

Application: 25-11-001
(U 39 M)
Exhibit No.: PGE-04
Date: June 19, 2026
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

**KINCADE AND DIXIE AB 1054 WILDFIRE COST
REVIEW AND RECOVERY**

REBUTTAL TESTIMONY

SUPPORTING ATTACHMENTS

PUBLIC VERSION



PACIFIC GAS AND ELECTRIC COMPANY
KINCADE AND DIXIE AB 1054 WILDFIRE COST REVIEW AND RECOVERY
REBUTTAL TESTIMONY
SUPPORTING ATTACHMENTS

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PACIFIC GAS AND ELECTRIC COMPANY
REBUTTAL TESTIMONY SUPPORTING ATTACHMENTS
ATTACHMENT 1
CAL ADVOCATES' RESPONSE TO
KINCADEDIXIEAB1054_DR_PGE_CALADVOCATES_004



Public Advocates Office's Response to Data Request

Proceeding: A.25-11-001: Cost Recovery for 2019 Kincade Fire and 2021 Dixie Fire

Data request: KincadeDixieAB1054_DR_PGE_CalAdvocates_004
Date of receipt: May 29, 2026
Response date: June 12, 2026

Question 1

Responding witness: Holly Wehrman

Question:

Please provide all workpapers supporting Cal Advocates' prepared testimony in this proceeding that were not previously served as part of Cal Advocates' supporting attachments.

Answer:

Cal Advocates is providing the following supporting workpapers:

CA-03

- HWKC1_ca-03.xlsx

CA-04

- HWKC1.2026-04-16_aai_v2.xlsx
- Kincade_weather_stations.csv
- PG005.2026-04-17_aai_v2.xlsx
- PG177.2026-04-17_aai_v2.xlsx
- PG303.2026-04-17_aai_v2.xlsx
- PG305.2026-04-16_aai_v2.xlsx
- PG553.2026-04-17_aai_v2.xlsx
- PG558.2026-04-17_aai_v2.xlsx
- PG562.2026-04-17_aai_v2.xlsx

CA-08

- BK-WORKPAPER_KincadeDixieAB1054_D07-Q005Atch01_WireDown

These workpapers are attached in the zip folder attachment “*PGE_CalAdvocates_004Q1.zip*”

Question 2

Responding witness: Herman Eng

Question:

CA-06 at p. 10 states: “PG&E made this choice with full knowledge that a phase-to-phase fault had occurred.” Does Cal Advocates contend that, on July 13, 2021 prior to ignition of the Dixie Fire, PG&E was aware that the fault that occurred at 6:48 a.m. on the Bucks Creek 1101 Circuit was a phase-to-phase fault, yes or no? If yes, please describe with specificity all facts supporting Cal Advocates’ contention, including the time at which Cal Advocates contends PG&E became aware, and provide supporting documents.

Answer:

Cal Advocates objects to this question to the extent it misstates Cal Advocates’ testimony, is moot, and/or mischaracterizes Cal Advocates’ position. Cal Advocates served Exhibit CA-06-E on June 4, 2026. As corrected, the testimony does not assert that PG&E acted “with full knowledge that a phase-to-phase fault had occurred.”

Subject to and without waiving the foregoing objections, no, Cal Advocates does not contend that, on July 13, 2021, prior to ignition of the Dixie Fire, PG&E had actual or confirmed knowledge that the fault that occurred at 6:48 a.m. on the Bucks Creek 1101 Circuit was a phase-to-phase fault. At 6:48 a.m., PG&E did not have enough information to determine if the fault was a phase-to-phase fault.

Cal Advocates’ contention, as clarified in its errata testimony, is that PG&E could have inferred that the fault was most likely a phase-to-phase fault, and knew that at least two fuses from Fuse 17733 had operated and that two customers had lost power downstream of Fuse 17733.¹

Question 3

Responding witness: Herman Eng

Question:

CA-06 at p. 8 states: “[A] ground current of 0 to 1.6 amps on a circuit with confirmed downstream outages was itself an anomaly requiring investigation.” Please describe with specificity all facts supporting Cal Advocates’ contention that the recorded ground currents of 0 to 1.6 amps became anomalous because there were outages downstream of Fuse 17733 and

¹ CA-06-E at 10.

provide supporting documents.

Answer:

Cal Advocates objects to this question to the extent it misstates Cal Advocates' testimony and mischaracterizes Cal Advocates' position. Cal Advocates does not contend that "the recorded ground currents of 0 to 1.6 amps became anomalous" solely "because there were outages downstream of Fuse 17733."

Subject to and without waiving the foregoing objections, as discussed in CA-06-E at pp 9, PG&E had sufficient information to infer that at least two fuses were blown at Fuse 17733, and that two customers had lost power downstream of Fuse 17733. Since there was a possibility that one of the phases could still be energized, and the Bucks Creek 1101 Circuit traversed a high fire risk area, PG&E should have accounted for the possibility that a high-impedance fault was responsible for the ground current of up to 1.6 amps and investigated accordingly.

Question 4

Responding witness: Herman Eng

Question:

CA-01 at pp. 7-8 states: "With reasonable analysis given that two of the three fuses of Fuse 17733 had operated, the operator could have inferred that there was no power flowing to the two downstream customers." Does Cal Advocates contend that, on July 13, 2021 prior to ignition of the Dixie Fire, PG&E was aware that only two of the three fuses at Fuse 17733 had operated, yes or no? If yes, please describe with specificity all facts supporting Cal Advocates' contention, including the time at which Cal Advocates contends PG&E became aware, and provide supporting documents.

Answer:

Cal Advocates objects to this question to the extent it misstates Cal Advocates' testimony, is moot, and/or mischaracterizes Cal Advocates' position. CA-01, at pp. 7-8 does not assert that PG&E was aware that only two of the three fuses at Fuse 17733 had operated. Further, Cal Advocates served Exhibit CA-06-E on June 4, 2026. As corrected, the testimony does not assert that PG&E acted "with full knowledge that a phase-to-phase fault had occurred."

Subject to and without waiving the foregoing objections, no, Cal Advocates does not contend that, on July 13, 2021, prior to ignition of the Dixie Fire, PG&E had actual or confirmed knowledge that only two of the three fuses at Fuse 17733 had operated. As discussed in CA-06 at lines 6-10, PG&E had sufficient information to infer that *at least* two fuses were blown at Fuse 17733.

Question 5

Responding witness: Herman Eng

Question:

Does Cal Advocates contend that the operation of one or more fuses is itself an indication of an ongoing or continuing safety hazard, yes or no? If yes, please describe with specificity all facts supporting Cal Advocates' contention and provide supporting documents.

Answer:

Cal Advocates objects to this question to the extent it misstates Cal Advocates' testimony or mischaracterizes Cal Advocates' position.

Subject to and without waiving the foregoing objections, no, Cal Advocates does not contend that the operation of one or more fuses is itself an indication of an ongoing or continuing safety hazard. As discussed in CA-06, blown fuses in a high fire risk area, such as the Bucks Creek 1101 Circuit, could indicate a safety hazard.

Question 6

Responding witness: Aaron Louie

Question:

Cal Advocates' testimony in CA-07 analyzes the practices of Southern California Edison Company and San Diego Gas & Electric Company related to "fast trip" or increased sensitivity settings on protective devices. For purposes of this proceeding, did Cal Advocates analyze the practices of any other utilities in California or other jurisdictions with respect to such settings on protective devices? If yes, please describe with specificity Cal Advocates' analysis and provide supporting documents.

Answer:

No, Cal Advocates did not analyze the practices of any other utilities in California or in other jurisdictions with respect to such settings on protective devices.

Question 7

Responding witness: Herman Eng

Question:

During Cal Advocates witness Herman Eng's tenure at the Los Angeles Department of Water and Power (LADWP), and particularly as of July 13, 2021, did LADWP use "fast trip" or increased sensitivity settings on protective devices as a wildfire mitigation measure? If so,

please state when such fast trip settings were first implemented and describe the settings and any changes over time, including the time period.

Answer:

Cal Advocates objects to this question on the grounds that it is irrelevant to this proceeding and not reasonably calculated to lead to the discovery of admissible evidence. This proceeding concerns the prudence of PG&E's practices and operations in connection with the 2019 and 2020 fires. The question seeks information about the internal practice and protective device settings of a municipal utility, LADWP, whose practices are not at issue. Furthermore, Cal Advocates' testimony does not cite or rely on LADWP's protective device settings or wildfire mitigation measures. LADWP's settings do not tend to prove or disprove any contention in Cal Advocate's testimony.

Subject to the foregoing objections, Cal Advocates will not provide information about LADWP's sensitivity settings on protective devices or LADWP's wildfire mitigation measures. Cal Advocates is available to meet and confer regarding the relevance of the information PG&E sought.

Question 8

Responding witness: Charles Madison

Question:

CA-08 presents testimony regarding the configuration of the jumper that failed on October 23, 2019. Does Cal Advocates contend that this jumper configuration violated any PG&E standard, peer utility or industry standard, or established industry practice, yes or no? If yes, please describe with specificity all facts supporting Cal Advocates' contention and provide supporting documents.

Answer:

Although PG&E's question 8 refers to "CA-08," Cal Advocates believes this is an error and the question is instead intended to reference CA-03, which covers the design and construction that led to the Kincade Fire. With regards to CA-03, Cal Advocates does not contend that the jumper configuration that failed on October 23, 2019 violated any specific PG&E standard, peer utility standard, industry standard, or established industry practice. However, the record indicates that the jumper configuration differed from established industry practices, which created a foreseeable risk of fatigue failure. Moreover, the configuration remained energized even when it lacked an active purpose.

PACIFIC GAS AND ELECTRIC COMPANY
REBUTTAL TESTIMONY SUPPORTING ATTACHMENTS
ATTACHMENT 2
PG&E'S RESPONSE TO
KINCADEDIXIEAB1054_DR_CALADVOCATES_K07-Q003 AND
EXCERPTS OF SELECT ATTACHMENT

PACIFIC GAS AND ELECTRIC COMPANY
Kincade and DixieAB1054-Wildfire Cost Review and Recovery
Application 25-11-001
Data Response

PG&E Data Request No.:	CalAdvocates_K07-Q003
PG&E File Name:	KincadeDixieAB1054_DR_CalAdvocates_K07-Q003
Request Date:	January 23, 2026
Requester DR No.:	K07
Requesting Party:	Public Advocates Office
Requester:	Charles Madison
Date Sent:	February 6, 2026
PG&E Witness(es):	Carrell James Gill – Electric Engineering

QUESTION 003

From 2006 to 2019:

- a) Identify all PG&E's design standards applicable to jumper configurations on transmission towers with disconnected circuits. Provide documentation to support your answer.
- b) Describe the specific jumper configuration PG&E used at Tower 001/006 for the jumper involved in the Kincade fire ignition and how the configuration differed from a standard in service configuration.
- c) Provide any engineering analysis PG&E performed before or after the jumper modification to evaluate mechanical motion, fatigue risk, or oscillation behavior, particularly during high wind events.
- d) Identify whether PG&E applied any deviation, waiver, or exception process to this jumper configuration. If so, produce all related documentation.

ANSWER 003

- a) PG&E objects to this subpart on grounds that it is vague and ambiguous, particularly as to the term "disconnected circuits." Subject to and without waiving its objections, PG&E responds as follows: PG&E refers Cal Advocates to the following design standards:
 - Vibration Damper Requirements for Various Types of Overhead Conductors, PGE-KINCADE-00040410
 - Spacer Installation, Two Conductor Horizontal Bundle, PGE-KINCADE-00002001
 - Overhead Transmission Line Design Criteria, PGE-KINCADE-00040661
 - Clearance Tables, CPUC General Order 95, KINCADE-00040644

PG&E also refers Cal Advocates to two comprehensive and authoritative reference manuals, both published in 2017 by two leading electric industry organizations—the International Council on Large Electric Systems (CIGRE),¹ and the Electric Power Research Institute (EPRI).²

- b) PG&E refers Cal Advocates to Chapter 3A and figures therein (pp. 3A-15 to 3A-21 and Figure 3A-7). As described in Chapter 3A, Tower 001/006 conformed to PG&E's internal design standards. PG&E refers Cal Advocates to its response to SED Data Request No. 2, which identifies (by Bates number) drawings specific to Tower 001/006, as well as other drawings that depict the equipment on the tower.
- c) PG&E objects to this Subpart to the extent that it calls for information protected by the attorney-client privilege or work-product doctrine. Subject to and without waiving its objections, PG&E responds as follows: PG&E is producing an Applied Technology Services (ATS) post-event study titled "Low Cycle Fatigue Investigation." This particular study was deprived as part of expert-witness disclosures in the civil litigation on October 12, 2022.
- d) Because the jumper configuration at Tower 001/006 complied with PG&E's standards, there was no reason for a deviation, waiver, or exception. PG&E refers Cal Advocates to Chapter 3A (pages 15 - 21) of PG&E's prepared testimony. PG&E further refers Cal Advocates to its response to KincadeDixieAB1054_DR_CalAdvocates_K06_004(a), which explains that the last three spans of the Geysers #9 line and the associated jumper and insulator hardware complied with PG&E's applicable design standards as of the time of the Kincade Fire.

¹ See PGE-KINCADE-00038429.

² See PGE-KINCADE-00039776.

CIGRE Green Books

International Council on Large
Electric Systems (CIGRE)
Study Committee B2: Overhead Lines

Overhead Lines



 Springer Reference

CIGRE Green Books

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Editor

Overhead Lines

With 868 Figures and 175 Tables



Editor

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Malters, Switzerland

ISSN 2367-2625
CIGRE Green Books

ISSN 2367-2633 (electronic)

ISBN 978-3-319-31746-5 ISBN 978-3-319-31747-2 (eBook)
ISBN 978-3-319-31748-9 (print and electronic bundle)
DOI 10.1007/978-3-319-31747-2

Library of Congress Control Number: 2016946971

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Printed on acid-free paper

This Springer imprint is published by Springer Nature
The registered company is Springer International Publishing Switzerland Pte Ltd.
The registered company address is: Gewerbestrasse 11, 6330 Cham, Switzerland

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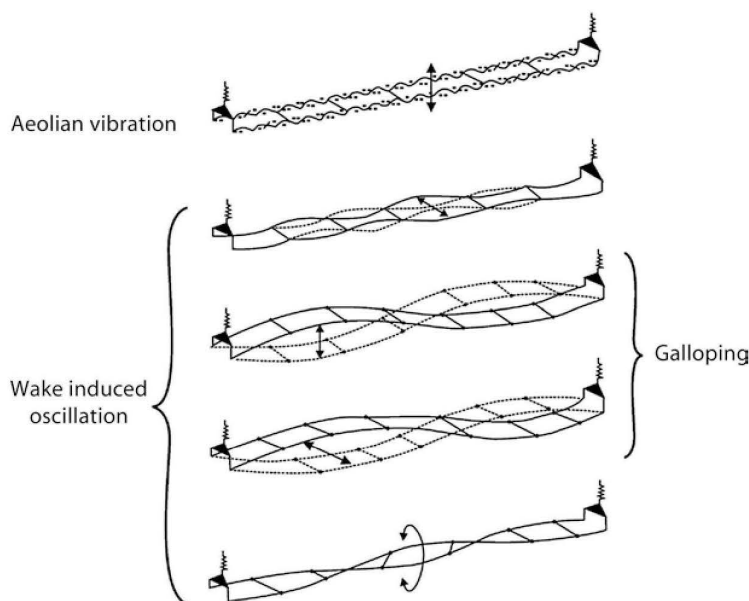


Figure 10.1 Wind-induced conductor motions.

result of reducing the tendency toward instability. Although the levels of all the conductor motions decrease with the increase of the wind turbulence, it has been observed that galloping is the least sensitive to this effect.

10.3.2 Aeolian vibration

Aeolian vibration is a small amplitude and relatively high frequency movement of the conductor induced by the wind and takes its name from the aeolian harp (Figure 10.2), an instrument devised by the ancient civilizations. Rabbinic records report that King David used to hang his harp over his bed where it emitted a melodic chord in the midnight breeze.

It has been known for a long time that the primary cause of aeolian vibrations is the alternate shedding of wind-induced vortices from the top and the bottom of the leeward side of the conductor. This is known as “Von Karman effect” after the scientist who first (1912) developed a theoretical explanation of the phenomenon.

10.3.2.1 Cause and Effects

The detachment of vortices creates an alternating pressure unbalance, which generates forces able to move the conductor up and down at right angles to the direction of air flow (Figure 10.3).

For single conductors, if it is assumed that the wind speed is constant and that there is therefore no turbulence, uses is made of the energy measured in a wind tunnel (Diana and Falco 1971).

The wind turbulence can also be taken into account, using the wind power functions illustrated in Figures 10.12 and 10.13 and in (Noiseux et al. 1986; Rawlins 1983).

The effect of tension variation on the vibration amplitudes of a medium size conductor is shown in Figure 10.25 for four different values of the EDS and a constant wind turbulence of 5 %. The vertical red dot lines encompass the vibration range calculated using the Strouhal formula (10.1) for wind velocities between 1–7 m/s. The following should be noted:

- Increasing the vibration frequency, the vibration amplitude decreases
- Increasing the conductor tension the vibration amplitudes increase
- Establishing a safety limit for the antinode vibration amplitude, it can be noted that, for lower tensions, the range of vibration frequencies exceeding this limit is reduced, which means that the additional damping is required only for a smaller frequency range. Starting from the curve of the vibration amplitude relevant to an EDS of 20% RTS and 5% turbulence, Figure 10.26 shows how the vibration amplitudes vary with increasing turbulence. The effect is more pronounced at higher vibration frequencies.

10.3.2.7 Fatigue Endurance Capability of Conductor/Clamp Systems

Introduction

Fatigue endurance capability of conductor/clamp systems is another important parameter taken into consideration at the design stage of a transmission line. It remains an important factor when comes the time to assess the residual service life of a particular transmission line.

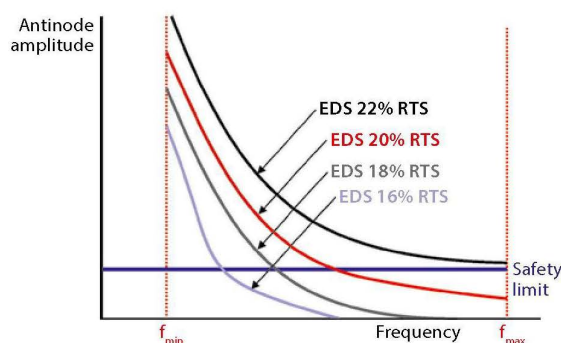


Figure 10.25 Effect of tension variations on vibration amplitude.

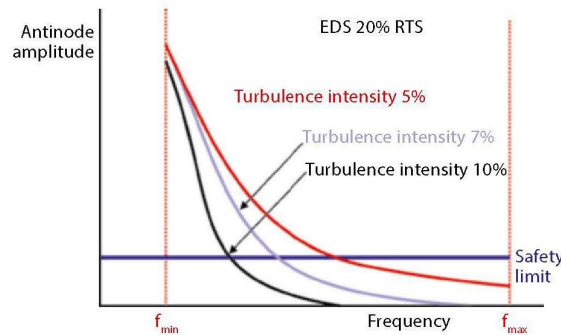


Figure 10.26 Effect of wind turbulence variations on vibration amplitude.

The fundamental cause of conductor fatigue failures is the cyclic bending stress imposed by aeolian vibrations. At singular points of the conductor where motion is constrained against transverse vibration, more frequently at suspension clamps, but also at spacer, dampers and hardware clamps, bending causes the strands of the conductor to slip relative to each other. The friction forces combined with the relative motion cause fretting at interstrand and clamp contacts. Once an initial crack is induced from the fretting mark surface, it may propagate, leading to the rupture of the wire and eventually to the complete breaking of a conductor.

Even though the presence of fretting in conductor fatigue is a well known phenomenon, fretting fatigue is not understood enough yet to allow the prediction of the life of a conductor-clamp system by the solution of a mathematical model when knowing the mechanical and physical properties of the wires. The standard method of evaluation is still based on experimental tests on a case by case basis (Cigré 2007).

Mechanism of Fretting Fatigue

Fretting fatigue is a contact damage phenomenon that takes place when a structural component experiences surface microslip associated with small-scale oscillatory motion on the order of 20–100 μm . This phenomenon is often responsible for unexpected fatigue failures and limits component life in aeronautical and automotive structures and common industrial machinery such as steam and gas turbines, cables, bolted plates, shaft keys and bearings.

A vast amount of research work has been published on fretting fatigue. Fretting is complex (Vincent et al. 1992; Waterhouse 1992; Hoepfner 1994; Mutoh 1995) since it is influenced by a number of factors including the normal contact load, the amplitude of relative slip, friction coefficient, surface conditions, contact materials and environment. The fretting fatigue process is also recognized as the result from the interaction between wear, corrosive and fatigue phenomena driven by both the microslip at the contact surface and cyclic local stresses.

In particular, the mechanism of fretting damage of aluminium material involves several stages of evolution (Hoepfner 1994). At the beginning, a surface oxide film is removed and, then, bare surfaces in contact start to rub against each other. At the

$$R^2 = \left(f + \frac{E_0}{\frac{2}{3}mgL} \right)^2 - f^2 =$$

$$\left(9.8 + \frac{10803}{\frac{2}{3}3.1 \times 9.81 \times 400} \right)^2 \quad (10.53)$$

$$-9.8^2 = 27.99 \text{ means } R = 5.2 \text{ m}$$

Thus the reduction in phase spacing is $2 \times 0.8 \times 5.2 = 8.32 \text{ m}$.

It means that the remaining clearance is $8.5 - 8.3 = 0.2 \text{ m}$.

For the same case at 45 kA, the results are:

$$E_0 = 2812 \text{ Joules}$$

$$T_{\max} = 66270 \text{ N}$$

$$\text{Remaining clearance} = 4.3 \text{ m}$$

It can be noted that that energy varies as the fourth power of the short-circuit current.

This is due to the fact that short-circuit forces vary with the square of the current, so the speed of the conductor at the end of the short-circuit also varies with the square of the current, and energy in the system varies with the square of that speed.

10.4.2.6 Interphase Spacers as a Mean to Limit Clearances Problem Linked with Short Circuit

Interphase spacers have been proposed to solve the phase-clearance problem during short circuits (Declercq 1998). Experience has shown that appropriate installation of such devices may effectively maintain appropriate clearances since conductor movement is restricted at some location in the span.

A major challenge is defining the design load on these interphase spacers. Tests can be performed. Advanced calculation methods may also help to define these loads. Interphase spacers may be subjected to bending stresses induced by conductor movements.

10.4.2.7 Short Circuit Forces on Bundled Jumper Loops and Slack Spans

Jumper loops are installed in tension towers to electrically connect the conductors of the adjacent spans. On bundled lines, the jumper loops have, generally, the same configuration as the spans, but are subjected to a much lower tension. Jumper loops can also assume different configurations aiming to optimize tower dimensions; one of the most common is the reduction of the bundle spacing, for example from 400 mm to 200 mm, in order to increase the clearance between the jumper and the tower.

Jumper loops are not subjected to wind induced conductor motions such as aeolian vibration and sub-span oscillations. For this reason, no vibration dampers and spacer dampers are required and rigid spacers can be installed to maintain the design spacing between the sub-conductors. However, it is common practice to install the same spacers or spacer dampers used on the line spans, unless the bundle configuration changes or counterweighted spacers are required to reduce swing of the jumper loop under wind pressure.

The so-called “Sticking Effect” may happen on jumper loops of a transmission line whose switch-gears are equipped with an automatic re-closing system operating under fault conditions.

The current flow produces attractive forces between the sub-conductors but under normal service conditions, only a minor sub-conductor deflection occurs and the sub-conductors remain well separated.

Under short circuit conditions, there are strongly increased attraction forces that deflect the sub-conductors, which rapidly clash. The sub-conductors come into contact with the exception of short lengths around the spacers and at loop extremities which, for this reason, are subjected to compressive forces generally of the order of, 1-2 kN.

On line spans, when the fault is cleared, the elastic forces due to the high tensile load in the conductor (besides gravity) are quite sufficient to restore the design configuration of the bundle after some inertial oscillations that apply to the spacers decreasing tension and compression forces.

On jumper loops, as a consequence of the low tensile load, when the switchgears open the circuit, the small elastic forces may not be able to move the sub-conductors apart sufficiently before the automatic re-closing system restores the normal line current. In this case, the reduced distance between the sub-conductors increases the attractive forces and the sub-conductors remain stuck together even with the normal line current (Lilien and Papailiou 2000).

The usual way to prevent this occurrence is to place spacers at a short distance from each other, in order to reduce the attractive forces and increase the elastic ones.

In bundled jumper loops, the installation of a spacer every 4-5 m is generally sufficient to prevent the sticking effect. In any case, calculation of the optimum distance of the spacers can be made using the algorithms provided by the Manuzio (1965) paper and considering the nominal current and the maximum short circuit current of the line, the loop geometry, the sub-conductor characteristics and mechanical tension.

Slack spans that are tensioned at low values may experience the same sticking effect as the jumper loops.

10.4.3 Corona Vibration

EHV and UHV transmission lines are designed to minimize Corona emissions and their negative effects. This is achieved by choosing the conductor size or by the use of bundled conductors in order to keep the surface voltage gradient below 15 kV/cm.

10.4.7 Earthquake

Earthquakes are a sudden release of energy in the earth's crust, usually caused by movement along geologic fault plane or by volcanic activity and resulting in the generation of seismic waves which may be destructive. The vast majority of earthquakes do not last for more than a few seconds and the horizontal acceleration is in the range 0.05-0.5 g. In rare and particular circumstances only, disastrous motions can have acceleration of more than 1 g and last for a longer time.

The natural frequencies of normal towers, that are nominally rigid, and those of the conductors, are generally detuned, thus no seismic force can be transmitted from line supporting structures to the conductors and vice versa. However, tall towers of long crossing spans and high voltage tubular poles are more flexible and the natural frequencies are closer to the conductor frequencies. In these cases conductors may transmit to the towers additional longitudinal loads especially in tension-tension spans (CENELEC 2001).

Besides soil deformation, earthquake induced vibration can generate liquefaction of saturated sandy soil, that then loses strength and stiffness and can no longer support weights causing buildings or other objects on the surface to sink or fall over; earthquake can also produce landslides on unstable slopes. These earthquake effects may cause tower dislocation as well as damage and large relative displacement of the foundations that in turn may damage the line structures. Cases of tower failure have been reported on a few occasions, as well as cases of conductor failure requiring the application of joints, but in general, transmission lines demonstrate a very low sensitivity to earthquake and the designers do not pay much attention to this phenomenon unless the transmission line has strategic importance and must be provided with high reliability. In these cases, design solutions to mitigate the effect of earthquake should be considered and a post-earthquake procedure should be established in order to recover service as fast as possible. In the design codes, very little information is given about anti-seismic criteria for transmission lines (EPRI 2009). The IEC Std. 60826 (IEC 2003) does not consider seismic loads on transmission lines. However, computer simulations based on finite element calculation are available for transmission line designers (Clough and Penzler 1993). On the other hand, substations are more vulnerable and are carefully designed in order to resist earthquakes.

10.5 Highlights

Wind induced conductor motion can be classified, in three main categories: aeolian vibration, wake induced oscillation and conductor galloping.

10.5.1 Aeolian Vibration

Aeolian vibration (Figure 10.93) is the most common and the most dangerous for the conductor integrity. It is generated by the alternate detachment of wind induced

PACIFIC GAS AND ELECTRIC COMPANY
REBUTTAL TESTIMONY SUPPORTING ATTACHMENTS
ATTACHMENT 3
SCE'S RESPONSE TO CALADVOCATES-SCE-A2511001-005,
QUESTION 6(A)

Southern California Edison
A.25-11-001 – APGE-Fire1054

DATA REQUEST SET CalAdvocates - SCE - A 2511001 - 005

To: Cal Advocates
Prepared by: Hunly Chy
Job Title: Senior Manager
Received Date: 3/3/2026

Response Date: 3/17/2026

Question 06.a:

The questions below examine SCE's transmission operations and maintenance practices prior to the Kincade Fire (2019).

The primary focus is on the standards, controls, and decision-making processes that authorize the continued energization of idle transmission facilities, as well as the procedures implemented to manage these configurations.

- a) From 2001 to 2019, did SCE update or establish policies regarding:
 - i. Unused but energized conductors?
 - ii. Redundant spans?
 - iii. Nonessential infrastructure?

Response to Question 06.a:

From 2001 to 2019, SCE did not have separate policies for unused but energized conductors, redundant spans, or nonessential transmission facilities. These assets would have been managed under the same transmission inspection and maintenance programs as energized facilities.

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REBUTTAL TESTIMONY SUPPORTING ATTACHMENTS
ATTACHMENT 4
SCE'S RESPONSE TO CALADVOCATES-SCE-A2511001-005,
QUESTION 3(E)

Southern California Edison
A.25-11-001 – APGE-Fire1054

DATA REQUEST SET CalAdvocates - SCE - A2511001-005

To: Cal Advocates
Prepared by: Hunly Chy
Job Title: Senior Manager
Received Date: 3/3/2026

Response Date: 3/17/2026

Question 03.e:

The questions below examine SCE's transmission operations and maintenance practices prior to the Kincade Fire (2019).

The primary focus is on the standards, controls, and decision-making processes that authorize the continued energization of idle transmission facilities, as well as the procedures implemented to manage these configurations.

Between 2001 and 2019:

e) If a jumper had a known 10-year service life and exceeded that age, did it require replacement even if the line was not actively being used? Explain why or why not.

Response to Question 03.e:

From 2001 to 2019, SCE did not employ an aged-based replacement program for jumpers. Rather, jumpers were evaluated through routine inspections and replaced when those inspections identified a condition warranting replacement.

PACIFIC GAS AND ELECTRIC COMPANY
REBUTTAL TESTIMONY SUPPORTING ATTACHMENTS
ATTACHMENT 5
ETPM TABLE 6 BULLETIN

(REDACTED)

New CIRT and DIRT Procedures and Updated ETPM Table 6

SUMMARY

This bulletin provides an update to TD-1001M, Electric Transmission Preventive Maintenance (ETPM) Manual referencing changes that need to be implemented as part of the Wildfire Safety Inspection Program (WSIP). Specifically:

- New electronic tools are available that are used by the Qualified Company Representative (QCR) during overhead inspections.
- A Drone Inspection Review Team (DIRT) and a Centralized Inspection Review Team (CIRT) have been developed with associated new procedures which supplement the existing ETPM procedures.
- An update to ETPM Table 6, Guide for Assigning Priority Codes, is now available to include more examples of conditions and associated priority codes.
- Decision trees have been developed to support Table 6 for determining the priority when evaluating conditions, for example, fiberglass guy strain insulators and wood poles.
- Clarification of processing LC notifications if there is a work scope change.

