was loose prior to the Woolsey Fire. As described in SCE-02, this distribution guy relates to the ignition at the secondary telecommunications location, and was not involved in the initiating event or the ignition at the Subject Pole. Cal Advocates points out that two photographs SCE took in connection with two pole loading analyses in March and May 2015 appeared to show that the lower distribution down guy was slack while the Telecom Pole still had crossarms attached to the upper end of the pole. The photographs, which SCE identified in connection with preparing this Application, were taken with the purpose of aiding pole loading analyses to identify attachments on the pole, not to visually identify conditions for remediation.[52] SCE acknowledges that it has not located records showing that the distribution guy was tightened between the time when the pole loading photographs were taken and the Woolsey Fire. However, SCE's records with respect to the Telecom Pole are no longer complete given the passage of time. In mid-2015, the crossarms and guy wire on the Telecom Pole were removed and the 06123 Line was transferred from the Telecom Pole to the Subject Pole. Based on a reasonable investigation, SCE believes this work occurred on or before June 28, 2015. SCE has been unable to

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[51] EPUC's similar claim that SCE missed a slack guy during its inspections is based on an apparent misunderstanding of an SCE data request response. EPUC claims that based on evidence of "older arcing," "a fault on the [subject subtransmission] down guy wire occurred about a year before the Woolsey Fire" in November 2017, and concludes that SCE's subsequent inspections must have been deficient because they did not identify the condition that caused the arcing. EPUC Testimony, p. 31. Yet the data request response that EPUC cites pertains to older arcing on SCE's communication line, not the subtransmission guy. *See* EPUC Testimony, p. 31, n.64. SCE has not identified any fault or outage on the Big Rock Circuit in November 2017 and is not aware of any evidence (such as relay records) showing that a fault occurred at the Subject Pole in November 2017.

[52] A March 2, 2015, photograph was taken in connection with a March 6, 2015, pole loading analysis performed in connection with the installation of the 06123 Line. Two May 20, 2015, photographs were taken by an SCE contractor as the result of a July 30, 2014, pole loading analysis.

locate documentation showing the details of this work that could indicate whether the guy was tightened. Photographs taken after May 2015 and prior to the Woolsey Fire do not show obvious slack in the distribution guy, though the photos were taken for other purposes and are not definitive.[53]

Cal Advocates also faults SCE's inspections prior to the Woolsey Fire for not identifying the lack of a fault return conductor at the Subject Pole.[54] As an initial matter, this standard was not required by the Commission's General Orders, and the presence of a fault return conductor would not have prevented the Woolsey Fire.[55] Moreover, SCE inspectors could not reasonably have been tasked with identifying a planning requirement to install a fault return conductor, required only on some lightweight steel poles constructed in some years. Consistent with GO 165, GO 95, and industry practice, the goal of an inspection is to identify deterioration, degradation, or other conditions that require remediation to support safety and reliability and compliance with applicable GO 95 requirements. SCE's Transmission Overhead Construction Standards (TOH) outlined the complex process that planners used to determine which lightweight steel poles require a fault return conductor and which do not, a process that takes into account factors such as the number of lightweight steel poles on the circuit, whether the pole is in a rural area, how far the poles are from each other, and how far the pole is from the substation. Adding to the complexity, SCE's TOH and other related design standards change from year to year. Although SCE's inspectors were specifically directed to report incorrectly installed fault return conductors,[56] tasking inspectors with confirming compliance with hundreds of TOH construction and design standards that vary from year to year and from pole to pole would be infeasible and inefficient. Indeed, Cal Advocates

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[53] Cal Advocates also claims that SCE inspectors did not identify that, when taut, the clearance between the lower distribution guy and a telecommunications through-bolt would have been 6 inches, less than the 18 inches of clearance required under GO 95, Table 2. Cal Advocates points out that a 7-inch clearance on the subtransmission guy, when it was already slack, was not sufficient to prevent contact with the distribution jumper, and thus concludes that a 6-inch clearance when taut would not have prevented contact. This comparison is inapposite. Whether a *slack* guy with 7-inches of clearance would have contacted an adjacent facility in high wind conditions does not prove that a *taut* guy with similar clearance would have done the same. Regardless, SCE's independent electrical expert affirmed that the technical clearance violation was not causal to the secondary ignition because the clearance of the distribution down guy, if taut, was more than sufficient to avoid electrical contact with the communication facilities. *See* CA06SA-0665 (SCE's response to CalAdvocates-SCE-A2410002-064, Question 7, prepared by SCE's independent electrical expert Dr. Don Russell) ("Based on my knowledge and experience and the analysis presented in my testimony, approximately six inches of clearance would have been more than sufficient to prevent arcing between the distribution down guy and the through-bolt on the Telecom Pole.").

[54] CA-09, p. 25.

[55] SCE-02, pp. 7, 24.

[56] *See* Appendix A, p. A-24.

has not put forth—and SCE is not aware of—any industry standard or good utility practice, or the policies of any other electrical utility in North America, that requires field inspectors to confirm that each pole complies with all design and construction standards applicable at the time of installation that are not GO 95 requirements.

Finally, Cal Advocates asserts that the Subject Pole did not undergo a detailed inspection for "nearly ten years after its installation in 2008."[57] Cal Advocates attributes this lack of inspection to (1) SCE inadvertently classifying the pole as transmission only until 2014, notwithstanding that distribution facilities were transferred to the pole in 2008, and (2) SCE's use of patrol inspections for transmission facilities prior to 2018. But pursuant to SCE's programs, the Subject Pole would have undergone both an ODI in 2013 and a thorough, structure-by-structure inspection each year under the transmission patrol program. Although SCE does not have an ODI record for the Subject Pole in 2013, as set forth in SCE-03E, the DIMP in effect at that time provided that "[t]he ODI inspector shall perform a close in-depth visual inspection *of all the overhead electrical distribution facilities within the assigned inspection area*."[58] SCE has records of ODIs being performed for all of the distribution poles in the immediate vicinity of the Subject Pole on January 16, 2013, as indicated by the yellow pins in Figure II-2 below.

[57] CA-10, p. 6.

[58] SCE-03E, p. 41E, n.90; *see also* Appendix D, p. D-29 (DIMP 2010-Fourth Quarter Issue (Oct. 29, 2010) (excerpt), IN-1, Section 2.0) (emphasis added).

Figure II-2
Poles in the Vicinity of the Subject Pole with January 16, 2013 ODIs

It would defy the inspector's training, DIMP guidance, and logic for the inspector to ignore the Subject Pole while completing ODIs for all other distribution facilities in the area. The inspector who completed the ODIs in 2013 had undergone two QC reviews in 2012 and received high conformance rates on both (between 91 percent and 100 percent), indicating familiarity with and adherence to DIMP guidelines. Thus, while SCE regrets the recordkeeping error, SCE's program guidelines and available ODI records indicate that the inspector would have reviewed the Subject Pole and identified any nonconformances.

In any event, a Senior Patrolman inspected the Subject Pole annually via transmission grid patrols. As set forth in Section II.A, Cal Advocates' characterization of grid patrols as ineffective is without merit. Annual grid patrol guidelines required a top-to-bottom review of each structure and included an extensive checklist of conditions to review.

III.

SCE'S PROGRAMS REDUCED RISK ON ITS ELECTRIC SYSTEM

As described in SCE-03 and in the preceding sections, SCE appropriately inspected its electrical facilities, including the Specific Facilities, through comprehensive inspection and maintenance programs that met or exceeded Commission requirements.[59] These programs—along with numerous other proactive programs and practices through which SCE analyzed asset issues on a local or circuit level—reduced risk on SCE's electric system.

Cal Advocates makes several incorrect assertions regarding SCE's risk management on the Big Rock Circuit based on its interpretation of notification data. First, Cal Advocates observes that there were large increases in the number of asset notifications on the Big Rock Circuit in 2016 and 2018, which it posits should have alerted management to an issue.[60] These increases reflect the timing and cadence of SCE's ODIs, which were consistent with GO 165 requirements. Cal Advocates also presents testimony regarding open and overdue notifications on the Big Rock Circuit on the day of the Woolsey Fire.[61] The notifications open on that day are simply a snapshot of SCE's effective inspection and maintenance program at work. Moreover, all were unrelated to the Woolsey Fire, and all but one of the overdue notifications had either been completed timely or required third-party coordination. Cal Advocates also suggests that the asset inspection data for the Big Rock Circuit should have raised concerns with SCE's management regarding guy-related conditions and led to SCE adopting circuit-specific mitigations.[62] This conclusion is based primarily on an arbitrary selection of search terms; other metrics show that the Big Rock Circuit did not have an unusually high incidence of guy-related notifications that would have indicated a systemic issue.

Cal Advocates' assertions about SCE's purported inability to identify and address circuit and local conditions generally are also incorrect. As discussed further below, SCE faced no technical limitations in linking assets to circuits and had numerous programs and practices through which it analyzed asset issues on a local or circuit level and proactively replaced infrastructure accordingly.

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[59] SCE-03, Section IV.

[60] CA-09, pp. 3–5.

[61] CA-08, pp. 7–10.

[62] CA-09, pp. 6–10.

A. Asset Data Demonstrate the Effectiveness of SCE's Inspection and Maintenance Programs

1. Increased Findings in Certain Years Resulted from the ODI Inspection Cycle, Which Was Consistent with Regulatory Requirements

Cal Advocates observes that there were large increases in the number of asset notifications on the Big Rock Circuit in 2016 and 2018, which it posits "should have raised concerns with SCE's management about issues with either the assets or SCE's inspection programs . . . ."[63] But as Cal Advocates acknowledges, the asset notifications in those years were a function of SCE's five-year ODI cycle.[64] There were 169 ODI inspections on the Big Rock Circuit in 2016 and 440 in 2018, with none occurring in 2015 or 2017. Therefore, the greater numbers of notifications in 2016 and 2018 are not indicative of any imprudence; rather, they demonstrate that SCE's ODIs were successfully identifying issues for remediation in the years they occurred.

Nevertheless, Cal Advocates asserts that SCE's inspection and maintenance program resulted in "[i]nsufficient circuit-level oversight" that could allow certain circuits to go "unmonitored for substantial periods of time."[65] Cal Advocates' assertion that circuits went unmonitored for any extended period of time is wrong; distribution facilities, including those on the Big Rock Circuit, were subject to regular inspections in the years prior to the Woolsey Fire, including at a minimum an AGP each year to identify obvious structural problems and hazards.[66] And to the extent Cal Advocates takes issue with the length of time between detailed inspections, its critique is unreasonable. A five-year detailed inspection cycle conforms to the requirements of GO 165 and standard industry practice. Indeed, both Pacific Gas

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[63] CA-09, p. 4.

[64] CA-09, p. 5.

[65] CA-09, p. 5. Cal Advocates states that "relying primarily on regional or system-wide inspection schedules rather than data-driven, circuit-specific assessments created critical gaps in oversight." SCE is unclear what Cal Advocates is referring to, but notes that its inspection schedule was consistent with GO 165 and reported annually to the Commission pursuant to D.12-01-032.

[66] In the spreadsheet entitled "CalAdv-SCEA2410002-001 Q1.xlsx" that SCE attached to its response to CalAdvocates-SCE-A2410002-001, Question 1 (CA09SA-0001-15), SCE identified more than 6,000 AGPs (by structure) and more than 600 ODIs completed on the Big Rock Circuit between 2014 and 2018. *See also* CA-09, p. 18, Table 4 (SCE's Distribution Inspections Performed, by Program). Cal Advocates omits the units from this table, creating the impression that there were more ODIs each year than AGPs; however, AGPs are reported by grid, while ODIs are reported by structure. *See* CA09SA-0437–CA09SA-0438.

and Electric Company (PG&E) and SDG&E performed detailed inspections of distribution equipment on a five-year cycle, consistent with SCE's practice.[67]

2. Notification Data for the Big Rock Circuit Confirms the Effectiveness of SCE's Robust Inspection and Maintenance Program

Cal Advocates does not dispute that the Specific Facilities and the Big Rock Circuit were subject to frequent inspections through ODIs, AGPs, and IPIs and evaluation under SCE's PLP; that SCE completed an infrared inspection for the entirety of the Big Rock Circuit in 2018 without identifying any hot spots; or that the Specific Facilities had no past due maintenance notifications at the time of the fire. Yet Cal Advocates challenges SCE's inspection and maintenance practices on the Big Rock Circuit based on its observations that (1) there were open notifications on the day of the Woolsey Fire; (2) some of those notifications were overdue; and (3) others had due dates in 2020 and beyond.

Contrary to Cal Advocates' characterization of the notification data, outstanding notifications confirm the robustness of SCE's inspection and maintenance programs, which were and are specifically designed to identify and timely resolve issues based on an appropriate assessment of risk. SCE maintains its system to be safe and reliable and does so, in part, by conducting inspections, identifying maintenance needs, and then performing the needed maintenance within appropriate timeframes calibrated to risk. Thus, open notifications are a necessary and unremarkable feature of diligent utility system maintenance.

As to the 52 notifications that Cal Advocates suggests were past their due date,[68] analysis shows that these notifications were either not overdue or that there were valid reasons for the delays. None of these notifications involved the Specific Facilities or had any connection to the Woolsey Fire. Twelve of the notifications (for pole replacements due to pole loading failures) that appear more than two years overdue were not actually overdue; SCE completed the work prior to the due date but closed

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[67] *See* Appendix E, p. E-9 (excerpt of Cal Advocates' response to SCE-CalAdvocates-A241002-001, providing PG&E's response to CalAdvocates-PGE-A2410002-CKM-002, Question 1(b)); CA09SA-449 (SDG&E's response to CALPA-SDGE-A2410002-CKM-003, Question 1(a)) (providing that "[d]etailed inspections are performed every five years throughout SDG&E's service territory" and noting that SDG&E performed supplemental "QC inspections" on a three-year cycle in certain extreme and very high fire threat areas); *see also* CA09SA-449 (SDG&E's response to CALPA-SDGE-A2410002-CKM-003, Question 1(c)) ("SDG&E does not perform annual detailed inspections on every transmission and distribution asset. Therefore, there were years between 2014 and 2018 when poles did not receive a detailed inspection.").

[68] CA-08, pp. 9–10.

the notifications in SAP after the due date.[69] An additional 39 of the 52 notifications involved third parties (e.g., conditions relating to third-party communication equipment or customer-installed equipment) and were delayed due to either an inability to contact the third party or the third party's failure to remediate the issue.[70] Accordingly, only one of the 52 notifications was overdue not due to third-party coordination at the time of the Woolsey Fire. That notification—for a deteriorated pole—was created during a transmission patrol in November 2017 and was just four days overdue as of November 8, 2018.[71]

Cal Advocates also identifies 39 Priority 2 asset notifications with due dates in 2020 or later and implies that those due dates were inconsistent with SCE's procedures. Cal Advocates is correct that after the Commission revised GO 95, Rule 18 to require Priority 2 conditions in High Fire-Threat District (HFTD) Tier 3 that created a fire risk to be remediated within 6 months,[72] SCE updated its field tool so that Priority 2 notifications defaulted to "ignition risk" status and the remediation timeframe was limited to a maximum interval of 6 months. However, 36 of the 39 notifications that Cal Advocates references were issued prior to December 17, 2017, when that revision took effect. Moreover, all 39 of the notifications arose from the PLP (38 notifications) or IPI program (1 notification), which did not rely on the referenced field tool. Rather, SCE's PLP and IPI programs evaluated whether a pole marked as "fail" presented a fire risk based on the condition of the pole. All 39 notifications were issued dates for remediation consistent with SCE's pole remediation timeframe policy or IPI program, as applicable.[73] And the majority of the notifications (31 out of 39) were completed by 2019, well in advance of their scheduled due dates.

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69 *See* Appendix F.

70 *See* Appendix F.

71 A second notification to replace this pole originated from the IPI program and was dated June 22, 2017, but was not overdue at the time of the Woolsey Fire. Both notifications were closed when the pole was replaced in early 2019.