Level of Use: Informational Use

AFFECTED DOCUMENT

Electric Transmission Preventative Maintenance Manual (ETPM) TD-1001M

TARGET AUDIENCE

Electric transmission maintenance employees, electric engineers, contractors, supervisors, and superintendents involved in the maintenance of transmission line facilities.

WHAT YOU NEED TO KNOW

1 General Information

- 1.1 Transmission line has begun implementing new electronic applications to record overhead inspections and create notifications. A mobile device is utilized with PRONTO to complete detailed inspection forms and climbing inspection forms by QCRs. Another application, INSPECT, has been added to create notifications. The existing ET AI App can still be utilized to create notifications. All existing hand-written records noted in the ETPM Manual are still being used. All electronic records are recorded in the appropriate SAP databases.
- 1.2 Drone inspections are an additional tool that is being used to inspect overhead facilities. The DIRT members review the drone pictures to perform the inspections, record inspections in PRONTO and create notifications in SAP.

New CIRT and DIRT Procedures and Updated ETPM Table 6

- 1.3 CIRT members review the PRONTO forms and staging (S5) notifications along with other information and perform the gatekeeping function to move the notification to an LC with appropriate priority and FDA code.
- 1.4 An updated Table 6 Guide for Assigning Priority Codes has been issued with refined criteria in multiple areas and additional examples.
- 1.5 Additional guidance is also provided below for the steps to take when work scope changes and the notifications are updated

2 New Electronic Applications

- 2.1 The PRONTO application provides an electronic form to capture information for detailed ground inspections, climbing inspections and corrective work verification forms. It also provides the form to track the overhead inspection of structures on the circuit, thus replacing TD-1001M-F01, "Transmission Line Inspection/Patrol Datasheet" and TD-1001M-F05, "Object List – Typical", during detailed inspections and climbing inspections. This application identifies the structures that were inspected and captures the deficiencies that were observed. As needed, the abnormal conditions are entered in INSPECT or ET AI App to create the notifications.
- 2.2 Additional notes, comments and photos are captured in PRONTO for each facility, including items such as:
 - 1. Accessibility notes describing the navigation path or procedure used to safely and efficiently access the target structure or equipment
 - 2. Status of conditions that are not at the level of a deficiency (non-findings) intended to be monitored through the next inspection, such as woodpecker hole position and size; ground movement near the structure, vegetation in the area.
- 2.3 After detailed and climbing inspections are completed utilizing PRONTO and notifications are created in INSPECT, the information is uploaded to SAP. PRONTO and INSPECT provides a system to confirm that all required fields have been completed, includes the electronic signature of the QCR completing the form, and, as appropriate, names of other QCRs involved in the inspection.

3 DIRT Procedure

- 3.1 Transmission line has begun implementing drone imagery for inspecting overhead facilities as part of WSIP. Drone operators receive instructions on which facilities to inspect with drones in the field. Drone pilots take still photos of each facility, including pictures of the structure number, overall pictures and pictures of specific locations on the structure relating to previously determined Failure Modes (referred to as FMEA) that create a potential wildfire ignition source.

New CIRT and DIRT Procedures and Updated ETPM Table 6

- 3.2 DIRT Procedures have been established in TD-1001P-11 Drone Inspection Review Team (DIRT), including the following steps:
1. Pictures from the drones are reviewed for quality and clarity and then released to the DIRT members.
 2. DIRT members review the information from the drone pictures, complete a PRONTO inspection form for each structure/asset
 3. Any required SAP notifications to capture nonconformances are created by DIRT members.

3.3 The DIRT Procedure outlines:

1. Team responsibilities
2. Membership
3. Photograph quality
4. Decision Making
5. Inspections
6. Notification Creation
7. Documentation

4 CIRT Procedure

- 4.1 CIRT was established to provide an efficient process to review PRONTO inspection results and INSPECT notifications during transmission detailed ground and climbing inspections. CIRT performs the role of accepting or rejecting SAP staging notifications.
- 4.2 CIRT Procedures have been established in TD-1001P-10 Centralized Inspection Review Team (CIRT), including the following steps:
1. Members review PRONTO forms and INSPECT forms while reviewing associated notifications
 2. Members confirm or update the Facility, Damage, Action (FDA) Code, assign the Priority Code and complete the documentation.
 3. Members move the notification from S5 status to LC status.
 4. CIRT members will forward notifications to other groups, as appropriate, for additional information and/or forward to other departments for completion (e.g., vegetation, land management, distribution).

New CIRT and DIRT Procedures and Updated ETPM Table 6

4.3 The CIRT Procedure outlines:

1. Team responsibilities
2. Membership
3. Notification review and comparison with other available information
4. FDA and Priority Code assignment
5. Routing as appropriate
6. Documentation

5 Table 6 Update

- 5.1 An updated ETPM Table 6, Guide for Assigning Priority Codes, is being issued to provide additional examples of facility conditions and associated Priority Codes. Table 6 does not provide a comprehensive list of conditions that can be encountered. The Priority Code levels are for typical adverse conditions and must be adjusted up or down based on the inspectors or subject matter experts' judgement of the actual condition observed.
- 5.2 ETPM Job Aids in the form of decision trees have been developed for areas where evaluation of conditions is multifaceted and more detailed guidance is needed for consistency. For example, decision trees have been developed for evaluating fiberglass guy strain insulators and wood poles.
- 5.3 See [Appendix 1, "Updated ETPM Table 6,"](#) starting on Page 7.

6 Work Scope Changes

- 6.1 Work scope of a notification may change for various reasons, such as:
 1. An action has been taken to correct the initial condition (temporary or otherwise). Examples are:
 - a. A partial or temporary repair was completed; thus, the condition has changed, requiring a new priority to complete the full repair or replacement
 2. New information becomes available that was not available at the time the initial priority was established. Examples are:
 - a. Photographs and a more accurate description of the condition is provided, and the conditions are significantly different than originally reviewed.
 - b. New information creates a significantly different perspective

New CIRT and DIRT Procedures and Updated ETPM Table 6

- 6.2 Shown below are the actions to take if a Repair notification is changed to a Replace notification
1. Document the conditions that impact why the repair cannot be completed on the notification, which assumes that some repair actions have been taken to change the condition.
 2. Close the Repair notification
 3. Initiate a new Replace notification in the staging (S5) status that describes the new conditions and refers to the closed Repair notification
 4. CIRT will review and prioritize the new Replace notification with the date of the new notification as the start date since the condition has changed
- 6.3 Shown below are the actions to take if a Replace notification is temporarily repaired
1. Perform the temporary repair to make the condition safer
 2. Update the Replace notification with the actions taken AND description of the new condition
 3. Close the Replace notification
 4. Initiate a NEW Replace notification with:
 - a. the description of the new condition based on the temporary repair
 - b. reference the closed Replace notification and confirm actions for the temporary repair
 - c. reference the cost order of the closed Replace notification if the cost from the closed Replace notification is to be captured on the new notification
 5. CIRT will review and prioritize the new Replace notification with the current start date since the condition has changed



New CIRT and DIRT Procedures and Updated ETPM Table 6

DOCUMENT APPROVER

██████████, Senior Director Transmission Lines

██████████, Senior Director Enhanced Accelerated Inspection & Repair

DOCUMENT CONTACT

██████████, Manager CIRT

INCLUSION PLAN

ETPM Table 6, Guide for Assigning Priority Codes is part of TD-1001M, Electric Transmission Preventive Maintenance (ETPM) Manual. This bulletin will be located in the Technical Information Library. When TD-1001M is revised, this table, or subsequent updates, will be included in the revision.

New CIRT and DIRT Procedures and Updated ETPM Table 6

Appendix 1, Updated ETPM Table 6

Table 6. Guide for Assigning Priority Codes

Component ¹	Priority Code			
	A (Immediate)	B (3 months)	E (12 months)	F (24 months)
Anchor-Steel (ANCS)		Cracked 30 - 50% Slack 500kV guy Over tension >50%	Rust 30-50% material loss Worn 30-50% material loss Cracked 5 - 30%	For the following configurations: - T1 or TH - vertical suspension - no bird perching opportunities - sufficient distance from bird perching to energized parts - guys under hard tension (not storm guy) connected to bond wire or guy fixture AND guy bonded and not sectionalized (e.g., does provide a path to ground)
Anchor-Wood (ANCW)		Clearance from energized conductors Broken or missing storm guy where required	Soil Movement/slide/standing water Load bearing guy anchor being pulled out	Storm guy anchor being pulled out
Guy Wire-Steel (GYWS)	Rust >50% material loss	Anchor rod concrete has significant cracking, needs repair and resealing (e.g., mastic)	Slack guy Over tension 10 - 50%	Anchor in good condition/extension needed
Guy Wire-Wood (GYWW)	Worn >50% material loss		Twisted/Bent anchor rod	
Guy Splices	Cracked >50%		Guy insulator in poor condition Guy tails in contact with earth	Anchor rod in concrete not sealed (e.g., mastic)
Guy Pole (GUYS, GUYD)	Broken or missing load bearing guy	For the following configurations: - tri-pin - arm construction or wishbone - close vertical distances - close jumper distances - anywhere with limiting distance where a bird can land and reach energized parts	Preform grips not in thimbles Preform cross ties not properly installed	
Guy Stub (STUS, STUW)				
NOTE: Anchor head buried (per Dwg. 025998, e.g., incomplete inspection) ²				

¹ For Action Code abbreviations use INST (install), REPA (Repair), REPL (Replace)

² Return to field for completion. Do not process notification (keep in S5 status) until completed in field and anchor condition identified.

New CIRT and DIRT Procedures and Updated ETPM Table 6

Appendix 1, Updated ETPM Table 6

Component ¹	Priority Code			
	A (Immediate)	B (3 months)	E (12 months)	F (24 months)
		AND guy bonded and not sectionalized (e.g., does provide a path to ground) ³	Anchor rod concrete has minor cracking, needs resealing (e.g., mastic)	condition (e.g. rocky terrain without nearby vegetation)
Conductor-Steel (CONS)		Broken strands and out-of-lay strands (e.g., gunshot) 15 - 40% Dwg 028855		
Conductor-Wood (CNDW)	Corrosion >50% material loss	Corrosion 40% - 50% material loss		
Shield Wire/OPGW (SHLS) (SHLW)	Gunshot >40% of strands broken	Conductor clearances	Corrosion 10 - 40% material loss	Broken strands and out-of-lay strands (e.g., gunshot) 5 - 15% Dwg 028855
Jumpers (JUMS) (JUMW)	Arcing	Broken or loose tie wire (conductor well seated in the saddle with vertical load or partially captured with tie wire)	Uneven sag (send to engineering for evaluation)	Vibrating
Tie Wire (TIES, TIED)	Broken or loose tie wire (conductor not well seated in the saddle with vertical load or not fully captured with tie wire)	Broken ground wire, loose connector, tie wire, or weight	Conductor kinked/pinched at clamp	
Ground Wire (GRWS, GRWT, GRWW)		Twisted bundled conductor		
		Jumper clearance less than requirement Dwg 068177		No 24 month tags

³ Mitigate using new guy standard /bird mitigation

New CIRT and DIRT Procedures and Updated ETPM Table 6

Appendix 1, Updated ETPM Table 6

Component ¹	Priority Code			
	A (Immediate)	B (3 months)	E (12 months)	F (24 months)
Damper-Steel (DAMS) Damper-Wood (DAMW) Spacers (SPAS, SPAW)	Corrosion >50% material loss Cracked >50%	Cracked 30 - 50% Corrosion 40% - 50% material loss Broken spacer Broken/missing/ out of position damper ⁴ Bent >45 degrees damper	Out of position damper Missing spacer (where required) Corrosion 10% - 40% material loss	Cracked 5 - 30%
Splices (SPLS) (SPLW)	Corrosion >50% material loss	Corrosion, Hot, Broken, Cracked, Split, Loose/Slipped Automatic splice (replace or shunt) <10' to clamp	Automatic splice (replace or shunt) >10' to clamp	
Electrical clearances: GO95 Clear Infract- Tower (GO9S) GO95 Clear Infract- Wood (GO9W)	Tree contacting line or showing signs of contact (burnt leaves or limbs)	Circuit-to-circuit Burnt Trees Clearance < G.O. 95	Ground Clearance < G.O. 95	Grade change (Ground Clearance < G.O. 95) No 24 month tags

⁴ May assign Priority E if multiple dampers per phase are present and only outboard damper is broken/missing

New CIRT and DIRT Procedures and Updated ETPM Table 6

Appendix 1, Updated ETPM Table 6

Component ¹	Priority Code			
	A (Immediate)	B (3 months)	E (12 months)	F (24 months)
Foundation/ Concrete-Tower (FOND) NOTE: Earth covered /buried foundation (covering steel member) (incomplete inspection) ⁵	Significant soil erosion or movement causing lack of support around the foundation. Damage to, or separation of, main structural support members or stub angle tower leg that compromises structural integrity	Rust (rebar exposed with >50% material loss) Cracked (cracks >1/2") Buckled rebar, concrete spalling Stub in concrete, has significant cracking, needs repair and resealing (e.g., mastic)	Stub in concrete, has minor cracking, needs resealing (e.g., mastic) Soil movement (e.g., erosion or piled dirt, movement causing some bowing of tower main legs) Slide 10 - 15 inches Exposed wood pile Erosion 1'-3'	For optimization of permitting, estimating, and engineering criteria; as well as long-lead time materials and environmental reviews Stub in concrete needs resealing (e.g., mastic was previously applied)
Direct buried grillage NOTE: Uncover 6" to determine conditions. If no issue, rebury, no tag needed. Based on condition seen, if additional excavation needed, expose stub <18" ⁶	Direct buried grillage rust, corrosion >50% material loss	Erosion (vertical) > 3'	Rotated Cracked 5 - 30% Out-of-plumb suspension insulator > 2 bells out-of-plumb	No 24 month tags
Insulator (INSU) Insulator-Steel (INSS) Insulator-Wood	Rust >50% material loss Worn >50% material loss Cracked >50%	Cracked 30 - 50% Contaminated (heavy) Tracking (heavy)	Rust 30 - 50% material loss Worn 30 - 50% material loss	

⁵ Return to field for completion. Do not process notification (keep in S5 status) until completed in field and foundation condition identified

⁶ Less than 18" minimizes the need for extensive excavation that could compromise tower stability and compaction effort.

New CIRT and DIRT Procedures and Updated ETPM Table 6

Appendix 1, Updated ETPM Table 6

Component ¹	Priority Code			
	A (Immediate)	B (3 months)	E (12 months)	F (24 months)
(INSW) (Insulators with these conditions, see Error! Reference source not found. ₁) Flashed Cracked, Broken, Gunshot, Chipped > 1½ inches)	Porcelain cracked to the cap Contaminated (arcing)	Chalking/cracking on polymer Missing/loose/not fully seated cotter key or retainer pin Out-of-plumb post or suspension insulator exhibiting signs of impacting conductor	Contaminated (medium) Tracking (medium) Missing grading ring on polymer (where necessary) Corona rings damaged, missing (where required) or improperly installed (500kV only)	Out-of-plumb post insulator > 6"
Hardware (HRDS) (HRDT) (HRDD) Bolts, J-Bolts, U-Bolts, links, clamps, hot-end or cold-end hardware, shoe assembly, shackles, cotter key/pin, turnbuckle	Rust >50% material loss Worn >50% material loss Cracked >50% Contaminated (arcing) Cotter key missing AND retainer pin not fully seated	Cracked 30 - 50% Missing hardware (if necessary, send to engineering for evaluation) Missing or loose cotter key	Rust 30 - 50% material loss Worn 30 - 50% material loss Loose Turnbuckle out of threads	Cracked 5 - 30% Turnbuckle not punched
Switch (SWTC) Switch-Steel (SWIS)	Rust >50% material loss Cracked >50%	Cracked 30 - 50% Corrosion (heavy) Contaminated (heavy)	Rust 30 - 50% material loss Contaminated (medium)	Cracked 5 - 30% Corrosion (medium) For optimization of permitting, estimating, and

New CIRT and DIRT Procedures and Updated ETPM Table 6

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Component ¹	Priority Code			
	A (Immediate)	B (3 months)	E (12 months)	F (24 months)
Switch-Wood (SWIW) (Switch insulators with these conditions, see Error! Reference source not found., Flashed, Cracked, Broken, Gunshot, Chipped > 1½ inches)	Arcing Open (unlocked) Inoperable Out of adjustment (blades and load break devices not fully seated) Switch handle not bonded to platform	Tracking (heavy) Burnt Loose Broken Missing	Tracking (medium) Heating Bent/Bowed	engineering criteria; as well as long-lead time materials and environmental reviews
Structure-Steel (STRS) Structure-Tower (STRT) Hanger Plates Shield Wire Plates Crossarms (CRSL, CRST)	Critical/Main member: Rust/Worn >50% material loss Cracked >50% Broken/missing Severe damage to main structural support members compromising structural integrity (stub, leg, cross arm) < ¼" material remaining on plate ⁷	Moderate damage to main structural support members compromising structural integrity (stub, leg, cross arm) H-frame cross brace broken Missing bolts on single bolt connection on critical member Broken/missing secondary member Cracked 30 - 50%	Rust 30 - 50% material loss Pack-rust at joints, crevices or overlaps Cracked 10 - 30% Worn 30 - 50% material loss Buckled/bent secondary member Out of plumb (send to engineering for evaluation)	For optimization of permitting, estimating, and engineering criteria; as well as long-lead time materials and environmental reviews Bolts not punched Paint /Galvanizing finish deteriorating and little rust or

⁷ Thickness of material (i.e., plate thickness) can determine if Priority A or Priority B. A relatively thin plate (e.g., less material) will be a Priority A

New CIRT and DIRT Procedures and Updated ETPM Table 6

Appendix 1, Updated ETPM Table 6

Component ¹	Priority Code				
	A (Immediate)	B (3 months)	E (12 months)	F (24 months)	
	Internal corrosion of tubular members	1/4" – 1/2" material remaining on plate		metal loss	
Markers (i.e. signs)- Steel (MRKS) Markers (i.e. signs)- Wood (MRKW) Guy Markers (GMKS, GMKW)	Facilities or structures which have a recent history of trespass or third-party unauthorized access	Marker balls in poor condition and wearing on conductor	Marker balls damaged	Anti-climbing guards broken, cracked, damaged	Cracked, Broken, Loose, Missing Anti-climbing guards missing where required per TD-1009S-F01
Right of Way (ROW1) Vegetation (VEGN) Vegetation-Tower (VEGT)	Tree contacting line or showing signs of contact (burnt leaves or limbs) Encroachments	Tree clearance < G.O. 95 Clearances < G.O. 95	Significant vegetation around base of structure, maybe impacting climbing	Grade change (Ground Clearance < G.O. 95)	Encroachments to be resolved via Land Management
Road (ROAD)	If posing threat to facilities due to wash out or land motion				Access road repair or replacement
SCADA-Steel		Repair SCADA			Replace or

New CIRT and DIRT Procedures and Updated ETPM Table 6

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Component ¹	Priority Code				
	A (Immediate)	B (3 months)	E (12 months)	F (24 months)	
(SCDS) SCADA-Wood (SCDW)					install SCADA
Structure-Wood (STRW) (see note below) Includes pole, crossarms (CRSW, CRSL), bonding, bearing plates	Burnt/Rotten >50% material loss	Burnt/Rotten 40 - 50% material loss	Burnt/Rotten 20-40% material loss		For optimization of permitting, estimating, and engineering criteria; as well as long-lead time materials and environmental reviews
	Crossarm bracing missing or broken	Cracked >50% Broken	Cracked 10 - 50%		
	Bond wire broken < 1/4" gap	Twisted (severe)	Twisted (medium)		Worn/woodpecker/ insect damage (medium or minor damage near hardware)
	Severe pole top damage or split top compromising hardware or crossarm integrity	H-frame cross brace broken	Slide 1 - 5 feet		Ground wire in poor condition (corrosion, flushed, broken, missing)
		Out of plumb >5 feet (causing insulators and conductor compromised)	Out of plumb 3 - 5 feet (causing insulators and conductor compromised)		Ground molding in poor condition or missing (230kV with shield wire)
		Slide >5 feet	Erosion 1 - 3 feet in the ground		Erosion <1 foot in the ground
		Soil Movement (Erosion >3 feet in the ground)	Standing water (not including seasonal conditions)		Climbing steps in poor condition
		Worn/woodpecker/insect damage (severe and/or near hardware)			

New CIRT and DIRT Procedures and Updated ETPM Table 6

Appendix 1, Updated ETPM Table 6

Component ¹	Priority Code			
	A (Immediate)	B (3 months)	E (12 months)	F (24 months)
Structure (Fiberglass or concrete)		Crossarm bracing loose Moderate pole top damage or split top compromising hardware or crossarm integrity		
	Crossarm bracing missing Buckled (deformation)	Cracked fiberglass Cracked concrete into rebar Out of plumb >5 feet (causing insulators and conductor compromised) Soil Movement (Erosion >3 feet in the ground) H-frame cross brace broken Crossarm bracing loose	Cracked concrete (cracks > 1/2") not into rebar Out of plumb 3 - 5 feet (causing insulators and conductor compromised) Erosion 1 - 3 feet in the ground	For optimization of permitting, and estimating, and engineering criteria; as well as long-lead time materials and environmental reviews Erosion <1 foot in the ground
Idle Facilities (any facility type)	Removal of idle facilities posing an immediate threat to life, property or	-	-	For planning optimization of removal of non-emergency idle

New CIRT and DIRT Procedures and Updated ETPM Table 6**Appendix 1, Updated ETPM Table 6**

Component ¹	Priority Code			
	A (Immediate)	B (3 months)	E (12 months)	F (24 months)
	reliability			facilities

Note: If, on performing the required visual inspection and hammer test, the QCR believes the pole to be suspect, the pole must be tested further in accordance with Utility Standard TD-2325S, "Wood Pole Inspection, Testing, and Maintenance," and Work Procedure TD-2325P-01, "Wood Poles - Testing, Reinforcing and Reusing." This standard establishes the requirements for inspecting and testing the structural integrity of wood poles, the requirements for reinforcing and reusing, and requirements for testing wood poles prior to climbing. After completing the pole inspection, the QCR must complete the TD-2325P-01-F01, "Attachment 1 - Pole Inspection/Test Report," and forward it to the supervisor. The supervisor will forward it to the estimating group for further evaluation and appropriate corrective action identification.

PACIFIC GAS AND ELECTRIC COMPANY
REBUTTAL TESTIMONY SUPPORTING ATTACHMENTS
ATTACHMENT 6
KINCADEDIXIEAB1054_DR_CALADVOCATES_K16-
Q002ATCH02 (WILDFIRE SAFETY INSPECTIONS PROGRAM
DIRT HANDBOOK)



Wildfire Safety Inspections Program

DIRT Handbook





WILDFIRE SAFETY INSPECTIONS PROGRAM

DIRT Handbook

Revision	Revision Date	Revision notes
0.0	11/30/18	Document created
1.0	12/28/18	Initial revisions and edits
2.0	01/04/19	- Added "STEEL STRUCTURE FOUNDATION" section - Added more examples of corrosion - Adjusted priority codes
3.0	01/08/19	- Added language and tables to more accurately classify guy issues - Added information on damage to polymer insulators - Clarified bridging on fiberglass distribution arms - Clarified metal vs plastic guy markers
4.0	01/11/19	- From 12 inches to 10 foot clearance for guy attachment bonding requirement - Added priority codes and conditions for many images - Added examples of shell rot/wood pole damage - Added examples of storm/down guys - Fixed "slide >15 feet" typo in all priority code tables (to inches) - Added appendices for voltage signs and guy bonding/insulation - Added example of over-tight jumpers
5.0	01/28/19	- Clarified conductor splice requirements - Removed some conditions that cannot be assessed visually (e.g. < 1 mil zinc remaining) - Removed irrelevant conditions from non-steel framing and added clarification - Fixed duplicate conditions in Guys and Anchors - Fixed duplicate conditions in Steel Structures - Fixed duplicate conditions in Steel Structure Foundations - Material re-organized - Removed option for priority code F
6.0	3/18/19	Updated to adhere to the new ETMP Table 6
7.0	3/20/19	- Clarified situations pertaining to buried members - Added missing or broken bond wire to Table 1
8.0	3/27/19	- Clarified notifications for bird nests - Added examples of 500kV anchors and cross ties - Clarified grounding requirements for shield wires/opgw
9.0	4/11/19	- Removed distribution - Updated priority codes for Automatic splices to adhere to new ETPM Table 6
10.0	4/22/19	- Added FDA code table - Added FDA diagram for towers - Added section on 500kV towers - Added examples of shunted splices
11.0	4/30/19	- Added HV sign section - Added information about implosive jumper splices - Clarified FDA codes for some issues - Clarified wording regarding guy insulators on steel poles
12.0	5/15/19	- Integrated changes to splice priority codes - Integrated changes to woodpecker damage priority codes - Clarified some language regarding OPGW/Shield wire - Clarified language around FDA table



WILDFIRE SAFETY INSPECTIONS PROGRAM

DIRT Handbook

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Component ¹	Priority Code				
	A (Immediate)	B (3 months)	E (12 months)		F (24 months)
Anchor-Steel (ANCS) Anchor-Wood (ANCW) Guy Wire-Steel (GYWS) Guy Wire-Wood (GYWW) Guy Splices Guy Pole (GUYS, GUYD) Guy Stub (STUS, STUW) NOTE: Anchor head buried (per Dwg. 025998, e.g., incomplete inspection) ²	 Rust >50% material loss Worn >50% material loss Cracked >50% Broken or missing load bearing guy	Cracked 30 - 50% Slack 500kV guy Over tension >50% Clearance from energized conductors Broken or missing storm guy where required Anchor rod concrete has significant cracking, needs repair and resealing (e.g., mastic) For the following configurations: - tri-pin - arm construction or wishbone - close vertical distances - close jumper distances - anywhere with limiting distance where a bird can land and reach energized parts <u>AND</u> guy bonded and not sectionalized (e.g., does provide a path to ground) ³	Rust 30-50% material loss Worn 30-50% material loss Cracked 5 - 30% Soil Movement/slide/standing water Load bearing guy anchor being pulled out Slack guy Over tension 10 - 50% Twisted/Bent anchor rod Guy insulator in poor condition Guy tails in contact with earth Preform grips not in thimbles Preform cross ties not properly installed Anchor rod concrete has minor cracking, needs resealing (e.g., mastic)	For the following configurations: - T1 or TH - vertical suspension - no bird perching opportunities - sufficient distance from bird perching to energized parts - guys under hard tension (not storm guy) connected to bond wire or guy fixture <u>AND</u> guy bonded and not sectionalized (e.g., does provide a path to ground) Guy bonded and not sectionalized (e.g., does provide a path to ground) <u>BUT</u> over-insulated OR mitigating environmental condition (e.g. rocky terrain without nearby vegetation)	Storm guy anchor being pulled out Anchor in good condition/extension needed Anchor rod in concrete not sealed (e.g., mastic)

¹ For Action Code abbreviations use INST (install), REPA (Repair), REPL (Replace)

² Return to field for completion. Do not process notification (keep in S5 status) until completed in field and anchor condition identified.