72 D.17-12-024, Appendix B, p. B-3.

73 That policy evaluated potential fire risk based on the pole's safety factor as compared to both SCE's wind loading standards (which were higher than regulatory requirements) and the wind loading standards in effect at the time the pole was constructed. SCE's IPI program prioritized pole replacements based on their Remaining Section Modulus (RSM) value.

3. Notifications Do Not Show Any Particular Guy or Clearance-Related Conditions on the Big Rock Circuit

Cal Advocates also posits that SCE should have identified "emerging issues" on the Big Rock Circuit based on the number of notifications containing the words "Clear," "Guy," or "Loose," which Cal Advocates suggests should have prompted SCE to develop a plan "focused on resolving clearance issues and ensuring the integrity of down-guy support structures."[74] Cal Advocates' assertion is incorrect and based primarily on an arbitrary selection of search terms.

As an initial matter, guy and clearance-related notifications on the Big Rock Circuit indicate that inspectors were attuned to those issues and actively identifying them for remediation. In other words, these notifications themselves resulted from operational practices that Cal Advocates supports, such as devoting resources to field inspections, asset condition monitoring, and assuring compliance with GO 95.[75]

Moreover, Cal Advocates' three selected keywords do not indicate any particular asset condition. For example, of the 108 notifications that contain Cal Advocates' keywords:

- 15 were Priority 2 notifications for unauthorized signs (13 notifications), a light, and a mirror attached to poles;
- 10 were Priority 3 notifications for missing guy guards;[76] and
- 21 were "Priority 9" notifications, which are for "minor repairs at the Public level"[77] performed as part of the detailed inspection.[78]

These notifications alone account for more than 40 percent of the 108 notifications containing "Clear," "Guy," or "Loose," yet have nothing to do with clearance or the structural integrity or tautness of down guys. Eliminating some of these irrelevant notifications yields a more apt comparison. For example, excluding problem statements that indicate a missing guy guard or a third party, customer, or Communications Infrastructure Provider (CIP) issue, 14.5 percent of ODI

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74 CA-09, pp. 6–10, Fig. 2.

75 *See* CA-09, p. 10.

76 Guy guards are typically plastic, steel, or PVC covers used to mark and protect guy wires.

77 DIMP Manual Section 3.4.

78 Although the problem code for these 21 notifications is "REPLC DAMAGE PUBLIC GUY POLE," they were likely minor repairs such as trimming or wrapping frays. ODI inspectors would not have replaced a guy itself during an inspection.

notifications systemwide from 2014-2018 contain Cal Advocates' keywords as compared to 13.2 percent for the Big Rock Circuit.[79]

Even if one could develop a keyword search that reasonably proxies relevant guy-related issues, comparing the proportion of those notifications to other notifications may not yield a meaningful comparison.[80] For this reason, in evaluating asset conditions SCE often considers the "find rate" for specific issues, which is the number of notifications for a specific issue as compared to the number of inspections.[81] There was no meaningful difference between the 2014-2018 ODI find rates for Priority 2 and 3 notifications for which the equipment type was "Guy" (there were no Priority 1 notifications for this equipment type) on the Big Rock Circuit and the system overall (3.45 percent for the Big Rock Circuit and 3.46 percent systemwide).

By these metrics, the Big Rock Circuit did not have a markedly higher incidence of guy-related issues than the system overall, and there is no pattern of conditions that indicate any particular issue or needed mitigation.

B. SCE Had Numerous Programs and Practices to Proactively Identify Asset Replacement Projects at a Circuit and Local Level

More generally, Cal Advocates asserts that SCE's recordkeeping system did not link structures to circuits and so did not "readily enabl[e] a comprehensive assessment of wildfire hazards and risks on individual circuits" and created "delays in post-event analysis" and "limitations in executing targeted infrastructure improvements."[82] This argument ignores SCE's numerous proactive asset replacement programs and practices designed to identify and minimize safety and reliability risks systemwide and on the local and circuit levels and is premised on a misunderstanding of SCE's system capabilities and data request responses.

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[79] Cal Advocates did not include deleted notifications in its count for the Big Rock Circuit, but did include them for the system overall. Correcting for this issue does not make a meaningful difference to Cal Advocates' data. For these figures, SCE has included deleted notifications both for the Big Rock Circuit and systemwide.

[80] For example, if SCE inspected 10 poles on the Big Rock Circuit and found 5 notifications with the words "GUY," "CLEAR," or "LOOSE" and 5 without, and inspected 100 poles systemwide and found 50 notifications with those words and 200 without, the *find rate* would be the same (50 percent) but the Big Rock Circuit would reflect a much higher *percentage of notifications* (50 percent versus 20 percent) due to the number of *non*-guy related notifications.

[81] For example, SCE uses find rates in forecasting maintenance costs in its General Rate Case and in reporting notification trends to the Safety and Enforcement Division.

[82] CA-09, p. 3.

Contrary to Cal Advocates' assertions, SCE's systems *do* link structures to circuits. SCE's Geographic Information System (GIS) contains all structure-to-circuit associations for the system's current configuration. That information can then be utilized with SAP, SCE's asset management system of record, to obtain associated inspection, notification, and work order records for a given circuit. Accordingly, now and as of 2018, SCE could easily identify all asset records for a given circuit.[83] As explained below, SCE can and does incorporate asset data from SAP into various circuit-level analyses in its proactive asset replacement programs.

1. SCE Proactively Replaced Distribution Conductor Through Its Overhead Conductor Program

As set forth in SCE-03, in 2013 SCE began developing a proactive approach to replace existing distribution conductor throughout its service area in an effort to reduce the frequency and impact of wire down events.[84] SCE's research culminated in the launch of the OCP in 2014, which involved analyzing "risk factors" for each distribution circuit to identify and prioritize circuits for conductor replacement. The OCP utilized SCE's Prioritized Risk-Informed Strategic Management (PRISM) framework, which SCE developed in 2014 to facilitate risk analysis and spend prioritization across its system. PRISM provided a consistent and transparent risk scoring framework to enable SCE to directly compare risks based on their frequency and potential impact.

SCE incorporated several factors into its risk analysis for OCP, including historical wire downs, circuit breaker operations, fault duty, miles of small conductor, and conductor-related maintenance notifications. By comparing these circuit-specific attributes relative to average circuit attributes, SCE developed a predicted wire down count for each circuit, or Triggering Event Frequency (TEF).[85] SCE also determined a Consequence Percentage (probability that a consequence occurs when a triggering event occurs) for each circuit based on circuit attributes such as high fire miles, high wind

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[83] Cal Advocates' misunderstanding of SCE's ability to link structures to circuits seemingly stems from a caveat SCE provided in response to a Cal Advocates data request, in which SCE noted that it utilized contemporaneous GIS data to determine structures on the Big Rock Circuit near the time of the fire. CA09SA-003. SCE flagged this process only to note that circuits change over time; SCE did not intend to suggest that SCE is unable to link assets to circuits generally.

[84] SCE-03, pp. 25–26.

[85] A.16-09-001 (SCE's 2018 General Rate Case), SCE-02, Vol. 1, Appendix, pp. 2, 11.

miles, proximity to canyons, and customer density.[86] SCE utilized its risk rankings by circuit to scope proactive OCP work.

Accordingly, through its OCP SCE was performing exactly the type of proactive, circuit-specific analysis that Cal Advocates asserts was impeded by SCE's systems. Notably, ORA and other intervenors recommended a slower ramp-up for the OCP and lower replacement quantities than those requested by SCE for 2017 and 2018 to "create[] a reasonable balance between insuring [sic] that SCE's system reliability will improve, and moderating future customer rate increases."[87]

2. SCE Analyzed Reliability Impacts of Aging Infrastructure on a Circuit-by-Circuit Basis Through Its Worst Circuit Rehabilitation Program

As set forth in SCE-03, since 2005 SCE has also utilized its Worst Circuit Rehabilitation program to identify and minimize the impact of aging infrastructure on system reliability.[88] This program ranked each of SCE's 4,600 circuits according to key reliability metrics including the System Average Interruption Duration Index (SAIDI) and System Average Interruption Index (SAIFI).[89] Although Cal Advocates criticizes SAIDI and SAIFI as "lagging indicators," they are industry standard measures of reliability, developed by the Institute of Electrical and Electronics Engineers (IEEE)[90] and endorsed by the Commission for use in reliability reporting and circuit performance ranking.[91] SCE then selected the top-ranked (i.e., worst performing) circuits in each category for further evaluation and potential corrective actions including fusing, installation of isolation devices (e.g., automation and

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86 A.16-09-001 (SCE's 2018 General Rate Case), SCE-02, Vol. 1, Appendix, pp. 1, 11.

87 *See, e.g.*, A.16-09-001, ORA-08, p. 22.

88 SCE initially implemented this program in 1997, known as the Annual Circuit Review (ACR). That program was halted in 2004 due to lingering effects of the financial crisis of 2002-2003, and the program was restarted in 2005 as the Worst Circuit Rehabilitation Program.

89 Circuits were evaluated based on certain metrics including: (1) contribution to system-wide SAIDI; (2) contribution to system-wide SAIFI; (3) circuit-level SAIDI; (4) circuit-level SAIFI; (5) peak load x number of interruptions/number of customers; and (6) source loss customer interruption.

90 IEEE Standard 1366.

91 *See* D.16-01-008, Appendix B (updating electric reliability reporting requirements and requiring utilities to provide SAIDI and SAIFI information and identify Worst Performing Circuits based on SAIDI and SAIFI); *see also* CPUC Energy Division, Electric System Reliability, pp. 4 & 9 (Feb. 17, 2021), *available at* https://www.cpuc.ca.gov/-/media/cpuc-website/transparency/commissioner-committees/emerging-trends/2021/2021-02-17-electric-system-reliability-presentation---final.pdf (describing SAIDI and SAIFI as "the generally accepted standards by which electric utilities across the US measure and report system reliability" and noting that utilities use electric reliability metrics to "track[] performance of circuits to address service issues" and target circuits for remediation).

automatic reclosures), and conductor replacement. This program primarily focused on underground cable given that those facilities tended to have a greater impact on reliability, but did result in some overhead conductor replacement, including in high fire risk areas (HFRA).

3. Local Experts Provided Input on Emerging Asset Issues for Remediation

In addition to the formal circuit ranking and asset replacement programs described above, SCE's inspection and maintenance programs in both transmission and distribution allowed local experts to provide input on emerging asset issues. For transmission, as discussed in SCE-03, SCE assigned Senior Patrolmen to circuits or circuit segments. The assigned Senior Patrolman was responsible for completing an annual circuit patrol to document or monitor issues.[92] This model enabled the assigned Senior Patrolman to become familiar with the facilities on the circuit and to identify recurring asset conditions. Senior Patrolmen could then identify any specific concerns to the Grid Manager.[93] Senior Patrolmen met with their Grid Manager regularly, including at monthly safety meetings and monthly operational meetings, and met with Senior Patrolmen from across the service area at patrol all-hands meetings. These frequent touch points allowed Senior Patrolmen to raise any issues that warranted additional focus in inspections or more proactive infrastructure replacement.

In addition, capital investments for transmission in the years prior to the Woolsey Fire were driven by Grid leadership and field observations. Specifically, transmission adopted an Infrastructure Replacement (IR) program that allowed Grids to request funding for specific projects in response to issues observed in the field. Transmission Grids could submit an IR initiation form for review and approval by SCE's Design Governance and Transmission, Substations & Operations organization. As an example of a proactive IR program driven by the Grids, the Transmission group deployed capital to replace potheads after Senior Patrolmen observed numerous pothead failures in the field. Similarly, SCE proactively replaced wood poles supporting conductor over freeway crossings due to the observed potential for safety and reliability issues.

Inspectors and crews responsible for maintenance of distribution lines similarly had opportunities to identify asset issues and local concerns. For example, a district crew responding to an outage could complete a Material Performance Failure Report for review by Apparatus Engineering. Based on those reports, SCE's Apparatus Engineering team identified trends with specific equipment

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92 *See* SCE-03, p. 44.

93 SCE's transmission system was divided into eight operational Grids, each with a Grid Manager who oversaw all operational roles (patrolmen and heavy crews) within that Grid.

and developed a plan to address the issue, such as working directly with the vendor or launching a proactive replacement program. Gatekeepers also tracked common issues that arose in notifications they reviewed and could raise those issues at periodic Gatekeeper meetings. Gatekeepers brought common findings identified through those meetings to Apparatus Engineering for evaluation.

As an example of a proactive distribution asset replacement program developed through these processes, in 2005 plastic transformer mounting brackets known as Scott Brackets failed in the field, causing three transformers to fall from a pole. The Scott Brackets were submitted to Apparatus Engineering for review. SCE's Apparatus Engineering consulted with an outside polymer expert to evaluate the brackets and, as a result, determined that brackets of a certain vintage could be expected to suffer from aging and crack propagation. In response, SCE conducted field inspections of the more than 58,000 transformer banks on its system to identify and prioritize brackets for risk mitigation. SCE proactively replaced, removed, or restrained more than 16,000 transformer banks through this program.

At the District level, inspectors and field crews brought reliability challenges to Distribution Engineering for review. Distribution Engineering would then propose localized projects to address the issues. In addition, SCE convened District Grid Team meetings, which included representatives from District leadership, Distribution Engineering, and Grid Operations, to review reliability issues for circuits within the District and identify possible solutions, such as reconductoring or installing new switches. The District Grid Teams would then present proposed projects to the Regional Grid Team to request funding.

In sum, SCE was performing exactly the type of proactive, targeted infrastructure replacement that Cal Advocates asserts is emblematic of a prudent utility inspection and maintenance program.

Appendix A

Maintenance Practices for Transmission Facilities Under the Operational Control of the California Independent System Operator, Revision 5 (Excerpt)

Southern California Edison Company

Maintenance Practices for Transmission Facilities under the Operational Control of the California Independent System Operator (ISO)

Revision 5

January 2013

Table of Contents

1.0 INTRODUCTION

This document describes the Maintenance Practices employed by the Southern California Edison (SCE) Company for the Inspection, Maintenance, and Restoration of Transmission line and Substation facilities.

2.0 PURPOSE

The intent of these Practices is to help ensure the safe delivery of reliable power in a cost-effective manner and compliance with applicable regulatory requirements and standards.

These Practices are based in part upon internal system knowledge, experience and expertise, as well as accepted Good Utility Practice. The application of these Practices takes into consideration competing influences, such as operating protocols, storm conditions, capital projects, regulatory requirements and environmental conditions.

Deviations to established maintenance intervals of up to twenty-five (25) percent, can be expected and not be considered as a deviation to these Maintenance Practices.* Prior to going beyond the established maintenance intervals such impending deviations shall be evaluated with due consideration given to Good Utility Practices and impact on Availability performance. Certain scheduled activities may also be extended beyond the allowable twenty-five (25) percent deviation period under special circumstances and, contingent upon the results of the ISO deferral process*, not be considered as a deviation to these Maintenance Practices. In all cases, the responsible manager or supervisor is accountable for monitoring program deviations and ensuring the completion of scheduled activities.

***** - Excludes Protection System Components and Tests performed on an Annual/Calendar interval

3.0 DEFINITIONS

3.1 Annual or Calendar - Activities to be completed anytime within the year activities are due.

3.2 Availability - A measure of time a Transmission Line Circuit under the ISO Operational Control is capable of providing service, whether or not it actually is in service.

3.3 Discrepancy - A noteworthy material or structural deficiency, or a condition that does not a) meet SCE standards and specifications, or b) conform to regulatory requirements.

3.4 Fully Monitored - Applies to microprocessor relays and other associated Protection System Components in which every element or function required for correct operation of the Protection System Component is monitored continuously or verified, including verification of the means by which failure alarms or indicators are transmitted to a central location within 1 hour or less of the maintenance-correctable issue occurring. For fully-monitored systems or segments, documentation is required that shows how every possible failure, including a failure in the verification or monitoring system or alarming channel, is detected. This is the highest level of monitoring and would require no interference for routine testing as the system is continuously monitored.

3.5 Good Utility Practice - Any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods, and acts, which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Good Utility Practices is not intended to be any one of a number of optimum practices, methods, or acts to the exclusion of all others, but rather acceptable practices, methods, or acts generally in practice in the region.