³ Mitigate using new guy standard /bird mitigation

Component ¹	Priority Code				
	A (Immediate)	B (3 months)	E (12 months)	F (24 months)	
Conductor-Steel (CONS) Conductor-Wood (CNDW) Shield Wire/OPGW (SHLS) (SHLW) Jumpers (JUMS) (JUMW) Tie Wire (TIES, TIED) Ground Wire (GRWS, GRWT, GRWW)	Corrosion >50% material loss Gunshot >40% of strands broken Arcing Broken or loose tie wire (conductor not well seated in the saddle with vertical load or not fully captured with tie wire)	Broken strands and out-of-lay strands (e.g., gunshot) 15 - 40% Dwg 028855 Corrosion 40% - 50% material loss Conductor clearances Broken or loose tie wire (conductor well seated in the saddle with vertical load or partially captured with tie wire) Broken ground wire, loose connector, tie wire, or weight Twisted bundled conductor Jumper clearance less than requirement Dwg 068177	Corrosion 10 - 40% material loss Uneven sag (send to engineering for evaluation) Conductor kinked/pinched at clamp	Broken strands and out- of-lay strands (e.g., gunshot) 5 - 15% Dwg 028855 Vibrating	No 24 month tags
Damper-Steel (DAMS) Damper-Wood (DAMW) Spacers	Corrosion >50% material loss Cracked >50%	Cracked 30 - 50% Corrosion 40% - 50% material loss Broken spacer Broken/missing/ out of position damper ⁴	Out of position damper Missing spacer (where required)	Cracked 5 - 30%	

⁴ May assign Priority E if multiple dampers per phase are present and only outboard damper is broken/missing
Rev. 12.0 Internal

Component ¹	Priority Code				
	A (Immediate)	B (3 months)	E (12 months)		F (24 months)
(SPAS, SPAW)		Bent >45 degrees damper	Corrosion 10% - 40% material loss		
Splices (SPLS) (SPLW)	Corrosion >50% material loss	Corrosion, Hot, Broken, Cracked, Split, Loose/Slipped Automatic splice (replace or shunt) <10' to clamp	Automatic splice (replace or shunt) >10' to clamp		
Electrical clearances: GO95 Clear Infract-Tower (GO9S) GO95 Clear Infract-Wood (GO9W)	Tree contacting line or showing signs of contact (burnt leaves or limbs)	Circuit-to-circuit Burnt Trees Clearance < G.O. 95	Ground Clearance < G.O. 95	Grade change (Ground Clearance < G.O. 95)	No 24 month tags
Foundation/ Concrete-Tower (FOND) NOTE: Earth covered /buried foundation (covering steel member) (incomplete inspection) ⁵ Direct buried grillage NOTE: Uncover 6" to determine conditions. If no issue, rebury, no tag needed. Based on	Significant soil erosion or movement causing lack of support around the foundation. Damage to, or separation of, main structural support members or stub angle tower leg that compromises structural integrity	Rust (rebar exposed with >50% material loss) Cracked (cracks >1/2") Buckled rebar, concrete spalling Stub in concrete, has significant cracking, needs repair and resealing (e.g., mastic) Soil movement (e.g., movement causing significant bowing of tower members)	Stub in concrete, has minor cracking, needs resealing (e.g., mastic) Soil movement (e.g., erosion or piled dirt, movement causing some bowing of tower main legs) Slide 10 - 15 inches Exposed wood pile	Rust 30 - 50% material loss of foundation or stub Cracked (cracks > 1/16") Direct buried grillage rust, corrosion 30% - 50% material loss Rotated	For optimization of permitting, estimating, and engineering criteria; as well as long-lead time materials and environmental reviews

⁵ Return to field for completion. Do not process notification (keep in S5 status) until completed in field and foundation condition identified
Rev. 12.0 Internal

Component ¹	Priority Code			
	A (Immediate)	B (3 months)	E (12 months)	F (24 months)
condition seen, if additional excavation needed, expose stub <18" ⁶	Direct buried grillage rust, corrosion >50% material loss	Erosion (vertical) > 3'	Erosion 1'-3'	
Insulator (INSU) Insulator-Steel (INSS) Insulator-Wood (INSW) (Insulators with these conditions, see Error! Reference source not found. Flashed Cracked, Broken, Gunshot, Chipped >1½ inches)	Rust >50% material loss Worn >50% material loss Cracked >50% Porcelain cracked to the cap Contaminated (arcing)	Cracked 30 - 50% Contaminated (heavy) Tracking (heavy) Chalking/cracking on polymer Missing/loose/not fully seated cotter key or retainer pin Out-of-plumb post or suspension insulator exhibiting signs of impacting conductor	Rust 30 - 50% material loss Worn 30 - 50% material loss Contaminated (medium) Tracking (medium) Missing grading ring on polymer (where necessary) Corona rings damaged, missing (where required) or improperly installed (500kV only)	Cracked 5 - 30% Out-of-plumb suspension insulator > 2 bells out-of-plumb Out-of-plumb post insulator > 6"

⁶ Less than 18" minimizes the need for extensive excavation that could compromise tower stability and compaction effort.
 Rev. 12.0

Component ¹	Priority Code				
	A (Immediate)	B (3 months)	E (12 months)		F (24 months)
Hardware (HRDS) (HRDT) (HRDD) Bolts, J-Bolts, U-Bolts, links, clamps, hot-end or cold-end hardware, shoe assembly, shackles, cotter key/pin, turnbuckle	Rust >50% material loss Worn >50% material loss Cracked >50% Contaminated (arcing) Cotter key missing AND retainer pin not fully seated	Cracked 30 - 50% Missing hardware (if necessary, send to engineering for evaluation) Missing or loose cotter key	Rust 30 - 50% material loss Worn 30 - 50% material loss Loose Turnbuckle out of threads	Cracked 5 - 30%	Turnbuckle not punched
Switch (SWTC) Switch-Steel (SWIS) Switch-Wood (SWIW) (Switch insulators with these conditions, see Error! Reference source not found. ¹ Flashed, Cracked, Broken, Gunshot, Chipped >1½ inches)	Rust >50% material loss Cracked >50% Arcing Open (unlocked) Inoperable Out of adjustment (blades and load break devices not fully seated) Switch handle not bonded to platform	Cracked 30 - 50% Corrosion (heavy) Contaminated (heavy) Tracking (heavy) Burnt Loose Broken Missing	Rust 30 - 50% material loss Contaminated (medium) Tracking (medium) Heating Bent/Bowed	Cracked 5 - 30% Corrosion (medium)	For optimization of permitting, estimating, and engineering criteria; as well as long-lead time materials and environmental reviews

Component ¹	Priority Code				
	A (Immediate)	B (3 months)	E (12 months)		F (24 months)
Structure-Steel (STRS) Structure-Tower (STRT) Hanger Plates Shield Wire Plates Crossarms (CRSL, CRST)	Critical/Main member: Rust/Worn >50% material loss Cracked >50% Broken/missing Severe damage to main structural support members compromising structural integrity (stub, leg, cross arm) < ¼" material remaining on plate ⁷ Internal corrosion of tubular members	Moderate damage to main structural support members compromising structural integrity (stub, leg, cross arm) H-frame cross brace broken Missing bolts on single bolt connection on critical member Broken/missing secondary member Cracked 30 - 50% ¼" – ½" material remaining on plate	Rust 30 - 50% material loss Pack-rust at joints, crevices or overlaps Cracked 10 - 30% Worn 30 - 50% material loss Buckled/bent secondary member Out of plumb (send to engineering for evaluation)	Vibrating members Twisted Loose bolts, etc. Single bolt missing of multi-bolt connection Climbing steps in poor condition	For optimization of permitting, estimating, and engineering criteria; as well as long-lead time materials and environmental reviews Bolts not punched Paint /Galva-nizing finish deteriorating and little rust or metal loss
Markers (i.e. signs)-Steel (MRKS) Markers (i.e. signs)-Wood (MRKW) Guy Markers (GMKS, GMKW)	Facilities or structures which have a recent history of trespass or third-party unauthorized access	Marker balls in poor condition and wearing on conductor	Marker balls damaged	Anti-climbing guards broken, cracked, damaged	Cracked, Broken, Loose, Missing Anti-climbing guards missing where required per TD-1009S-F01

⁷ Thickness of material (i.e., plate thickness) can determine if Priority A or Priority B. A relatively thin plate (e.g., less material) will be a Priority A
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Component ¹	Priority Code				
	A (Immediate)	B (3 months)	E (12 months)		F (24 months)
Right of Way (ROW1) Vegetation (VEGN) Vegetation-Tower (VEGT)	Tree contacting line or showing signs of contact (burnt leaves or limbs) Encroachments	Tree clearance < G.O. 95 Clearances < G.O. 95	Significant vegetation around base of structure, maybe impacting climbing	Grade change (Ground Clearance < G.O. 95)	Encroachments to be resolved via Land Management
Road (ROAD)	If posing threat to facilities due to wash out or land motion				Access road repair or replacement
SCADA-Steel (SCDS) SCADA-Wood (SCDW)		Repair SCADA			Replace or install SCADA
Structure-Wood (STRW) (see note below) Includes pole, crossarms (CRSW, CRSL), bonding, bearing plates	Burnt/Rotten >50% material loss Crossarm bracing missing or broken Bond wire broken < ¼" gap Severe pole top damage or split top compromising hardware or crossarm integrity	Burnt/Rotten 40 - 50% material loss Cracked >50% Broken Twisted (severe) H-frame cross brace broken	Burnt/Rotten 20-40% material loss Cracked 10 - 50% Twisted (medium) Slide 1 - 5 feet Out of plumb 3 - 5 feet (causing insulators and conductor compromised)	Worn/woodpecker/ insect damage (medium or minor damage near hardware) Ground wire in poor condition (corrosion, flashed, broken, missing) Ground molding in poor condition or missing (230kV with shield wire)	For optimization of permitting, estimating, and engineering criteria; as well as long-lead time materials and environmental reviews Erosion <1 foot in the ground

Component ¹	Priority Code				
	A (Immediate)	B (3 months)	E (12 months)		F (24 months)
		Out of plumb >5 feet (causing insulators and conductor compromised) Slide >5 feet Soil Movement (Erosion >3 feet in the ground) Worn/woodpecker/insect damage (severe and/or near hardware) Crossarm bracing loose Moderate pole top damage or split top compromising hardware or crossarm integrity	Erosion 1 - 3 feet in the ground Standing water (not including seasonal conditions)	Climbing steps in poor condition	
Structure (Fiberglass or concrete)	Crossarm bracing missing Buckled (deformation)	Cracked fiberglass Cracked concrete into rebar Out of plumb >5 feet (causing insulators and conductor compromised) Soil Movement (Erosion >3 feet in the ground) H-frame cross brace broken	Cracked concrete (cracks > ½") not into rebar Out of plumb 3 - 5 feet (causing insulators and conductor compromised) Erosion 1 - 3 feet in the ground	Climbing steps in poor condition	For optimization of permitting, estimating, and engineering criteria; as well as long-lead time materials and environmental reviews

Component ¹	Priority Code				
	A (Immediate)	B (3 months)	E (12 months)		F (24 months)
		Crossarm bracing loose			Erosion <1 foot in the ground
Idle Facilities (any facility type)	Removal of idle facilities posing an immediate threat to life, property or reliability	-	-	-	For planning optimization of removal of non-emergency idle facilities



WILDFIRE SAFETY INSPECTIONS PROGRAM

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Condition: 5

Priority: A

FDA: Conductor-Steel(or wood)| No Good | Repair



Condition: 5

Priority: A

FDA: Splice-Steel(or wood)| No Good | Repair

Figure 67 Connector failure possibly due to overloading (left), failed splice (right).



Condition: 3

Priority: E

FDA: Conductor-Steel(or wood)| No Good | Repair



Condition: 4

Priority: B

FDA: Conductor-Steel(or wood)| No Good | Repair

Figure 68 Conductor damage (left), bird-caging conductor (right).



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Bent dampers are only considered a notification if they are bent at or more than 45deg away from the conductor



Condition: 3

Priority: B

FDA: Damper-Steel(or wood) | No Good | Replace

Figure 69 Damaged stockbridge dampers (left, center, right).

See [WSIP Transmission CIRT – Job Aid – Conductor/Jumper Splices](#) in *03-Onboarding/Helpful Standards* for a more detailed and complete guide to priority assignment for splices



Condition: 2

Priority: No notification required

The use of automatic splices at any location on the conductor requires a notification. Automatic splices within 10' of the conductor clamp is considered a "B" notification. If the splice is 10' or more from the clamp or on the guy wire it should be priority "E".



Condition:1

Priority: E

FDA: Splice-Wood | No Good | Replace

Figure 70 Mild bird-caging conductor (left), example of automatic splice (right).

PACIFIC GAS AND ELECTRIC COMPANY
REBUTTAL TESTIMONY SUPPORTING ATTACHMENTS
ATTACHMENT 7
TOT037 IFA 2005 08 03 (INTERCONNECTION AGREEMENT
BETWEEN INLAND EMPIRE ENERGY CENTER, LLC AND
SOUTHERN CALIFORNIA EDISON COMPANY)

INTERCONNECTION FACILITIES AGREEMENT

BETWEEN

INLAND EMPIRE ENERGY CENTER, LLC

AND

SOUTHERN CALIFORNIA EDISON COMPANY

Issued by: James A. Cuillier
Manager, FERC Rates & Regulation
Issued on: **AUG 03 2005**

Effective: **AUG 04 2005**

Atch7-1

**INTERCONNECTION FACILITIES AGREEMENT BETWEEN
INLAND EMPIRE ENERGY CENTER, LLC
AND
SOUTHERN CALIFORNIA EDISON COMPANY**

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**INTERCONNECTION FACILITIES AGREEMENT BETWEEN
INLAND EMPIRE ENERGY CENTER, LLC
AND
SOUTHERN CALIFORNIA EDISON COMPANY**

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**INTERCONNECTION FACILITIES AGREEMENT BETWEEN
INLAND EMPIRE ENERGY CENTER, LLC
AND
SOUTHERN CALIFORNIA EDISON COMPANY**

1. Parties:

The Parties to this Interconnection Facilities Agreement are Inland Empire Energy Center, LLC, ("IEEC"), a Delaware limited liability company and Southern California Edison Company ("SCE"), a California corporation, hereinafter sometimes referred to individually as "Party" and collectively as "Parties."

2. Recitals:

This Agreement is made with reference to the following facts, among others:

- 2.1. SCE is a California public utility engaged in the business of generating and transmitting electric energy in the States of Arizona, California, Nevada, and New Mexico. SCE is further engaged in the business of distributing such energy in the State of California.
- 2.2. Calpine Corporation ("Calpine") is a California corporation engaged in the development, construction, ownership and operation of power generation facilities and the sale of electricity predominantly in the United States, as well as in Canada and the United Kingdom, and owns among other things, Inland Empire Energy Center, LLC.
- 2.3. IEEC, and indirect, wholly owned subsidiary of Calpine, owns and operates the Inland Empire Energy Center Project.
- 2.4. IEEC intends to design and construct the Inland Empire Energy Center Project and interconnect to the ISO Controlled Grid at SCE's Valley 500 kV Substation Switchyard via a 500 kV transmission line originating from the Inland Empire Energy Center Project generation station switchyard.
- 2.5. On August 7, 2000, Calpine submitted a request to SCE to interconnect the original 669 MW proposed project to the ISO Controlled Grid in accordance with the terms of SCE's Transmission Owner Tariff ("TO Tariff") in order to deliver Energy and/or Ancillary Services from the project to the ISO Controlled Grid.
- 2.6. SCE performed a System Impact Study, which was transmitted to Calpine on January 19, 2001, that indicated that SCE's electrical system is not adequate to accommodate the original proposed project and that upgrades and additions to SCE's electrical system are required.
- 2.7. SCE performed a Facilities Study, which was transmitted to Calpine on June 21, 2001, that identified the facilities and associated costs required to accommodate the original proposed project.
- 2.8. SCE re-evaluated the load flow and short circuit duty results previously

Issued by: James A. Cuillier
Manager, FERC Rates & Regulation
Issued on: **AUG 03 2005**

Atch7-4

Effective:
AUG 04 2005

- performed for the original proposed project, due to other generating projects preceding Calpine in SCE's interconnection queue having withdrawn their interconnection applications. Such re-evaluation, which was transmitted to Calpine on June 13, 2002 revised the list of identified facilities and associated costs required to accommodate the original proposed project.
- 2.9. On December 21, 2004, SCE received a copy of the new Generator Interconnection Application Form submitted by Calpine to the ISO. Calpine's revised Interconnection Application increased the rated output of the project to 810 MW and included machines different than those listed in the original application. The remainder of the original project was unchanged.
- 2.10. The Parties entered into a Combined System Impact and Facilities Study Agreement on March 25, 2005. SCE transmitted the results of the System Impact Study to IEEC on May 24, 2005. SCE is in the process of completing the Facilities Study. The revised Facilities Study for the Inland Empire Energy Center Project is not expected to be completed prior to the execution of this Agreement.
- 2.11. The Parties desire to enter into this Agreement to specify the terms for SCE to provide Interconnection service; for SCE to engineer, design, construct, install, own, operate and maintain the Interconnection Facilities and Reliability Upgrades; and for IEEC to pay for such service and facilities.
- 2.12. SCE is in the process of performing an updated Facilities Study for the Inland Empire Energy Center Project. The Parties anticipate that the results of the Facilities Study may require updates to the Interconnection Facilities Description in Exhibit A-1, the Reliability Upgrades Facilities Description in Exhibit A-2, the Cost Estimate set forth in Exhibit B and conforming updates to Exhibit C. If such updates are required, the Parties intend to timely amend this Agreement.

3. Agreement:

In consideration of the premises and the mutual covenants and agreements contained herein, the Parties agree as follows:

4. Definitions:

All terms with initial capitalization not otherwise defined herein shall have the meanings assigned to them in the TO Tariff as that Tariff may be amended from time to time. The following terms, when used herein with initial capitalization, whether in the singular or the plural, shall have the meanings specified:

- 4.1. Accounting Practice: Generally accepted accounting principles and practices applicable to electric utility operations.
- 4.2. Agreement: This Interconnection Facilities Agreement between Inland Empire Energy Center, LLC and Southern California Edison Company.
- 4.3. Authorized Representative: The representative of a Party designated in accordance with Section 18.
- 4.4. Capital Additions: Any Units of Property which are added to the

- Interconnection Facilities; the enlargement, modification or betterment of any Units of Property constituting a part of the Interconnection Facilities; or the replacement of any Units of Property constituting a part of the Interconnection Facilities, irrespective of whether such replacement constitutes an enlargement, modification or betterment of that which it replaces; the costs of which additions, enlargements, modifications, betterments or replacements in accordance with Accounting Practice would be capitalized and have not previously been included in the Interconnection Facilities Cost.
- 4.5. Capital Additions Cost: All costs, excluding One-Time Cost, determined by SCE to be associated with the design, engineering, procurement, construction and installation of Capital Additions.
- 4.6. Capital Additions Payment: The sum of the Capital Additions Cost and associated One-Time Cost.
- 4.7. CPUC: The California Public Utilities Commission, or its regulatory successor.
- 4.8. Credit Provider: Provider of any Credit Support.
- 4.9. Credit Support: Parent guarantee, letter of credit, surety bond, cash or other security meeting the requirements of Section 7.2.
- 4.10. Customer-Financed Monthly Rate: The rate most recently adopted by the CPUC for application to SCE's retail electric customers for customer-financed added facilities, which does not compensate SCE for replacement of added facilities. The currently effective Customer-Financed Monthly Rate is stated in Exhibit B.
- 4.11. FERC: Federal Energy Regulatory Commission, or its regulatory successor.
- 4.12. Generation Tie-Line Facilities Agreement: The agreement to be entered into by IEEC and SCE to specify the terms for (i) SCE to engineer, design, procure, construct, install, own, operate and maintain a 500 kV generation tie-line from the Inland Empire Energy Center Project switchyard to the interconnection at SCE's Valley Substation, and appurtenant facilities; (ii) SCE to apply to the CPUC for regulatory approvals required for construction of the generation tie-line, and appurtenant facilities; and (iii) IEEC to pay SCE to engineer, design, procure, construct, install, own, operate and maintain the generation tie-line and to apply to the CPUC for a Certificate of Public Convenience and Necessity for construction of the generation tie-line and appurtenant facilities.
- 4.13. Inland Empire Energy Center Project: All equipment and facilities comprising the Inland Empire Energy Center generating station, as disclosed by Calpine in its interconnection application, totaling 810 MW, including but not limited to two "H System" natural gas combined cycle combustion turbine generating system units, which consist of two General Electric Company combustion turbine generators and one Toshiba steam turbine generator per H System unit, two 19.5 kV/525 kV step up power transformers, meters, Remote Terminal Units, switchgear and appurtenant facilities.
- 4.14. Interconnection Facilities: Facilities, as specified in Exhibit A-1 and as shown in Exhibit D, owned by SCE to interconnect the Inland Empire Energy Center Project to the ISO Controlled Grid, as such facilities may be modified during

- the term of this Agreement.
- 4.15. Interconnection Facilities Charge: The monthly charge to IEEC to recover the revenue requirements for the Interconnection Facilities, calculated as the product of the Customer-Financed Monthly Rate and the Interconnection Facilities Cost.
- 4.16. Interconnection Facilities Cost: All costs, excluding One-Time Cost, determined by SCE to be associated with the design, engineering, procurement, construction and installation of the Interconnection Facilities. The Interconnection Facilities Cost is provided in Exhibit B.
- 4.17. Interconnection Facilities In-Service Date: The date upon which the construction of the Interconnection Facilities is complete and such facilities are successfully tested and ready for service.
- 4.18. Interconnection Facilities Payment: The sum of the Interconnection Facilities Cost, and associated One-Time Cost. The Interconnection Facilities Payment is provided in Exhibit B.
- 4.19. IRS: The Internal Revenue Service.
- 4.20. One-Time Cost: All costs determined by SCE to be associated with the installation of Interconnection Facilities, Reliability Upgrades or Capital Additions which are not capitalized. The Interconnection Facilities One-Time Cost and Reliability Upgrades One-Time Cost is provided in Exhibit B.
- 4.21. Reliability Upgrades: Facilities, as specified in Exhibit A-2, beyond the first point of interconnection, excluding the Interconnection Facilities, necessary to interconnect the Inland Empire Energy Center Project safely and reliably to SCE's electrical system and the ISO Controlled Grid, which facilities would not be necessary but for the interconnection of the Inland Empire Energy Center Project (and other projects with interconnection applications preceding that of Calpine), including without limitation, upgrades necessary to remedy short circuit or stability problems potentially resulting from the interconnection of the Inland Empire Energy Center Project (and other projects with interconnection applications preceding that of Calpine) to SCE's electrical system and the ISO Controlled Grid, as such facilities may be modified during the term of this Agreement.
- 4.22. Reliability Upgrades Cost: All costs, excluding One-Time Cost, determined by SCE to be associated with the design, engineering, procurement, construction and installation of the Reliability Upgrades. The Reliability Upgrades Cost is provided in Exhibit B.
- 4.23. Reliability Upgrades In-Service Date: The date upon which the construction of the Reliability Upgrades is complete and such facilities are successfully tested and ready for service.
- 4.24. Reliability Upgrades Payment: The sum of the Reliability Upgrades Cost, and associated One-Time Cost. The Reliability Upgrades Payment is provided in Exhibit B.
- 4.25. Removal Cost: The actual cost SCE incurs for the removal of the Interconnection Facilities, which is calculated as the amount, if positive, of the costs of removal minus the salvage value of the Interconnection Facilities.

- 4.26. Special Protection System ("SPS"): A system that reduces or trips generation under contingency outages to maintain system stability or to limit overloads on system facilities.
- 4.27. Units of Property: As described in FERC's "List of Units of Property for Use in Connection with Uniform System of Accounts Prescribed for Public Utilities and Licensees" in effect as of the date of this Agreement, and as such list may be amended from time to time.
- 4.28. WECC: The Western Electricity Coordinating Council or a successor entity.

5. Effective Date And Term:

- 5.1. This Agreement shall become effective upon the effective date ordered by FERC ("Effective Date").
- 5.2. This Agreement shall terminate on the earliest of: (i) the date thirty (30) years from the Interconnection Facilities In-Service Date, (ii) termination date of the Generation Tie-Line Facilities Agreement entered into by the Parties, (iii) the date specified by IEEC upon one hundred eighty (180) calendar days advance written notice to SCE if the notice of termination is received by SCE on or after the earliest of the Interconnection Facilities In-Service Date or the Reliability Upgrades In-Service Date, (iv) the date specified by IEEC upon thirty (30) calendar days written notice to SCE if the notice of termination is received by SCE before the earliest of the Interconnection Facilities In-Service Date or the Reliability Upgrades In-Service Date, (v) the date specified pursuant to Section 8.13, or (v) the date specified pursuant to Section 15.4. In addition SCE shall have the right to terminate this Agreement subject to FERC acceptance and approval, if IEEC: (1) notifies SCE that it terminates its plan to complete and energize the Inland Empire Energy Center Project prior to the Interconnection Facilities In-Service Date; or (2) fails to utilize the Interconnection Facilities provided under this Agreement for a period of two consecutive years or more following the Interconnection Facilities In-Service Date (except for any period when IEEC does not utilize the Interconnection Facilities due to the occurrence of an Uncontrollable Force or default of SCE under this Agreement).
- 5.3. Any obligations of one Party to the other, including payment obligations, as a result of this Agreement, which accrued prior to or as a result of termination of this Agreement, shall survive termination.
- 5.4. If IEEC has given notice of termination and a filing with FERC is required to terminate this Agreement, IEEC shall support such filing before the FERC if requested by SCE.
- 5.5. Upon termination of this Agreement, IEEC shall pay SCE any remaining balance owed for SCE's costs incurred or irrevocably committed to be incurred pursuant to this Agreement as of the effective date of termination, within sixty (60) calendar days following receipt of a billing from SCE requiring such payment. Such billing shall reflect all payments received by SCE, which shall be credited against the amount of SCE's costs and expenses incurred or irrevocably committed to be incurred in accordance with this Agreement.

6. Agreement Pursuant To The TO Tariff:

This Agreement governs services pursuant to the TO Tariff as such Tariff may be amended from time to time. Accordingly, the rights and obligations of the Parties pursuant to this Agreement are subject to applicable provisions of the TO Tariff, including without limitation its provisions regarding indemnification and Uncontrollable Force, in addition to the provisions of this Agreement. In case of a conflict in the terms contained in this Agreement and the terms in the TO Tariff, the terms of the TO Tariff shall apply. IEEC has read and is familiar with the terms of the TO Tariff.

7. Creditworthiness:

- 7.1. Upon the Effective Date and until all payment obligations of IEEC to SCE under this Agreement, including any obligation to pay Removal Costs in accordance with Section 12.2, 14.1 and 15.2 have been finally and irrevocably paid after the termination date pursuant to Section 5, IEEC shall either maintain Eligible Credit Ratings or provide and maintain additional security as described in Section 7.2 clauses (a) through (e). Eligible Credit Ratings means with respect to an entity, that such entity's senior unsecured long-term debt is rated at least Baa3 from Moody's Investor Service, Inc. ("Moody's") or BBB- from Standard and Poor's Corporation ("S&P").
- 7.2. Within the earlier of (i) one year after the Effective Date or, (ii) the Interconnection Facilities In-Service Date, IEEC shall provide to SCE, in a form that is acceptable to SCE in its sole discretion, evidence that IEEC has the ratings specified in Section 7.1. If at any time during the applicable period as specified in this Section 7.2, IEEC fails to maintain such ratings, IEEC shall provide to SCE, in a form that is acceptable to SCE in its sole discretion; (a) an unconditional and irrevocable guarantee of IEEC's obligations from an entity that meets the ratings specified in Section 7.1; (b) an unconditional and irrevocable letter of credit in US dollars from a depository institution organized under the laws of the United States of America or any State (or any domestic branch of a foreign bank), which (i) has either (A) a long-term unsecured debt rating of A or higher by S&P and A2 or higher by Moody's or (B) a certificate of deposit rating of A-1+ by S&P and P-1 by Moody's, and (ii) whose deposits are insured by FDIC, together with evidence of such ratings; (c) an unconditional and irrevocable surety bond in US dollars issued by an insurance company that has and maintains an Insurance Financial Strength rating of A2 or higher from Moody's and A or higher from S&P, and is rated no less than A- (with a minimum size rating of VIII) by Best's Insurance Guide and Key Ratings, together with evidence of such ratings; (d) cash or (e) other security that is acceptable to SCE in its sole discretion.
- 7.3. Until all payment obligations of IEEC to SCE under this Agreement, including any obligation to pay Removal Costs in accordance with Sections 12.2, 14.1 and 15.2, have been finally and irrevocably paid after the termination date

- pursuant to Section 5, if any such applicable rating is reduced at any time, IEEC shall notify SCE in writing within five (5) calendar days after such reduction.
- 7.4. Any Credit Support provided hereunder shall be payable in at least the amount specified in Section 7.5, and shall be issued in favor of or for the benefit of SCE and its successors and assignees, and shall state that it may be drawn upon in whole or in part by SCE or its successors or assignees at any time (i) if a substitute Credit Support meeting the requirements of Section 7.2 is not provided within fifteen (15) calendar days after any reduction in the applicable rating of the Credit Provider meeting the requirements of Section 7.2 below the level specified herein; (ii) if a substitute Credit Support has not been provided at least thirty (30) calendar days before any expiration of the Credit Support; or (iii) upon any failure by IEEC to make any payment required by this Agreement when due and following the expiration of any applicable cure period, pursuant to Section 15.4.
- 7.5. The amount available to be drawn under any Credit Support shall be equal to \$204,800.00. The disposition of any released Credit Support shall be directed by IEEC.
- 7.6. In addition to the provisions described above, any Credit Support provided hereunder shall contain such terms, conditions, waivers, representations, covenants, and other provisions as may be customary for similar instruments delivered in the State of California, as approved by SCE in its reasonable discretion.

8. Interconnection Principles:

- 8.1. SCE shall design, engineer, procure, construct, install and own the Interconnection Facilities and Reliability Upgrades pursuant to Good Utility Practice and apply for any regulatory approvals necessary for the construction, operation and maintenance of the Interconnection Facilities and Reliability Upgrades.
- 8.2. IEEC, at its sole expense, shall engineer, design, procure, construct, install and own the Inland Empire Energy Center Project.
- 8.3. IEEC shall connect the Inland Empire Energy Center Project with SCE's electrical system in accordance with all applicable ISO, WECC and NERC criteria, SCE specifications, and Good Utility Practice.
- 8.4. IEEC shall execute the Reliability Management System Agreement in Exhibit E.
- 8.5. Certain metering and communications equipment required for SCE to obtain real-time telemetry from IEEC in accordance with Section 10.7 and Interconnection Facilities (which may include such metering and communications equipment) will be located on property which is leased or owned by IEEC. IEEC shall grant, or cause to be granted, easements to SCE for the term of this Agreement, at no cost to SCE, providing for appropriate space and access rights for installation, operation, maintenance, replacement

- and removal of such metering and communications equipment, Interconnection Facilities and Special Protection Systems. SCE and IEEC shall make all arrangements necessary to effectuate such easements.
- 8.6. IEEC shall acquire all permits and other approvals in addition to completing all environmental impact studies necessary for the construction, operation, and maintenance of the Inland Empire Energy Center Project. IEEC shall include the Interconnection Facilities and Reliability Upgrades in all such environmental impact studies. IEEC shall provide the results of such studies and approvals to SCE for use in SCE's application(s) to obtain any regulatory approvals required to be obtained by SCE for the construction of SCE's facilities.
- 8.7. At SCE's request, IEEC shall provide to SCE those electrical specifications and design drawings pertaining to the Inland Empire Energy Center Project which may potentially have an impact on the SCE transmission and distribution system, as determined by SCE, for SCE's review prior to finalizing the design and before beginning construction work based on such specifications and drawings. IEEC shall provide to SCE reasonable advance written notice of any changes in the Inland Empire Energy Center Project and provide to SCE specifications and design drawings of any such changes for SCE review and approval. Such approval shall not be unreasonably withheld. SCE may require modifications to such specifications and design drawings as it deems necessary to allow SCE to operate its electric system in accordance with Good Utility Practice.
- 8.8. SCE shall have the right to review and consult with IEEC regarding IEEC's construction schedule for the Inland Empire Energy Center Project.
- 8.9. SCE shall have the right to inspect the Inland Empire Energy Center Project prior to initial operation upon advance notice to IEEC. IEEC, at its option, may be present at such inspection.
- 8.10. SCE shall use commercially reasonable efforts to construct, successfully test and declare ready for service the Interconnection Facilities and Reliability Upgrades on or before twenty four (24) months following the Effective Date. However, IEEC understands and acknowledges that such date is only an estimate and that equipment and material lead times, labor availability, outage coordination, regulatory approvals, or other unforeseen events could delay the actual in-service date beyond that specified.
- 8.11. The maximum capacity of the Interconnection Facilities made available by SCE to IEEC for the purpose of the interconnection of the Inland Empire Energy Center Project to the ISO Controlled Grid under this Agreement shall be 790 MW. IEEC acknowledges that if IEEC wishes to increase the amount of Interconnection capacity provided pursuant to this Agreement, IEEC shall be required to submit a new application in accordance with the terms and conditions of the TO Tariff.
- 8.12. As of the date of execution of this Agreement by the Parties, SCE is in the process of completing a Facilities Study for the Inland Empire Energy Center Project. IEEC's cost responsibility with respect to any additional upgrades

- pursuant to the results of the System Impact and Facilities Study shall be consistent with FERC's costs allocation principles, and shall be reflected in an amendment to this Agreement, subject to FERC acceptance.
- 8.13. After the Inland Empire Energy Center Project is synchronized to the transmission system, IEEC shall provide SCE advance notice prior to making any changes (other than maintenance) to the generation, power transformation, or transmission facilities and equipment which comprise the Inland Empire Energy Center Project. IEEC shall notify SCE within a reasonable time prior to the date when any such changes are planned to be placed in service so that SCE and the ISO can evaluate any potential system impacts which may occur as a result of such changes and whether such changes will require a new application pursuant to the ISO Tariff. If IEEC fails to provide SCE advance notice of changes to the generation, power transformation, or transmission equipment and facilities comprising the Inland Empire Energy Center Project and any such change does or may cause material system impacts or is or may be materially inconsistent with the service provided pursuant to this Agreement, SCE shall have the right to terminate this Agreement subject to FERC acceptance or approval.
- 8.14. The costs associated with any mitigation measures required to third party transmission systems resulting from the interconnection of the Inland Empire Energy Center Project to SCE's electrical system are not reflected in this Agreement. SCE shall have no responsibility to pay costs associated with any such mitigation measures.
- 8.15. In the event the Interconnection Facilities are utilized to provide retail service to IEEC in addition to the wholesale Interconnection service provided herein, and IEEC fails to make payment for such retail service in accordance with SCE's applicable retail tariffs, the Interconnection Facilities may be removed from service to IEEC, subject to the notice and cure provisions of such retail tariffs, until payment is made by IEEC pursuant to such retail tariffs.

9. Interconnected Operations:

- 9.1. SCE shall operate and maintain the Interconnection Facilities in accordance with the applicable ISO Tariff provisions and protocols, TO Tariff provisions, WECC and NERC reliability criteria, established operating procedures and Good Utility Practice as they may change from time to time.
- 9.2. IEEC shall operate and maintain the Inland Empire Energy Center Project in accordance with the applicable ISO Tariff provisions and protocols, TO Tariff provisions, WECC and NERC reliability criteria, established operating procedures and Good Utility Practice as they may change from time to time.
- 9.3. The operating power factor at the point of interconnection to the ISO Controlled Grid at Valley Substation shall be at unity unless IEEC is otherwise notified by SCE or the ISO to maintain a specified voltage schedule while operating within the power factor range of 0.90 boost to 0.95 buck.
- 9.4. The Inland Empire Energy Center Project shall be operated so as to prevent or

- protect against the following adverse conditions on SCE's electric system:
inadvertent and unwanted re-energizing of a utility dead line or bus;
interconnection while out of synchronization; overcurrent; voltage imbalance;
ground faults; generated alternating current frequency outside permitted safe
limits; poor power factor or reactive power outside permitted limits; and
abnormal waveforms.
- 9.5. The Inland Empire Energy Center Project shall be operated with all of IEEC's protective apparatus in service whenever the Inland Empire Energy Center Project is connected to, or is operated in parallel with, SCE's electric system. Any deviation for brief periods of emergency or maintenance shall only be by agreement of the Authorized Representatives.
- 9.6. IEEC shall cause the Inland Empire Energy Center Project to participate in ISO congestion management. IEEC is aware that the Inland Empire Energy Center Project will compete with other market generation for available transmission capacity in accordance with ISO protocols.
- 9.7. IEEC shall cause the Inland Empire Energy Center Project to participate in any SPS required to prevent thermal overloads and unstable conditions resulting from outages. Such participation shall be in accordance with applicable FERC regulations, and ISO Tariff provisions and protocols. IEEC will not be entitled to any compensation from SCE, pursuant to this Agreement, for loss of generation output if (i) Inland Empire Energy Center Project generation is reduced or tripped off-line due to implementation of the SPS; or (ii) such generation output is restricted in the event the SPS becomes inoperable.
- 9.8. IEEC shall maintain operating communications with SCE's designated switching center. The operating communications shall include, but not be limited to, system parallel operation or separation, scheduled and unscheduled outages, equipment clearances, protective relay operations, and levels of operating voltage and reactive power.
- 9.9. IEEC shall not commence initial parallel operation of the Inland Empire Energy Center Project with SCE's electric system until written approval for operation of the Inland Empire Energy Center Project has been given by SCE. Such approval shall not be unreasonably withheld. Following outages of the Interconnection Facilities or the Inland Empire Energy Center Project, IEEC shall not energize the Inland Empire Energy Center Project for any reason without specific permission from SCE operations. Such permission shall not be unreasonably withheld.
- 9.10. IEEC shall provide written notice to SCE at least fourteen (14) calendar days prior to the initial and subsequent testing of IEEC's protective apparatus. IEEC's protective apparatus shall be tested at intervals not to exceed four (4) years. All such tests shall be performed using qualified personnel. SCE shall have the right to have a representative present at the initial and subsequent testing of IEEC's protective apparatus and to receive copies of the test results.
- 9.11. SCE shall not have any responsibility for protection of the Inland Empire Energy Center Project. IEEC shall be responsible for protecting the Inland Empire Energy Center Project in such a manner that faults or other

- disturbances on SCE's electric system do not cause damage to the Inland Empire Energy Center Project.
- 9.12. SCE may require IEEC, at IEEC's expense, to demonstrate to SCE's satisfaction the correct calibration and operation of IEEC's protective apparatus at any time SCE has reason to believe that said protective apparatus may impair SCE's electric system integrity.
- 9.13. The Parties shall cooperate with one another in scheduling maintenance to the Interconnection Facilities or the Inland Empire Energy Center Project or in taking the Interconnection Facilities or the Inland Empire Energy Center Project out of service, provided that in an emergency SCE may take the Interconnection Facilities out of service without notice to IEEC. The Parties shall use commercially reasonable efforts to avoid performing regularly scheduled maintenance during system peak conditions.
- 9.14. Subsequent to the Interconnection Facilities In-Service Date, IEEC shall notify SCE by January 1, May 1, and September 1 of each year, of the estimated scheduled maintenance for the succeeding four months.
- 9.15. Review by SCE of the electrical specifications, design, construction, operation, or maintenance of the Inland Empire Energy Center Project shall not constitute any representation as to the economic or technical feasibility, operational capability, or reliability of such facilities. IEEC shall in no way represent to any third party that any such review by SCE of such facilities, including, but not limited to, any review of the design, construction, operation, or maintenance of such facilities by SCE, is a representation by SCE as to the economic or technical feasibility, operational capability, or reliability of the Inland Empire Energy Center Project.
- 9.16. This Agreement governs the Interconnection of the Inland Empire Energy Center Project to the ISO Controlled Grid pursuant to the TO Tariff and as described herein. IEEC shall be responsible for making all necessary operational arrangements with the ISO, including, without limitation, arrangements for obtaining transmission service from the ISO, and for scheduling delivery of energy and other services to the ISO Controlled Grid.

10. Metering:

- 10.1. The ISO meters shall be located on IEEC's side of the point of interconnection.
- 10.2. IEEC shall be responsible for the installation, maintenance and certification of ISO quality metering for the Inland Empire Energy Center Project in accordance with applicable ISO Tariff provisions and metering protocol.
- 10.3. IEEC shall own all ISO metering infrastructure and be responsible for all costs of such infrastructure including, without limitation, testing and certification of ISO metering.
- 10.4. IEEC shall be responsible for obtaining ISO approval for the installation of ISO metering at the Inland Empire Energy Center Project prior to operation.
- 10.5. IEEC shall be responsible for any loss correction factor applicable to IEEC's metering in accordance with applicable ISO Tariff provisions and metering

protocol.

- 10.6. Metering of IEEC generation and load shall be in accordance with applicable ISO Tariff provisions and metering protocol and applicable SCE retail tariffs, respectively. Any ISO meters shall be capable of measuring energy flow to and from the point of interconnection and shall satisfy the technical requirements for participation in the wholesale market and for taking retail service.
- 10.7. IEEC shall deliver to SCE real-time telemetry generator unit data, which shall include, for each generator unit, MW, MVAR, generator status, generator circuit breaker status and generator output voltage.

11. Capital Additions:

- 11.1. SCE shall engineer, design, construct, install, own, operate and maintain all Capital Additions pursuant to Good Utility Practice.
- 11.2. Except as otherwise provided in Section 11.3, whenever Capital Additions are required by SCE pursuant to Good Utility Practice (which may include compliance with system or regulatory requirements), IEEC shall pay all charges associated with such Capital Additions in accordance with Section 15.
- 11.3. In the event that Capital Additions are required in order to benefit SCE, or because of damage caused by negligence or willful misconduct of SCE, IEEC shall not bear cost responsibility for such Capital Additions. No adjustment will be made to the Interconnection Facilities Cost and no Capital Additions Cost, or One-Time Cost will be charged to IEEC for such Capital Additions.

12. Removal Of Interconnection Facilities:

- 12.1. Following termination of this Agreement, SCE will remove the Interconnection Facilities from service to IEEC.
- 12.2. On or before the date one year following termination of this Agreement, SCE shall notify IEEC, in writing, whether SCE intends to physically remove the Interconnection Facilities or any part thereof. If SCE intends to physically remove the Interconnection Facilities or any part thereof, then SCE shall physically remove such facilities within two years from the date of notification of intent, and IEEC shall pay the Removal Cost in accordance with Sections 14.1 and 15.2. If SCE does not intend to physically remove the Interconnection Facilities or any part thereof, then IEEC shall have no obligation to pay such Removal Cost.

13. Other Taxes:

- 13.1. **IEEC Payments Not Taxable.** The Parties intend that all payments or property transfers made by IEEC to SCE for the installation of Interconnection Facilities, Capital Additions and Reliability Upgrades shall be non-taxable, either as contributions to capital, or as a refundable advance, in accordance with the Internal Revenue Code and any applicable state income tax laws and shall not be taxable as contributions in aid of construction or otherwise under

the Internal Revenue Code and any applicable state income tax laws.

- 13.2. **Representations And Covenants.** In accordance with IRS Notice 2001-82 and IRS Notice 88-129, IEEC represents and covenants that (i) ownership of the electricity generated at the Inland Empire Energy Center Project will pass to another party prior to the transmission of the electricity on the ISO Controlled Grid, (ii) for income tax purposes, the amount of any payments and the cost of any property transferred to SCE for SCE's Interconnection Facilities and Capital Additions will be capitalized by IEEC as an intangible asset and recovered using the straight-line method over a useful life of twenty (20) years, and (iii) any portion of SCE's Interconnection Facilities or Capital Additions that is a "dual-use intertie," within the meaning of IRS Notice 88-129, is reasonably expected to carry only a de minimis amount of electricity in the direction of the Inland Empire Energy Center Project. For this purpose, "de minimis amount" means no more than 5 percent of the total power flows in both directions, calculated in accordance with the "5 percent test" set forth in IRS Notice 88-129. This is not intended to be an exclusive list of the relevant conditions that must be met to conform to IRS requirements for non-taxable treatment.

At SCE's request, IEEC shall provide SCE with a report from an independent engineer confirming its representation in clause (iii), above. SCE represents and covenants that the cost of SCE's Interconnection Facilities and Capital Additions paid for by IEEC without possibility of refund or credit will have no net effect on the base upon which rates are determined.

- 13.3. **Indemnification for the Cost Consequences of Current Tax Liability Imposed Upon SCE.** Notwithstanding Section 13.1, IEEC shall protect, indemnify and hold harmless SCE from the cost consequences of any current tax liability imposed against SCE as the result of payments or property transfers made by IEEC to SCE under this Agreement for Interconnection Facilities or Capital Additions, as well as any interest and penalties, other than interest and penalties attributable to any delay caused by SCE. IEEC shall reimburse SCE for such costs on a fully grossed-up basis, in accordance with Section 13.4, within thirty (30) calendar days of receiving written notification from SCE of the amount due, including detail about how the amount was calculated.

SCE shall not include a gross-up for the cost consequences of any current tax liability in the amounts it charges IEEC under this Agreement unless (i) SCE has determined, in good faith, that the payments or property transfers made by IEEC to SCE should be reported as income subject to taxation or (ii) any Governmental Authority directs SCE to report payments or property as income subject to taxation; provided, however, that IEEC shall, within thirty (30) days of the Effective Date, provide security in the form of an unconditional and irrevocable letter of credit ("Letter of Credit") for Interconnection Facilities and Capital Additions, in a form reasonably acceptable to SCE, in the amount of

\$509,600.00 which equal to the cost consequences of any current tax liability under this Section 13. Such Letter of Credit shall be issued from a Creditworthy entity. "Creditworthy" means that the outstanding debt securities of the relevant entity shall have an unsecured long-term debt rating of A2 or higher from Moody's Investor Service, Inc. ("Moody's") or A or higher from Standard and Poor's Corporation ("S&P") or if such entity does not have an unsecured debt rating, it shall have an issuer rating of A2 or higher from Moody's or A or higher from S&P.

The indemnification obligation shall terminate at the later of (1) the expiration of the ten year testing period and the applicable statute of limitation, as it may be extended by SCE upon request of the IRS, to keep these years open for audit or adjustment, or (2) the date the risk of subsequent taxability as described in Section 13.6 no longer exists, as reasonably determined by SCE.

- 13.4. **Tax Gross-Up Amount.** IEEC's liability for the cost consequences of any current tax liability under this Section 13 shall be calculated on a fully grossed-up basis. Except as may otherwise be agreed to by the Parties, this means that IEEC will pay SCE, in addition to the amount paid for the Interconnection Facilities, Capital Additions and Reliability Upgrades an amount equal to (1) the current taxes imposed on SCE ("Current Taxes") on the excess of (a) the gross income realized by SCE as a result of payments or property transfers made by IEEC to SCE under this Agreement (without regard to any payments under this Section 13) (the "Gross Income Amount") over (b) the present value of future tax deductions for depreciation that will be available as a result of such payments or property transfers (the "Present Value Depreciation Amount"), plus (2) an additional amount sufficient to permit SCE to receive and retain, after the payment of all Current Taxes, an amount equal to the net amount described in clause (1).

For this purpose, (i) Current Taxes shall be computed based on SCE's composite federal and state tax rates at the time the payments or property transfers are received and SCE will be treated as being subject to tax at the highest marginal rates in effect at that time (the "Current Tax Rate"), and (ii) the Present Value Depreciation Amount shall be computed by discounting SCE's anticipated tax depreciation deductions as a result of such payments or property transfers by SCE's current weighted average cost of capital. Thus, the formula for calculating IEEC's liability to SCE pursuant to this Section 13.4 can be expressed as follows: $(\text{Current Tax Rate} \times (\text{Gross Income Amount} - \text{Present Value of Tax Depreciation})) / (1 - \text{Current Tax Rate})$. IEEC's estimated tax liability in the event taxes are imposed is stated in Section 13.3.

- 13.5. **Private Letter Ruling or Change or Clarification of Law.** At IEEC's request and expense, SCE shall file with the IRS a request for a private letter ruling as to whether any property transferred or sums paid, or to be paid, by IEEC to SCE under this Agreement are subject to federal income taxation. IEEC will prepare the initial draft of the request for a private letter ruling, and

will certify under penalties of perjury that all facts represented in such request are true and accurate to the best of IEEC's knowledge. SCE and IEEC shall cooperate in good faith with respect to the submission of such request; provided, however, IEEC and SCE explicitly acknowledge (and nothing herein is intended to alter) SCE's obligation under law to certify that the facts presented in the ruling request are true, correct and complete.

SCE shall keep IEEC fully informed of the status of such request for a private letter ruling and shall execute either a privacy act waiver or a limited power of attorney, in a form acceptable to the IRS, that authorizes IEEC to participate in all discussions with the IRS regarding such request for a private letter ruling. SCE shall allow IEEC to attend all meetings with IRS officials about the request and shall permit IEEC to prepare the initial drafts of any follow-up letters in connection with the request.

- 13.6. **Subsequent Taxable Events.** If (i) IEEC breaches the covenants contained in Section 13.2, (ii) a "disqualification event" occurs within the meaning of IRS Notice 88-129, or (iii) this Agreement terminates and SCE retains ownership of the Interconnection Facilities, Capital Additions and Reliability Upgrades, IEEC shall pay a tax gross-up for the cost consequences of any current tax liability imposed on SCE, calculated using the methodology described in Section 13.4 and in accordance with IRS Notice 90-60.

- 13.7. **Contests.** In the event any Governmental Authority determines that SCE's receipt of payments or property constitutes income that is subject to taxation, SCE shall notify IEEC, in writing, within thirty (30) Calendar Days of receiving notification of such determination by a Governmental Authority. Upon the timely written request by IEEC and at IEEC's sole expense, SCE may appeal, protest, seek abatement of, or otherwise oppose such determination. Upon IEEC's written request and sole expense, SCE may file a claim for refund with respect to any taxes paid under this Section 13, whether or not it has received such a determination. SCE reserves the right to make all decisions with regard to the prosecution of such appeal, protest, abatement or other contest, including the selection of counsel and compromise or settlement of the claim, but SCE shall keep IEEC informed, shall consider in good faith suggestions from IEEC about the conduct of the contest, and shall reasonably permit IEEC or a IEEC representative to attend contest proceedings.

IEEC shall pay to SCE on a periodic basis, as invoiced by SCE, SCE's documented reasonable costs of prosecuting such appeal, protest, abatement or other contest, including any costs associated with obtaining the opinion of independent tax counsel described in this Section 13.7. SCE may abandon any contest if IEEC fails to provide payment to SCE within 30 calendar days of receiving such invoice.

At any time during the contest, SCE may agree to a settlement either with IEEC's consent or, if such consent is refused, after obtaining written advice

from independent nationally-recognized tax counsel, selected by SCE, but reasonably acceptable to IEEC, that the proposed settlement represents a reasonable settlement given the hazards of litigation. IEEC's obligation shall be based on the amount of the settlement agreed to by IEEC, or if a higher amount, so much of the settlement that is supported by the written advice from nationally-recognized tax counsel selected under the terms of the preceding paragraph. The settlement amount shall be calculated on a fully grossed-up basis to cover any related cost consequences of the current tax liability. SCE may also settle any tax controversy without receiving IEEC's consent or any such written advice; however, any such settlement will relieve IEEC from any obligation to indemnify SCE for the tax at issue in the contest (unless the failure to obtain written advice is attributable to IEEC's unreasonable refusal to the appointment of independent tax counsel.

- 13.8. **Refund.** In the event that (a) a private letter ruling is issued to SCE which holds that any amount paid or the value of any property transferred by IEEC to SCE under the terms of this Agreement is not subject to federal income taxation, (b) any legislative change or administrative announcement, notice, ruling or other determination makes it reasonably clear to SCE in good faith that any amount paid or the value of any property transferred by IEEC to SCE under the terms of this Agreement is not taxable to SCE, (c) any abatement, appeal, protest, or other contest results in a determination that any payments or transfers made by IEEC to SCE are not subject to federal income tax, or (d) if SCE receives a refund from any taxing authority for any overpayment of tax attributable to any payment or property transfer made by IEEC to SCE pursuant to this Agreement, SCE shall promptly refund to IEEC the following:
- (i) any payment made by IEEC under this Section 13 for taxes that is attributable to the amount determined to be non-taxable, together with interest thereon,
 - (ii) interest on any amounts paid by IEEC to SCE for such taxes which IEEC did not submit to the taxing authority, calculated in accordance with the methodology set forth in FERC's regulations at 18 C.F.R. §35.19a(a)(2)(iii) from the date payment was made by IEEC to the date SCE refunds such payment to IEEC, and
 - (iii) with respect to any such taxes paid by SCE, any refund or credit SCE receives or to which it may be entitled from any Governmental Authority, interest (or that portion thereof attributable to the payment described in clause (i), above) owed to SCE for such overpayment of taxes (including any reduction in interest otherwise payable by SCE to any Governmental Authority resulting from an offset or credit); provided, however, that SCE will remit such amount promptly to IEEC only after and to the extent that SCE has received a tax refund, credit or offset from any Governmental Authority for any applicable overpayment of income tax related to IEEC's Interconnection Facilities or Capital Additions.

The intent of this provision is to leave the Parties, to the extent practicable, in the event that no taxes are due with respect to any payment for Interconnection Facilities, Capital Additions and Reliability Upgrades hereunder, in the same position they would have been in had no such tax payments been made.

- 13.9. **Taxes Other Than Income Taxes.** Upon the timely request by IEEC, and at IEEC's sole expense, SCE may appeal, protest, seek abatement of, or otherwise contest any tax (other than federal or state income tax) asserted or assessed against SCE for which IEEC may be required to reimburse SCE under the terms of this Agreement. IEEC shall pay to SCE on a periodic basis, as invoiced by SCE, SCE's documented reasonable costs of prosecuting such appeal, protest, abatement, or other contest. IEEC and SCE shall cooperate in good faith with respect to any such contest. Unless the payment of such taxes is a prerequisite to an appeal or abatement or cannot be deferred, no amount shall be payable by IEEC to SCE for such taxes until they are assessed by a final, non-appealable order by any court or agency of competent jurisdiction. In the event that a tax payment is withheld and ultimately due and payable after appeal, IEEC will be responsible for all taxes, interest and penalties, other than penalties attributable to any delay caused by SCE.

14. Charges:

- 14.1. IEEC shall pay to SCE the following charges in accordance with this Agreement: (a) Interconnection Facilities Payment; (b) Reliability Upgrades Payment; (c) Interconnection Facilities Charge; (d) Capital Additions Payment; (e) any reimbursable FERC fees pursuant to Section 19.4; (f) Removal Cost pursuant to Section 12; (g) other taxes pursuant to Section 13; and (h) termination charges pursuant to Section 5.5.
- 14.2. The Interconnection Facilities Cost, Reliability Upgrades Cost, Capital Additions Cost, One-Time Cost and Removal Cost shall be compiled in accordance with Accounting Practice.
- 14.3. If, during the term of this Agreement, SCE executes an agreement to provide service to another entity (other than retail load) which contributes to the need for the Interconnection Facilities, the charges due hereunder may be adjusted to appropriately reflect such service based on SCE's cost allocation principles in effect at such time and shall be subject to FERC approval.
- 14.4. SCE will provide transmission credits, with interest, in the amount of Reliability Upgrades Cost, and any applicable One-Time Cost associated with the Reliability Upgrades paid by IEEC. Such transmission credits shall be in the form of twenty (20) cash payments, including interest, paid to IEEC on the last business day of each quarter over five (5) year period. Payment of such transmission credits to IEEC will commence not earlier than sixty (60) days after the later of the following events: (i) the Reliability Upgrades In-Service Date; (ii) acceptance of operational control of the Reliability Upgrades by the ISO; or (iii) the commercial operation date of the Inland Empire Energy Center Project. Interest will be calculated in accordance with the methodology

specified for interest on refunds in FERC's regulations at 18 CFR section 35.19a(a)(2)(iii) from the date SCE received payment of the Reliability Upgrades Costs and applicable One-Time Costs from IEEC. Credit payments will be adjusted to reflect actual recorded Reliability Upgrades Costs pursuant to Section 15.1.8. All payments made to IEEC pursuant to this Section 14.4 shall be made in immediately available funds payable by wire transfer to a bank designated by IEEC. The foregoing methodology for providing transmission credits is subject to change to reflect the FERC's final order in Docket No. RM02-1-000. Nothing herein shall prejudice or affect SCE's or IEEC's ability to seek any modification or review of the FERC's final order in Docket No. RM02-1-000.

15. Billing And Payment:

15.1. Billing Procedure.

- 15.1.1. Except as otherwise specifically provided herein, commencing on or following the Effective Date, SCE will render bills to IEEC for charges and payments under this Agreement and IEEC shall pay such bills within twenty (20) calendar days of receipt of such bills. All payments shall be made in immediately available funds payable to SCE, or by wire transfer to a bank named by SCE.
- 15.1.2. IEEC shall make payments to SCE for the Interconnection Facilities Payment and Reliability Upgrades Payment according to the payment schedules shown in Exhibit C. The amounts of such Interconnection Facilities Payment and Reliability Upgrades Payment are based on SCE's cost estimates and shall be subject to later adjustment pursuant to Section 15.1.8.
- 15.1.3. Commencing on or following the Interconnection Facilities In-Service Date, each month SCE will render bills to IEEC for the Interconnection Facilities Charge. The Interconnection Facilities Charge payments shall initially be based on SCE's best estimate of the Interconnection Facilities Cost upon the Interconnection Facilities In-Service Date (such cost estimate may differ from the Interconnection Facilities Cost estimate set forth in Exhibit B), and such payments shall be subject to later adjustment pursuant to Sections 15.1.8.3 and 15.1.8.4. The Interconnection Facilities Charge for the first and last month of service hereunder shall be pro-rated based on the number of days in which service was provided during said months.
- 15.1.4. SCE will bill IEEC for the Capital Additions Payment prior to commencing any work on any Capital Additions in accordance with Section 11.2; provided that, at SCE's sole discretion, SCE may bill IEEC for the Capital Additions Payment after commencing such work if SCE determines that Capital Additions are required in accordance with safety or regulatory requirements or to preserve system integrity or reliability. Such

- billing shall initially be based on SCE's cost estimates and shall be subject to later adjustment pursuant to Sections 15.1.8.1 and 15.1.8.2.
- 15.1.5. Except as otherwise provided in Section 11.3, if certain Interconnection Facilities are removed to accommodate such Capital Additions and such removal results in a change in the Interconnection Facilities Cost, the Interconnection Facilities Charge shall be adjusted as of the in-service date of such Capital Additions to reflect the change in the Interconnection Facilities Cost.
- 15.1.6. Except as otherwise provided in Section 11.3, if such Capital Additions result in an increase in the Interconnection Facilities Cost, then the Interconnection Facilities Charge shall be adjusted as of the in-service date of such Capital Additions to reflect the change in the Interconnection Facilities Cost.
- 15.1.7. Commencing on the Effective Date, SCE will render bills to IEEC for any reimbursable FERC fees in accordance with Section 19.4. Such billing shall be for any reimbursable FERC fees or costs incurred since the preceding billing.
- 15.1.8. Within twelve (12) months following the Interconnection Facilities In-Service Date, the Reliability Upgrades In-Service Date, or the in-service date of any Capital Additions, as the case may be, SCE shall determine the actual recorded Interconnection Facilities Cost, Reliability Upgrades Cost, or the Capital Additions Cost, including the associated One-Time Cost, and provide IEEC with a final invoice.
- 15.1.8.1. If the amounts paid for the estimated Interconnection Facilities Payment, Reliability Upgrades Payment, or the Capital Additions Payment are less than the amounts due for the Interconnection Facilities Payment, Reliability Upgrades Payment, or the Capital Additions Payment as determined from the actual recorded Interconnection Facilities Cost, Reliability Upgrades Cost, or the Capital Additions Cost, including the associated One-Time Cost, SCE will bill IEEC for the difference between the amounts previously paid by IEEC and the actual recorded costs, without interest, within twenty (20) calendar days of the date of such invoice.
- 15.1.8.2. If the amounts paid for the estimated Interconnection Facilities Payment, Reliability Upgrades Payment, or the Capital Additions Payment are greater than the amounts due for the Interconnection Facilities Payment, Reliability Upgrades Payment, or the Capital Additions Payment as determined from the actual recorded Interconnection Facilities Cost, Reliability Upgrades Cost, or the Capital Additions Cost, including the associated One-Time Cost, SCE will refund IEEC the difference between the amounts previously paid by IEEC and the actual recorded costs, without interest, within twenty (20) calendar days of the date of such invoice.

- 15.1.8.3. If the amounts paid for the Interconnection Facilities Charge are less than the amounts due for the Interconnection Facilities Charge as determined from the actual recorded Interconnection Facilities Cost, SCE will bill IEEC for the difference between the amounts previously paid by IEEC and the amounts which would have been paid based on actual recorded costs, without interest, on the next regular billing.
- 15.1.8.4. If the amounts paid for the Interconnection Facilities Charge are greater than the amounts due for the Interconnection Facilities Charge as determined from the actual recorded Interconnection Facilities Cost, SCE will credit IEEC the difference between the amounts previously paid by IEEC and the amounts which would have been paid based on actual recorded costs, without interest, on the next regular billing.
- 15.1.9. Charges for payments upon termination shall be billed and paid as provided in Section 5.

15.2. Removal Costs.

- 15.2.1. If, in accordance with Section 12.2, SCE decides to physically remove the Interconnection Facilities, SCE shall render a bill to IEEC for the Removal Cost. IEEC shall pay the Removal Cost in accordance with Section 14.1. Such billing shall be initially based on SCE's estimate of the Removal Cost. Within 12 months following the removal of the Interconnection Facilities, SCE shall determine the recorded Removal Cost and provide IEEC with a final invoice.
- 15.2.2. If the amount paid for the Removal Cost is less than the amount due for the Removal Cost as determined from the actual recorded Removal Cost, SCE will bill IEEC for the difference between the amount previously paid by IEEC and the amount which would have been paid based on actual recorded costs, without interest, within twenty (20) calendar days of the date of such invoice.
- 15.2.3. If the amount paid for the Removal Cost is greater than the amount due for the Removal Cost as determined from the actual recorded Removal Cost, SCE will refund IEEC the difference between the amount previously paid by IEEC and the amount which would have been paid based on actual recorded costs, without interest, within twenty (20) calendar days of the date of such invoice.

15.3. Interest On Unpaid Balances.

Interest on any unpaid amounts shall be calculated in accordance with the methodology specified for interest on refunds in FERC's regulations at 18 C.F.R. Section 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments

are made by mail, bills shall be considered as having been paid on the date of receipt by SCE.

15.4. Default.

In the event that IEEC fails for any reason to make payment to SCE on or before the due date as provided above, and such failure of payment is not corrected within thirty (30) calendar days after SCE notifies IEEC to cure such failure, a default by IEEC shall be deemed to exist. Upon the occurrence of a default, SCE shall have the right to terminate this Agreement subject to FERC acceptance or approval.

15.5. Billing Dispute.

In the event IEEC desires to dispute all or any part of any bill submitted by SCE, including, but not limited to, any bill submitted pursuant to Section 5.5 hereof, IEEC shall nevertheless pay the full amount of the bill when due and give written notification to SCE's Authorized Representative within one hundred eighty (180) calendar days from the date of the billing stating the grounds for the dispute and the amount in dispute. IEEC shall not be entitled to an adjustment on any bill not brought to the attention of SCE within the time and in the manner herein specified. For any payments to IEEC resulting from dispute resolutions, interest calculated in accordance with the methodology specified for interest on refunds in FERC's regulations at 18 C.F.R. Section 35.19a(a)(2)(iii) shall be added to the amount of any overpayment, and the entire amount refunded to IEEC.