3.6 Inspection

- **Routine (Substation) -** A basic visual and/or auditory evaluation of equipment, parts, and structural components for the purpose of identifying Discrepancies.
- **Detailed (Transmission) -** A systematic, technical appraisal or diagnostic testing of facilities.

3.7 Maintenance - Encompasses inspection, assessment, maintenance, repair and replacement activities performed with respect to Transmission Facilities.

3.8 Operation - The mechanical action of equipment or component parts.

3.9 Partially Monitored - Applies to microprocessor relays and associated Protection System Components whose self-monitoring alarms are transmitted to a location (at least daily) where action can be taken for alarmed failures. Given these advanced monitoring capabilities, it is known that there are specific and routine testing functions occurring within the device. Because of this ongoing monitoring, hands-on action is required less often because some routine testing is automated.

3.10 Patrol (Transmission Line)

- **Emergency -** A visual assessment (typically unscheduled) performed at ground level or via aircraft, often following a circuit interruption, to identify damaged facilities.
- **Routine -** A visual assessment (typically scheduled) performed at ground level or via aircraft, for the purpose of identifying, priorities and recording discrepancies. This activity may include effecting minor or temporary repairs.

3.11 Protection System

- Protective relays which respond to electrical quantities
- Communications systems necessary for correct operation of protective functions
- Voltage and current sensing devices providing inputs to protective relays
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply)
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices

3.12 Reliability Centered Maintenance - The necessary repair, reinforcement, and/or replacement activities to correct an observed Discrepancy, which is the simultaneous use of predictive, periodic, proactive, reactive strategies to achieve a high level of system reliability.

- **Predictive -** Action based on an assessment of the equipment condition (Conditioned Based)
- **Periodic -** Action performed on a predetermined interval
- **Proactive -** Action performed to prevent a failure of a class of equipment or component based on root-cause analysis
- **Reactive -** Action performed as a result of a major, unforeseen event, such as storms, earthquakes, or failure of equipment that affects safety or reliability of the transmission system

3.13 Repair (Maintenance Correctable Issue) - The restoration or reconditioning of equipment and components.

3.14 Replacement - The installation of new or refurbished equipment or components.

3.15 Special Protection Scheme (SPS) - Also called Remedial Action Scheme (RAS). An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (Mega Watt and Mega VAR), or system configuration to maintain system stability, acceptable voltage, or power flows.

3.16 Station Log - A business record of events occurring within a Station.

3.17 Substation/Station - The secured site or location containing equipment (i.e. switches, circuit breakers, buses, transformers) and components (relays, batteries, communication lines, misc. wiring, etc..) uniquely located and under the control of qualified SCE employees, through which energy is passed for the purpose of stabilization, switching and/or transformation.

3.18 Supervisory Control and Data Acquisition (SCADA) - A communication network that allows a system operator to remotely monitor and control elements of an electric system.

3.19 Test (Substation) - The assessment of equipment or components through the use of one or more diagnostic methods.

3.20 Transmission Facility - All equipment and components transferred to the ISO for operational control.

3.21 Transmission Lines - The continuous set of conductor and/or cable, including structures, switches and similar components, including associated Rights Of Way, located outside of Substations.

3.22 Trigger - A condition or threshold that requires inspection and/or maintenance of equipment/structure(s) at a frequency other than the scheduled intervals.

3.23 Unmonitored - Applies to electromechanical relays, solid state relays, and their associated Protection System Components whose capabilities do not include self-monitoring attributes.

3.24 Work Management System (WMS) - The interactive database used to collect data, schedule, and monitor pending and completed activities.

4.0 Responsibilities

Six departments within SCE's Transmission and Distribution Business Units and one department in SCE's Generation Business Unit and Information Technology are responsible for performing Patrol, Inspection or, Maintenance, and restoration activities.

4.1 Transmission and Distribution Business Unit

4.1.1 Central Design - responsible for administering SCE's Pole Replacement Program and Intrusive Inspections

4.1.2 Distribution Construction and Maintenance - responsible for administering SCE's Transmission Vegetation Management Program

4.1.3 Grid Operations - responsible for the 24-hour operation of the electric system (Grid), including the monthly Inspection of Station equipment and components

4.1.4 Resource Planning and Performance Management - responsible for the governance and oversight of Transmission Line Patrol and Substation Inspection and Maintenance, and restoration programs, including Work Management System records

4.1.5 Substation Construction and Maintenance - responsible for the construction, maintenance and testing of designated Substation facilities and administering associated Work Management System records not under the operational jurisdiction of the Power Production Department

4.1.6 Transmission - responsible for the design, construction, patrol, inspection and maintenance and restoration of designated overhead and underground transmission line facilities (including Rights Of Way), and the administration of associated Work Management System records

4.2 Generation Business Unit

4.2.1 Power Production Division - responsible for performing substation inspection, maintenance and testing activities located in or adjacent to all Generation Facilities and for the administration of associated Work Management System data

4.3 Information Technology Department - responsible for the Maintenance of Station communication and monitoring systems equipment

5.0 PRACTICES

5.1 Transmission Lines

5.1.1 Patrols and Inspections

5.1.1.1 Routine Patrol - performed and completed on an annual basis by a Senior Patrolman or qualified lineman. Based on initial findings, the responsible Senior Patrolman or lineman, in consultation with a Grid Manager and/or Engineer, may determine that a Detailed Inspection is needed.

5.1.1.2 Emergency Patrol - performed on an "as-needed" basis by a Senior Patrolman or qualified lineman, typically after a circuit relay, system event, or storm to affirm structures, lines, and/or equipment are suitable for service.

5.1.1.3 Detailed Inspection - typically performed following a Routine or Emergency Patrol by a Senior Patrolman, engineer, or technical specialist, but may also be performed by contract personnel.

5.1.2 Methodology

5.1.2.1 Routine Patrol - typically conducted from the ground level by truck, foot, or snow cat. Helicopters are also used in certain rural or mountainous areas where ground-level access is restricted or considered unsafe.

5.1.2.2 Emergency Patrol - typically conducted from the air by helicopter or fixed wing aircraft, but may also be conducted from the ground level by truck, foot, or snow cat.

5.1.2.3 Detailed Inspection - often accomplished by climbing support structures or towers to identify broken, missing or worn hardware. Also includes, but is not limited to the excavation of soil, intrusive testing of wood poles and performing infrared scans.

5.1.3 Frequency

Facility/Equipment	Routine Patrol		Emergency Patrol		Insulator Wash
	Ground	Aerial	Ground	Aerial	Ground
Overhead Lines and Communication Circuits[2]	Annual[1]	As needed	As needed	As needed	As needed
Idle[3] Overhead Lines and Communication Circuits	2 Years	As needed	As needed	As needed	As needed
Underground Lines	1 Year[4, 5]	N/A	As needed	N/A	N/A
	3 years[6]				
Idle[3] Underground Lines	3 years[6]	N/A	N/A	N/A	N/A

Notes:

1. May be performed by air on alternate years.
2. Encompasses SCE open wire communication, control and alarm circuits.
3. Lines and Line segments are considered idle after being declared “Out of Service”.
4. Only those lines and line elements visible above ground level.
5. Includes 220 kV “piped cables”. Supplemental tests performed on an “as-needed” basis.
6. Includes vault or enclosure entry.

5.1.4 Priority Ratings

Discrepancies identified during Patrols or Detailed Inspections that require remedial action are prioritized according to the table below. Factors influencing the initial rating assignment include, but are not limited to: public and employee safety; system condition; accessibility; and environmental conditions.

Priority	Overhead and Underground	Wood Poles	Rights of Way	Encroachments
1	Initiate corrective action	Initiate corrective action	Initiate corrective action	Initiate corrective action
2	Remedy within one (1) or up to three (3) years	Remedy within one (1) year or up to three (3) years *	Remedy within one (1) year or up to three (3) years	Remedy within one (1) year or up to three (3) years
3	Re-evaluate next routine patrol cycle	Re-evaluate next inspection cycle	Re-evaluate next inspection cycle	Re-evaluate next inspection cycle

* may include reinforcement or life-extension action.

5.1.5 Maintenance

Facilities listed below identified as a Priority 1 condition are immediately repaired, replaced or reinforced in such a manner as to preserve public and worker safety, and system reliability. Affected facilities may be repaired or reinforced on a temporary basis, re-assigned as a Priority 2 condition and scheduled for completion at a later date. Facilities listed below identified as a Priority 2 are scheduled for completion in consideration of resources (parts, equipment and manpower) availability, design and/or engineering requirements; required circuit outages; environmental impacts; and other limiting factors.

5.1.5.1 Overhead Facilities

- Anchors/Guys (includes span guys)
- Conductors/Shield wires (includes associated insulators, accessories, and hardware)
- Cross arms (includes Timbers and Spar Arms)
- Ground wires
- Rights Of Way
- Structures (includes associated foundations)
- Switches
- Wood poles
- Vegetation Management

5.1.5.2 Underground Facilities

- Arrestors
- Cables/Cable systems (including splices)
- Cathodic protection
- Fluid pumping facilities
- Rights Of Way
- Subsurface structures (includes vaults and manholes)
- Terminations

5.1.6 Supporting Programs

Certain Inspection and Maintenance, and restoration activities are administered separately in cooperation with the Transmission Department.

5.1.6.1 Pole Replacement Program

The Central Design Department administers the Pole Replacement Program, which encompasses the visual and intrusive testing of Transmission and Distribution wood poles; including necessary repair, reinforcement and replacement.

5.1.6.2 Wood Pole Inspection Program

5.1.6.2.1 Visual Inspection - a 360-degree visual assessment of the pole that may include a sound (echo) test at or near the ground line. Visual inspections of poles that have been repaired or reinforced are conducted on a 10-year cycle. Typically performed by Senior Patrolmen and construction crews, these inspections may also be performed by contract personnel.

5.1.6.2.2 Intrusive Inspection - the boring of holes to identify degradation. These inspections are categorized as either: “Partial Dig”, “Full Treatment”, or “Sound and Bore” (for poles set in asphalt or concrete) and are typically performed by contract personnel according to SCE specifications. SCE crews may also perform such an inspection if the integrity of a pole is suspect.

Intrusive Inspection of poles with twenty (20) years or more of service are conducted on a fifteen (15) year cycle. A chemical fumigant is also applied internally, according to SCE specifications, when appropriate.

Visual and Intrusive test results are recorded and submitted to the responsible M&I Program administrator for review and input into a Work Management System.

5.1.6.2.3 Maintenance - activities are categorized as repair, reinforcement or replacement. SCE’s reinforcement techniques typically include “steel stubbing” or “fiberglass-wrap”.

Poles identified for replacement are routed through the Pole Replacement Program. Pole replacement activities are accomplished by SCE crews or contract personnel.

5.1.6.2.4 Record Keeping - administered by Resource Planning and Performance Management staff and retained in accordance with SCE's Transmission and Distribution Business Unit policy or other contract/regulatory requirements, if more prescriptive.

5.1.6.3 Rights Of Way

The Transmission Rights Of Way group is responsible for assuring SCE's property rights are upheld and resolving rights related to technical issues inherent in the interface between the operational, maintenance, and developmental goals of the Transmission Department. Assigned specialists, in association with Senior Patrolmen and Grid Managers oversee maintenance activities in accordance with the terms of relevant rights documents, public regulations, ordinances and corporate standards.

5.1.6.3.1 Assessments - Senior Patrolmen and qualified linemen are responsible for identifying Discrepancies during Routine or Emergency Patrols and recording actionable items in the Work Management System or Encroachment Management System. Discrepancies that require immediate action are reported to the assigned Grid Manager and/or Transmission ROW specialist.

ROW specialists are responsible for ensuring their assigned corridors and access roads are properly maintained and may conduct supplemental assessments to affirm additional needs or to monitor ongoing maintenance activities.

5.1.6.3.2 Maintenance - encompasses one or more of the four basic categories: infractions/encroachments, road construction/grading, weed abatement, and anti-climbing guards.

5.1.6.3.3 Record Keeping - tracking encroachments, infractions, and related maintenance activities are the responsibility of the ROW specialists.

Encroachment records are retained in accordance with SCE's Transmission and Distribution Business Unit policy or other contract/regulatory requirements if more prescriptive.

5.1.6.4 Vegetation Management

The Vegetation Management (VM) Department is responsible for all line-clearing activities occurring within each Transmission Grid. VM Supervisors and Technical Specialists in cooperation with Senior Patrolmen are responsible for preventing outages caused by trees located below or adjacent to Transmission Lines.

Associated vegetation to line clearances are established to comply with requirements set forth in General Order 95, Rule 35; California Public Resources Code 4292; and NERC Reliability Standard FAC-003.

5.1.6.4.1 Inspections - typically conducted from the ground level by contract personnel in accordance with the VM Department's annual operational plan. Any revisions to scheduled inspections due to fires, storms, or access restrictions are approved by VM Supervisors.

Senior Patrolmen and qualified linemen may also identify trees requiring remediation during the course of performing a Patrol or Inspection.

Post-maintenance inspections are conducted by VM Technical Specialists and may be performed from the ground level or via aircraft.

5.1.6.4.2 Maintenance - typically performed by contract personnel. Required maintenance (trims and removals) is accomplished by mechanical means in accordance with the terms and conditions of a pre-established contract. Supplemental and/or emergency maintenance may also be identified and initiated by VM Supervisors and Technical Specialists, but may also be performed by Senior Patrolmen or qualified linemen as needed.

5.1.6.4.3 Record Keeping - typically consists of inspection and maintenance information submitted by contract personnel (and SCE personnel as needed) to the VM Department analyst for entry in a Work Management System.

Records are administered and retained in accordance with SCE's Transmission and Distribution Business Unit policy or other contract/regulatory requirements if more prescriptive.

5.1.7 Record Keeping

SCE's Maintenance records shall, at a minimum, include the: 1) responsible person; 2) Maintenance date; 3) Transmission Facility; 4) findings (if any); 5) priority rating (if any) and 6) description of Maintenance activity performed.

Responsible departments will retain documentation for six (6) years or two (2) maintenance cycles, whichever is greater.

5.1.8 Restoration Practices

5.1.8.1 Oversight

In general, restoration of transmission facilities is administered by the Transmission Department's Construction & Maintenance group. If sufficient resources are not available the Division Logistic Support Group will assist with the restoration efforts.

5.1.8.2 Preventative Measures

Prior to the various seasonal weather changes, each work group evaluates Transmission Facilities at locations which could impact the system. Results are reported to the appropriate supervisor or Grid Manager. Record keeping for pre-storm inspections is by exception only and recorded in the Work Management System.

Preventative measures which can be accomplished to minimize problems include, but are not limited to, the following:

- Check and clean drainage systems, such as culverts and over-side drains
- Check access roads for signs of erosion
- Check proper drainage around poles and towers
- Check for potential ponding on access roads
- Check for indication of soil slippage above or below any facility
- Tree Removal

5.1.8.3 Damage Assessment

Each work group will communicate damage assessment information and available resources to the appropriate supervisor or Grid Manager. Restoration plans are developed and executed as needed.

5.1.8.4 Damage Repair

Each work group will coordinate repair efforts and deploy resources to the highest priority locations.

5.2 Substation

5.2.1 Inspections

5.2.1.1 Scheduled

Stations are inspected monthly. When the operator enters the station an entry is made in the station logbook which lists the identity of the inspector, the purpose for entering the station, and the date of the entry. During the inspection, findings which impact the safety and reliability of the station are entered in the station logbook. Safety and reliability issues are immediately reported to the appropriate supervisor for appropriate action. Identified discrepancies that require immediate action are communicated to the responsible supervisor. Discrepancies identified that do not require immediate action are recorded in the Station Log and/or Work Management System. Responsible supervisors review identified discrepancies and assign a priority rating and schedule as necessary.

5.2.1.2 Unscheduled

Following storms, fires, earthquakes or system events, Grid Operations and/or Substation Department personnel are dispatched to assess equipment, components and the general condition of impacted Stations. Also, the monitoring of certain pieces of equipment (by SCADA or other electronic means) often requires personnel to respond to switching center alarms (indicating Station trouble) to identify the cause.