15.6. Addresses For Billing And Payment.

15.6.1. All payments to be made by IEEC to SCE shall be sent to:

Southern California Edison Company
Accounts Receivable
Box 600
Rosemead, California 91770-0600
(626) 302-9448
(626) 302-9392

SCE may, at any time, by written notice to IEEC pursuant to Section 26, change the address to which payments will be sent.

15.6.2. All billings to be presented by SCE to IEEC shall be sent to:

Inland Empire Energy Center, LLC
Attn: Accounts Receivables

4160 Dublin Boulevard
Dublin, California 94568
(925) 479-6600
(925) 479-7311 (Fax)

IEEC may, at any time, by written notice to SCE pursuant to Section 26, change the address to which billings will be sent.

16. Disputes:

With the exception of disputes referenced in Section 15.5 and except as otherwise limited by law, the ISO ADR Procedures set forth in Section 13 of the ISO Tariff shall apply to all disputes between IEEC and SCE which arise under this Agreement; provided, however, that the ISO ADR Procedures set forth in Section 13 of the ISO Tariff shall not be used to determine whether rates and charges set forth in this Agreement are just and reasonable under the Federal Power Act.

17. Audits:

- 17.1. SCE will maintain records and accounts of all costs incurred in sufficient detail to allow verification of all costs incurred, including, but not limited to, labor and associated labor burden, material and supplies, outside services, and administrative and general expenses.
- 17.2. IEEC shall have the right, upon reasonable notice, at a reasonable time at SCE's offices and at its own expense, to audit SCE's records and accounts as necessary and as appropriate in order to verify costs incurred by SCE. Any audit requested by IEEC shall be limited to the costs reflected in the final invoice as set forth in Sections 15.1.8 or 15.2.1, and shall be completed, and written notice of any audit dispute provided to SCE's Authorized Representative, within one hundred eighty (180) calendar days following receipt by IEEC of such final invoice.

18. Authorized Representatives:

- 18.1. In order to provide for the exchange of information and preparation of any necessary operating procedures or revisions to operating procedures regarding the activities required under this Agreement, each Party shall have an Authorized Representative as provided below.
- 18.2. Following execution of this Agreement and prior to the Interconnection Facilities In-Service Date, the Authorized Representatives shall be as follows:

Southern California Edison Company:
Mr. Frederick W. Salzmann
Project Manager
1321 South State College Boulevard
Fullerton, California 92831

(714) 626-4674
(714) 626-4710 (Fax)

Inland Empire Energy Center, LLC
Mr. Richard L. Thomas
Vice President
4160 Dublin Boulevard
Dublin, California 94568
(925) 479-6600
(925) 479-7311 (Fax)

- 18.3. Upon and subsequent to the Interconnection Facilities In-Service Date, the Authorized Representatives shall be as follows:

Southern California Edison Company:
Mr. Gilbert H. L. Tam
Director of Grid Contracts, Transmission and Distribution
2244 Walnut Grove Avenue
Rosemead, California 91770
(626) 302-1771
(626) 302-1152 (Fax)

Inland Empire Energy Center, LLC
Mr. Richard L. Thomas
Vice President
4160 Dublin Boulevard
Dublin, California 94568
(925) 479-6600
(925) 479-7311 (Fax)

- 18.4. The Authorized Representatives are authorized to act on behalf of the Party they represent in the implementation of this Agreement. Any action taken or determination made by the Authorized Representatives in the implementation of this Agreement will be in writing.
- 18.5. The Authorized Representatives shall have no authority or power to modify, add, waive or eliminate any terms or conditions of this Agreement.
- 18.6. Either Party may at any time change the designation of its Authorized Representative by written notice to the other Party pursuant to Section 26.

19. Regulatory Authority:

- 19.1. No later than thirty (30) calendar days following the execution of this Agreement, SCE shall tender this Agreement for filing with FERC with a request that it be made effective upon acceptance without suspension, and IEEC shall support SCE in obtaining all necessary authorizations and approvals

- for this Agreement.
- 19.2. Upon issuance of the FERC's final and nonappealable order making effective the Large Generator Interconnection Procedures and Large Generator Interconnection Agreement ("LGIA") for SCE and the ISO, SCE agrees, at IEEC's sole option and after receiving a written request by IEEC, to file with FERC a request that this Agreement be terminated and replaced with the LGIA. If IEEC elects to execute an LGIA pursuant to this Section 19.2, the Parties agree to negotiate such LGIA in good faith.
- 19.3. Nothing contained herein shall be construed as affecting in any way: (i) the right of SCE to unilaterally make application to the FERC for a change in rates, charges, classification, or service, or any rule, regulation, or contract relating thereto, under Section 205 of the Federal Power Act and pursuant to the Rules and Regulations promulgated by FERC thereunder; (ii) the right of IEEC to oppose such changes under Section 205 of the Federal Power Act; (iii) the right of IEEC to file a complaint requesting a change in rates, charges, classification, or service, or any rule, regulation, or contract relating thereto, or rate methodology or design relating to services provided hereunder, under Section 206 of the Federal Power Act and pursuant to the rules and regulations promulgated by the FERC thereunder; or (iv) the right of SCE to oppose such complaint by IEEC under Section 206 of the Federal Power Act. Any change shall become effective pursuant to Section 205 of the Federal Power Act.
- 19.4. IEEC shall reimburse SCE for all fees and charges imposed on SCE by the FERC attributable to the service provided under this Agreement, or any amendments thereto.

20. No Dedication Of Facilities:

Any undertaking by one Party to the other Party under this Agreement shall not constitute the dedication of the electrical system or any portion thereof of the undertaking Party to the public or to the other Party, and it is understood and agreed that any such undertaking by a Party will cease upon the termination of its obligations hereunder.

21. No Third Party Rights:

Unless otherwise specifically provided in this Agreement, the Parties do not intend to create rights in or grant remedies to any third party as a beneficiary of this Agreement or of any duty, covenant, obligation, or undertaking established hereunder.

22. Assignments:

Neither Party shall assign or transfer any right, obligation, or privilege given to it under this Agreement without the prior written consent of the other Party. With respect to any request for a consent to an assignment in accordance with this Section 22, such consent shall not be unreasonably withheld. The assigning Party agrees that it shall remain liable for all obligations and liabilities of the assigning Party under this

Agreement up to the time of the Assignment. Moreover, any such assignment shall be void unless the assignee unconditionally agrees in writing to assume all of the assigning Party's obligations and liabilities under this Agreement, arising both prior to and after the assignment. Notwithstanding the above, either Party may, without the need for consent from the other Party, transfer, sell, pledge, encumber or assign the accounts, revenues, proceeds or savings realized or to be realized under this Agreement. IEEC may also transfer, lease, assign, mortgage, pledge, hypothecate or otherwise transfer its interest in this Agreement or any right, obligation or privilege hereunder in connection with any financing or other financial arrangements, as security for indebtedness incurred by IEEC; provided that as a condition precedent to the effectiveness of such assignment to a financing party, SCE shall consent to the assignment by executing the Consent to Assignment For Collateral Security in the form attached as Exhibit F hereto, and IEEC and the financing party shall also execute the Consent to Assignment For Collateral Security and agree to the terms set forth therein. This Agreement shall be binding upon and inure to the benefit of the Parties and their respective permitted successors and assigns.

23. Relationship Of Parties:

The covenants, obligations, and liabilities of the Parties are intended to be several and not joint or collective, and nothing contained in this Agreement shall ever be construed to create an association, joint venture, trust, or partnership, or to impose a trust or partnership covenant, obligation, or liability on or with regard to either Party. Each Party will be individually responsible for its own covenants, obligations, and liabilities as provided in this Agreement. Neither Party shall be under the control of or will be deemed to control the other Party. Neither Party will be the agent of or have a right or power to bind the other Party without such other Party's express written consent.

24. Waivers:

Any waiver at any time by either Party of its rights with respect to a default under this Agreement, or with respect to any other matter arising in connection with this Agreement, will not be deemed a waiver with respect to any other or subsequent default or other matter arising in connection therewith. Any delay, short of any statutory period of limitation, in asserting or enforcing any right, will not be deemed a waiver of such right.

25. Governing Law:

Except as otherwise provided by federal law, this Agreement shall be governed by and construed in accordance with, the laws of the state of California.

26. Notices:

Any notice, demand, or request provided in this Agreement, or served, given, or made

in connection with it, will be in writing and deemed properly served, given, or made if delivered in person, transmitted by facsimile (followed by written confirmation) or sent by United States mail, postage prepaid, to the persons specified herein unless otherwise provided in this Agreement:

Southern California Edison Company
Director of Grid Contracts
P.O. Box 800
Rosemead, California 91770
(626) 302-1771
(626) 302-1152 (Fax)

Inland Empire Energy Center, LLC
Mr. Richard L. Thomas
Vice President
4160 Dublin Boulevard
Dublin, California 94568
(925) 479-6600
(925) 479-7311 (Fax)

Either Party may at any time, by notice to the other Party, change the designation or address of the person so specified as the one to receive notices pursuant to this Agreement.

27. Severability:

In the event that any term, provision, covenant, or condition of this Agreement or the application of any such term, covenant, or condition will be held invalid as to any person, entity, or circumstance by any court, arbitration, or regulatory authority having jurisdiction, the invalidity of such term, covenant or condition shall not affect the validity of any other term, provision, condition or covenant and such term, provision, covenant or condition shall remain in force and effect as applied to this Agreement to the maximum extent permitted by law. The Parties hereto further agree to negotiate in good faith to establish new and valid terms, conditions and covenants to replace any found invalid so as to place each Party as nearly as possible in the position contemplated by this Agreement.

28. Entire Agreement:

This Agreement constitutes the complete and final expression of the agreement between the Parties and is intended as a complete and exclusive statement of the terms of their agreement which supercede all prior and contemporaneous offers, promises, representations, negotiations, discussions, communications, and other agreements which may have been made in connection with the subject matter of this Agreement.

29. Ambiguities:

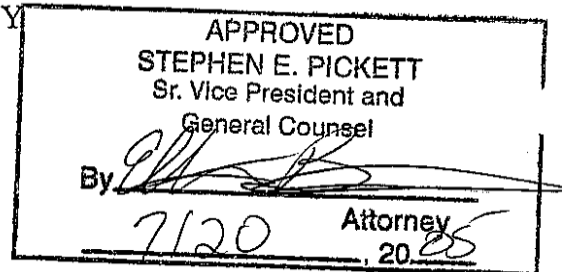
Ambiguities or uncertainties in the wording of this Agreement shall not be construed for or against any Party, but will be construed in the manner that most accurately reflects the Parties' intent as of the date they executed this Agreement.

30. Signature Clause:

The signatories hereto represent that they are authorized to enter into this Agreement on behalf of the Party for whom they sign. This Agreement is hereby executed as of the 29th day of July, 2005.

SOUTHERN CALIFORNIA EDISON COMPANY

By: [Signature]
Name: Ronald L. Litzinger
Title: Senior Vice President



INLAND EMPIRE ENERGY CENTER, LLC

By: [Signature]
Name: Brian P. Ray
Title: MANAGER

Exhibit A-1

Interconnection Facilities Description

A. Valley Substation:

1. Engineer and construct a new line dead end structure and install all new required line protection relays.

2. Telecommunications:

- a. Install new fiber optic terminal equipment at Valley Substation to interface with line protection relays for the new Inland-Valley 500 kV Generation Tie-Line.
- b. Install microwave path to provide redundant telecommunications link for the line protection relays for the new Inland-Valley 500 kV Generation Tie-Line. It is assumed that line-of-site is available between the Generation Station and Valley Substation, and no intermediate stations are required.

3. Power System Controls:

Install additional points at the existing RTU at Valley Substation to monitor status of the two new circuit breakers and incoming generation MW and MVAR.

4. Transmission:

- a. Inland-Valley 500 kV Transmission Line

Install two new 500 kV dead-end lattice towers and three new spans of 2-2156KCMIL ACSR conductors per phase and ½ inch fiber optic ground wire for approximately 2,100 circuit feet of new line from the 500 kV switchyard to the point of interconnection. This work requires the installation of approximately 6,300 ft. of 2156KCMIL ACSR conductor and 4,200 ft. of fiber optic ground wire.

Exhibit A-2
Reliability Upgrades Facilities Description

A. Valley Substation:

1. Engineer and construct a new Double Breaker 500 kV Line Position to terminate the new Inland 500 kV Generation Tie-Line and install all new required bus protection relays. The position will include, two circuit breakers and four disconnect switches.

[Additional Reliability Upgrades Facilities Description to be inserted after completion of the Facilities Study pursuant to Section 8.12 of this Agreement]

Exhibit B

Interconnection Facilities and Reliability Cost

Estimated

Element	Interconnection Facilities Costs	Reliability Upgrades Costs	One-Time Cost	Total Cost
Valley Substation Interconnect 500 kV	\$ 325,000	\$4,545,000		\$4,870,000
Transmission: Inland 500 kV transmission line w/in Valley Substation	\$ 151,000			\$ 151,000
Telecommunications	\$ 970,000			\$ 970,000
Power System Controls	\$ 10,000			\$ 10,000
Total	\$1,456,000	\$4,545,000		\$6,001,000

Interconnection Facilities Payment = (Interconnection Facilities Costs + One-Time Cost*) =
 [\$325,000+\$151,000+\$970,000+\$10,000] = \$1,456,000

Reliability Upgrades Payment = (Reliability Upgrades Costs + One-Time Cost**) = \$4,545,000

* One-Time Cost associated with Interconnection Facilities Only

**One-Time Cost associated with Reliability Upgrades Only

Monthly Charges:

Estimated Interconnection Facilities Charge:

Effective Date	Facilities	Customer- Financed Monthly Rate	Estimated Interconnection Facilities Cost	Interconnection Facilities Charge Based on Estimated Cost
	Interconnection Facilities	0.34%	\$1,456,000	\$4,950.40

Exhibit B (Cont.)

Interconnection Facilities and Reliability Cost

Actual

[To be inserted after completion of the recorded cost true-up pursuant to Section 15 of this Agreement]

Actual Interconnection Facilities Charge:

Effective Date	Facilities	Customer-Financed Monthly Rate	Interconnection Facilities Cost	Interconnection Facilities Charge Based on Actual Cost
	Interconnection Facilities	0.34%		

Exhibit C

**Engineering and Construction
 Payment Schedule**

Payment Period					Due Date
	Interconnection Facilities Cost	Reliability Upgrades Cost	One-Time Cost	Project Payment	
1	\$55,000	\$183,000		\$238,000	Ten days after Effective Date
2	\$113,000	\$378,000		\$491,000	September 15, 2005
3	\$222,000	\$685,000		\$907,000	December 15, 2005
4	\$216,000	\$611,000		\$827,000	March 15, 2006
5	\$448,000	\$1,397,000		\$1,845,000	June 15, 2006
6	\$402,000	\$1,291,000		\$1,693,000	September 15, 2006
Total	\$1,456,000	\$4,545,000		\$6,001,000	

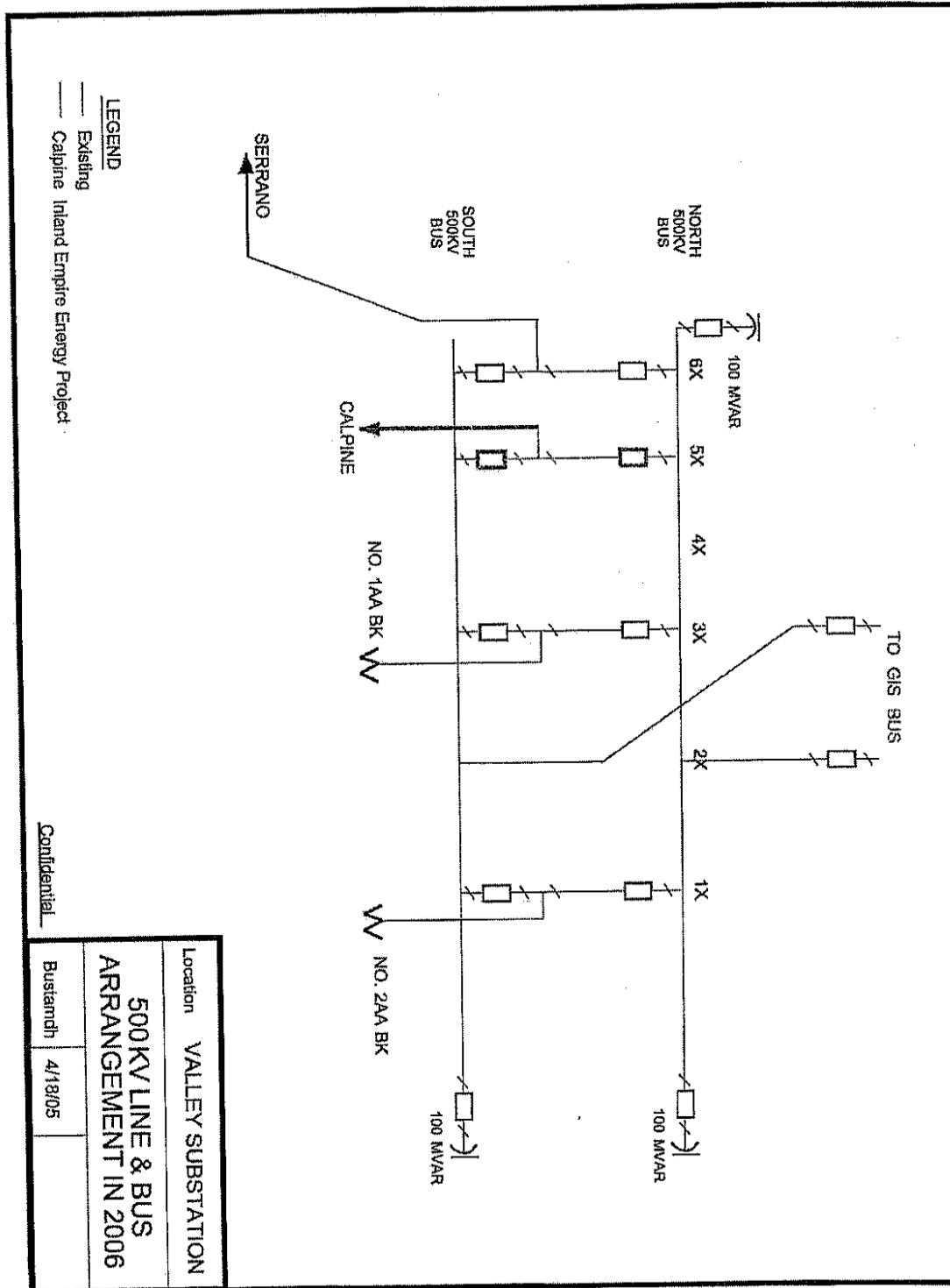
Issued by: ~~James A. Cuillier~~
 Manager, FERC Rates & Regulation
 Issued on: **AUG 03 2005**

Atch7-35

Effective:
AUG 04 2005

Exhibit D

One-Line Diagram



Issued by: James A. Cuillier
 Manager, FERC Rates & Regulation
 Issued on: **AUG 03 2005**

Atch7-36

Effective:
AUG 04 2005

Exhibit E

RELIABILITY MANAGEMENT SYSTEM AGREEMENT

by and between

SOUTHERN CALIFORNIA EDISON COMPANY

and

INLAND EMPIRE ENERGY CENTER, LLC

THIS RELIABILITY MANAGEMENT SYSTEM AGREEMENT (the "Agreement"), is entered into this ____ day of _____, 2005, by and between Southern California Edison Company (the "Transmission Operator") and Inland Empire Energy Center, LLC (the "Generator").

WHEREAS, there is a need to maintain the reliability of the interconnected electric systems encompassed by the WECC in a restructured and competitive electric utility industry;

WHEREAS, with the transition of the electric industry to a more competitive structure, it is desirable to have a uniform set of electric system operating rules within the Western Interconnection, applicable in a fair, comparable and non-discriminatory manner, with which all market participants comply; and

WHEREAS, the members of the WECC, including the Transmission Operator, have determined that a contractual Reliability Management System provides a reasonable, currently available means of maintaining such reliability.

NOW, THEREFORE, in consideration of the mutual agreements contained herein, and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Transmission Operator and the Generator agree as follows:

1. PURPOSE OF AGREEMENT

The purpose of this Agreement is to maintain the reliable operation of the Western Interconnection through the Generator's commitment to comply with certain reliability standards.

2. DEFINITIONS

In addition to terms defined in the beginning of this Agreement and in the Recitals hereto, for purposes of this Agreement the following terms shall have the meanings set forth beside them below.

Control Area means an electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the Western Interconnection.

FERC means the Federal Energy Regulatory Commission or a successor agency.

Member means any party to the WECC Agreement.

Party means either the Generator or the Transmission Operator and **Parties** means both of the Generator and the Transmission Operator.

Reliability Management System or **RMS** means the contractual reliability management program implemented through the WECC Reliability Criteria Agreement, the WECC RMS Agreement, this Agreement, and any similar contractual arrangement.

Western Interconnection means the area comprising those states and provinces, or portions thereof, in Western Canada, Northern Mexico and the Western United States in which Members of the WECC operate synchronously connected transmission systems.

Working Day means Monday through Friday except for recognized legal holidays in the state in which any notice is received pursuant to Section 8.

WECC means the Western Electricity Coordinating Council or a successor entity.

WECC Agreement means the Western Electricity Coordinating Council Agreement dated March 20, 1967, as such may be amended from time to time.

WECC Reliability Criteria Agreement means the Western Electricity Coordinating Council Reliability Criteria Agreement dated June 18, 1999 among

the WECC and certain of its member transmission operators, as such may be amended from time to time.

WECC RMS Agreement means an agreement between the WECC and the Transmission Operator requiring the Transmission Operator to comply with the reliability criteria contained in the WECC Reliability Criteria Agreement.

WECC Staff means those employees of the WECC, including personnel hired by the WECC on a contract basis, designated as responsible for the administration of the RMS.

3. TERM AND TERMINATION

- 3.1 Term.** This Agreement shall become effective thirty (30) days after the date of issuance of a final FERC order accepting this Agreement for filing without requiring any changes to this Agreement unacceptable to either Party. Required changes to this Agreement shall be deemed unacceptable to a Party only if that Party provides notice to the other Party within fifteen (15) days of issuance of the applicable FERC order that such order is unacceptable.
- 3.2 Notice of Termination of WECC RMS Agreement.** The Transmission Operator shall give the Generator notice of any notice of termination of the WECC RMS Agreement by the WECC or by the Transmission Operator within fifteen (15) days of receipt by the WECC or the Transmission Operator of such notice of termination.
- 3.3 Termination by the Generator.** The Generator may terminate this Agreement as follows:
- (a) following the termination of the WECC RMS Agreement for any reason by the WECC or by the Transmission Operator, provided such notice is provided within forty-five (45) days of the termination of the WECC RMS Agreement;
 - (b) following the Effective Date of an amendment to the requirements of the WECC Reliability Criteria Agreement that adversely affects the Generator, provided notice of such termination is given within forty-five (45) days of the date of issuance of a FERC order accepting such amendment for filing, provided further that the forty-five (45) day period within which notice of termination is required may be extended by the Generator for an additional forty-five (45) days if the Generator gives written notice to the Transmission Operator of such requested extension within the initial forty-five (45) day period; or
 - (c) for any reason on one year's written notice to the Transmission Operator

and the WECC.

- 3.4 Termination by the Transmission Operator.** The Transmission Operator may terminate this Agreement on thirty (30) days' written notice following the termination of the WECC RMS Agreement for any reason by the WECC or by the Transmission Operator, provided such notice is provided within thirty (30) days of the termination of the WECC RMS Agreement.
- 3.5 Mutual Agreement.** This Agreement may be terminated at any time by the mutual agreement of the Transmission Operator and the Generator.

4. COMPLIANCE WITH AND AMENDMENT OF WECC RELIABILITY CRITERIA

- 4.1 Compliance with Reliability Criteria.** The Generator agrees to comply with the requirements of the WECC Reliability Criteria Agreement, including the applicable WECC reliability criteria contained in Section IV of Annex A thereof, and, in the event of failure to comply, agrees to be subject to the sanctions applicable to such failure. Each and all of the provisions of the WECC Reliability Criteria Agreement are hereby incorporated by reference into this Agreement as though set forth fully herein, and the Generator shall for all purposes be considered a Participant, and shall be entitled to all of the rights and privileges and be subject to all of the obligations of a Participant, under and in connection with the WECC Reliability Criteria Agreement, including but not limited to the rights, privileges and obligations set forth in Sections 5, 6 and 10 of the WECC Reliability Criteria Agreement.
- 4.2 Modifications to WECC Reliability Criteria Agreement.** The Transmission Operator shall notify the Generator within fifteen (15) days of the receipt of notice from the WECC of the initiation of any WECC process to modify the WECC Reliability Criteria Agreement. The WECC RMS Agreement specifies that such process shall comply with the procedures, rules, and regulations then applicable to the WECC for modifications to reliability criteria.
- 4.3 Notice of Modifications to WECC Reliability Criteria Agreement.** If, following the process specified in Section 4.2, any modification to the WECC Reliability Criteria Agreement is to take effect, the Transmission Operator shall provide notice to the Generator at least forty-five (45) days before such modification is scheduled to take effect.
- 4.4 Effective Date.** Any modification to the WECC Reliability Criteria Agreement shall take effect on the date specified by FERC in an order accepting such modification for filing.
- 4.5 Transfer of Control or Sale of Generation Facilities.** In any sale or transfer of

control of any generation facilities subject to this Agreement, the Generator shall as a condition of such sale or transfer require the acquiring party or transferee with respect to the transferred facilities either to assume the obligations of the Generator with respect to this Agreement or to enter into an agreement with the Control Area Operator in substantially the form of this Agreement.

5. SANCTIONS

- 5.1 Payment of Monetary Sanctions.** The Generator shall be responsible for payment directly to the WECC of any monetary sanction assessed against the Generator pursuant to this Agreement and the WECC Reliability Criteria Agreement. Any such payment shall be made pursuant to the procedures specified in the WECC Reliability Criteria Agreement.
- 5.2 Publication.** The Generator consents to the release by the WECC of information related to the Generator's compliance with this Agreement only in accordance with the WECC Reliability Criteria Agreement.
- 5.3 Reserved Rights.** Nothing in the RMS or the WECC Reliability Criteria Agreement shall affect the right of the Transmission Operator, subject to any necessary regulatory approval, to take such other measures to maintain reliability, including disconnection, which the Transmission Operator may otherwise be entitled to take.

6. THIRD PARTIES

Except for the rights and obligations between the WECC and Generator specified in Sections 4 and 5, this Agreement creates contractual rights and obligations solely between the Parties. Nothing in this Agreement shall create, as between the Parties or with respect to the WECC: (1) any obligation or liability whatsoever (other than as expressly provided in this Agreement), or (2) any duty or standard of care whatsoever. In addition, nothing in this Agreement shall create any duty, liability, or standard of care whatsoever as to any other party. Except for the rights, as a third-party beneficiary with respect to Sections 4 and 5, of the WECC against Generator, no third party shall have any rights whatsoever with respect to enforcement of any provision of this Agreement. Transmission Operator and Generator expressly intend that the WECC is a third-party beneficiary to this Agreement, and the WECC shall have the right to seek to enforce against Generator any provisions of Sections 4 and 5, provided that specific performance shall be the sole remedy available to the WECC pursuant to this Agreement, and Generator shall not be liable to the WECC pursuant to this Agreement for damages of any kind whatsoever (other than the payment of sanctions to the WECC, if so construed), whether direct, compensatory, special, indirect, consequential, or punitive.

7. REGULATORY APPROVALS

This Agreement shall be filed with FERC by the Transmission Operator under Section 205 of the Federal Power Act. In such filing, the Transmission Operator shall request that FERC accept this Agreement for filing without modification to become effective on the day after the date of a FERC order accepting this Agreement for filing.

8. NOTICES

Any notice, demand or request required or authorized by this Agreement to be given in writing to a Party shall be delivered by hand, courier or overnight delivery service, mailed by certified mail (return receipt requested) postage prepaid, faxed, or delivered by mutually agreed electronic means to such Party at the following address:

Transmission Operator: Southern California Edison Company
Director of Grid Contracts
P.O. Box 800
2244 Walnut Grove Avenue
Rosemead, California 91770
Telephone No. (626) 302-1771
Telefax No. (626) 302-1152

Generator: Inland Empire Energy Center, LLC
4160 Dublin Boulevard
Dublin, California 94568
Telephone No. (925) 479-6600
Telefax No. (925) 479-7311

The designation of such person and/or address may be changed at any time by either Party upon receipt by the other of written notice. Such a notice served by mail shall be effective upon receipt. Notice transmitted by facsimile shall be effective upon receipt if received prior to 5:00 p.m. on a Working Day, and if not received prior to 5:00 p.m. on a Working Day, receipt shall be effective on the next Working Day.

9. APPLICABILITY

This Agreement (including all appendices hereto and, by reference, the WECC Reliability Criteria Agreement) constitutes the entire understanding between the Parties hereto with respect to the subject matter hereof, supersedes any and all previous understandings between the Parties with respect to the subject matter hereof, and binds and inures to the benefit of the Parties and their successors.

10. AMENDMENT

No amendment of all or any part of this Agreement shall be valid unless it is reduced to writing and signed by both Parties hereto. The terms and conditions herein specified shall remain in effect throughout the term and shall not be subject to change through application to the FERC or other governmental body or authority, absent the agreement of the Parties.

11. INTERPRETATION

Interpretation and performance of this Agreement shall be in accordance with, and shall be controlled by, the laws of the State of California but without giving effect to the provisions thereof relating to conflicts of law. Article and section headings are for convenience only and shall not affect the interpretation of this Agreement. References to articles, sections and appendices are, unless the context otherwise requires, references to articles, sections and appendices of this Agreement.

12. PROHIBITION ON ASSIGNMENT

This Agreement may not be assigned by either Party without the consent of the other Party, which consent shall not be unreasonably withheld; provided that the Generator may without the consent of the WECC assign the obligations of the Generator pursuant to this Agreement to a transferee with respect to any obligations assumed by the transferee by virtue of Section 4.5 of this Agreement.

13. SEVERABILITY

If one or more provisions herein shall be invalid, illegal or unenforceable in any respect, it shall be given effect to the extent permitted by applicable law, and such invalidity, illegality or unenforceability shall not affect the validity of the other provisions of this Agreement.

14. COUNTERPARTS

This Agreement may be executed in counterparts and each shall have the same force and effect as an original.

IN WITNESS WHEREOF, the Transmission Operator and the
Generator have each caused this Reliability Management System Agreement to be

Issued by: James A. Cuillier
Manager, FERC Rates & Regulation
Issued on: **AUG 03 2005**

Atch7-43

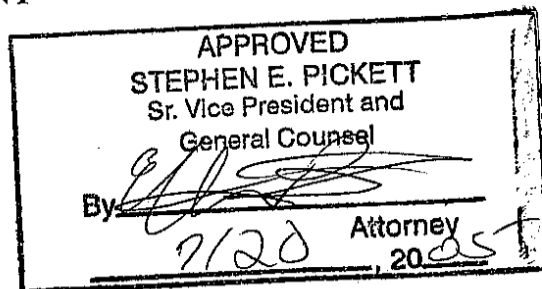
Effective:

AUG 04 2005

executed by their respective duly authorized officers as of the date first above written.

SOUTHERN CALIFORNIA EDISON COMPANY

By: *Ronald L. Litzinger*
Name: Ronald L. Litzinger
Title: Senior Vice President



INLAND EMPIRE ENERGY CENTER, LLC

By: *Brian P. Ray*
Name: Brian P. Ray
Title: MANAGER

Exhibit F

Consent to Assignment For Collateral Security

CONSENT TO ASSIGNMENT FOR COLLATERAL SECURITY

Subject to the following conditions, Southern California Edison Company ("SCE"), a California corporation hereby consents to the assignment as collateral security of the Interconnection Facilities Agreement between it and Inland Empire Energy Center, LLC, a Delaware limited liability company ("Seller") dated [date], as amended, from Seller to _____, a _____ ("Collateral Assignee"). SCE, Seller and Collateral Assignee are sometimes referred to herein individually as a "Party" and jointly as the "Parties."

RECITALS

A. Pursuant to Section 22 of the Interconnection Facilities Agreement ("IFA"), Seller must obtain SCE's consent to any assignment of the IFA as collateral security.

B. Pursuant to the Security Agreement between Seller and Collateral Assignee, Seller wishes to assign the IFA to Collateral Assignee as collateral security.

C. SCE hereby consents to the "Assignment" of the IFA as collateral security by Seller to Collateral Assignee under the terms and conditions of this Consent to Assignment for Collateral Security ("Consent").

AGREEMENT

The Parties agree:

1. The Assignment is an assignment for security only and not a present assignment of Seller's rights, duties or obligations under the IFA.

2. If Collateral Assignee enforces the Assignment, it shall notify SCE pursuant to paragraph 9 of this Consent. Upon such notice, Collateral Assignee shall receive the rights and shall assume and be liable for each and every duty of obligation of the Seller (as such term is defined in the IFA) under the IFA. The duties and obligations include, but are not limited to, those duties and obligations that accrued prior to the Assignment. The obligations and liabilities of Collateral Assignee under the immediately preceding sentence shall be satisfied solely from the assets of Seller, including any assets

Issued by: James A. Cuillier
Manager, FERC Rates & Regulation
Issued on:

AUG 03 2005

Atch7-45

Effective:

AUG 04 2005

of Seller transferred to Collateral Assignee pursuant to enforcement of the assignment and which assets for the purposes of this Consent shall at a minimum include the IFA and the Inland Empire Energy Center Project (as defined in the IFA), and there shall be no separate recourse to any assets of Collateral Assignee.

3. Seller hereby acknowledges and agrees that it shall remain liable to SCE for the duties and obligations of Seller under the IFA if Collateral Assignee enforces the Assignment.

4. This Consent is neither a modification of, nor an amendment to, the IFA, which is, and shall remain, in full force and effect.

5. SCE's consent to the Assignment contained herein is also subject to the condition that the Assignment shall in no manner diminish SCE's rights or increase its obligations under the IFA.

6. Seller or, upon Collateral Assignee enforcement of this Assignment, Collateral Assignee, agrees to pay, and to hold SCE harmless from, any and all balance owed, loss, liability, damage, claim, cost or expense (including, without limitation, any direct, indirect or consequential loss, liability, damage, claim, cost or expense, including legal fees and expenses) in connection with or arising out of any of the transactions contemplated by the Assignment or this Consent. The obligations of Collateral Assignee under the immediately preceding sentence shall be satisfied solely from the assets of Seller, as described in Paragraph 2 of this Consent.

7. SCE is not a party to and has no obligation under any documents or agreements other than those it has signed. To the extent that this Consent is inconsistent with any other documents or agreement, as between the Parties, this Consent shall govern.

8. This Consent shall be binding upon, inure to the benefit of, and be enforceable by, SCE and its permitted successors and assigns and shall inure to the further benefit of, and be enforceable by, any assignee or transferee permitted hereby and by the IFA. No assignment of the IFA by Seller or Collateral Assignee, other than this Assignment, shall be valid without SCE's written consent, which consent shall not be unreasonably withheld.

9. All notices, requests, consents, approvals, elections, demands and other communications (all, "Notices") required or permitted to be given under this Consent shall be in writing and shall be given to a Party at the address set forth on the signature page hereof, or at such other address as such Party may hereafter specify for such purpose by Notice under this Paragraph 9. Such Notice shall be deemed to be made (i) on the fifth business day after deposit thereof in the United States mail, first class postage prepaid; (ii) when received if delivered by hand; (iii) when received in full if sent by facsimile transmission; or (iv) on the first business day following deposit in overnight mail, postage

prepaid.

10. This Consent shall be interpreted, governed and construed under the laws of the State of California (without giving effect to its conflict of laws provisions that could apply the law of another jurisdiction) as if executed in and to be performed wholly within the State of California.

11. Notwithstanding any right that they may otherwise have under law to venue in other counties or location, the Parties consent to jurisdiction and venue in Los Angeles County, California for any litigation or arbitration of any disputes of any nature arising out of or relating to this Consent, including without limitation, disputes sounding in contract, tort or based on statute or regulation, that the Parties are unable to settle between themselves.

12. This Consent may not be altered or modified by any of the Parties except by a written instrument executed by each of them.

13. The Parties acknowledge that they have read and understood this Consent. The Parties further acknowledge that, in entering into this Consent, they have been advised by attorneys of their choice. Further, all Parties have participated in the drafting and preparation of this Consent. Accordingly, no Party to this Consent shall be deemed to be the drafter of any part of it, and no ambiguity in its provisions shall be construed against any Party for that reason.

14. The Parties do not intend to create rights in, or grant remedies to, any third party as a beneficiary of this Consent or any duty, covenant, obligation or understanding established thereunder.

15. This Consent fully expresses the Parties' agreement concerning the subject matter hereof. It supersedes any prior agreement or understandings regarding the same subject matter.

16. This Consent may be executed in any number of counterparts, all of which together shall constitute a single instrument, and it shall not be necessary that any counterpart be signed by each Party.

17. The signatories hereto represent that they have been duly authorized to enter into this Consent on behalf of the Party for whom they sign.

18. This Consent shall be deemed dated on the date that the last Party executes it.

SOUTHERN CALIFORNIA EDISON COMPANY

By: _____
Name:
Title:
Date:

INLAND EMPIRE ENERGY CENTER, LLC

By: _____
Name:
Title:
Date:

[BANK]

By: _____
Name:
Title: Trust Officer
Date: _____

Address:

Issued by: James A. Cuillier
Manager, FERC Rates & Regulation
Issued on: **AUG 03 2005**

Effective:
AUG 04 2005

PACIFIC GAS AND ELECTRIC COMPANY
REBUTTAL TESTIMONY SUPPORTING ATTACHMENTS
ATTACHMENT 8
SCE'S RESPONSE TO CALADVOCATES-SCE-A2511001-005,
QUESTION 2(A)

Southern California Edison
A.25-11-001 – APGE-Fire1054

DATA REQUEST SET CalAdvocates - SCE - A 2 5 1 1 0 0 1 - 0 0 5

To: Cal Advocates
Prepared by: Lindsey Sayers
Job Title: Senior Manager
Received Date: 3/3/2026

Response Date: 3/17/2026

Question 02.a:

The questions below examine SCE's transmission operations and maintenance practices prior to the Kincade Fire (2019).

The primary focus is on the standards, controls, and decision-making processes that authorize the continued energization of idle transmission facilities, as well as the procedures implemented to manage these configurations.

Between 2001 and 2019:

a) When a generating facility disconnected from the grid was there a SCE standardized checklist requiring evaluation of upstream segments?

Response to Question 02.a:

No, SCE did not have a standardized checklist requiring evaluation of upstream segments.

PACIFIC GAS AND ELECTRIC COMPANY
REBUTTAL TESTIMONY SUPPORTING ATTACHMENTS
ATTACHMENT 9
SCE'S RESPONSE TO CALADVOCATES-SCE-A2511001-005,
QUESTION 2(B)

Southern California Edison
A.25-11-001 – APGE-Fire1054

DATA REQUEST SET CalAdvocates - SCE - A 2 5 1 1 0 0 1 - 0 0 5

To: Cal Advocates
Prepared by: Lindsey Sayers
Job Title: Senior Manager
Received Date: 3/3/2026

Response Date: 3/17/2026

Question 02.b:

The questions below examine SCE's transmission operations and maintenance practices prior to the Kincade Fire (2019).

The primary focus is on the standards, controls, and decision-making processes that authorize the continued energization of idle transmission facilities, as well as the procedures implemented to manage these configurations.

Between 2001 and 2019:

b) When a generating facility disconnected from the grid was a partial dismantlement (e.g., removal at plant termination but not upstream spans) addressed in SCEs procedures?

Response to Question 02.b:

SCE did not have a written procedure for disconnecting generating facilities. Upon termination of a FERC jurisdictional IFA, SCE's practice was to operationally disconnect the generating facility and remove the associated SCE-owned interconnection equipment from service. See response to Question 01.a.

PACIFIC GAS AND ELECTRIC COMPANY
REBUTTAL TESTIMONY SUPPORTING ATTACHMENTS
ATTACHMENT 10
SCE'S RESPONSE TO CALADVOCATES-SCE-A2511001-002,
QUESTION 3

Southern California Edison
A.25-11-001 – APGE-Fire1054

DATA REQUEST SET CalAdvocates - SCE - A2511001-002

To: Cal Advocates
Prepared by: Scott Mitchell
Job Title: Principal Manager, Wildfire Operational Strategies
Received Date: 2/17/2026

Response Date: 3/3/2026

Question 03.a-e:

These questions focus on how transmission assets, specifically unused ones, were treated under wildfire driven de-energization protocols before the Kincade Fire.

- a) Were transmission segments eligible for de-energization under Red Flag or PSPS protocols?
- b) Did PSPS decision criteria apply differently to transmission versus distribution assets?
- c) Were energized transmission segments not serving load subject to lower shutoff thresholds or different treatment?
- d) Under what conditions would SCE proactively de-energize a transmission segment that was not serving load but retained for operational flexibility or future use?
- e) Provide any procedures, standards, or other documentation that was in effect as of October 23, 2019, that relates to your responses to parts (a) through (d) of this question.

Response to Question 03.a-e:

CONFIDENTIAL

**The Attachment(s) Are Marked Confidential In Accordance With Applicable Law and Regulation.
Basis for Confidentiality In Accompanying Confidentiality Declaration.
Public Disclosure Restricted.**

SCE's PSPS protocols applied only to energized electrical assets, regardless of whether they were in-use or unused. As described in the response to Q1 of this data request, SCE did not and does not have any energized unused transmission assets.

- a.) By 6/1/2019, all energized circuits of any voltage in HFRA were eligible for de-energization under PSPS protocols. At that time PSPS operational procedures were contained within the SOB-322 document.
- b.) Yes, by 6/1/2019 and as of the date of the Kincade fire there were different PSPS decision criteria for transmission vs distribution assets. Scoping and de-energization windspeed criteria for transmission were higher than they were for distribution.
- c.) N/A - SCE did not have energized unused transmission segments.
- d.) N/A - SCE did not have energized unused transmission segments.
- e.) Please refer to the attached document:
 - System Operating Bulletin No. 322, revised 8/26/2019 titled "CONFIDENTIAL_sob0322 – 2019-08-26.pdf_Redacted"

PACIFIC GAS AND ELECTRIC COMPANY
REBUTTAL TESTIMONY SUPPORTING ATTACHMENTS
ATTACHMENT 11
SDG&E'S RESPONSE TO CALPA-SDGE-A2511001-003,
QUESTION 3

CALPA DATA REQUEST: CALPA-SDGE-A2511001-003
SDG&E RESPONSE

Date Received: 02-17-2026
Date Submitted: 03-03-2026

QUESTION 3

These questions focus on how transmission assets, specifically unused ones, were treated under wildfire driven de-energization protocols before the Kincade Fire.

- a) Were transmission segments eligible for de-energization under Red Flag or PSPS protocols?
- b) Did PSPS decision criteria apply differently to transmission versus distribution assets?
- c) Were energized transmission segments not serving load subject to lower shutoff thresholds or different treatment?
- d) Under what conditions would SDG&E proactively de-energize a transmission segment that was not serving load but retained for operational flexibility or future use?
- e) Provide any procedures, standards, or other documentation that was in effect as of October 23, 2019, that relates to your responses to parts (a) through (d) of this question.

RESPONSE 3

SDG&E objects to the request on the grounds set forth in General Objections Nos. 2 and 3. SDG&E provides its assumptions regarding defined terms in the answers below. SDG&E further objects to the request to the extent it calls for provision of confidential information not relevant to the subject matter of this proceeding. SDG&E has redacted such information in its response. Subject to and without waiving the foregoing objections, SDG&E responds as follows.

- 3a) Yes. Transmission segments were eligible for de-energization under Red Flag Conditions.
- 3b) Yes, PSPS decision criteria applied differently for transmission and distribution assets. Both transmission and distribution lines incorporate the review of open compliance conditions, however, the wind thresholds for transmission are higher than distribution. This is due to several factors including larger conductor height above grade and more conductor spacing between phases and between the phases and the structure.
- 3c) TL6931, the only energized transmission segment not always serving load in the SDG&E service territory, was treated the same as other energized transmission lines.
- 3d) SDG&E would apply the same criteria to in deciding to proactively de-energize TL6931 as it would all other energized transmission segments. The evaluation would be dependent on several variables including but not limited to; the maximum projected windspeeds throughout the service territory, how widespread the wind event is projected to be, how fast the anticipated ramp up in wind speeds would be, projected total impact to distribution circuits fed from substations fed by

CALPA DATA REQUEST: CALPA-SDGE-A2511001-003
SDG&E RESPONSE

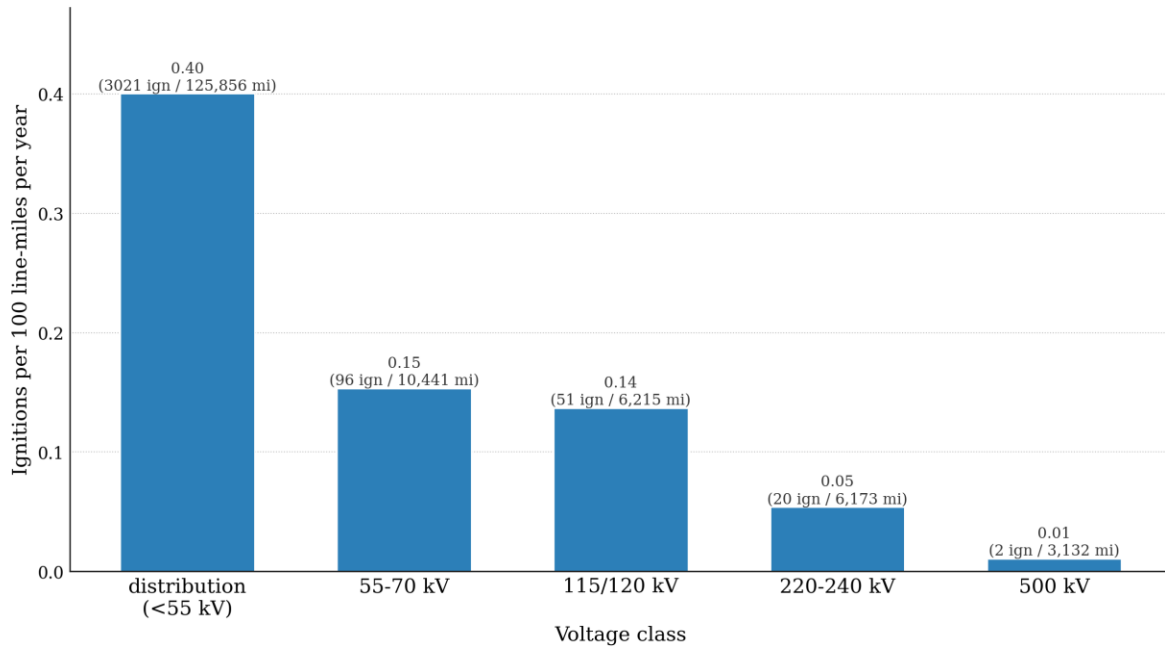
Date Received: 02-17-2026
Date Submitted: 03-03-2026

the transmission lines, and potential existing events within that may be ongoing throughout the service territory.

3e) See attached documents “GIP2590 – TL13844 TL6931 Procedure to Transfer Load at BUE and CW – Redacted.pdf”

PACIFIC GAS AND ELECTRIC COMPANY
REBUTTAL TESTIMONY SUPPORTING ATTACHMENTS
ATTACHMENT 12
ALL UTILITIES COMBINED – IGNITION RATE BY VOLTAGE
CLASS

**All Utilities Combined — Ignition Rate by Voltage Class
(ignitions per 100 line-miles per year, 2014-2019)**



PACIFIC GAS AND ELECTRIC COMPANY
REBUTTAL TESTIMONY SUPPORTING ATTACHMENTS
ATTACHMENT 13
SCE'S RESPONSE TO CALADVOCATES-SCE-A2511001-003,
QUESTION 2

Southern California Edison
A.25-11-001 – APGE-Fire1054

DATA REQUEST SET CalAdvocates - SCE - A 2511001 - 003

To: Cal Advocates
Prepared by: Al Watson
Job Title: Grid Control Center Sr. Manager
Received Date: 2/17/2026

Response Date: 3/3/2026

Question 02.a-c:

Regarding SCE's PSPS program related to its transmission lines:

- a) When did SCE first de-energize a transmission line?
- b) From 2009 through 2020, provide a list of each transmission line that SCE de-energized and the date(s) that the de-energization occurred.
- c) Provide a copy of the associated post-event report for each of the events listed in subpart (b) if not available on the Commission website.¹

¹ Available at: <https://www.cpuc.ca.gov/consumer-support/pmps/utility-company-pmps-reports-post-event-and-post-season>

Response to Question 02.a-c:

- a.) SCE considers lines and equipment at voltages between 55 kV and 115 kV as Subtransmission level and voltages between 161 kV and 500 kV as Transmission level. SCE has de-energized Subtransmission lines and equipment for PSPS with the first de-energization occurring on September 16, 2019. SCE has de-energized transmission lines and equipment for PSPS with the first de-energization occurring on January 12, 2025.
- b.) From 2009 through 2020, SCE did not de-energize any transmission voltage level lines or equipment. From 2009 through 2020, SCE did de-energize Subtransmission level lines and equipment. Refer to list below for occurrences.

CIRCUIT NAME	DATE OF DE-ENERGIZATION
CONTROL-PLANT 2 55 kV	9/16/2019
CONTROL-PLANT 3 - PLANT 4 115 kV	9/16/2019
SAUGUS-FILLMORE No.1 66 kV	10/10/2019
ARROWHEAD-DEVIL CANYON-MOHAVE SIPHON-SHANDON 115 kV	10/30/2019
BANDUCCI-CORRECTION-CUMMINGS-MONOLITH 66 kV	10/30/2019
SAUGUS-MOORPARK-SANTA SUSANA-TORREY 66 kV	10/30/2019
CONTROL-PLANT 2 55 kV	11/25/2019
ARROWHEAD-DEVIL CANYON-MOHAVE SIPHON-SHANDON 115 kV	11/27/2020

c.) All post-event reports listed in subpart b are available on the Commission's website.

PACIFIC GAS AND ELECTRIC COMPANY
REBUTTAL TESTIMONY SUPPORTING ATTACHMENTS
ATTACHMENT 14
SDG&E'S RESPONSE TO CALPA-SDGE-A2511001-002,
QUESTION 2

CALPA DATA REQUEST: CALPA-SDGE-A2511001-002
SDG&E RESPONSE

Date Received: 02-03-2026
Date Submitted: 02-13-2026

QUESTION 2

Regarding SDG&E's PSPS program related to its transmission lines:

- a) When did SDG&E first de-energize a transmission line?
- b) From 2009 through 2020, provide a list each transmission line that SDG&E de-energized and the date(s) that the de-energization occurred.
- c) Provide a copy of the associated post-event report for each of the events listed in subpart (b) if not available on the Commission website.¹

RESPONSE 2

SDG&E objects to the request on the grounds set forth in General Objections Numbers 2, 3, and 7. SDG&E notes that the CPUC initiated post-event reporting via D.12-04-024 issued on April 26, 2012, thus there are no reports for the events prior to that occasion. Subject to and without waiving the foregoing objections, SDG&E responds as follows:

- a) SDG&E's first instance of de-energizing a transmission line for Public Safety Power Shutoff was October 23, 2017.
- b)

Year	De-energization Date/Time	Transmission Line
2017	10/23/2017 9:26	TL626
2017	12/6/2017 21:35	TL626
2017	12/7/2017 6:53	TL629
2017	12/7/2017 7:19	TL625
2017	12/10/2017 7:49	TL629
2017	12/10/2017 7:49	TL6923
2018	1/27/2018 20:06	TL626
2018	11/12/2018 3:04	TL626
2018	11/12/2018 7:47	TL629
2018	11/15/2018 10:10	TL6923
2019	10/10/2019 18:25	TL626
2019	10/24/2019 4:09	TL626

¹ Available at: <https://www.cpuc.ca.gov/consumer-support/psps/utility-company-psps-reports-post-event-and-post-season>

CALPA DATA REQUEST: CALPA-SDGE-A2511001-002
SDG&E RESPONSE

Date Received: 02-03-2026
Date Submitted: 02-13-2026

Year	De-energization Date/Time	Transmission Line
2019	10/29/2019 23:17	TL626
2019	11/17/2019 5:07	TL626
2020	12/2/2020 18:14	TL6960
2020	12/2/2020 21:37	TL6923
2020	12/3/2020 5:12	TL686
2020	12/5/2020 5:00	TL6960
2020	12/7/2020 20:46	TL6960
2020	12/7/2020 23:07	TL685
2020	12/9/2020 14:00	TL6960

c) All SDG&E Post-Event Reports are available on the Commission website.

PACIFIC GAS AND ELECTRIC COMPANY
REBUTTAL TESTIMONY SUPPORTING ATTACHMENTS
ATTACHMENT 15
PG&E'S RESPONSE TO
KINCADEDIXIEAB1054_DR_CALADVOCATES_D01-
Q011SUPP01REV01 AND SELECT ATTACHMENTS

(REDACTED)

PACIFIC GAS AND ELECTRIC COMPANY
Kincade and Dixie AB1054-Wildfire Cost Review and Recovery
Application 25-11-001
Data Response

PG&E Data Request No.:	CalAdvocates_D01-Q011
PG&E File Name:	KincadeDixieAB1054_DR_CalAdvocates_D01-Q011Supp01Rev01
Request Date:	December 18, 2025
Requester DR No.:	D01
Requesting Party:	Public Advocates Office
Requester:	Holly Wehrman
Date Sent:	January 6, 2026 Original April 23, 2026 (Supplemental 01) June 17, 2026 (Revision 01)
PG&E Witness(es):	Angela Sanford – Electric Operations

Vegetation Management

QUESTION 011

Please provide a copy of any standards, policies, practices, or procedures that were in effect between 2017-2021, related to vegetation management inspections and work.

ANSWER 011 REVISION 01

PG&E objects to this Question as vague and ambiguous. PG&E understands this Question to be asking for guidance documents in effect during the specified time period for the vegetation management patrols identified in PG&E's response to CalAdvocates_D01-Q008 of this proceeding. Subject to and without waiving its objections, PG&E responds as follows: PG&E refers Cal Advocates to vegetation management guidance documents provided to SED in response to SED Data Request Dixie Fire – SED-005, Question 23,¹ which are being provided in response to CalAdvocates_D01-Q024 of this proceeding, as well as additional guidance documents that will be provided in response to CalAdvocates_D01-Q022. These guidance documents include:

Guidance Document	Bates Range
TD-7102S, Distribution Vegetation Management Standard	PGE-DIXIE-CPUC-000019556 – 572
TD-7102P-01, Distribution Routine Patrol Procedure	PGE-DIXIE-CPUC-000019514 – 538
TD-7102P-23, Vegetation Management Second Patrol Procedure	PGE-DIXIE-CIV-000062921 – 944; PGE-DIXIE-CIV-000063183 – 199; PGE-DIXIE-CPUC-000019491 – 508

¹ See PGE-DIXIE-CPUC-000019491 through PGE-DIXIE-CPUC-000019572.

TD-7102P-09, Reporting Abnormal Field Conditions Procedure	PGE-DIXIE-CPUC-000019509 – 513
TD-7102P-17, Vegetation Management Priority Tag Procedure	PGE-DIXIE-CIV-000062993 – 999; PGE-DIXIE-CIV-000027644 – 651; PGE-DIXIE-CPUC-000019539 – 546
TD-7102P-08, Facility Protect and Work Difficulty Classification Procedure	PGE-DIXIE-CPUC-000019547 – 555
TD-05, Vegetation Management Policy	PGE-DIXIE-CIV-000063586 – 588
TD-7102B-005, Valley Elderberry Longhorn Beetle (VELB) Habitat Range Update	PGE-DIXIE-CIV-000352177 – 180
TD-7102B-006, Working Trees Near High Voltage Electric Lines Using Cranes	PGE-DIXIE-CIV-000256848 – 852
TD-7102B-007, Second Patrol - Scope of Work Requirements	PGE-DIXIE-CIV-000062916 – 920
TD-7102B-008, Expanded Wood Management Marking Guidelines	PGE-DIXIE-CIV-000256821 – 824
TD-7102B-009, Expanded Wood Management Data Entry	PGE-DIXIE-CIV-000352181 – 197
TD-7102B-010, Establishing Danger Zone for Tree Felling Operations	PGE-DIXIE-CIV-000256899 – 902; PGE-DIXIE-CIV-000258173 – 176
TD-7102B-011, Estimating Arborist Compliance with Riparian Review	PGE-DIXIE-CIV-000256819 – 820
TD-7102B-012, VM CEMA Tier 3 Patrol Practices	PGE-DIXIE-CIV-000062950 – 954; PGE-DIXIE-CIV-000063015 – 017
TD-7102B-013, Identify and Mark Trees Requiring Special Equipment or Work Method	PGE-DIXIE-CIV-000256917 – 919
TD-7102B-015, High Fire-Threat District Bulletin	PGE-DIXIE-CIV-000027678 – 680
TD-7102B-016, Bulletin for TD-7102P-25 VM Contractor Safety	PGE-DIXIE-CIV-000062777 – 779
TD-7102B-017, Hazardous Tree Removal - Fall Protection-Roping and Rigging	PGE-DIXIE-CIV-000062762 – 766
TD-7102B-018, Vegetation Management Line Clearance Request	PGE-DIXIE-CIV-000062878 – 887
TD-7102B-019, CEMA High Fire Threat District Planning	PGE-DIXIE-CIV-000062848 – 850
TD-7102P-01-B021, Evaluation of Tree Growth Rates Bulletins	PGE-DIXIE-CIV-000062759 – 761

TD-7102P-01-B027, Update to Inspection of Trees within the High Fire Threat District (HFTD)	PGE-DIXIE-CIV-000062797 - 800
TD-7102P-03, Project Monitoring	PGE-DIXIE-CIV-000063589 – 593
TD-7102P-05, Major Woody Stem Exemption	PGE-DIXIE-CIV-000063711 – 724
TD-7102P-05-B023, Changes to Major Woody Stem Exemption Procedure	PGE-DIXIE-CIV-000063823
TD-7102P-06, Inspection Mapping	PGE-DIXIE-CIV-000063873 – 883
TD-7102P-06-B024, Bulletin for Inspection Mapping	PGE-DIXIE-CIV-000063734
TD-7102P-07, Vegetation Management Hazard Tree Rating and Scoring Procedure	PGE-DIXIE-CIV-000062857 – 877; PGE-DIXIE-CIV-000063138 – 158
TD-7102P-10, Third-Party Tree Safety Zone Procedure	PGE-DIXIE-CIV-000063813 – 822
TD-7102P-15, Vegetation Management Distribution Line Clearance Request Procedure	PGE-DIXIE-CIV-000063563 – 576
TD-7102P-21, Using Tree Growth Regulator to Limit Tree Growth	PGE-DIXIE-CIV-000063604 – 617
TD-7102P-24, Vegetation Management Combined First and Routine Patrol	PGE-DIXIE-CIV-000063200 – 206
TD-7102P-25, Vegetation Management Contractor Safety	PGE-DIXIE-CIV-000062895 - 911; PGE-DIXIE-CIV-000062780 – 796; PGE-DIXIE-CIV-000062955 – 971
TD-7102P-25-B025, High Hazard Roadway Assessment, Alerts and Controls for Vegetation Management	PGE-DIXIE-CIV-000256888 – 889
TD-7102P-26, Wood Management	PGE-DIXIE-CIV-000063795 – 812
TD-7102P-27, Vegetation Management Bird Nest Procedure	PGE-DIXIE-CIV-000063938 – 951
TD-7102P-27-B022, Changes to Vegetation Management Bird Nest Procedure	PGE-DIXIE-CIV-000256847
TD-7102P-29, Vegetation Management T&D Tree Trimming & Estimating Procedure	PGE-DIXIE-CIV-000063770 – 786
TD-7102S-B001, Vegetation Management Hazard Tree Assessment Tool	PGE-DIXIE-CIV-000062757 – 758
TD-7103P-09, Vegetation Management Hazard Notification Procedure	PGE-DIXIE-CIV-000063343 – 358; PGE-DIXIE-CIV-000062801 – 816;

	PGE-DIXIE-CIV-000063517 – 524
TD-7105P-01-B001, Vegetation Management Invoice Recommending Procedure	PGE-DIXIE-CIV-000256843 – 846
TD-7105P-02, Vegetation Management Quality Control Vegetation Clearance Finding Dispute Procedure	PGE-DIXIE-CIV-000062888 – 894
TD-7105P-03, Vegetation Management Marking Procedure	PGE-DIXIE-CIV-000256809 – 815
TD-7107S, Vegetation Management Marking Standard	PGE-DIXIE-CIV-000256882 – 887
TD-7108S, Vegetation Management Crane Use Requirements	PGE-DIXIE-CIV-000256837 – 842

PG&E is also providing guidance documents related to PG&E's Enhanced Vegetation Management (EVM) program. As set forth in Chapter 3B, p. 3B-8, the Bucks Creek 1101 Circuit was prioritized for work pursuant to PG&E's EVM program; as of July 13, 2021, the line had not yet been planned for EVM work in a specific year based on the EVM prioritization list ranking under PG&E's 2021 Wildfire Distribution Risk Model. EVM documents include the following:

Guidance Document	Bates Range
TD-7102B-020, Enhanced Vegetation Management Scope	PGE-DIXIE-CIV-000062945 – 949; PGE-DIXIE-CIV-000062851 – 856; PGE-DIXIE-CIV-000062972 – 977
TD-7102P-01-B026, EVM Transition to Distribution Routine Patrol	PGE-DIXIE-CIV-000218389
TD-7106P-01, Enhanced Vegetation Management Pre-Inspection Procedure	PGE-DIXIE-CIV-000027681 – 686

PG&E is continuing to search for vegetation management guidance documents in effect during the specified time period and will supplement this response.