Identified Discrepancies that require immediate action are communicated to the responsible supervisor. Discrepancies identified that do not require immediate action are recorded in the Station Log and/or Work Management System. Responsible supervisors review identified discrepancies and assign a priority rating and schedule as necessary.

5.2.1.3 Substation Equipment Inspected

- Battery System
- Circuit Breakers
- Current/Potential Transformers
- Disconnect Switches
- Insulators/Bushings/Arresters
- Protective Relay Systems
- Reactive Power Components
- Perimeter fences and gates
- Station Service Equipment
- Structures/Foundations
- Station Grounds
- Transformers/Regulators
- Vegetation Management

5.2.2 Maintenance

5.2.2.1 Priority Rating

The responsible supervisor or upgraded employee will utilize a Reliability Centered approach when establishing a priority rating. Past performance and the significance of the equipment (e.g., potential load loss, safety, Grid stability, and cost impact) are considered during this decision making process.

Priority	Action
1	Initiate Corrective Action
2	Remedy within six (6) years or re-evaluate.
3	No action required. Re-evaluate during next inspection.

Each responsible supervisor may opt to increase the frequency of Inspections or Tests, and may reschedule necessary Maintenance.

5.2.2.2 Scheduled

Maintenance activities identified during Inspections, ongoing Maintenance or Testing are scheduled and performed by SC&M and Hydro personnel.

5.2.2.3 Unscheduled

Necessary Maintenance identified by personnel while performing scheduled Repair or Replacement tasks, after responding to Station alarms, and/or emergency conditions are completed under the direction of the responsible supervisor. Vegetation Management tasks (including weed abatement) in and around Stations are performed on an as-needed basis.

5.2.3 Equipment and Test Intervals

Substation equipment listed below is based on several factors, including, but not limited to: historical performance, circuit criticality, circuit voltage classification; known system anomalies; and manufacturer's recommendations.[1] Protection System Components listed below address circuit criticality and voltage classification by Protection System redundancy.

Protective System Component Types	**Test Intervals (Calendar Years)**		
	1	**6**	**12**
Batteries (Unmonitored) [2,4]	X		
Protective Relays (Unmonitored)		X	
Control and trip circuits with electromechanical trip or auxiliary contacts (Unmonitored)		X	
Associated communications systems (Unmonitored)		X	
Voltage and Current Sensing Inputs to Protective Relays and associated circuitry (Unmonitored) [3]			X
WECC Registered Remedial Action Schemes (RAS) Functional Test (Unmonitored & Partially Monitored)	X		
Protective Relays (Partially Monitored)			X
Control and trip circuitry (Partially Monitored)			X
Associated communications systems (Partially Monitored)			X
Protective System Components (Fully Monitored) No Testing Requirements	N/A	N/A	N/A
Other Equipment	**Test Intervals (Calendar Years)**		
	1	**6**	**12**
DFRs, SERs, and PMUs			X
Circuit Breaker Analysis (CBA)	X		
Oil Filled Reactors (Oil Analysis)	X		
Transformer Main Tank (Oil Analysis)	X		
Load Tap Changers (Oil Analysis)	X		
Insulators/Bushings/Arresters/Disconnect Switches Infrared (IR Inspections)		X	
Insulator Wash	As Needed		

Note:
1. Equipment not listed above, testing is performed at the time of installation, and in response to Inspection findings, Maintenance activities, or Emergency conditions
2. Not to exceed 18 months
3. PT/CT component testing will be implemented on a "phased in" approach
4. Unit Ohmic testing performed

5.2.4 Record Keeping

SCE's Maintenance records shall, at a minimum include: 1) responsible person; 2) Maintenance date; 3) Transmission Facility; 4) findings (if any); 5) priority rating (if any) and 6) description of Maintenance activities performed.

All business units shall retain documentation for six (6) years or two (2) maintenance cycles, whichever is greater.

5.2.5 Restoration Practices

5.2.5.1 Oversight

In general, restoration of transmission facilities shall be administered by the Substation Construction & Maintenance and Grid Operations. If sufficient resources are not available the Division Logistic Support Group will assist with the restoration efforts.

5.2.5.2 Preventative Measures

Prior to the various seasonal weather changes, each work group evaluates Transmission Facilities at locations which could impact the system. Results are reported to the appropriate supervisor or Manager. Record keeping for pre-storm inspections is by exception only and recorded in the Work Management System.

Preventative measures which can be accomplished to minimize problems include, but are not limited to, the following:

- Check and clean drainage systems, such as culverts and over-side drains
- Check all sump pumps, repair as necessary
- Remove trees which lean towards facilities
- Check surrounding area of substations and access roads for potential water flow or change in grade
- Check for indication of soil slippage above or below any facility
- Check retaining walls

5.2.5.3 Damage Assessment

Each work group will communicate the damage assessment information and available resources to the appropriate supervisor. Restoration plans are developed and executed as needed.

5.2.5.4 Damage Repair

Each work group will coordinate repair efforts and deploy resources to the highest priority locations.

SOUTHERN CALIFORNIA EDISON
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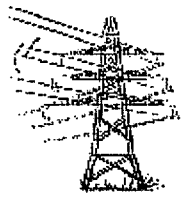
Attachment 1 (IM–4): Transmission Routine Patrol Condensed Activity List
Table 1 (IM–4): Transmission Patrol Condensed Activity List: Overhead Lines



Transmission Patrol Condensed Activity List

Overhead Lines

1.0 Check each Structure Top to Bottom:

- ☐ Condition of arms
- ☐ High voltage signs (where applicable)
- ☐ Loose, bent or missing lattice steel on towers
- ☐ Loose or missing bolts, fills, or steps.
- ☐ Damaged, pitted or flaking galvanizing.
- ☐ Condition of bird guards and / or climbing discouragers including requirements for same
- ☐ Condition of poles, and crossarm bonds and covers
- ☐ Condition of distribution facilities on structures
- ☐ Condition of Fiber Optic Ground Wire (FOGW) if applicable including splice boxes - SkyWrap
- ☐ Unauthorized foreign attachments
- ☐ Base of pole or tower footings stable and secure
- ☐ Tower footings leg extensions are clear of brush and trees
- ☐ Tower footings have proper concrete projections for site conditions
- ☐ Corrosion of grillage footings, stub angles
- ☐ Tower site has proper drainage and erosion control measures as required for site
- ☐ Jumper loops have proper clearances and attachments with swing string insulators and weights including spacers on bundle conductors
- ☐ Bird nests or other foreign material (active or abandoned)
- ☐ Danger signs and anti-climbing barrier on towers
- ☐ Graffiti

Attachment 1 (IM–4): Transmission Routine Patrol Condensed Activity List

Table 1 (IM–4): Transmission Patrol Condensed Activity List: Overhead Lines – *Continued*

- ❑ Climbing steps are correct and comply with specifications
- ❑ Visibility strips correctly installed and in good condition
- ❑ Line names, mile/tower numbers, switch numbers, crossing markers installed correctly & legible on towers
- ❑ Line names, switch numbers, crossing markers installed correctly & legible on poles & other structures

2.0 Check Insulators / Hardware / Conductors:

- ❑ Broken, cracked and/or shot
- ❑ Proper size, proper quantity, (i.e., skirt orientation toward or away from the tower on dead end strings)
- ❑ Torn weathersheds or exposed core rod on polymer insulators
- ❑ Polymer insulators for signs of excessive tracking or corona damage
- ❑ Proper installation / application of corona rings on polymer units
- ❑ OHGW for damaged or flashed over insulators (applies to 500 kV circuits)
- ❑ OHGW for proper grounding scheme (applies to 500 kV circuits)
- ❑ Suspension insulators hanging plumb (including OHGW where applicable)
- ❑ Condition of load bearing hardware (signs of wear, or incorrect installation)
- ❑ Vibration dampers, armor rods, and spacers
- ❑ Signs of abnormal wear, vandalism, or broken / damaged strands
- ❑ Fault return conductors installed (LWS Poles) correctly, grounds installed correctly & secure
- ❑ Conductor splices for signs of abnormal conditions or broken / damaged strands of aluminum
- ❑ Contamination
- ❑ Loose insulator bonds
- ❑ Old or new flashovers
- ❑ Cotter keys and pins in wind or vibration problem areas

Attachment 1 (IM–4): Transmission Routine Patrol Condensed Activity List

Table 1 (IM–4): Transmission Patrol Condensed Activity List: Overhead Lines – *Continued*

3.0 Check Guys:

- ❑ Correct breaker placement (where required)
- ❑ Clearances from conductors and jumper loops and over railroads, roads, highways, sidewalks and paths
- ❑ Clearances through distribution circuits
- ❑ Possibility of conductors or jumper loops swinging into guy during wind or washing
- ❑ Anchor rod eyes are 6‴ out of ground
- ❑ Guy covers installed and in good condition
- ❑ Rust conditions of anchors, guys and fittings
- ❑ Proper tension
- ❑ Pole attachments are tight, etc.

4.0 Check Conductors:

- ❑ Uneven sag or uneven sub-conductors in bundle circuits
- ❑ Condition of spacers for bundled conductors in spans ahead and back
- ❑ Spans ahead and back for signs of conductor damage
- ❑ Damage from gunshot or other causes
- ❑ Non-compression jumper loop connections are secure and comply with Forestry regulations.
- ❑ Clearances from other phases or circuits, and from ground or grounded objects
- ❑ Splices for signs of overheating (compound oozing from splice) ahead and back

5.0 Check Surrounding Area for Natural Conditions:

- ❑ Trees - establish clearances needed and make comparisons on the pole or tower to judge clearances, i.e., 66 kV string of insulators about 30", 220 kV strings about 6' - 7', etc.
- ❑ Brush and potential fire hazard to lines
- ❑ Water or wind erosion near structures, anchors, etc.
- ❑ lides or wind-caused dirt or sand piled over tower footings or above treatment line on poles

Attachment 1 (IM–4): Transmission Routine Patrol Condensed Activity List

Table 1 (IM–4): Transmission Patrol Condensed Activity List: Overhead Lines – *Continued*

6.0 Check Construction or Activities that Affect the Line:

- ❑ Houses or structures under lines or on right-of-way
- ❑ New roads or pipeline construction near or approaching rights of way
- ❑ Excavations under lines, on right of way, or near structures
- ❑ Evidence of additional utility or communication/CATV facilities
- ❑ Indications that work is planned by others near the right-of-way (survey stakes, equipment parked nearby, etc.)
- ❑ Investigate housing tracts near lines
- ❑ Investigate highway or street construction work that may encroach on or cross rights of way
- ❑ Take note of activities that cause dust or smoke contamination to insulators (crop dusting, harvesting, or planting of crops, fires near lines, industrial plants, etc.)

7.0 Check Access Roads:

- ❑ Water or wind erosion, rocks or slides which impair access to facilities
- ❑ Water drains from tower site and does not pool at site or at individual footings
- ❑ Access road grades are proper and water bars are installed and operational when required
- ❑ Access roads are graded clear of brush and vegetation
- ❑ Trees that intrude on the traveled way
- ❑ Overhanging brush
- ❑ Farm or ranch roads that cut off access
- ❑ Gates locked and in good condition
- ❑ Fences and gates grounded properly
- ❑ Culverts or over-side drains are clear of weeds and debris, properly located, connected, and anchored
- ❑ Grass, weeds, or other combustible material that could causing a fire hazard on the road

Attachment 1 (IM–4): Transmission Routine Patrol Condensed Activity List

Table 1 (IM–4): Transmission Patrol Condensed Activity List: Overhead Lines – *Continued*

8.0 Completing the Patrol

- ❑ Create 'As-Found' repair records for those repairs completed during the patrol
- ❑ Create WMS Work Requests in the Transmission Field Tool (TFT) for problems found but not repaired using the correct problem code and priority.
- ❑ Complete the WMS Work Control Document for the Routine Patrol in the TFT, entering the date of completion and all required data.
- ❑ Plan to repair those items that were not fixed during the patrol, including a discussion with the patrol supervisor, programming lines, accumulating material, etc.
- ❑ Complete the WMS Work Control Document(s) for the repair(s) in the TFT after repair(s) are completed.

Attachment 1 (IM–4): Transmission Routine Patrol Condensed Activity List

Table 2 (IM–4): Transmission Patrol Condensed Activity List: *Underground Lines*

Underground Lines:

1.0 Check Terminations

- ❑ Cracks and chips in the porcelain
- ❑ Tracking or tears in polymer terminations
- ❑ Cable jacketing for deterioration
- ❑ Leaking oil
- ❑ Loose electrical connection
- ❑ Any indication of flashover

2.0 Check Riser Poles (Wood and Steel):

- ❑ Cable slippage
- ❑ Cable support grip deterioration
- ❑ P.V.C. riser damage or deterioration
- ❑ Loose pole hardware

3.0 Check Arresters:

- ❑ Cracks or chips in the porcelain
- ❑ Tracking or tears in polymer arresters
- ❑ Indication of flashover or burning around the exhaust ports
- ❑ Loose electrical connections
- ❑ Grounds properly installed

Attachment 1 (IM–4): Transmission Routine Patrol Condensed Activity List

Table 2 (IM–4): Transmission Patrol Condensed Activity List: *Underground Lines – Continued*

4.0 Check Vaults "Externally":

- ☐ Missing or damaged bolts in cover
- ☐ Ownership markings and vault number
- ☐ Traffic damage or subsidence around vault or over trench
- ☐ Water or leaks from ducts, lids or covers
- ☐ Proper signage for vaults containing shield arresters
- ☐ Check vaults "internally":
- ☐ Duct plugs are installed (where necessary) and in good working order
- ☐ Water, Sand, Dirt, mud, signs of vermin, debris, etc., inside structure
- ☐ Corroding racks, hooks, ground lugs and vault grounds
- ☐ Concrete spalling and rebar rusting
- ☐ Cable slippage, movement or strain (monitor / record as needed)
- ☐ Cable properly tagged and consistent with circuit map
- ☐ Scan splices for:
- ☐ Excessive heat
- ☐ Deteriorating arc proofing tape
- ☐ Splitting or deteriorating insulating tape
- ☐ Splitting or deteriorating jacketing tape
- ☐ Splitting or deteriorating heat shrink jacketing
- ☐ Deteriorating cable clamps
- ☐ Loose bond connections

Appendix B

Quality Control Data for Inspections on Transmission Facilities

Figure B-1: SCE Intrusive Pole Inspection (IPI) QC Inspections on Transmission Assets, 2016-2018

Year	2016	2017	2018
No. of Transmission IPI Inspections	9743	13208	15534
No. of Transmission IPI QC Inspections	226	432	253
% QC	2.3%	3.3%	1.6%
No. of QC Inspections Deemed "Pass"	191	401	250
Transmission IPI QC Conformance Rate	84.5%	92.8%	98.8%
Average Yearly QC Inspections Transmission IPI 2016-2018	12828		
Average % QC 2016-2018	2.4%		
Average Conformance Rate 2016-2018	92.4%		

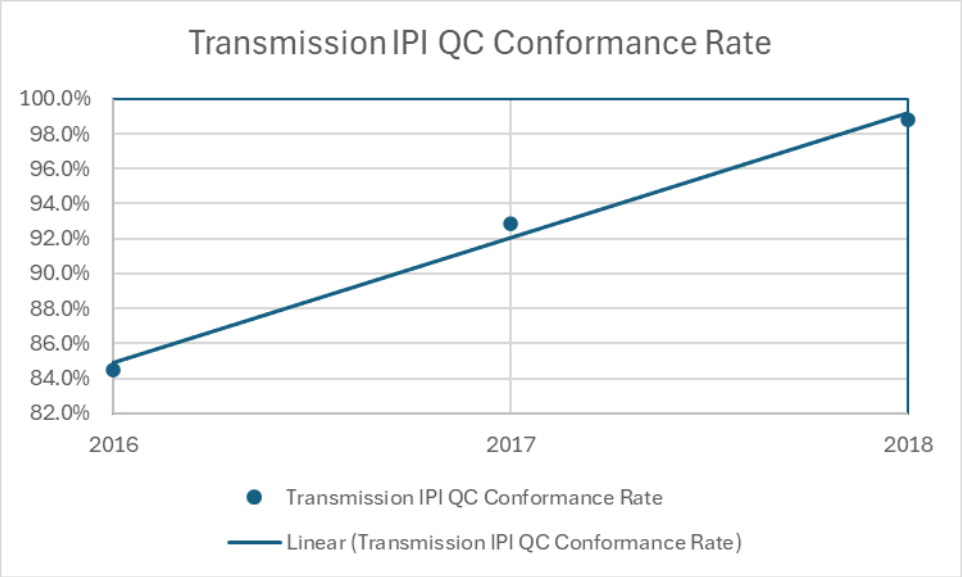


Figure B-2: SCE Pole Loading Program (PLP) QC Inspections on Transmission Assets, 2016-2018

Year	2016	2017	2018
No. of Transmission PLP Inspections	20333	16804	16868
No. of Transmission PLP QC Inspections	375	788	653
% QC	1.8%	4.7%	3.9%
No. of QC Inspections Deemed "Pass"	346	701	606
Transmission PLP QC Conformance Rate	92.3%	89.0%	92.8%
Average Yearly QC Inspections Transmission PLP 2016-2018	18002		
Average % QC 2016-2018	3.4%		
Average Conformance Rate 2016-2018	91.0%		

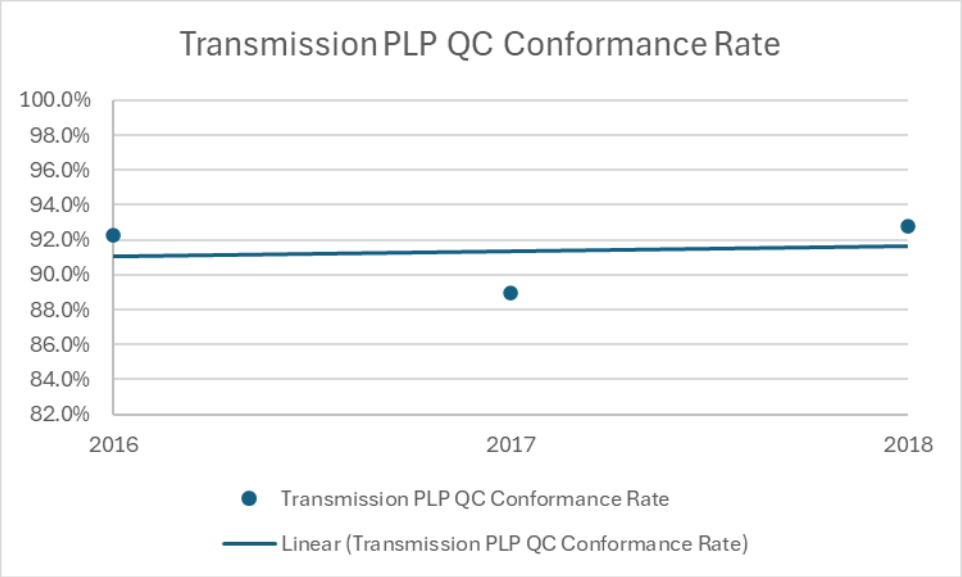


Figure B-3: Summary of IPI QC Inspections for Structures Inspected by Chatsworth-Thrust Circuit Inspectors, by Contractor, 2016-2018

Contractor*	No. of Intrusive Inspections	No. of QC Inspections	% QC	Conforming Structures	Conformance Rate
Contractor 1	7552	95	1.3%	81	85.3%
Contractor 2	2582	37	1.4%	36	97.3%
Contractor 3	2947	41	1.4%	38	92.7%

*Contractor names have been anonymized to protect confidentiality. Two additional contractors who completed IPIs on the Chatsworth-Thrust Circuit had not undergone QC inspections given their limited number of IPIs (78 and 301, respectively).

Appendix C

Vegetation in Guy Trim Record, Notification No. 409142215

[redacted]

From: [redacted]
Sent: Thursday, April 26, 2018 1:31 PM
To: [redacted]
Cc: [redacted]

Subject: 902382742 / KATHERINE RD SIMI VALLEY / DUE 8.1.2018 / HIGH FIRE AREA
Attachments: 409142215.pdf

FUNC LOC# OH-810065H
TREE LIMB HAS GROWN AROUND DOWN GUY AND IS DEFLECTING IT
NO POLE REPLACEMENT

PLEASE REPLY TO ALL WHEN COMPLETED.

Thank you ☺

[redacted]
Thousand Oaks Local Planning Department
[redacted]

SOUTHERN CALIFORNIA EDISON® | Energy for What's Ahead™

Vegetation Management Contract / Daily Tree Log

☐ Mid Cycle ☐ WCD ☐ TEMA
☐ Routine ☐ Storm ☑ Hourly

LOCATION/ADDRESS	SPECIES	TRIM L	TRIM C	REMOVE L	REMOVE C	HOURLY L	HOURLY C	LINE NO.	DOOR HANGER	COMMENTS
Katherine RD	Oak					1		N/A		cut back two large limbs to free guy wires from heavy tension tree was grown into guywire
Total Trees						1				
Total Hours				18						

C-Crew

Total Trees 1 Total Hours 18

LABOR DISTRIBUTION	NT	OT	DT	STAND-BY	STORM
Foreman [redacted]	6				
Trimmer [redacted]	6				
Appr. Tree Trimmer [redacted]	6				
Groundman					
General Foreman					
Other					
	18				

EQUIPMENT DISTRIBUTION TYPE	NO.	HOURS
Lift Truck	1	6
P. L. Truck		
Chipper	1	6
Pick-Up		
Stump Grinder		
Other		
	2	12

Chip Disposal	TRIPS	COST

Date 4-30-18 Grid N/A Work Location #35 Work Order No. 902382742

SCE 14-176 REV 9/09

COPY DISTRIBUTION: White - Vegetation Management, Canary - SCE/Contract, Green - Contract

Vegetation Management Contract / Daily Tree Log

☐ Mid Cycle	☐ WCD	☐ TEMA
☐ Routine	☐ Storm	☒ Hourly

LOCATION/ADDRESS	SPECIES	TRIM L	TRIM C	REMOVE L	REMOVE C	HOURLY L	HOURLY C	LINE NO.	DOOR HANGER	COMMENTS
Katherine Rd.								N/A		E-crew
										Present
P#OH-810065-H										for
										Trimming.

Total Trees 0

Total Hours 4

E-Crew

Total Trees Ø Total Hours 4

Foreman [redacted]

Trimmer

Appr. Tree Trimmer

Groundman

General Foreman

Other

LABOR DISTRIBUTION NT	OT	DT	STAND-BY	STORM
4				
4				

EQUIPMENT DISTRIBUTION TYPE	NO.	HOURS
Lift Truck		
P. L. Truck		
Chipper		
Pick-Up	1	4
Stump Grinder		
Other		
	1	4

Chip Disposal	TRIPS	COST

Date 4/30/18 Grid N/A Work Location 35. Work Order No. 902382742

SCE 14-178 REV 0/09

COPY DISTRIBUTION: White - Vegetation Management, Canary - SCE/Contract, Green - Contract

Appendix D

Distribution Inspection and Maintenance Program (DIMP) October 29, 2010 Issue (Excerpt)

SOUTHERN CALIFORNIA EDISON
TRANSMISSION AND DISTRIBUTION BUSINESS UNIT

Distribution Inspection and Maintenance Program (DIMP)

2010—FOURTH QUARTER ISSUE
October 29, 2010

This document is classified "Internal" per EPPC Policy 04.001.001.

▸ SCE Internal ◂

SOUTHERN CALIFORNIA EDISON
TRANSMISSION AND DISTRIBUTION BUSINESS UNIT
STANDARDS AND PUBLICATIONS
9500 CLEVELAND AVENUE, SUITE 115, RANCHO CUCAMONGA, CALIFORNIA 91730-5906
PAX: 10445 • VOICE: (909) 942-8445 • FAX: (909) 942-8319 • EMAIL: marcus.stelly@sce.com

Distribution Inspection and Maintenance Program (DIMP)

Revision Summary

2010—Fourth Quarter Issue

Effective Date: October 29, 2010

Overview

The main purpose of this revision summary is to describe notable revisions for the current quarter (Table RS–3). In addition, this revision summary provides:

- A list of the items in the revision package (Table RS–1)
- Directions to a Web site giving instructions for ordering additional copies of revision packages or complete manuals on CD or in paper format
- Contact information

Note: *Some or all of the information in this revision summary may have been previously communicated to field personnel by other means.*

Table RS–1: List of Items in Revision Package

Item	Description
1	Title Page
2	Revision Summary (this document)
3	Table of Contents
4	CG–Table of Contents: Condition Guides
5	CG–3: Underground Equipment and Structure Condition Guide

Ordering Information

For instructions on ordering the manual through the Edison Portal, visit Transmission & Distribution > Standards and Publications, and click the appropriate link under “Place an Order.”

Summary of Revisions

Standards-approved revisions are identified with **change bars** and can be “Admin” (Administrative), “New,” or “Technical” revisions. These three types of revisions are defined below in Table RS–2, followed by the revisions themselves in Table RS–3.

Table RS–2: Definitions of Revision Types

Type	Definition
Admin	Admin revisions do not significantly affect design, construction, maintenance or operation of the electrical distribution, substation, and transmission systems. These revisions do not require Standards Review Team (SRT) or management approval; however, these revisions have been approved by other organizations as appropriate. Admin revisions may include updates to material codes, updates to references, updates to standards for clarity, or deletions of outdated information.
New	Refers to a new standard. New technical standards require SRT and management approval.
Technical	Technical revisions are engineering changes to existing standards. These revisions affect the design, construction, maintenance or operation of the electrical distribution, substation, and transmission systems. These revisions require SRT and management approval.

Table RS–3: DOM Manual Revisions

Standard	Page	Description	Type
		Underground Equipment and Structure Condition Guide	
CG-3	13	Attachment 11 (CG-3) was updated to include a new Solid Dielectric Vacuum Switch table to identify the reliability and failure risk potentials.	Technical

Getting Help

Technical Revisions

If you have any comments, corrections, questions, or suggestions concerning this manual, please contact one of the following individuals:

- [redacted] — PAX: 54156, Outside: (714) 895-0156
- [redacted] — PAX: 54142, Outside: (714) 895-0142
- [redacted] — PAX: 54733, Outside: (714) 895-0733

Address Corrections

Send address changes to:

Southern California Edison
9500 Cleveland Ave., Suite 115
Rancho Cucamonga, CA. 91730
[redacted]

[redacted]
Engineering Director

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TOC

Table of Contents

GENERAL

GE

GE–TOC: General

Table of Contents

GE–1: Overview of Distribution Inspection and Maintenance Program

1.0 Introduction

1.1 Mission Statement

The Distribution Inspection and Maintenance Program (DIMP) seeks to ensure public and worker safety and regulatory compliance by completing scheduled Detailed Inspections and Grid Patrols, as described in Chapter IM-2 of the Distribution Operations and Maintenance Policies and Procedures (DOM) Manual, in conformity to the California Public Utilities Commission's (CPUC) General Order (G.O.) 165 and the performance of Distribution Maintenance, as described in Chapter IM-3 of the DOM, in accordance with G.O. 95, G.O. 128, SCE standards, and good utility practice. The purpose of this manual is to provide the necessary reference information to allow the field inspectors to perform the inspections in accordance with the program goals.

1.2 Program Overview

The DIMP is an ongoing Company-wide program established to maintain the distribution system in accordance with good utility practices and the CPUC's G.O. 165.

Over the years SCE has developed and improved its various maintenance and inspection programs to ensure the safety of its workers and the general public, as well as to provide reliable service to our customers.

General Order 165 was enacted on March 31, 1997 to establish maximum time intervals of inspection frequency of all electric distribution facilities within the jurisdiction of the CPUC. The basic premise of G.O. 165 is that all distribution assets must be patrolled every year for safety and reliability issues and the identification of significant G.O. 95 and 128 discrepancies. General Order 165 also requires these same assets to have a close up detailed inspection every 5 years (or less) to identify safety and reliability issues as well as all G.O. 95 and 128 discrepancies.

DIMP is SCE's approach to combining these two worthwhile endeavors into one efficient and cost effective program. This is a very large undertaking for SCE as there are over 2 million assets to be inspected and numerous SCE organizations involved.

1.3 Operations

The following is a listing of the major organizations involved in operations and their primary responsibilities:

A. Maintenance and Inspection

Maintenance and Inspection (M&I) is responsible for oversight and improvement of the DIMP, which includes:

- Strategic direction of IM program and governance of policies, including frequency, scope (including checklists), inspection methods, inspection forms, corrective action time frames, and documentation of inspection and repairs requirements
- Providing technical advisory staff
- Providing annual and informal training
- Developing performance measures

- Analyzing and tracking program department performance
- Providing staff to manage audits conducted by the CPUC

B. Distribution Construction and Maintenance

Distribution Construction and Maintenance is responsible for identifying and scheduling resources to achieve program goals and seek to ensure:

- Detail Inspections are completed correctly and timely
- Grid Patrols are completed correctly and timely
- Discrepancies are identified and rated correctly
- Rated discrepancies are recorded timely
- Priority 2 rated discrepancies are reviewed prior to Work Management System (WMS) upload
- Resultant Maintenance activities are scheduled properly
- Maintenance work is completed safely and according to policy

C. Performance Management and Analysis

Performance Management and Analysis is responsible for identifying and allocating resources to achieve DIMP goals and seeks to ensure:

- Work Management System work order errors are corrected
- Work Management System work orders are properly packaged for completion
- Pending and completed work orders are tracked

D. System Support and Administration

System Support and Administration is responsible for identifying and allocating resources to achieve DIMP goals by ensuring field tools (that is, recording devices) and the Work Management System are functioning properly.

E. Quality Control is responsible for administering an effective quality assurance program, assessing compliance with regulatory requirements and supporting continuous improvement of the DIMP.

1.4 Maintenance

The following is a listing of the major organizations involved in maintenance and their primary responsibilities:

A. Maintenance and Inspection creates and submits a report illustrating SCE's compliance with the requirements of G.O. 165 to the Law Department (for filing to the CPUC) by July 1st each year and produces supplemental internal reports as needed.

B. Performance Management and Analysis will assist the DIMP Governance to track and report on the following G.O. 165 mandated activities:

- Grid Patrols
- Overhead Detailed Inspections

- Underground Detailed Inspections
- Intrusive Pole Inspections
- Reportable Maintenance

1.5 Regulatory

Maintenance and Inspection has primary responsibility for resolving all CPUC audits of G.O. 95, G.O. 128, G.O. 165, and for responding to G.O. 165 requirements annually.

2.0 Action Prioritization

There are three basic elements to the overall inspection program: 1) Identification of actionable items, 2) Risk assessment and action prioritization, and 3) Actual repairs

2.1 Identification and Repair of Actionable Items

Information required to identify and repair actionable items (Items 1 and 3 above) are contained in the various SCE standards manuals as well as G.O. 95 and 128. The Condition Tables included in this document provide typical conditions, criteria and tests that have associated Priority 1 and 2 ratings. These tables are intended only to serve as aids, and do not, nor cannot, contain all the possible safety and reliability issues and/or General Order discrepancies that the inspector is expected to identify.

2.2 Risk Assessment and Action Prioritization

Risk assessment and prioritization of repair efforts for these actionable items (Item 2 above) requires evaluation of site and equipment specific conditions by the inspector to determine the appropriate priority rating and action time frame.