ANSWER 011 SUPPLEMENTAL 01

Per Cal Advocates' e-mail request on April 20, 2026, please see attached redacted versions of the requested files that can be found in
"KincadeDixieAB1054_DR_CalAdvocates_D01-Q011Supp01Atch01.zip"

Distribution Routine Patrol Procedure (DRPP)

SUMMARY

The purpose of the Distribution Routine Patrol Procedure (DRPP) is to:

- Detail the steps and requirements for routine inspection of vegetation around PG&E electric distribution lines, including distribution underbuild lines.
- Maintain the safe and reliable operation of distribution and underbuild facilities.

Level of Use: Informational Use

TARGET AUDIENCE

- Vegetation Management Governance and Support
- Vegetation Management Operations
- VM Contractors: Pre-Inspector (PI), Tree Contractor (TC), Quality Control (QC), Quality Assurance (QA), Vegetation Control (VC)

SAFETY

PG&E or contract worker must review and follow all applicable safety standards and procedures before performing work, which includes review of tailboards and wearing appropriate Personal Protective Equipment for the job.

BEFORE YOU START

1. Ensure familiarization with entire procedure including the Definitions Section of this document
2. Read Distribution Vegetation Management Standard (DVMS)
3. Read Transmission Vegetation Management Standard (TVMS)
4. Read Transmission Routine (Non-Orchard) Patrol Procedure (TRPP)
5. Read Transmission and Distribution Vegetation Hazard Notification Procedure

Distribution Routine Patrol Procedure (DRPP)

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PROCEDURE STEPS

1 Distribution Patrol Practices

- 1.1 Pre-Inspection and tree work is performed in accordance with PI and TC Contract Specifications, Distribution Vegetation Management Standard (DVMS), practices described in this document, and other applicable standards and procedures.
- 1.2 PI INSPECTS lines once per cycle, generally November 15th of the current year – November 14th of the following year.

1. IF VM employee or contractor identifies any of the following conditions:

- Poses a hazard to the public or utility worker
- Negatively impacts service reliability or asset life of PG&E facilities
- Adversely impacts the ability to safely operate or inspect PG&E's facilities
- Creates a condition that causes PG&E's facilities to be out of compliance with California Public Utilities Commission (CPUC) General Order (G.O.) 95 or 128

THEN NOTIFY the area Vegetation Program Manager (VPM) and Senior Consulting Utility Forester (SCUF).

2. IF the condition only involves PG&E facilities or poses an immediate risk,
THEN FOLLOW the Reporting Abnormal Field Conditions Procedure.



Distribution Routine Patrol Procedure (DRPP)

3. IF the condition is created by a 3rd party Utility (electric, communication, etc.),

THEN FOLLOW the Notification of Conditions to Third-Party Utility Procedure, TD 2014P-01.
4. IF the 3rd party is a non-utility,

THEN FOLLOW the Notification of Conditions to Non-Utility Third-Party Procedure, TD 2015P-01.
5. Primary Lines:
 - a. IF a tree is evaluated as having potential to encroach within minimum distances required to maintain compliance with G.O. 95, Rule 35, or PRC 4293 (see Appendix A, Minimum Distance Requirements (MDRs),

OR may fall into or impact primary conductors before next scheduled prune,

THEN LIST tree in the handheld device for one of the following:
 - Prune
 - Remove
 - Facility Protect (FP)
6. Secondary Lines:
 - a. IF a tree shows evidence of strain or abrasion on secondary lines,

OR may fall into or otherwise impact secondary conductors,

THEN RECOMMEND one of the following:
 - Prune
 - Remove
 - Facility Protect (FP)
 - Reconstruction, as advised by Maintenance and Construction (M&C)

Distribution Routine Patrol Procedure (DRPP)

NOTE

Strain or abrasion on a conductor is present when contact with vegetation significantly compromises the structural integrity of distribution supply facilities. Contact between vegetation and conductors in and of itself does not constitute non-conformance with the rule.

7. Distribution Underbuild:

- a. Distribution PI INSPECTS distribution underbuild spans per requirements for transmission, primary and secondary, as described in this document and the Transmission Routine (Non-Orchard) Patrol Procedure (TRPP).

NOTE

Transmission PI is responsible for listing tree work on transmission spans that begin with underbuild and then diverge.

1.3 Inspection Area

1. Distribution PI INSPECTS:

- a. All vegetation with potential to grow, sway, or fall into PG&E's electric distribution and distribution underbuild conductors.
- b. Distribution underbuild for vegetation that could fall into transmission structures, guys, or poles, regardless of Right-of-Way (ROW) or easement width.
- c. Areas outside fenced areas, including portions of distribution line span crossing substation fence at substations, generation stations, or switchyards in inspection area.
 - IF distribution PI identifies vegetation inside substation, generation substation, or switchyard that requires tree work,

THEN NOTIFY VPM.

1.4 Idle Lines

1. IF idle or de-energized conductor is main line,
THEN distribution PI will treat de-energized conductor as if energized,
AND PATROL and PRUNE to maintain compliance.
2. IF circuit map identifies tap line as idle,
THEN line is NOT patrolled or pruned.



Distribution Routine Patrol Procedure (DRPP)

3. IF tap line is not identified as idle on circuit map,

AND is de-energized by discontinuation of conductor (jumpers either removed, disconnected, or entire span is removed),

THEN line is NOT patrolled or pruned,

AND PI will COMPLETE Idle Facilities Investigation Work form (Idle Facilities Tag),

AND FORWARD Idle Facilities Tag to VPM.
4. IF an Idle Facility Tag does not already exist,

THEN VPM will EMAIL Idle Facilities Tag to Public Safety & Regulatory (PS&R) for input to SAP,

AND PS&R will NOTIFY VM if line is only seasonally or temporarily idle.
5. IF an Idle Facilities Tag already exists for removal of idle facility,

THEN line will NOT be patrolled or pruned,

AND PI will FILE copy of Idle Facilities Tag in the active circuit folder for reference during next patrol.
6. IF no Idle Facilities Tag exists for removing an idle facility,

THEN VPM will FORWARD the completed Idle Facilities Tag to M&C Compliance Supervisor,

AND line is NOT patrolled or pruned,

AND PI will FILE copy of submitted Idle Facilities Tag in the active circuit folder.

1.5 Non-PG&E Owned Distribution Lines

1. IF during patrol, PI identifies Private Facilities (PF),

THEN NOTIFY VPM,

AND FOLLOW the requirements of the Private Facilities Procedure (Dec. 2015).

Distribution Routine Patrol Procedure (DRPP)

2 Distribution Patrol Prescriptions

2.1 Hazard Notification (HN)

NOTE

A Hazard Notification occurs when a vegetation condition affecting distribution or transmission lines has the potential to become an imminent threat. This condition could be the result of vegetation encroaching on the MDR or may arise from outside the ROW due to potential tree or limb failure.

1. IF PI identifies a HN tree,

THEN FOLLOW the requirements of the Transmission and Distribution Vegetation Hazard Notification Procedure.

2.2 General Practice – All Primary, Secondary, and Distribution Underbuild Lines

1. PI will:

- a. PRESCRIBE pruning in accordance with the most current ISA, Best Management Practices – Utility Pruning of Trees – Special Companion Publication to the ANSI 300 Part 1 and Part 7 (IVM).
- b. CONSIDER minimum clearances per MDR (Appendix A) sufficient to maintain mandated clearances under all foreseeable conditions of:
 - Tree Growth
 - Wind
 - Weather
 - Line loading
 - Line sag
 - Line blow-out
 - Tree sway
 - Snow Loading
- c. LIST hazard trees for removal or facility protect.
- d. PRESCRIBE stump treatment when removing re-sprouting species, unless specifically denied by the property owner, land manager, or regulations.



Distribution Routine Patrol Procedure (DRPP)

2.3 Priority Work Codes

1. IF PI identifies a tree for routine pruning or removal work that may not maintain compliance with MDR (Section 2.3.4),

OR may be in contact with Tree Wire before TC would normally complete work,

THEN ASSIGN priority code "Accelerate",

AND in consultation with VPM, CREATE Tag for issue early to TC.

NOTE

Additional management and follow through to completion on accelerate trees may be necessary to mitigate risk and ensure timely completion. PI should be aware of TC schedule and know approximately how many weeks until the work will be completed.

2. IF PI identifies tree for routine pruning or removal work that is currently in compliance with the MDR,

AND tree will maintain compliance until TC is scheduled to complete work,

THEN ASSIGN priority code "Routine".

NOTE

For priority code determination, trees at locations with Tree Wire that are not in contact with tree wire can be considered in compliance with MDR. See Major Woody Stem Exemption Procedure to identify tree wire.

3. IF PI identifies tree for routine pruning or removal on secondary conductors,

THEN ASSIGN priority code "Routine".

4. Facility Protect (FP)

- a. IF PI identifies FP tree that has potential to fail before TC is scheduled to complete work,

THEN FOLLOW requirements per Transmission & Distribution Vegetation Hazard Notification Procedure.

- b. IF PI identifies FP tree that is not likely fail before TC can complete work,

THEN ASSIGN priority code "Routine".



Distribution Routine Patrol Procedure (DRPP)

2.4 Pruning

1. PI PRESCRIBES clearance, sufficient to obtain 2 - 3 years clearance and no less than one year before next prune.
 - a. IF clearance to maintain one year compliance is not attainable based on field conditions and not property owner refusal,

THEN FOLLOW the instructions in Section 2.8 of this document, Bi-Annuals.
 - b. IF tree is being worked for current year compliance,

THEN CLEAR all overhanging branches to minimum of 15 feet, unless branches qualify for Major Woody Stem exemption.

2.5 Removal

1. IF PI identifies tree that will not hold compliance by pruning for one year minimum,

OR required clearance would leave the tree less than 4.5 feet tall,

THEN PI should PRESCRIBE removal, regardless of Diameter at Breast Height (DBH).
2. IF tree DBH is less than 12 inches,

THEN PI should PRESCRIBE removal rather than prune.
3. IF tree DBH is equal to or greater than 12 inches and less than 24 inches,

AND it is not possible to obtain 2-year clearance through pruning,

THEN PI should PRESCRIBE removal rather than prune.
4. IF the DBH is equal to or greater than 24 inches,

AND tree is unlikely to encroach for period greater than one year,

THEN PRUNE tree rather than remove.

2.6 Hazard Trees / Facility Protection Trees

1. IF PI identifies trees or portions of trees that are dead, shows signs of disease, decay or ground or root disturbance,

AND may fall into or otherwise impact primary or secondary conductors,

THEN PRESCRIBE work to make tree Facility Safe per Facility Protect and Work Difficulty Classification Procedure.



Distribution Routine Patrol Procedure (DRPP)

NOTE

This requirement does not apply to Rule 16 secondary line serving a single customer, typically a service drop.

2.7 Refusal

1. IF property owners, land managers, Federal, State or local agency policies or site conditions restrict, constrain, or otherwise interfere with the ability to meet the requirements of this DRPP,

THEN PI will FOLLOW the requirements of the Distribution Vegetation Refusal Procedure.

2.8 Bi-annuals

NOTE

The purpose of the bi-annual cycle code is to effectively address fast growing trees that may not hold compliance for a full cycle. The intent is not simply to identify and perform bi-annual work, but to find the best way to manage these trees.

1. IF PI identifies a potential bi-annual tree on a routine OR bi-annual patrol,

THEN CONSULT with the PI Supervisor to consider options described in Alternatives to Manage and Reduce Bi-Annuals document (Appendix B).
2. IF clearance to maintain one-year compliance is not attainable,

AND no other alternatives are available,

THEN ASSIGN bi-annual cycle code.
3. IF tree cannot be kept compliant even with bi-annual work,

THEN NOTIFY VPM.
4. Following completion of circuit, the Database Manager will:
 - a. PRINT list of all Bi-annuals listed for PI Supervisor to evaluate and enter written comments.
 - b. FORWARD list to VPM per VM Database Monitoring Procedure.



Distribution Routine Patrol Procedure (DRPP)

5. Bi-Annual Patrol

NOTE

The goal of a bi-annual patrol is to quickly evaluate trees which may become compliance issues before next routine cycle and prescribe additional work if needed.

- a. PI REVIEWS Alternatives to Manage and Reduce Bi-Annuals before prescribing work (Appendix B).
- b. Supervisor and PI MEET to set goals for unit reduction prior to start of a bi-annual patrol.

6. Planning in Project Management Database (PMD)

- a. Depending on the number of bi-annuals in a division, VPM CREATES additional projects to account for all bi-annual trees.
- b. VPM will:
 - (1) ADD projects to PMD to track bi-annual trees.
 - (2) CREATE multiple bi-annual projects depending on local designations, including district and contractor.

7. Pre-Loaded Data

NOTE

A bi-annual preload file contains only addresses that have at least one tree set to "bi-annual" as the cycle.

- a. PI will:
 - (1) CONDUCT bi-annual patrols using PMD pre-loaded data.
 - (2) CREATE list of all circuits in quarter in which the patrol is performed.
 - (3) MOVE data that is not part of the pre-load to history.

Distribution Routine Patrol Procedure (DRPP)



CAUTION

DO NOT change the routing of the locations during bi-annual patrol as they do not have all the data for that source side, or source side routing number.

DO NOT “add” locations that are not in pre-load as this can cause duplicate locations in inventory.

CHANGE information only when appropriate as same data is part of normal routine preload, including changing a tree from bi-annual back to routine cycle if tree has maintained compliance and will continue to hold until next routine cycle.

- b. PI will make every effort to notify each customer personally to discuss removals.
- c. IF during bi-annual patrol PI identifies additional trees which will not hold compliance until the next routine cycle,

THEN ENTER tree as “Tag”, with appropriate handheld code.

NOTE

Because of their unpredictable growth and proximity to the lines, Major Woody Stems with epicormic sprouting should not be managed as bi-annuals.

- d. Upon work generation, Database Manager ASSIGNS PMD project number to each TC Work Request associated with that bi-annual patrol.
- e. TC COMPLETES tree work within 30-day maintenance window.



CAUTION

DO NOT ADD trees on a bi-annual cycle unless approved by SCUF or VPM.

2.9 Stump Re-Sprouts

- 1. PI will:
 - a. VERIFY stump death of past removals from previous patrols for all re-sprouting species during current routine patrol.
 - b. LIST all re-sprouting stumps for tree re-work in VMD using trim code “TRT” when following conditions are met:

Distribution Routine Patrol Procedure (DRPP)

- Stump is or will become a compliance issue in future, regardless of time frame.
 - Herbicide treatment was prescribed and customer, agency, or local ordinances approve the herbicide application.
 - Herbicide will not translocate to other living vegetation.
 - Re-sprouts are not root sprouts.
- c. DELETE tree record from handheld when stump is verified as dead.
 - d. NOTIFY customer of re-treat in person or with door card.
 - e. UPDATE VMD records and add comments when TC notifies PI of locations where herbicide treatments cannot be applied.

2. TC will:

- a. RE-TREAT and kill any re-sprouts that have been prescribed trim code "TRT" during routine activities.
- b. VERIFY herbicide treatments result in the death of stump.
- c. NOTIFY PI on same working day when re-sprouts have been prescribed for re-treat work and the stump cannot be treated.
 - (1) Enter NO WORK on the Work Request.
- d. PRUNE stump re-sprout unit when unit cannot be re-treated and will be non-compliant before next annual cycle, and documents and invoices the unit as an "add".

2.10 Palms

1. PI will:

- a. REVIEW VMD pre-patrol report prior to patrolling circuits to identify potential palm tree problems on circuit.
 - IF PI identifies a palm in the field that routine pruning will not maintain compliance for at least one cycle,

THEN PRESCRIBE tree removal, or removal of "heart" of palm.

Distribution Routine Patrol Procedure (DRPP)

- IF palm is in contact with line(s),

THEN FOLLOW Transmission & Distribution Hazard Notification Procedure,

AND CONTACT property owner to discuss removing palm.
- IF customer is not present at time of visit,

THEN LEAVE the Palm Tree Alert door card with name and contact number,

AND contact PG&E clerk to obtain customer's phone number to discuss palm removal,

AND PI NOTIFIES VPM of each Palm identified in the field that may require the Palm Letter.

NOTE

Palm Letters are only used when removal of tree or "heart" of the palm is required to maintain compliance.

2. VPM will:
 - a. CONDUCT site visit, when appropriate, to verify condition of palm(s) after receiving information from PI.
 - IF VPM or PI is unable to contact property owner,

THEN VPM will make an additional attempt to NOTIFY customer that their palm needs removal.
 - IF customer responds and refuses to remove the palm,

THEN VPM will FOLLOW steps described in the Distribution Vegetation Refusal Procedure.
3. PI will:
 - a. IDENTIFY palm species code (Queen, Fan, or Date).
 - b. REFER to Strategies to Manage and Reduce Palms (Appendix C) if tree removal is not feasible.
 - c. RECOMMEND remediation based on tree and site conditions.
 - d. REVIEW VMD palm work history.



Distribution Routine Patrol Procedure (DRPP)

- e. FORWARD information on new palm plantings under PG&E facilities to VPM.
 - IF there is no response after repeated attempts to contact property owner,

THEN VM Palm Letter is SIGNED by VPM and SENT to property owner.
 - f. The Palm Letter:
 - (1) LISTS all Palm Letters sent to property owners in the Issue Tracking System (ITS) with record Type = Non Refusal, Subtype: = Palm Letter.
 - (2) INDICATES palm species in Comment section.
 - (3) DESCRIBES conditions and any communications with property owner in the ITS Comments section.
 - (4) RECORDS the date pruning is scheduled to occur in the ITS Follow-up Section.
 - IF the property owner responds and refuses to remove the palm,

THEN as appropriate, FOLLOW steps outlined in the Distribution Vegetation Refusal Procedure.
 - g. PROVIDE photo documentation of palm condition, if necessary.
4. VPM will:
- a. DECIDE whether any outside agencies need be notified.
 - IF palm is on a section of line which appears to be Rule 16,

THEN land rights must be requested before Palm Letter is sent.
 - IF Palm Letter is sent and customer does not respond within 10 calendar days,

THEN TC will PROCEED with the tree work.
5. Database Manager will:
- a. CHANGE the trim type to Top in VMD.
 - b. ADD prescribed clearance in the Comment section, regardless of where the heart of the palm is located.



Distribution Routine Patrol Procedure (DRPP)

- c. PROVIDE TC with copies of the Work Request and the following:
 - Removal Form, with detailed tree work and debris removal prescriptions, signed by VPM
 - Palm Letter
 - Land Rights Letter, if land rights were requested

2.11 Orchards

1. Orchard PI will:
 - a. INSPECT all orchards per requirements for transmission, primary and secondary, as described in this document and Transmission Routine (Non-Orchard) Patrol Procedure (TRPP).
 - b. FOLLOW Orchard Best Management Practices (Appendix D).

END of Instructions

Distribution Routine Patrol Procedure (DRPP)

DEFINITIONS

Distribution Underbuild – The presence of electric distribution lines located directly under and parallel with the transmission lines, and attached to the same pole or structure.

Easement (or Right of Way) – For the purposes of this Standard, the as-built condition of a geographically described strip of land upon which PG&E's electric facilities are constructed, operated and maintained. "Easement" refers to the legal description of that corridor.

Hazard Condition – A vegetation condition affecting transmission or distribution lines which does not pose an imminent threat, but where the condition has the potential to become an imminent threat and is at or encroaching the PG&E clearance distance.

Hazard Trees - Any tree whose height is at or approaching the PG&E Minimum Clearance Requirements (Appendix A).

- **All lines:** Trees that are dead, show signs of disease, decay or ground or root disturbance, which may fall into or otherwise impact the conductors, towers or guy wires before the next inspection cycle.

Minimum Clearance Requirement – PG&E defined minimum clearance designed to meet or exceed all applicable regulatory requirements at all times.

Orchard – Any commercial-producing orchard. Only includes trees that are part of the production crop.

Orchard Tree – Any commercial-producing fruit or nut tree that is part of a production crop.

Private Facilities (PF): Includes all Private Owned Lines (POL), Primary Metered / Primary Service (PM / PS), Private Owned Transmission Lines (POTL).

- **Private Owned Line (POL):** Private lines are defined as distribution main or line extension facilities, or service facilities that are not owned, operated and maintained by PG&E.
- **Primary Metered / Primary Service (PM / PS):** All pole-top primary metering installations with Primary Service are considered Primary Metered. Facilities beyond the interconnection point should be considered customer owned.
- **Private Owned Transmission Lines (POTL):** All privately owned line connected to PG&E facilities designated on GIS / ETGIS or other application as Non-PG&E Owned energized at 60KV or greater connected to PG&E facilities

Right-of-Way – See Easement.

Refusal – A situation that occurs when a customer / property owner refuses to allow PG&E to perform pre-inspection work or complete 100% of the work prescribed.

Distribution Routine Patrol Procedure (DRPP)

Tap Line – Section of overhead primary line that deviates off of the mainline of a distribution circuit. Tap Line may be a hard tap (non-fused) or a fused tap.

IMPLEMENTATION RESPONSIBILITIES

The Vegetation Management Document Owner is responsible for the rollout and communication of this Standard as well as the periodic review of this document. Vegetation Management Operations is responsible for the distribution of this Standard by providing training and conducting regular reviews.

GOVERNING DOCUMENT

Distribution Vegetation Management Standard

Transmission Vegetation Management Standard

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

[General Order 95, Rule 35](#)

General Order 95, Rule 18, Section B

[Public Resource Code \(PRC\) 4292](#)

[Public Resource Code \(PRC\) 4293](#)

ANSI/ISO/ASQC Q10011 Guidelines for Auditing Quality Systems

REFERENCE DOCUMENTS

Database Monitoring Procedure

Distribution Refusal Procedure

Mapping Procedure

Private Facilities Procedure (Dec. 2015)

Project Management Database (PMD) Standardization Guidelines (Dec. 2015)

Transmission & Distribution Vegetation Hazard Notification Procedure

Transmission Routine (Non-Orchard) Patrol Procedure (TRPP)

Notification of Conditions to Third-Party Utility Procedure, TD-2014P-01

Notification of Conditions to Non-Utility Third-Party Procedure, TD- 2015P-01

Distribution Routine Patrol Procedure (DRPP)**APPENDICES**

Appendix A: Minimum Distance Requirements

Appendix B: Alternatives to Manage and Reduce Bi-Annals

Appendix C: Strategies to Manage and Reduce Palms

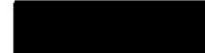
Appendix D: Orchard Best Management Practices

ATTACHMENTS

NA

DOCUMENT REVISION

NA

DOCUMENT APPROVER Vegetation Management Operations Manager - North Vegetation Management Operations Manager - South**DOCUMENT OWNER** Vegetation Program Manager**DOCUMENT CONTACT** Vegetation Program Manager**REVISION NOTES**

Where?	What Changed?
Entire document	This is a new procedure, formatted to meet GDM requirements.
Entire document	Renumbered per the GDM Numbering Procedure in preparation for Documentum migration.

Distribution Routine Patrol Procedure (DRPP)

Appendix A: Minimum Distance Requirements

MINIMUM DISTANCE REQUIREMENTS

CPUC Rule 35 Applicable at all times (1) (feet)	Santa Barbara County CPUC Rule 35, Table 1, Case 14 (hhh) Applicable in extreme and very high fire threat zones in Southern California at all times (1) (feet)	PRC 4293 Applicable in SRA during fire season (1) (feet)	Potential Line Sag (2) (feet)
1.5'	4'	4'	1 - 4'

- 1) Vegetation shall not encroach within the minimum distance at any time between inspection and one year or next scheduled tree work cycle.
- 2) Depending on span length, facility construction and conductor material, potential sag and sway can range from 1' at quarter-span to 4' at mid-span.

Distribution Routine Patrol Procedure (DRPP)

Appendix B: Alternatives to Manage and Reduce Bi-Annuals

ALTERNATIVES TO MANAGE & REDUCE BI-ANNUALS	
PURPOSE: The purpose of the Bi-annual Cycle code is to effectively address fast growing trees that may not hold compliance for a full trim cycle. The intent is not simply to identify and perform bi-annual trims, but to find the best way to manage such trees using all the available tools listed below. These alternatives include increasing line clearance, changing the trim type, pursuing removal, applying tree growth regulators, or seeking engineering solutions. If it is found that a tree cannot be kept in compliance even with bi-annual pruning, as with palms, the VPM shall be notified. DEFINITION: A bi-annual is a tree that should be inspected between routine inspections so as to ensure compliance with applicable laws and regulations. However, the following management alternatives must be considered before listing a tree as a bi-annual:	
ALTERNATIVE	CONSIDERATIONS
Refusal	IF property owners, land managers, Federal, State or local agency policies or site conditions restrict, constrain, or otherwise interfere with the ability to meet the requirements of this DRPP, then follow the Distribution Vegetation Refusal Procedure.
Increase Line Clearance Prescriptions	- Additional notification is necessary if larger wood needs to be taken from the tree to maintain compliance and meet ANSI A300 standards. Set realistic expectations with the customer <u>but do not negotiate clearance distances.</u> - Determine whether previous clearance distance maintained compliance for at least one (1) trim cycle. May need to check last trim date in VMD. - Increase clearance to match site conditions and species' specific growth rates.
Change Trim Type	- Determine whether the previous trim type contributed to the tree not maintaining compliance for at least one (1) trim cycle. - Prescribe directional pruning versus topping (if possible).
Seek Removal	- Is this an appropriate removal? Consider the following: - Cost-effectiveness - Tree species, DBH, and height - Reliability and facility protection - Is the trunk positioned below or within close proximity to the conductors? - Will replacement tree(s) facilitate successful removal negotiations with the customer? - Use herbicides on removals for control of re-sprouting species unless directed otherwise by the customer. - Do the land rights give PG&E the authority to remove the tree in question?
Apply Tree Growth Regulators	- TGRs can help PG&E more cost-effectively manage fast growing species, manage more trees annually, extend trim cycles, increase reliability, and reduce biomass as it relates to trimming and cleanup time. - Do not discuss TGRs with the customer. TGR notification requires specialized training. Consult your SCUF or VPM to find out more about your area-specific TGR management plan.

Distribution Routine Patrol Procedure (DRPP)

Seek Engineering & Line Construction Solutions	• Do not discuss engineering alternatives with the customer (VPM/SCUF only). • The best time to address the adverse effects of trees on distribution lines is at the time of initial design. • Notify the SCUF of potential infrastructure alterations including new line construction, upgrades to the electrical system, and road widening or relocation projects. • Consider overhead construction alternatives including: ○ Alley or wing arm construction ○ Compact construction ○ Covered overhead primary (i.e. "Ray Chem") ○ Squirrel guard on tree (use "side wrap" code in hand held) ○ Spacer ("Hendrix") system (combination of covered wire and compact construction) ○ Aerial cable • Only in exceptional cases can the cost of converting an existing system to an alternative construction type be justified on the basis of reliability, avoided cost of future tree maintenance, or infrastructure repair.
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Distribution Routine Patrol Procedure (DRPP)

Appendix C: Strategies to Manage and Reduce Palms

STRATEGIES TO MANAGE AND REDUCE PALMS	
PURPOSE: The purpose of this document is to provide additional strategies for managing palms, including removal, strategic pruning, bi-annual patrols, transplantation, and engineering solutions. Note: any additional costs associated with transplantation, re-engineering, and/or line re-construction will be at the property owner's expense.	
ALTERNATIVE	CONSIDERATIONS
Removal	- Is this an appropriate removal? Consider the following: - Is palm positioned below the conductors? - Will the tree be in violation before the next cycle? - DBH and height - Reliability & facility protection - Is the tree protected under any municipal regulations? Is it a City tree? - Will replacement tree(s) facilitate successful removal negotiations with the customer? Vouchers may be provided at VPM discretion. - VPM may consider additional T&M for wood removal, in order to secure removal permission from reluctant customers. Use of 3rd party contractor list can be considered for wood removal if approved by VPM. Customer can provide dumpster for wood. - Do the land rights give PG&E the authority to remove the tree in question?
Prune	- To be used only for palms to the side that will grow past the lines. - Do not negotiate pruning prescriptions with the customer. - Determine whether previous clearance distance maintained compliance for at least one (1) trim cycle. - Increasing the radial clearance may not be the best way to maximize the time the tree will stay in compliance. Palms grow quickly in response to trimming. - Prescribe a side trim or slope cut, and make notes to cut upper fronds that will droop down into violation in the future. - For feather palms, consider removing partial fronds when side pruning to slow the downward movement of upper fronds. Palms maintain a certain number of fronds at any one time. As you remove living fronds, new frond growth is encouraged. Not removing the whole frond may actually provide a longer cycle before next trim is required. - Inspection during subsequent cycles, including bi-annual patrols, can help determine whether trimming strategies are maintaining compliance. If not, consider alternatives such as removal.
Work Tracking	- Utilize the Future Palm letter for customers with palms that will require removal in the future. - Palm letters by themselves do not ensure that one full year of clearance will be obtained. Individual palms or locations may fall through the cracks. For palms that will not hold clearance for a full year with normal pruning, the refusal process should be used. - The refusal process is used to track unmanageable palms when the customer refuses removal. Although PG&E may or may not have the right to remove or kill the palm, PG&E does have the right and responsibility to obtain one-year' worth of clearance even if that clearance removes the heart of the palm and kills it.