A. Rating System

The current program utilizes three priority ratings as compared to the five rating system used in the original detailed inspection program where “1” was the highest maintenance priority progressing down to “5” as the lowest maintenance priority. The new three priority rating system is designed to identify those action items that are truly 'safety and reliability' issues (defined as a condition which presents a hazard to worker or public or may cause a system failure), and to set action time frames that result in shorter overall time frames for repair. The three priority system retains “1” as the highest maintenance priority progressing down to “3” as the lowest. The three priorities are as follows:

1. Priority 1
   - Immediate action
   - Temporary repairs can be made then re-rated to Priority 2

2. Priority 2

   Zero to 24 months, based on the Risk Assessment principles

3. Priority 3
   - General Order 95/128 infractions that are not an imminent safety and/or reliability risk
   - Flag for Apparatus, replacement program
   - Can be re-prioritized

Overhead structures present unique public safety exposure and work conditions depending on the height of the necessary repairs from the ground level. At ground level more public exposure exists, and repairs pose few hazards to linemen. At the highest levels, public safety/exposure is low, while linemen are exposed to greater height and electrical risk. The priority system addresses these differences.

B. Maintenance Priority Accuracy

Maintenance priorities will be thoroughly evaluated and accurately assigned and maintained. Training and continuing analysis will take place to prevent premature maintenance, and to prevent failure prior to repair or the next scheduled inspection.

Condition assessment and associated priorities may be changed. A condition may be reevaluated and assigned a more appropriate priority to reflect a more effective corrective action, life-extension decision, repair schedule, or future re-inspection interval.

A discrepancy not yet entered into WMS can be re-rated after being reviewed by a qualified electrical worker (or supervisor with equivalent knowledge) clearly demonstrates that it was prioritized incorrectly. The discrepancy should then be entered into WMS with the appropriate revised priority. The PMA shall also note on the work order that it was a field revision and enter the field review employee (or QC auditor) as the inspector. Retain the original inspection date.

3.0 Attachments

Attachment 1 (GE–1): Assigning Priority Levels (Page 5)

Attachment 2 (GE–1): Risk Assessment Matrix — Things to Consider when Assessing a Condition (Page 6)

Attachment 3 (GE–1): Risk Assessment Matrix (Page 8)

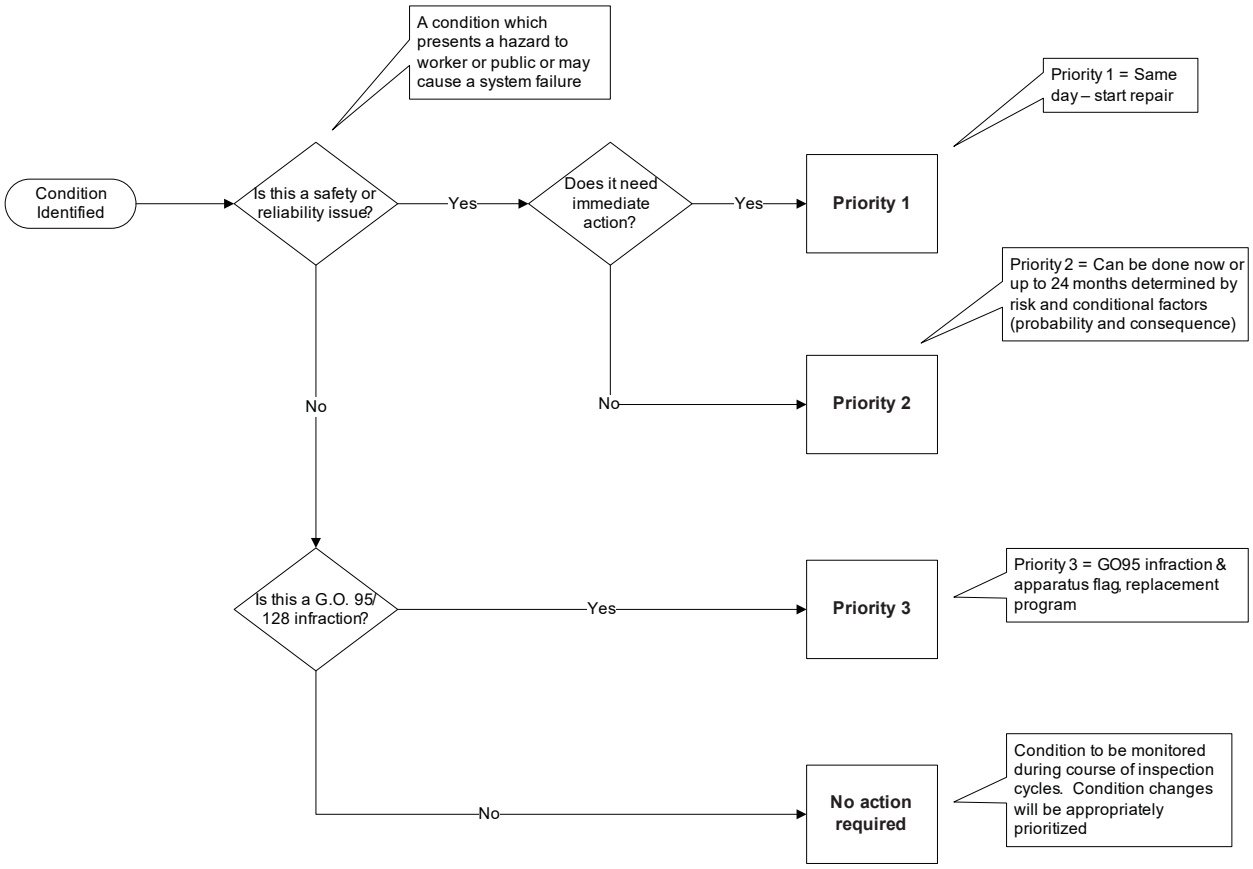
Attachment 1 (GE–1): Assigning Priority Levels

Once a condition is identified, the inspector asks up to three questions to determine the prioritization:

1. Is this a risk to safety and/or reliability?
2. If "Yes," does this require immediate action?
   a. If "Yes," then Priority 1
   b. If "No," then Priority 2
3. If "No," is this a G.O. 95/128 infraction or SCE standards deviation?
   a. If "Yes," then Priority 3
   b. If "No," then no action is required

This process is shown in Figure 1 (GE–1) on Page 5.

Figure 1 (GE–1): Priority Inspection Decision Flowchart



Once a condition has been determined to be a Priority 2, the inspector must now perform a risk assessment to properly establish a reasonable time frame within zero (0) to 24 months. This is done by assessing the condition through determination of the safety and reliability factors in accordance with Attachment 2 (GE–1): Risk Assessment Matrix — Things to Consider when Assessing a Condition (Page 6), and then applying this information to the risk assessment, Attachment 3 (GE–1): Risk Assessment Matrix (Page 8).

Attachment 2 (GE–1): Risk Assessment Matrix — Things to Consider when Assessing a Condition

NOTE Each problem or condition is independent from another.

Determine Safety Factors

Factors to consider when assessing the Safety Risk		
Public/Worker Safety	Property	Environmental
•Near a school/park •In front of a mall •Rear Property line •Behind a commercial strip center •In a vacant field •Minor pedestrian traffic •Major intersection •Impossible climbing space	•In a parking lot •In a high fire area •In an agricultural area	•In the desert •In costal areas •Mountainous •Urban/Rural •Time of season –High Wind –Rainy –High heat –Snow •Protective Habitats •Hazardous Spills
Its important to note that no one area weighs more than another. Only after you have considered all your surroundings, People/Property/Environment, can you make a true assessment of risk.		

Identifying the Safety Risk Impact Levels	
No/Slight Safety Impact	Any Condition which has *LITTLE/NO* safety risk to public or worker safety/Property/Environment.
Minor Safety Impact	Any Condition which has *MINOR* safety risk to public or worker safety/Property/Environment.
Moderate Safety Impact	Any Condition which has *MODERATE* safety risk to public or worker safety/Property/Environment.
High Safety Impact	Any Condition which has *HIGH* safety risk to public or worker safety/Property/Environment.

Attachment 2 (GE–1): Risk Assessment Matrix — Things to Consider when Assessing a Condition *(Continued)*

NOTE

Each problem or condition is independent from another.

Determine Reliability Factors

Construction Type

What is the component the condition is associated to?

What is the construction type of the component?

Is there any electrical equipment associated to the component?

Where is the condition located on the component?

What is the stress factor?

- Weight: High/Medium/Low
- Span Length: Long/Medium/Short

Circuit Type/Location

What is the highest voltage “Directly’ associated to the component?

What is the highest voltage “Indirectly” associated to component?

What is the load factor: High/Medium/Low

Is component located behind any fusing?

Attachment 3 (GE–1): Risk Assessment Matrix

Reliability (Failure Risk)	No/Slight Impact	Minor Impact	Moderate Impact	High Impact
Component Failure could lead to System Failure	**Priority 2** Action Required 13-24 Months	**Priority 2** Action Required 4-12 Months	**Priority 2** Action Required 0-3 Months	**Priority 1** Action Required Immediately
Component Has Failed No significant risk to system	**Priority 3/No Action Required** Only 95/128 Infractions Recorded	**Priority 2** Action Required 13-24 Months	**Priority 2** Action Required 4-12 Months	**Priority 2** Action Required 0-3 Months
Potential Component Failure	**Priority 3/No Action Required** Only 95/128 Infractions Recorded	**Priority 3/No Action Required** Only 95/128 Infractions Recorded	**Priority 2** Action Required 13-24 Months	**Priority 2** Action Required 4-12 Months
	Safety (People/Property/Environment)			

NOTE

This "Risk Assessment Matrix" is a training tool intended to give inspectors guidelines to assign a reasonable time frame for the correction or re-inspection of any distribution facility condition. It is not a substitute for the inspector's exercise of good judgment. These guidelines are based on DIMP safety and reliability principles developed in compliance with applicable decisions of the California Public Utilities Commission.

GE–2: Inspection and Maintenance Training

1.0 Purpose

Training for the SCE Distribution Inspection and Maintenance Program will promote safety and circuit reliability on all electrical distribution facilities for both underground and overhead systems through routine inspections.

2.0 Training Objectives

Initial training and necessary refresher training will be provided to all personnel inspecting distribution assets to ensure SCE will meet all inspection and maintenance objectives. These objectives include:

- Using proper field inspection procedures
- Accurately documenting and reporting the findings
- Prioritizing items identified for follow-up maintenance
- Compliance with PUC-required maintenance cycles on structures, equipment, conductors and/or components

Inspectors will be tested at completion of training.

3.0 Focus

The training focus for the SCE inspection program is to uniformly align all personnel, programs and responsibilities associated with inspections in an effort to achieve company-wide consistency with inspection practices and regulatory compliance.

The training shall also reinforce the program objectives, inspection procedures, reporting procedures and coordination of responsibilities among all key personnel throughout Power Delivery.

4.0 Operations

The Manager of Maintenance and Inspection is responsible for determination of training program requirements.

5.0 References

5.1 CPUC G.O. 95, Rules for Overhead Electric Line Construction

5.2 CPUC G.O. 128, Rules for Construction of Underground Electric Supply and Communication Systems

5.3 CPUC G.O. 165, Inspection Cycles for Electric Distribution Facilities

5.4 SCE Distribution Overhead Construction Standards (DOH)

5.5 SCE Distribution Underground Construction Standards (DUG)

5.6 SCE Distribution Operations and Maintenance Policies and Procedures (DOM)

5.7 SCE Accident Prevention Manual (APM)

5.8 SCE Environmental Policies and Procedures (EN)

5.9 Distribution Maintenance Program

5.10 Work Management System

5.11 Underground Corrosion Inspection and Maintenance Manual

5.12 SCE Training Manual for Performing Circuit Patrol, Detail Inspection and Intrusive Inspection of Wood Pole Structures

INSPECTION IN

INSPECTION

IN

IN–TOC: Inspection

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IN–1: Inspection Procedures — Overhead Detail Inspections

1.0 Purpose

The purpose of the overhead detail inspection (ODI) is to give a visual evaluation of SCE's overhead electrical distribution facilities with the intent to identify and document any hazardous conditions, SCE construction standards deviations, and/or the California Public Utility Commission's (CPUC) General Order (G.O.) 95 discrepancies for appropriate corrective action. Inspectors also identify and perform certain maintenance tasks during the course of a detailed inspection. Overhead detail inspections also accomplish the annual patrol of the overhead circuit.

2.0 Methods and Procedures

The ODI inspector shall perform a close in-depth visual inspection of all the overhead electrical distribution facilities within the assigned inspection area. The frequency of ODI is directed in the Distribution Operations and Maintenance Policies and Procedures (DOM) Manual, Chapter IM-1: Distribution Inspection and Maintenance Program.

3.0 Duties of ODI Inspector

The ODI inspector shall perform the following tasks for each facility detailed inspection:

3.1 Identification of Hazards and/or Discrepancies per the OH Detailed Inspection Checklist

The ODI inspector shall perform an in-depth visual examination of each overhead distribution facility using the following Detailed Inspection Checklist as a minimum guide. This list is a high level summary of the items and areas to inspect. Additional information showing typical conditions requiring corrective action (Priorities 1 and 2) is shown in the applicable overhead equipment and component Condition Guide attached. Identifiable Priority 3 conditions (no action required) can be found in the CPUC's G.O. 95 and the appropriate SCE standards manuals.

The ODI inspector shall also identify and report any G.O. 95/128 infractions created on or near Distribution facilities by non-utility third parties that are not subject to CPUC jurisdiction.

3.2 Establishment of Priorities per the Priority Decision Flowchart

Once the inspector has identified a condition requiring action, a risk assessment is performed using the Priority Decision Flowchart. This process helps identify the appropriate priority of the condition. The highest priorities are for those items that pose a safety hazard to the public or employees or could present a reliability threat to the system.

3.3 Establishment of Action Time Frames for Each Identified Priority 2 Condition per the Condition Guides, Condition Risk Assessment Matrix

Only Priority 1 and 2 conditions have action time frames for mitigation. Priority 1 requires same day action thus no action time frame decision is required from the inspector. As discussed in the General Section of this manual, Priority 2 conditions have zero (0) to 24-month time frame options depending on the severity of the situation.

3.4 Performance of Appropriate Minor Repairs at the "Public" Level

To improve the efficiency of our inspection and maintenance programs, it is cost effective for the ODI inspector to make minor repairs at the Public level while at the site for the detailed inspection, rather than taking the time to document and have other SCE personnel return at a later time to make the repairs. Following is a list of repairs that the ODI inspector is expected to perform:

- Repair damaged ground molding
- Install new and/or repair existing guy guard.
- Repair damaged visibility strips or install new strips in locations where necessary.
- Install or repair riser strap.
- Install pole number.
- Remove unauthorized attachments when safe to do so

3.5 Validation of Accuracy of Asset Information and Facility Inventory Mapping References

It is extremely important that SCE's records be as accurate as possible. The ODI inspector is a valuable force in realizing this goal. While at the facility site, the ODI inspector shall perform the following:

- Records corrections—asset details, pending repairs
- Mapping corrections

3.6 Document in the Field Tool

Refer to the Work Management System (WMS) Procedure Manual.

4.0 References

4.1 CPUC G.O. 95, Rules for Overhead Electric Line Construction

4.2 CPUC G.O. 165, Inspection Cycles for Electric Distribution Facilities

4.3 SCE Distribution Overhead Construction Standards (DOH)

4.4 SCE Distribution Operations and Maintenance Policies and Procedures (DOM)

4.5 SCE Accident Prevention Manual (APM)

4.6 SCE Environmental Policies and Procedures (EN)

4.7 Distribution Maintenance Program

4.8 Work Management System

4.9 SCE Training Manual for Performing Circuit Patrol, Detail Inspection and Intrusive Inspection of Wood Pole Structures

5.0 Attachments

Attachment 1 (IN–1): Overhead Detailed Inspection Checklist (Page 3)

Attachment 1 (IN–1): Overhead Detailed Inspection Checklist

1. Condition of Equipment, Apparatus, and Hardware
   - Broken, chipped, or severely contaminated insulators/Primary insulator or pin above 750 V (cracked/damaged/loose)
   - Pole switch indicating need for repair
   - Indication of equipment oil leak
   - Bulged or discolored capacitor units
   - Blown or dry fuses, blown surge arresters, broken fuse-holders
   - Streetlights broken or damaged
   - Animals, birds, foreign material interfering with operation
   - Evidence of tracking or burning
   - Broken pins or squatters (primary or secondary)
   - Broken, bent pole steps
   - Damaged or missing ground wire molding or ground wire exposed
2. Condition of Pole and Structures
   - Damage/deteriorated pole
   - Crossarm broken, split, or extremely canted
   - Washout or excavation around pole or anchor
   - Check pole setting depth marked from brand. (Brands are at 10 feet on 60-foot poles and less; at 13 feet for poles taller than 60 feet.)
   - Damage down guys, guy guard missing (Install guard where required.)
   - Excessive slack on down guys or span guys
   - Visually check pad-mounted equipment for movement and cabinet secured or locked.
   - Visually check BURD lids, vault lids, and vent pipes.
3. Conductors
   - Inadequate primary, secondary, or service ground clearances
   - Excessive slack in primary conductors in high wind areas
   - Clearance from building, television or radio antenna, billboard signs, scaffolding, streetlights, communication cable or hazardous locations for primary, secondary or services
   - Trees touching or above primary conductors (overhangs) unless special encased tree cable (18 inches required)
   - Hazardous tree conditions, limbs over wire, dead or decaying trees, palm fronds
   - Foreign objects in line, such as kites, Mylar balloons, and so forth
   - Bare conductors in rack construction
   - Bare service drops
   - Heavy branch, limb causing strain or abrasion on service drops
   - Abandoned conductors
4. Risers
   - Riser straps, blocks broken, unattached, and so forth
   - Opening in riser conduit coupling, damaged
   - Riser in climbing space in rack construction
5. Climbing Space
   - Obstructions in climbing space, bolts, wire, and so forth
   - Climbing space obstructed by cable TV or phone, and a hazard to climb
6. General Conditions
   - Unlocked substations, pole switches, equipment, and so forth
   - Verify circuit-to-circuit map for additional equipment and tap lines not identified.
   - Check status of fault indicators with circuit map inventory.

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IN–2: Inspection Procedures — Grid Patrols

1.0 Purpose

The purpose of the grid patrol is to give a yearly evaluation of SCE's electrical distribution facilities with the intent to identify and document any safety and reliability hazardous conditions that require corrective action.

2.0 Methods and Procedures

The grid patrol inspector shall perform a routine visual inspection of all the overhead electrical distribution facilities within the assigned inspection area. The frequency of Grid Patrols is directed in in the Distribution Operations and Maintenance Policies and Procedures (DOM) Manual, Chapter IM-1: Distribution Inspection and Maintenance Program.

The Patrol will observe the entire primary system and all publicly accessible overhead and underground assets in order to identify and record obvious safety and reliability items on the primary system and readily visible secondaries. Associated equipment includes conductors, pole line hardware, switches, automatic circuit reclosers, capacitor banks, and overhead transformers.

The inspections can be performed from vehicles, on foot, or by aircraft. The vehicle method is the most used as it provides the required accuracy while being cost effective. The problem conditions can generally be seen adequately by the naked eye or through the use of binoculars. Inspectors are not required to enter rear properties unless the structures are not readily visible from the street or other public property. The Patrol does not require the climbing of overhead structures (poles) or the opening of underground structures and equipment. Inspectors shall attempt to inspect all assigned structures from the ground when safe and practical to do so. If a portion of the circuit cannot be safely and/or cost effectively inspected from the ground, then that portion shall be bypassed and clearly documented in red on the inventory maps for follow-up air patrol.

Underground facilities such as pad-mounted transformers, BURD enclosures, vent pipes, and vault lids are also included as items to be visually observed for public safety hazards during an overhead circuit Patrol. Underground portions of the circuit, including pad-mounted equipment, that are located in rear property lines, within private property, or in limited access communities do not require a patrol as these structures and equipment are in a controlled environment. In these cases the Underground Detail Inspection will be used to ensure compliance.

3.0 Duties of Grid Patrol Inspector

The grid patrol inspector shall perform the following tasks for each facility in the grid:

3.1 Identification of Hazards and/or Discrepancies per the Grid Patrol Checklist

The grid patrol inspector shall perform a routine visual examination of each overhead distribution facility using the following Grid Patrol Checklist as a minimum guide. This list is a high level summary of the items and areas to inspect. Additional information showing typical conditions requiring corrective action (Priorities 1 and 2) is shown in the applicable equipment and component Condition Guide attached. Identifiable Priority 3 conditions are generally not identified or documented as part of a grid patrol.

3.2 Establishment of Priorities per the Priority Decision Flowchart

Once the inspector has identified a condition requiring action, a risk assessment is performed using the Priority Decision Flowchart. This process helps identify the appropriate priority of the condition. The highest priorities are for those items that pose a safety hazard to the public or employees or could present a reliability threat to the system.

3.3 Establishment of Action Time Frames for Each Identified Priority 2 Condition per the Condition Guides, Condition Risk Assessment Matrix

Only Priority 1 and 2 conditions have action time frames for mitigation. Priority 1 requires same day action thus no action time frame decision is required from the inspector. As discussed in the General Section of this manual, Priority 2 conditions have zero (0) to 24-month time frames.

3.4 Performance of Appropriate Routine Repairs

The Patrol shall also repair or install new guy guard/markers on down guys in general public proximity or exposed to pedestrians, areas easily accessible to the general public, parking lots, or areas exposed to vehicular contact. Any repair by inspector during a patrol will be recorded in the field tool.

3.5 Document in the Field Tool

Refer to Work Management System (WMS) Procedure Manual.

4.0 References

4.1 CPUC G.O. 95, Rules for Overhead Electric Line Construction

4.2 CPUC G.O. 165, Inspection Cycles for Electric Distribution Facilities

4.3 SCE Distribution Overhead Construction Standards (DOH)

4.4 SCE Distribution Operations and Maintenance Policies and Procedures (DOM)

4.5 SCE Accident Prevention Manual (APM)

4.6 SCE Environmental Policies and Procedures (EN)

4.7 Distribution Maintenance Program

4.8 Work Management System

4.9 SCE Training Manual for Performing Circuit Patrol, Detail Inspection and Intrusive Inspection of Wood Pole Structures

5.0 Attachments

Attachment 1 (IN–2): Grid Patrol Checklist (Page 3)

Attachment 1 (IN–2): Grid Patrol Checklist

1. Condition of Equipment, Apparatus, and Hardware
   - Broken, chipped, or severely contaminated insulators/Primary insulator or pin above 750 V (cracked/damaged/loose)
   - Pole switch indicating need for repair
   - Indication of equipment oil leak
   - Bulged or discolored capacitor units
   - Blown or dry fuses, blown surge arresters, broken fuse-holders
   - Streetlights broken or damaged — public hazard
   - Animals, birds, foreign material interfering with operation
   - Evidence of tracking or burning
   - Broken pins or squatters (primary or secondary)
2. Condition of Pole and Structures
   - Damage/deteriorated pole
   - Crossarm broken, split, or extremely canted
   - Washout or excavation around pole or anchor
   - Damage down guys, guy guard missing — public hazard
   - Excessive slack on down guys or span guys — clearance problem or pole integrity issue
   - Visually check pad-mounted equipment for movement and cabinet secured or locked.
   - Visually check BURD lids, vault lids, and vent pipes.
3. Conductors
   - Inadequate primary, secondary, or service ground clearances
   - Excessive slack in primary conductors in high wind areas
   - Clearance from building, television or radio antenna, billboard signs, scaffolding, streetlights, communication cable or hazardous locations for primary, secondary or services
   - Trees touching or above primary conductors (overhangs) unless special encased tree cable (18 inches required)
   - Hazardous tree conditions, limbs over wire, dead or decaying trees, palm fronds
   - Foreign objects in line, such as kites, Mylar balloons, and so forth
4. Risers
   - Riser straps, blocks broken, unattached — public hazard
   - Opening in riser conduit coupling, damaged conductor — public hazard
5. General Conditions
   - Unlocked substations, pole switches, equipment, and so forth

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Appendix E

Public Advocates Office's Response to SCE-CalAdvocates-A2410002-001 (Excerpt)

Public Advocates Office's Response to Data Request

Proceeding: A.24-10-002: Cost recovery for Woolsey Fire

Data request:	SCE-CalAdvocates-A2410002-001
Date of receipt:	May 19, 2025
Response date:	June 6, 2025 (Extension granted from June 3, 2025)

Question 1

Responding witness: Aaron Louie

Question:

Please provide a complete set of the data requests that Cal Advocates has served on any other entity in connection with this proceeding or otherwise in support of Cal Advocates' testimony (whether formally part of A.24-10-002 or "NonCase") and all responses to the same. This question is ongoing in nature and covers all discovery that Cal Advocates serves and responses Cal Advocates receives through the beginning of evidentiary hearings. For any future discovery, provide the data requests and responses within three business days of receiving the discovery responses.

Answer:

Cal Advocates has issued the following discovery requests to other entities in connection with this proceeding:

- CalAdvocates-PGE-A2410002-JD-001
- CalAdvocates-PGE-A2410002-CKM-002
- CalAdvocates-SDGE-A2410002-JD-001
- CalAdvocates-SDGE-A2410002-JD-002
- CalAdvocates-SDGE-A2410002-CKM-003
- CalAdvocates-SDGE-A2410002-004

Cal Advocates has provided the initial data request and the responses received by other entities are attached in the following zip folder attachment "*Cal Advocates DR.zip*". Specific responses provided by Pacific Gas and Electric (PG&E) related to "*CalAdvocates-PGE-A2410002-JD-001*" were marked as Confidential and were not provided.

Public Advocates Office Data Request

No. CalAdvocates-PGE-A2410002-CKM-002
Proceeding: A.24-10-002: Cost recovery for Woolsey Fire

Date of issuance: May 2, 2025
Responses due: May 15, 2025

To:

Wade Greenacre
Pacific Gas and Electric Company — Email: WAG9@pge.com

Regulatory Relations
Pacific Gas and Electric Company — Email: RegRelCPUCCases@pge.com

Andrew Ace
Pacific Gas and Electric Company — Email: ASAB@pge.com

Joel Crane
Pacific Gas and Electric Company — Email: JP39@pge.com

Aaron Shapiro
Pacific Gas and Electric Company — Email: AWSZ@pge.com

Electric Data Requests
Pacific Gas and Electric Company — Email: ElectricDataRequests@pge.com

From:

Charles Madison
Senior Utilities Engineer
Public Advocates Office — Email: Charles.Madison@cpuc.ca.gov

Aaron Louie
Utility Analyst
Public Advocates Office — Email: Aaron.Louie@cpuc.ca.gov

Crystal Yu
Attorney
Public Advocates Office — Email: Crystal.Yu@cpuc.ca.gov

Corwin Hockema
Attorney
Public Advocates Office — Email: Corwin.Hockema@cpuc.ca.gov

Cal Advocates Wildfire Discovery — Email: CalAdvocates.WildfireDiscovery@cpuc.ca.gov

INSTRUCTIONS

You are instructed to answer the following Data Request in the aforementioned proceeding, with written, verified responses pursuant to Public Utilities Code §§ 309.5(e), 314, 581 and 582, and Rule 1.1 of the California Public Utilities Commission's (CPUC) Rules of Practice and Procedure.

Restate the text of each data request question prior to providing the response. Provide the name and title of the responding individual (i.e., the person responsible for the content of your answer) for each data request question. If the responding individual is not your employee, please provide their name, title, and employer, as well as the name and title of your employee who is directly responsible for the work of the responding individual.

Please send your responses and inquiries to the originators of this data request (that is, the Public Advocates Office employees and attorneys listed on the cover page), with copies to the following representatives of the Public Advocates Office:

1. CalAdvocates.WildfireDiscovery@cpuc.ca.gov
2. Henry.Burton@cpuc.ca.gov
3. Holly.Wehrman@cpuc.ca.gov

Timing of responses: Please respond to each question as soon as your complete response to that specific question is available, and no later than the due date listed on the cover sheet.

Requests for Clarification: If a request, definition, or an instruction, is unclear, please notify the originators in writing within three (3) business days from the date of receipt of the Data Request, including a specific description of what you find unclear and why. If possible, please provide a proposal for resolving the issue. In any event, unless directed otherwise by the originators, answer the request to the fullest extent possible, explain why you are unable to answer in full, and describe the limitations of your response.

Incomplete responses: If after you have sought clarification you still believe any part of the Data Request to be unclear and you are unable to answer a question completely, accurately, and with the specificity requested, notify the originators within three (3) business days. If possible, please provide a proposal for resolving the issue. Answer the request to the fullest extent possible, explain why you are unable to answer in full and describe the limitations of your response.

Deadline extension requests: If you are unable to provide a complete response to each question by the due date noted on the cover page, contact the originators in writing to request a deadline extension as soon as feasible. In your deadline extension request, please (1) specify the questions affected by the delay, (2) propose an alternative response date and (3) provide a written explanation as to why the deadline cannot be met.

Objections: If you object to any portion of this Data Request, please submit your objections, including the specific legal basis for each objection, to the originators as soon as possible. *At latest*, submit your objections and legal bases by the deadline on the cover sheet.

Response format: Responses should be provided in the original electronic format if available, and otherwise, in hard copy. (If available in Word or Excel format, send the Word or Excel document not a PDF file.)

- All electronic documents submitted in response to this data request should be in readable, downloadable, printable, and searchable formats, unless the use of such formats is infeasible.
- Each page should be numbered.
- If any of your answers rely on, refer to or reflect calculations that are not shown therein, provide a copy of the supporting electronic files that were used to derive such calculations, such as Excel spreadsheets or computer programs, with data and formulas intact and functioning.
- Voluminous documents produced in response to the data request should be Bates-numbered and indexed.
- Responses to the data request that refer to or incorporate documents should identify the particular documents referenced, including the title and page number or, if available, Bates-numbers or Bates-range.

Assertions of privilege: If you contend that any question or sub-question seeks information that is covered by attorney-client privilege or another privilege:

- Identify and articulate the bases of each applicable privilege asserted, for each question or sub-question individually.
- Respond to the question as fully as possible, even if you assert that some responsive information is privileged. Provide all responsive information that is not privileged, and redact only the allegedly privileged information.
- Provide a privilege log for any responsive information that is withheld (including redactions and documents withheld in their entirety). A privilege log should include the name, date, and author(s) of each redacted document, the precise privilege(s) asserted for each redacted document, and a brief description of each redacted document and its contents or subject matter sufficient to determine whether the asserted privilege(s) applies. If you provide one privilege log in response to multiple questions or sub-questions, please also specify each question or sub-question the privileged document is responsive to.

Your privilege claims and privilege logs are due by the response deadline for this data request.

Other questions: For any questions, email the originators.

DEFINITIONS

A. As used herein, the terms "you," "your(s)," "Company," "SCE," and "Edison" mean Southern California Edison Company and any and all of its respective present and former employees, agents, consultants, attorneys, and officials, and any and all other persons acting on its behalf.

B. The terms "and" and "or" shall be construed either disjunctively or conjunctively whenever appropriate in order to bring within the scope of this Data Request any information or documents which might otherwise be considered to be beyond their scope.

C. Date ranges shall be construed to include the beginning and end dates named. For example, the phrases "from January 1 to January 31," "January 1-31," "January 1 to 31," and "January 1 through January 31" should be understood to include both the 1st of January and the 31st of January. Likewise, phrases such as "since January 1" and "from January 1 to the present" should be understood to include January 1st, and phrases such as "until January 31," "through January 31," and "up to January 31" should also be understood to include the 31st.

D. The singular form of a word shall be interpreted as plural, and the plural form of a word shall be interpreted as singular whenever appropriate in order to bring within the scope of this Data Request any information or documents which might otherwise be considered to be beyond their scope.

E. The term "communications" includes all verbal and written communications of every kind, including but not limited to telephone calls, conferences, notes, correspondence, and all memoranda concerning the requested communications. Where communications are not in writing, provide copies of all memoranda and documents made relating to the requested communication and describe in full the substance of the communication to the extent that the substance is not reflected in the memoranda and documents provided.

F. The terms "document," "documents," or "documentary material" include, without limitation, the following items, whether in electronic form, printed, recorded, or written or reproduced by hand: reports, studies, statistics, projections, forecasts, decisions, orders, intra-office and interoffice communications, correspondence, memoranda, financial data, summaries or records of conversations or interviews, statements, returns, diaries, calendars, work papers, graphs, notebooks, notes, charts, computations, plans, drawings, sketches, computer printouts, summaries or records of meetings or conferences, summaries or reports of investigations or negotiations, opinions or reports of consultants, photographs, bulletins, records or representations or publications of any kind (including microfilm, videotape, and records however produced or reproduced), electronic or mechanical or electrical records of any kind (including, without limitation, tapes, tape cassettes, discs, emails, and records), other data compilations (including, without limitation, input/output files, source codes, object codes, program documentation, computer programs, computer printouts, cards, tapes,

and discs and recordings used in automated data processing, together with the programming instructions and other material necessary to translate, understand, or use the same), and other documents or tangible things of whatever description which constitute or contain information within the scope of this Data Request.

G. "Relate to," "concern," and similar terms and phrases shall mean to consist of, refer to, reflect, comprise, discuss, underlie, comment upon, form the basis for, analyze, mention, or be connected with, in any way, the subject of this Data Request.

H. "Identify":

   i. When used in reference to a Company employee, "identify" includes stating their full name and title.

   ii. When used in reference to a consultant or contractor for the Company, "identify" includes stating the person's name, title, and employer, and the name and title of the Company employee who is directly responsible for the work of the consultant.

   iii. When used in reference to a person who is not a current Company employee, consultant or contractor, "identify" includes stating the person's name; most recent title and supervisor at the Company; and most recent known employer, title/position, and business address.

   iv. When used in reference to documents, "identify" includes stating the nature of the document (e.g., letter, memorandum, study), the date (if any), the title of the document, the identity of the author, and the general subject matter of the document. For documents not publicly available, please also provide the location of the document, and identify the person having possession, control or custody of the document.

I. When requested to "state the basis" for any statement (i.e., any analysis, workpaper, study, proposal, assertion, assumption, description, quantification, or conclusion), please describe every fact, statistic, inference, supposition, estimate, consideration, conclusion, study, report, and analysis available to you which you believe to support the statement, or which you contend to be evidence of the truth or accuracy thereof.

J. "CPUC" and "Commission" mean the California Public Utilities Commission.

K. "Cal Advocates" means the Public Advocates Office at the California Public Utilities Commission.

L. "VCFD" means Ventura County Fire Department.

M. "CAL FIRE" means California Department of Forestry and Fire Protection.

N. "SED" means the CPUC's Safety and Enforcement Division.

DATA REQUEST

Question 1

This question pertains to PG&E policies and practices regarding detailed inspections in Tier 2 and Tier 3 High Fire Threat District (HFTD) areas during the 2014–2018 period:

a) Did PG&E have an established policy or standard governing the frequency of detailed inspections in Tier 2 or Tier 3 HFTD areas between 2014 and 2018? If so, please describe.

b) What criteria or methodology did PG&E use to determine which regions or circuits would undergo detailed inspections each year during the 2014–2018 period? How frequently were circuits revisited within that timeframe?

c) Were there any years between 2014 and 2018 in which no detailed inspections were performed on certain circuits located in Tier 3 HFTD areas? If so, please explain the reasons.

d) Did PG&E modify its detailed inspection policies or schedules in response to major wildfire events or regulatory changes during the 2014–2018 period? If so, describe the nature of those changes.

e) During the 2014–2018 period, did PG&E perform any risk assessments to evaluate whether increased inspection frequency was necessary in specific Tier 3 areas? If so, please provide any results, summaries, or conclusions.

f) Between 2014 and 2018, were any detailed circuit inspections skipped, delayed, or deprioritized due to internal factors such as scheduling limitations, staffing constraints, or other resource-related issues? If so, please explain.

END OF REQUEST

PACIFIC GAS AND ELECTRIC COMPANY
PG&E Ref. DRU15660-Case-Cost Recovery for Woolsey Fire-A.24-10-002
Data Request CPUC Public Advocates Office
Requester DR No. CalAdvocates-PGE-A2410002-CKM-002

Requester: Louie, Aaron
Request Date: May 02, 2025
Response Date: May 27, 2025

Question No. 001:

This question pertains to PG&E policies and practices regarding detailed inspections in Tier 2 and Tier 3 High Fire Threat District (HFTD) areas during the 2014–2018 period:

a) Did PG&E have an established policy or standard governing the frequency of detailed inspections in Tier 2 or Tier 3 HFTD areas between 2014 and 2018? If so, please describe.
b) What criteria or methodology did PG&E use to determine which regions or circuits would undergo detailed inspections each year during the 2014–2018 period? How frequently were circuits revisited within that timeframe?
c) Were there any years between 2014 and 2018 in which no detailed inspections were performed on certain circuits located in Tier 3 HFTD areas? If so, please explain the reasons.
d) Did PG&E modify its detailed inspection policies or schedules in response to major wildfire events or regulatory changes during the 2014–2018 period? If so, describe the nature of those changes.
e) During the 2014–2018 period, did PG&E perform any risk assessments to evaluate whether increased inspection frequency was necessary in specific Tier 3 areas? If so, please provide any results, summaries, or conclusions.
f) Between 2014 and 2018, were any detailed circuit inspections skipped, delayed, or deprioritized due to internal factors such as scheduling limitations, staffing constraints, or other resource-related issues? If so, please explain.

Response to Question No. 001 Response No. 001:

a) HFTD areas were defined and identified by the California Public Utilities Commission (CPUC or the Commission) in 2018. The CPUC adopted the final CPUC Fire-Threat Map via disposition of Advice Letters 5211-E/3172-E, filed January 5, 2018, and approved January 19, 2018.

   Accordingly, PG&E implemented the HFTD "map" in 2018. Prior to 2018, HFTD Tier 2 and Tier 3 did not exist.

   - Please see attached "*DRU15660_Atch01_Rules Final Decision 1.pdf*" and "*DRU15660_Atch02_Map 2 Final Decision.pdf*".

   - Please see attached "*DRU15660_Atch03_TD-2301B-004 (1)_Redacted.pdf*" for the change to GO 165 *patrol* frequency to annually in HFTD areas beginning in 2018, per changes to GO 165 language for HFTD areas.

b) PG&E performed detailed inspections during the 2014-2018 period per GO 165 requirements to inspect OH facilities at least every 5 years.

c) HFTD, Tier 3 did not exist until 2018. During 2014-2018 period, PG&E performed OH detailed inspections per GO 165 requirements, at least once every 5 years.

d) No, PG&E did not modify OH detailed inspection policies or schedules during 2014-2018 period.

e) No, PG&E did not perform risk assessments to evaluate OH detailed inspection frequencies during 2014-2018 period.

f) During 2014-2018 period, there were no issues with GO 165 OH detailed inspections being skipped, delayed, or deprioritized due to internal factors such as scheduling limitations, staffing constraints, or other resource-related issues. PG&E performed detailed inspections during the 2014-2018 period per GO 165 requirements to inspect OH facilities at least every 5 years.

Appendix F

Big Rock Circuit Notifications Identified as Overdue as of November 8, 2018

Big Rock Circuit Notifications Identified as Overdue as of November 8, 2018

Notification Number	Functional Location	Notification Short Text	Short Text Explanation	Additional Explanation
405072858	OH-2241614E	3RDPRTY PLCFAIL PUBLIC GUY POLE	Communication company guy failed pole loading	Delay associated with SCE's coordination with third-party communication provider
405019734	OH-424842E	3RDPRTY PLCFAIL PUBLIC GUY POLE	Communication company guy failed pole loading	Delay associated with SCE's coordination with third-party communication provider
405178377	OH-4216485E	3RDPRTY PLCFAIL PUBLIC GUY POLE	Communication company guy failed pole loading	Delay associated with SCE's coordination with third-party communication provider
405345326	OH-431985E	3RDPRTY PLCFAIL PUBLIC GUY POLE	Communication company guy failed pole loading	Notification not overdue; issue resolved prior to due date
405345507	OH-432090E	3RDPRTY PLCFAIL PUBLIC GUY POLE	Communication company guy failed pole loading	Notification not overdue; issue resolved prior to due date
405348747	OH-413328E	3RDPRTY PLCFAIL PUBLIC GUY POLE	Communication company guy failed pole loading	Delay associated with SCE's coordination with third-party communication provider
406124016	OH-1709442E	REPLC PLPASSMT PUBLIC POLE	SCE pole failed pole loading	Notification not overdue; issue resolved prior to due date
406123805	OH-2107058E	REPLC PLPASSMT PUBLIC POLE	SCE pole failed pole loading	Notification not overdue; issue resolved prior to due date
406124077	OH-4125384E	REPLC PLPASSMT PUBLIC POLE	SCE pole failed pole loading	Notification not overdue; issue resolved prior to due date
406278521	OH-2114481E	REPLC PLCFAIL PUBLIC POLE	SCE pole failed pole loading	Notification not overdue; issue resolved prior to due date
406278522	OH-424267E	REPLC PLCFAIL PUBLIC POLE	SCE pole failed pole loading	Notification not overdue; issue resolved prior to due date
407450932	OH-4125780E	3RDPRTY PLCFAIL PUBLIC GUY POLE	Communication company guy failed pole loading	Delay associated with SCE's coordination with third-party communication provider
406606315	OH-4093977E	3RDPRTY PLPASSMT PUBLIC GUY POLE	Communication company guy failed pole loading	Delay associated with SCE's coordination with third-party communication provider
406676020	OH-2081875E	CIP PLCFAIL PUBLIC GUY POLE	Communication company guy failed pole loading	Delay associated with SCE's coordination with third-party communication provider
406675990	OH-4318736E	CIP PLCFAIL PUBLIC GUY POLE	Communication company guy failed pole loading	Delay associated with SCE's coordination with third-party communication provider
407224295	OH-4446725E	REPLC PLPASSMT PUBLIC POLE	Communication company guy failed pole loading	Notification not overdue; issue resolved prior to due date
406755224	OH-644792E	3RDPRTY PLCFAIL PUBLIC GUY POLE	Communication company guy failed pole loading	Delay associated with SCE's coordination with third-party communication provider
409139029	OH-4554834E	3RDPRTY PLPASSMT PUBLIC GUY POLE	Communication company guy failed pole loading	Delay associated with SCE's coordination with third-party communication provider
406972089	OH-1831569E	3RDPRTY PLPASSMT PUBLIC GUY POLE	Communication company guy failed pole loading	Delay associated with SCE's coordination with third-party communication provider/third-party action required
407005196	OH-4263288E	3RDPRTY PLPASSMT PUBLIC GUY POLE	Communication company guy failed pole loading	Delay associated with SCE's coordination with third-party communication provider
407104833	OH-1333044E	REPLC PLPASSMT PUBLIC POLE	SCE pole failed pole loading	Notification not overdue; issue resolved prior to due date
407104787	OH-1473361E	REPLC PLPASSMT PUBLIC POLE	SCE pole failed pole loading	Notification not overdue; issue resolved prior to due date

Notification Number	Functional Location	Notification Short Text	Short Text Explanation	Additional Explanation
407105645	OH-4263293E	REPLC PLPASSMT PUBLIC POLE	SCE pole failed pole loading	Notification not overdue; issue resolved prior to due date
407129575	OH-4249676E	3RDPRTY PLPASSMT PUBLIC GUY POLE	Communication company guy failed pole loading	Delay associated with SCE's coordination with third-party communication provider
407979614	OH-644791E	3RDPRTY PLPASSMT PUBLIC GUY POLE	Communication company guy failed pole loading	Delay associated with SCE's coordination with third-party communication provider
407153363	OH-4458378E	3RDPRTY PLPASSMT PUBLIC GUY POLE	Communication company guy failed pole loading	Delay associated with SCE's coordination with third-party communication provider
407605007	OH-4198532E	REPLC PLPASSMT PUBLIC POLE	SCE pole failed pole loading	Notification not overdue; issue resolved prior to due date
407651442	OH-1540787E	CUST CLEARNC PUBLIC POLE	Customer installed something too close to SCE's pole	Customer unauthorized attachment; customer action typically required
407665876	OH-1297479E	CUST CLEARNC SERV CBL/CND POLE	Customer installed something too close to SCE's conductor or cable	Delay associated with SCE's coordination with third-party customer
407735697	OH-4831171E	3RDPRTY PLPASSMT PUBLIC GUY POLE	Communication company guy failed pole loading	Delay associated with SCE's coordination with third-party communication provider
407793722	OH-4557408E	3RDPRTY PLPASSMT PUBLIC GUY POLE	Communication company guy failed pole loading	Delay associated with SCE's coordination with third-party communication provider
407806306	OH-4705883E	3RDPRTY PLPASSMT PUBLIC GUY POLE	Communication company guy failed pole loading	Delay associated with SCE's coordination with third-party communication provider
407133561	OH-4724775E	3RDPRTY PLPASSMT PUBLIC GUY POLE	Communication company guy failed pole loading	Delay associated with SCE's coordination with third-party communication provider
409051353	OH-1383829E	CIP DAMAGE COMM GUY POLE	Communication company guy is damaged	Delay associated with SCE's coordination with third-party communication provider
407641843	OH-2045777E	CIP LOOSE COMM CBL/CND POLE	Communication company conductor or cable is loose	Delay associated with SCE's coordination with third-party communication provider
407641863	OH-2045777E	CUST UNATH ATT SERV POLE	Customer installed something too close to SCE's pole	Customer unauthorized attachment; customer action typically required
408465649	OH-4263288E	3RDPRTY PLCFAIL PUBLIC GUY POLE	Communication company guy failed pole loading	Delay associated with SCE's coordination with third-party communication provider
408460695	OH-1831569E	3RDPRTY PLCFAIL PUBLIC GUY POLE	Communication company guy failed pole loading	Delay associated with SCE's coordination with third-party communication provider
409141671	OH-1754336E	CIP CLEARNC COMM CBL/CND POLE	Communication company installed something too close to SCE's conductor or cable	Delay associated with SCE's coordination with third-party communication provider
409144985	OH-4216486E	CUST CLEARNC PUBLIC POLE	Customer installed something too close to SCE's pole	Customer unauthorized attachment; customer action typically required
409145082	OH-4216487E	CUST CLEARNC COMM POLE	Customer installed something too close to SCE's pole	Customer unauthorized attachment; customer action typically required
409144486	OH-577848E	CUST CLEARNC COMM POLE	Customer installed something too close to SCE's pole	Customer unauthorized attachment; customer action typically required

Notification Number	Functional Location	Notification Short Text	Short Text Explanation	Additional Explanation
409150231	OH-4125800E	CUST CLEARNC PUBLIC POLE	Customer installed something too close to SCE's pole	Customer unauthorized attachment; customer action typically required
409148256	OH-4636259E	CUST CLEARNC COMM POLE	Customer installed something too close to SCE's pole	Customer unauthorized attachment; customer action typically required
409150217	OH-877836E	CUST CLEARNC COMM POLE	Customer installed something too close to SCE's pole	Customer unauthorized attachment; customer action typically required
409159808	OH-717206E	CIP CLEARNC COMM CBL/CND POLE	Communication company installed something too close to SCE's conductor or cable	Delay associated with SCE's coordination with third-party communication provider
409171057	OH-2102128E	CUST CLEARNC PUBLIC POLE	Customer installed something too close to SCE's pole	Customer unauthorized attachment; customer action typically required
409191484	OH-4590395E	CUST CLEARNC COMM POLE	Customer installed something too close to SCE's pole	Customer unauthorized attachment; customer action typically required
409209773	OH-2137060E	CUST CLEARNC COMM POLE	Customer installed something too close to SCE's pole	Customer unauthorized attachment; customer action typically required
409213749	OH-4557741E	CUST CLEARNC PUBLIC POLE	Customer installed something too close to SCE's pole	Customer unauthorized attachment; customer action typically required
409230613	OH-4382987E	CUST CLEARNC PUBLIC POLE	Customer installed something too close to SCE's pole	Customer unauthorized attachment; customer action typically required
408931798	OH-1528776E	REPLC DTRATN PUBLIC POLE	Pole deterioration requiring replacement	Overdue by four days as of November 8, 2018