Distribution Routine Patrol Procedure (DRPP)

Transplanting & Palm Brokers	• Palms may be valuable enough to justify transplantation by the customer. • Customer should contact palm broker and coordinate work. • This alternative should be initiated at least 2-3 years before the tree enters within 10' of the high voltage lines. Palm brokers may not be interested in trees that have been pruned due to concerns about disease or appearance. • Line-kills may be appropriate, at property owner expense, during transplantation to ensure safety. • Always prescribe necessary pruning to maintain compliance until the next cycle, even if the customer says they will move the palm.
Engineering & Line Construction Solutions April 2007	• Do not discuss engineering alternatives with the customer (VPM/Forester only). • The best opportunity to address the adverse effects of trees on distribution lines is at the time of initial design. Notify VPM/Forester of potential infrastructure alterations including new line construction, upgrades to the electrical system, and road widening or relocation projects. • At the customer's request and expense, the electric construction department may consider overhead construction alternatives including: ○ Alley or wing arm construction ○ Compact construction and/or changing pin spacing ○ Aerial cable ○ Raychem wire covering • Always prescribe necessary trimming to maintain compliance until the next cycle, even if the customer says they will pursue a construction change.



Distribution Routine Patrol Procedure (DRPP)

Appendix D: Orchard Best Management Practices

ORCHARD BEST MANAGEMENT PRACTICES

PIs and TCs are expected to follow Vegetation Management Best Management Practices, as follows:

GENERAL SAFETY

BMP 1: VM contractors will follow all Vegetation Management BMPs for environmental laws and procedures.

S:\Orchard - Distribution Project\VM BMPs

BMP 2: VM contractors will review and comply with all pesticide safety rules and regulations.

Do not enter an orchard if chemicals are suspected as a result of pesticide treatment; required spray re-entry signage may not be posted. When in doubt, verify with grower / orchard manager that orchard is safe to access.

S:\Orchard - Distribution Project\Safety

BMP 3: VM contractors must access orchards by using pavement or designated roads, and comply with seasonal entry restrictions. If vehicle access between rows is required, permission from orchard manager must be obtained. Vehicle speed limit (generally 10 mph) must be followed.

BMP 4: VM contractors will not enter during restricted entry intervals such as harvest, flooding or application of pesticides. For emergency tree work, immediately contact local PI supervisor (SCUF), VPM and notify orchard owner.

SCHEDULE

BMP 5: VM contractors will prescribe tree work according to the Distribution Patrol Standard (DPS) to ensure regulatory compliance. Any trees that require increased clearance, or removal, since they can't be managed on a one year cycle, must be discussed with the orchard owner and recorded in vegetation management database (VMD). PIs must tailboard increased clearance locations with TCs prior to tree work.

S:\Orchard - Distribution Project\5 Minute Meeting Annual Clearances

BMP 6: Whenever possible, VM Contractors will schedule distribution and transmission orchard-work at the same property, or corridor, and coordinate schedules using the project management database, seasonal restrictions and harvest schedule.

DATABASE MANAGEMENT

BMP 7: VM contractors will use "Orchard Projects" defined in PMD as a separate segment from the non-orchard patrol, identified by Circuit name as the Project name, and using Orchard as the descriptor. The PMD Standardization Guidelines must be utilized for specific guidance.

Note: Non-Orchard trees can be listed in an orchard project with "Private" as owner.

BMP 8: Pre-inspection contractor will maintain a list of Orchard Owners that will be updated / edited / corrected frequently so that accurate information can be used by TCs. The grower list for the transmission orchard



Distribution Routine Patrol Procedure (DRPP)

program will include distribution orchard owners if distribution lines exist on the same property. Pre-patrol notification letters must be mailed in advance of each scheduled quarter, and mailing coordinated with transmission orchard program pre-patrol letters to avoid duplications. To the extent possible, one letter should be sent when a property / grower has both transmission and distribution. PI transmission will send these letters - one for transmission only and one for distribution and transmission; distribution-only will be handled by PI distribution.

BMP 9: PI contractors will verify the accuracy of contact information and update the database as required. For obtaining current orchard owner phone numbers, PIs have access to a variety of databases including CCNB /S AP information provided by PG&E clerk

BMP 10: SCUF will provide orchard PIs with Pre-Planning reports for orchard projects from back office PMD, and discuss quality, schedule and compliance goals

PRE-WORK REVIEWS / BENCHMARKING

BMP 11: VM contractors will perform customer call outs utilizing the customer notification system, specific to orchard projects. Call out schedules must be coordinated with transmission orchard program to avoid duplications.

BMP 12: Locations: Identify orchards that have discussion topics (i.e., clearance, different species, older mature trees, new plantings, etc.). Contractors will work with the orchard owner to ensure coordination. Ensure benchmark locations are safe, away from main thoroughfares, and with plenty of parking.

Orchard owner notifications: Benchmarks should include the importance of proper notifications to all orchard owners / managers. They should be conducted pre-and post-harvest to help educate inspectors on the effects of leaf and nut loading, or changing tree-conductor clearances from dormant season to time of harvest.

VM contractors must conduct representative benchmarks prior to annual tree maintenance.

TALKING POINTS

BMP 13: VM contractors will review talking points when communicating with orchard owners to deliver a consistent message.

S:\Orchard - Distribution Project\Talking Points

Bulletins are intended to communicate the following:

- An immediate change in how business is done
- Information about a safety, health or environmental incident or issue and resulting required actions
- Information about a new mandatory compliance requirement

A clarification of a previous instruction to communicate why the document is being

Vegetation Management Second Patrol Procedure

SUMMARY

This utility procedure provides instructions for performing second patrol inspections (commonly referred to as patrol) and tree trimming within the following areas:

- State responsibility areas (SRAs)
- Wildland urban interface (WUI) areas
- Fire hazard severity zones (FHSZs)
- Designated high fire-threat districts (HFTDs)

The intention is to reduce the risk to the electric system by inspecting vegetation conditions on circuits within these areas approximately six months after the routine annual patrol.

California Public Utilities Commission (CPUC) decision R.15-05-006 adopted regulations to enhance fire safety in designated HFTDs across California. The HFTDs are divided into three areas: Zone 1 (tree mortality), Tier 2 (elevated fire risk), and Tier 3 (extreme fire risk). Second patrols include catastrophic event memorandum account (CEMA) recovery efforts, and the term "second patrol" is preferred and used in lieu of CEMA in this document.

The scope of work addresses the following:

- Dead, dying, and declining trees, or dead portions of trees including dead overhangs, that can contact PG&E facilities if they fail
- Green trees observed within the minimum distance requirement (MDR) or with the potential to encroach the MDR before the next patrol cycle
- Green hazard trees with the potential to impact the electric facilities
- Trees causing strain or abrasion on secondary lines
- Abnormal field conditions

Level of Use: Informational Use

TARGET AUDIENCE

PG&E vegetation management (VM) personnel

VM second patrol contractors, including pre-inspector (PI), tree crew general foreman (GF), quality control (QC), and quality assurance (QA)

SAFETY

NA

Vegetation Management Second Patrol Procedure

BEFORE YOU START

1. REVIEW the [Definitions Section](#) in this document.
2. ESTABLISH an understanding of the following VM utility procedures:
 - When inspecting transmission with underbuild, [TD-7103P-01, "Transmission Non-Orchard Routine Patrol Procedure \(TRPP\)"](#)
 - [TD-7102P-01, "Distribution Routine Patrol Procedure \(DRPP\)"](#)
 - [TD-7102P-04, "Distribution Vegetation Refusal Procedure"](#)
 - [TD-7102P-06, "Inspection Mapping"](#)
 - [TD-7102P-07, "Vegetation Management Hazard Tree Rating and Scoring"](#)
 - [TD-7102P-08, "Facility Protect and Work Difficulty Classification Procedure"](#)
 - [TD-7102P-09, "Reporting Abnormal Field Conditions Procedure"](#)
 - [TD-7102P-16, "VM Riparian Review Procedure"](#)
 - [TD-7102P-16-JA01, "Identifying Riparian Areas"](#)
 - [TD-7103P-09, "Vegetation Management Hazard Notification Procedure"](#)

Vegetation Management Second Patrol Procedure

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PROCEDURE STEPS

1 General Requirements

- 1.1 New regulations require a 4-foot (ft.) minimum clearance year-round in the designated HFTD areas; with a recommended clearance of 12 ft. at the time of trim.
- 1.2 CHECK the Fire Index Ratings for work locations before starting work.
- 1.3 FOLLOW all best management practices as defined in [Job Aid TD-7102P-01-JA01, "Best Management Practices \(BMPs\) for Vegetation Management Activities."](#)
- 1.4 FOLLOW all avoidance and minimization measures (AMMs) specific to the location.

Vegetation Management Second Patrol Procedure

2 Preparing Work for Second Patrol Inspections

- 2.1 The senior consulting utility forester (SCUF) must PERFORM the steps in [Appendix A, "SCUF – Prepare Work and Create Read-Only Packages for Second Patrol,"](#) to PREPARE second patrol work, CREATE read-only packages, AND ASSIGN work to a consulting utility forester (CUF).

3 Performing Patrol Types

- 3.1 For projects identified as **CEMA GROUND** and **CEMA Aerial** in the project management database (PMD), the PI must perform the following major steps:
1. INSPECT all portions of a line within the SRA and HFTD layers (including an HFTD in the LRA area designated as an Increased Clearance Area [ICA]) once per year, approximately 6 months after routine patrol inspection of the circuit.
 2. In accordance with Utility Procedure [Utility Procedure TD-7102P-06, "Inspection Mapping,"](#) DOCUMENT the completed inspection as follows:
 - a. HIGHLIGHT the line inspected on a circuit map.
 - b. SIGN AND DATE the circuit map.
- 3.2 For projects identified as CEMA WUI and CEMA FHSZ in the PMD, the PI must perform the following major steps:
1. INSPECT only portions of the circuit that are in local response areas (LRAs) outside HFTD ICA AND within the two GIS layers, WUI areas and FHSZs, once per year, approximately 6 months after routine patrol inspects the circuit.
 2. In accordance with [TD-7102P-06](#), DOCUMENT the completed inspection as follows:

NOTE

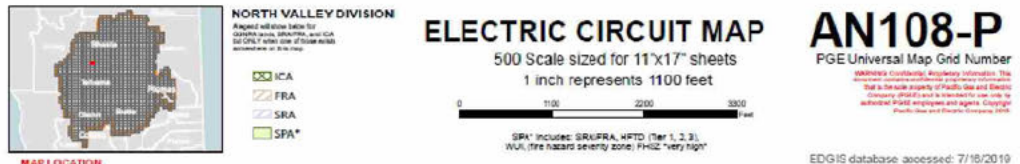
- Circuit maps with a layer designated as Second Patrol Area (SPA) are located on the Shared drive and can be accessed by going to the VMShared drive in the Second Patrol folder for the current year, within a subfolder named Second Patrol Area Maps.
- The second patrol area layer on the circuit maps contains the designated patrol areas of SRA, HFTD/ICA, WUI, and FHSZ.

- a. HIGHLIGHT the line inspected on a circuit map.
- b. SIGN AND DATE the circuit map.
- c. For projects designated as CEMA GROUND and CEMA AERIAL in the PMD, the PI must patrol all line segments WITHIN areas designated on the maps as SRA, FRA, and ICA.

Vegetation Management Second Patrol Procedure

3.2 (continued)

- d. For projects designated as CEMA WUI in the PMD, the PI must patrol all line segments within areas designated on the maps as SPA and that are NOT in the SRA/FRA or ICA layer.



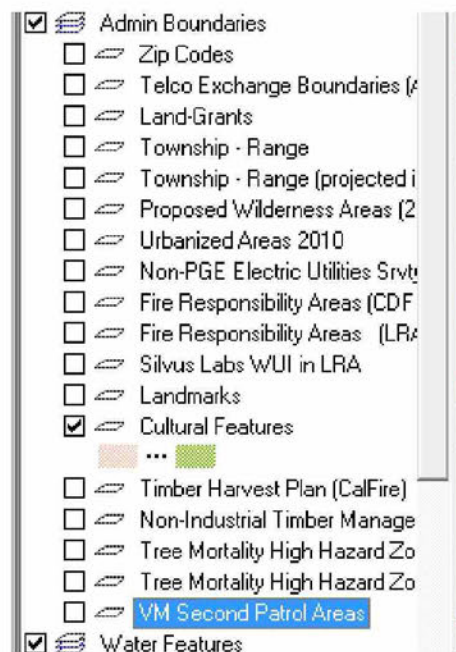
Vegetation Management Second Patrol Procedure

3.2 (continued)

3. To view these layers on MapGuide GIS, perform the following tasks:

- a. SELECT Admin Boundaries.
- b. For the SPA, SELECT **VM Second Patrol Areas**.

This layer is visible at the 500K scale.



4 Creating a New Packet on a Mobile Device

- 4.1 See [Appendix B, "CUF – Creating a New Packet on a Mobile Device for Second Patrol Projects,"](#) for instructions for the CUF to create a new packet for each second patrol project

5 Editing Location Route Information

- 5.1 The PI must perform the following steps to edit the location route information in the mobile device to indicate that it is a CEMA project location:

1. CLICK **Edit**.

The **Edit Location Route Info** window appears.

2. For **Circuit**, SELECT the circuit undergoing work.
3. For the source side device number (**SSD #**), ENTER the source side device (SSD) on which the project is located.

Vegetation Management Second Patrol Procedure

5.1 (continued)

4. For the source side route number (**SSD Rt#**), ENTER **606060** to ensure that a single work request is created for all locations.
5. For the location route number (**Loc Rt#**), make the following entries:
 - a. ENTER the first number from the number range assigned by the SCUF to the first location.
 - b. INCREMENT each subsequent location number by 10.

For example, if the SCUF-assigned range is 210 to 300, use 210 first, followed by 220, then 230, etc.

NOTE

The **Tag Type** and Tag Number (**Tag #**) fields are not used when the prescribed work is for dead, dying, and declining trees, or dead portions of trees including dead overhangs, that can contact PG&E facilities if they fail.

6. LEAVE the **Tag Type** and **Tag #** fields blank unless work identified is for trees approaching the MDR or trees that meet Hazard Notification criteria. Refer to [Section 10.1, Table 1, "Tree Conditions,"](#) for guidance on when to use appropriate tag types.
7. Click **Finish**.

6 Patrolling the Location Following the Second Patrol Scope-of Work

The scope of work addresses the following conditions:

- Dead, dying, and declining trees, or dead portions of trees including dead overhangs, that can contact PG&E facilities if they fail
- Green trees observed within the minimum distance requirement (MDR) or with the potential to encroach the MDR before next patrol cycle
- Green hazard trees with the potential to impact the electric facilities
- Trees causing strain or abrasion on secondary lines
- Abnormal field conditions

Vegetation Management Second Patrol Procedure

6.1 The CUF must RECEIVE the Locations Report from the SCUF AND must review the report to verify whether marked trees still unworked are listed on a pending work request.

1. IF the tree is on a pending work request but has declined or encroached on the MDR AND the inspector believes the tree is at risk of not holding,

THEN [TD-7103P-09](#) must be implemented.

2. The CUF must then INFORM the DMS so the pending work request line item can be closed as 'not worked' once the HN tag is generated.

7 Entering Tree Data

7.1 To enter tree data in the vegetation management database (VMD), the PI must perform the following steps:

1. On the VMD **Location** screen, CLICK the **Tree List** tab at the top of the screen.

2. CLICK **New** at the bottom of the page.

The **VMD - Tree** window appears.

3. CLICK **Edit**.

The **Edit Tree Detail Info** window appears.

4. ENTER the following information:

- a. For **Tree Type**, SELECT from the drop-down list.
- b. For **Species**, SELECT from the drop down list.
- c. For **Property Owner**, SELECT from the drop-down list.
- d. For **Quantity**, ENTER the number of trees.
- e. For **Joint Pole**, SELECT from the drop-down list.
- f. For **Tree Comments**, ENTER the location of the trees AND specific instructions for performing the work.
- g. For **Trim Code**, BASE the individual tree prescriptions on [TD-7102P-08](#), ["Facility Protect and Work Difficulty Classification Procedure"](#) AND SELECT from the drop-down list.
- h. For **Height**, ENTER the height in feet.
- i. For **DBH**, ENTER the diameter in inches.

Vegetation Management Second Patrol Procedure

7.1 (continued)

- j. For **Clearance**, ENTER 0 for all removals OR specify the clearance for trims in inches.
- k. For **Priority**, SELECT **Routine** from the drop-down list.
- l. For **Cycle**, SELECT **Routine** from the drop-down list.
- m. For **Crew**, ENTER the crew type.

5. CLICK **Finish**.

8 Communicating with the Customer

NOTE

ENTER the customer contact information for any safety issues or production impacts, such as the presence of a dog, requests to notify first, locked gate, and concerned customer alerts.

8.1 The PI must perform the following steps to contact and communicate with the customer:

- 1. ATTEMPT to CONTACT the customer.
- 2. IF successful,
THEN perform the following tasks:
 - a. EXPLAIN the scope of work being prescribed, including the scope of clean up and the amount of debris likely to be left behind.
 - b. When possible, OBTAIN a signed Notification of Tree Work (NTW) Form from the property owner for heavy trimming and removal work.

NOTE

All non-contact refusals (absent land owner locations) require photographs of the dead/dying tree canopy to be mitigated.

- 3. IF **unable** to contact the customer after 3 documented attempts within 5 business days,
THEN perform the following steps:
 - a. FOLLOW [Attachment 1, "Customer Notification Process."](#)
 - b. PROVIDE required photographs for the Customer Impact process.

Vegetation Management Second Patrol Procedure

9 Processing Refusals

9.1 IF the customer refuses work entirely OR limits the work so as to severely limit positive trim results, THEN the PI must perform the following steps:

1. INDICATE the location as a refusal in the mobile device AND CREATE an ITS record.
2. FOLLOW [TD-7102P-04, "Distribution Vegetation Refusal Procedure."](#)
3. ENTER the tree prescriptions into the mobile device.
4. MARK the location as "Refusal."

9.2 The local lead or refusal specialist must perform the following tasks:

1. ATTEMPT to make a second contact to resolve the refusal.
2. IF the refusal remains unresolved,

THEN PASS the refusal to the designated second patrol SCUF or second patrol VPM for further action.

10 Identifying Routine Compliance Work During Second Patrol

10.1 The PI must IDENTIFY the trees with conditions listed in Table 1 below AND PERFORM the action specified for each.

Table 1. Tree Conditions

Tree Condition Identified	Action
Green trees observed within the MDR, See TD-7102P-01 , Attachment 1, "Minimum Distance Requirements (MDR)."	FOLLOW Utility Procedure TD-7103P-09, "Vegetation Management Hazard Notification Procedure."
Trees that are approaching the MDR that are not expected to maintain compliance until the next routine inspection cycle.	ENTER the routine work in the mobile device as a Missed Tree tag.
Green, significantly leaning trees with indications of basal defect or soil instability, and uprooted trees in the surrounding stand, that are likely to fail into the facilities before the next annual patrol.	ENTER the routine work for these trees in the mobile device as an Unforeseen tag.
Structurally unsound green limbs and dead palm fronds above the conductors with the potential to fail into the facilities before the next routine patrol.	ENTER the routine work for these trees in the mobile device as an Unforeseen tag.

10.2 WHEN an abnormal field condition is identified,

THEN the PI and TC must FOLLOW [Utility Procedure TD-7102P-09, "Reporting Abnormal Field Conditions Procedure."](#)

Vegetation Management Second Patrol Procedure

- 10.3 The second patrol SCUF must NOTIFY the local area DMS of routine tags created and uploaded to the system.

11 Processing Trees within Riparian Areas

- 11.1 For identifying riparian areas, the PI must FOLLOW the instructions in [Job Aid TD-7102P-16-JA01, "Identifying Riparian Areas."](#)
- 11.2 For trees within a riparian area identified as needing work, the PI must FOLLOW [Utility Procedure TD-7102P-16, "VM Riparian Review Procedure."](#)

12 Post Patrol and Reporting

- 12.1 At least once a day, the PI must TRANSMIT the data collected using the mobile device.
- 12.2 At the end of each project, the PI must PERFORM the following steps:
1. COLLECT all project documents, which commonly include the following documents:
 - NTW
 - Highlighted Maps
 - Inspection Maps
 2. SUBMIT the documents to the SCUF.
 3. STORE the documents in the circuit folder.

13 Completing the Project

- 13.1 WHEN a project is complete,
THEN the SCUF must PERFORM the following steps:
1. SEND a completion email to the local DMS, providing the following information:
 - Project Name
 - Project Number
 - Date of closing
 - Total number of units

Vegetation Management Second Patrol Procedure

13.1 (continued)

2. FILE the project folders in the local office with all relevant documentation, including, but not limited to the following documents:
 - Index and Field maps highlighted and signed by the CUF and SCUF.
 - Original signed NTWs (where applicable).
 - Additional permits (ERTC communications, AMMs).

14 Performing Aerial Patrols

- 14.1 See [Attachment 3, "Aerial Patrols,"](#) for guidance on planning, executing and documenting aerial patrols.

END of Instructions

DEFINITIONS

CEMA: In 2014, PG&E implemented a CEMA program to recover costs due to increased tree mortality from prolonged drought and bark beetle infestations within the PG&E service territory.

Fire Hazard Severity Zone (FHSZ): A layer produced by CAL FIRE and the Resource Assessment Program (FRAP) using data and models describing development patterns, potential fuels over a 30-50 year time horizon, expected fire behavior, and expected burn probabilities, to quantify the likelihood and nature of vegetation fire exposure. This second patrol project pertains only to the **very high** fire severity zone within the LRA.

VM Back Office: A web-based software system that includes the VMD and the PMD.

Wildland Urban Interface: The area where structures and other human developments meet or intermingle with undeveloped wildland.

IMPLEMENTATION RESPONSIBILITIES

VM operations personnel are responsible for the rollout, communication, and distribution of this utility procedure.

GOVERNING DOCUMENT

[Utility Standard TD-7102S, "Distribution Vegetation Management Standard \(DVMS\)"](#)

Vegetation Management Second Patrol Procedure

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

[California Public Utilities Commission \(CPUC\) General Order \(G.O.\) 95, Rule 35](#)

[G.O. 95, Rule 18, Section B](#)

[Public Resource Code \(PRC\) 4292](#)

[PRC 4293](#)

REFERENCE DOCUMENTS

Supplemental References:

[TD-7102P-01, "Distribution Routine Patrol Procedure \(DRPP\)"](#)

[TD-7102P-01, Attachment 1, "Minimum Distance Requirements \(MDR\)"](#)

[TD-7102P-04, "Distribution Vegetation Refusal Procedure"](#)

[TD-7102P-06, "Inspection Mapping"](#)

[TD-7102P-08, "Facility Protect and Work Difficulty Classification Procedure"](#)

[TD-7102P-09, "Reporting Abnormal Field Conditions Procedure"](#)

[TD-7102P-16, "VM Riparian Review Procedure"](#)

[TD-7102P-16-JA01, "Identifying Riparian Areas"](#)

[TD-7103P-01, "Transmission Non-Orchard Routine Patrol Procedure \(TRPP\)"](#)

[TD-7103P-09, "Vegetation Management Hazard Notification Procedure"](#)

APPENDICES

[Appendix A, "SCUF – Prepare Work and Create Read-Only Packets for Second Patrol"](#)

[Appendix B, "CUF – Creating a New Packet on a Mobile Device for Second Patrol Projects"](#)

ATTACHMENTS

[Attachment 1, "Customer Notification Process"](#)

[Attachment 2, "Red Flag Patrols"](#)

[Attachment 3, "Aerial Patrols"](#)

Vegetation Management Second Patrol Procedure

DOCUMENT REVISION

TD-7102P-23, Vegetation Management 2016 Second Patrol - Practices, Rev. 0

TD-7102P-23, "Vegetation Management 2017 Second Patrol - Practices, Rev. 1"

DOCUMENT APPROVER

 Senior Manager, Vegetation Management

DOCUMENT OWNER

 Supervising Program Manager, Vegetation Management

DOCUMENT CONTACT

 Supervising Program Manager, Vegetation Management

 Supervising Program Manager, Vegetation Management

REVISION NOTES

Where?	What Changed?
Procedure Steps Section	Moved action steps previously located in the TD-7102B-007, "VM Second Patrol - Scope of Work" procedure to this procedure; reorganized and rewrote Procedure Steps section.
Incorporated B012 and B019.	To include HFTD to the current year's Second Patrol projects in PMD, Second Patrols are now in all HFTD areas, not limited to just SRA or Specific WUI LRA areas. Scope includes Dead/Dying trees listed as CEMA account type. Also includes trees within the MDR to be entered as HN Tags. Trees outside the MDR but that will not hold the MDR clearance until next PI cycle to be entered as missed tree tag (or other if applicable). Also includes abnormal field conditions and hazard trees due to structural defects that cannot wait for next cycle.
Red Flag Patrol Section Created Attachments for	Moved to attachment Aerial patrols Using LiDAR data
Created appendices for	Planning second patrol work and creating read only packets Creating new packet on mobile device for second patrol
Throughout	Edited for alignment with GDM documentation standards.



Vegetation Management Second Patrol Procedure

Appendix A, SCUF – Prepare Work and Create Read-Only Packets for Second Patrol

Page 1 of 3

- A. The SCUF must perform the following steps to prepare work for the second patrol:
1. IDENTIFY the project to work.
 2. SEND a “start of project” email to the DMS and local VPMs.
 3. CREATE a VMD Locations Report for locations where trees are marked for mitigation but still standing, as follows:
 - a In the VMD Locations Report, PERFORM an Advanced Search with the following information:
 - Division
 - Account type **maintenance**
 - Circuit Name
 - SSD RT #
 - Trim Type **IN LIST = ALL FP CODES**
 - b SELECT **VMD Locations**.
 - c SELECT **RUN**.
 4. RESEARCH, COMPILE, AND PROVIDE the following project information to the CUF performing the second patrol inspection:
 - Circuit name and project number
 - Number range for Location Route Number
 - Copy of line section / circuit map from local area DMS / SCUF
 - VMD Locations Report of previous First Patrol FP work
 - PI Tree Inspection Safety Report
 - Ownership issues
 - Agency issues
 - Customer issues
 - Municipal and/or local ordinances
 - Environmental issues, such as Limited Operating Periods (LOPs) and FERC areas
 5. ASSIGN the project to a CUF for patrol.

Vegetation Management Second Patrol Procedure

Appendix A, SCUF – Prepare Work and Create Read-Only Packets for Second Patrol

Page 2 of 3

- B. The SCUF must perform the following steps to create a read-only packet in VMD:

NOTE

The SCUF may assign CUF **read-only** routine maintenance pre-load packets for each project.

1. If needed, the SCUF must FOLLOW the instructions below to create a read-only packet:
 - a NAVIGATE to the Vegetation Management Website.
 - b In the **Functions** section, CLICK on **Back Office VMD**.
The **Back Office VMD Main Menu** screen appears.
 - c In the Back Office VMD Main Menu, CLICK on **Create Preload Packet**.
The PI Work Packet – Pre-Load Query screen appears.
 - d CREATE the preload packet as follows:
 - (1) For **Division**, SELECT the appropriate division.
 - (2) Under **Preload Account Type to Create**, SELECT **CEMA**.
 - (3) Under **Account Type to Search**, SELECT **Maintenance**.
 - (4) Under **Generation Criteria to Search**, SELECT **Circuit, SSD Route**.
 - (5) In the **Field** column, from the first **Select Field Option** pull-down menu, SELECT **Circuit Name**.
 - (6) At the bottom of the **PI Work Packet** screen, CLICK **Run Query**.
 - (7) The results of the query appear.
2. To ASSIGN circuits and routes, perform the following steps:
 - a CHECK the circuits and routes to assign.
 - b CLICK **Assign** at the bottom of the window.
The **Assign To Options** window pops up.

Vegetation Management Second Patrol Procedure

Appendix A, SCUF – Prepare Work and Create Read-Only Packets for Second Patrol

Page 3 of 3

B.2 (continued)

c ASSIGN options as follows:

- (1) For **Contractor**, SELECT the contractor.
- (2) For **Mobile User**, SELECT the CUF.
- (3) CLICK within the **PMD Project Name** field to display a drop-down list AND SELECT the appropriate project name.

The system automatically fills in the PMD **Project Number** field.

- (4) In the **Comments** field, TYPE "Read Only."



CAUTION

The **Read Only** box **must** be checked to prevent edits to routine maintenance records,

d At the bottom of the **Assign to Options** window, MAKE the following selections:

- (1) CHECK the **Read Only** field to make the packet read only.
- (2) CLICK **OK**.

Creation of the read-only packet is complete.



Vegetation Management Second Patrol Procedure

Appendix B, CUF – Create a New Packet on a Mobile Device for Second Patrol Projects

Page 1 of 1

- A. The CUF must perform the following steps to create a new packet for each second patrol project where work is prescribed using the VM mobile application on a mobile device:
1. In the **Applications** tab, SELECT the icon for **VM Application**.
The **Work Folder** screen appears.
 2. At the bottom of the **Work Folder** screen, CLICK **New**.
The Create Packet folder appears.
 3. Make the following selections for the fields in the **Create Packet** window:
 - a For **Account Type**, SELECT **CEMA**.
 - b For **Division**, SELECT the division in which the work is being performed.
 - c CLICK **Distribution**.
 - d For **Project ID** (required), ENTER the last six digits of the project ID provided by the SCUF, omitting the leading zero and without the dash (-). For example, for a PMD project number provided by the SCUF of 0xx-xxxx, enter the project ID in the following format: xxxxxx.
 - e CLICK **Finish**.

The new packet is created and the VMD **Location** screen appears.

Vegetation Management Hazard Tree Rating and Scoring Procedure

SUMMARY

This procedure describes how to use the Hazard Tree Rating System (HTRS) and Scoring Matrix spreadsheet to evaluate the condition of a whole tree or portion of a tree that has the potential to impact PG&E facilities if it fails and strikes them. The HTRS and Scoring Matrix help vegetation managers prioritize work, examine budget impacts, abate trees, and assess abatement decisions. The HTRS and Scoring Matrix assist personnel in making decisions about whether to work specific trees and in what priority.

This procedure also provides guidance for PG&E employees and contractors to meet or exceed the requirements of North American Electric Reliability Corporation (NERC) Standards for Vegetation Management, NERC FAC-003-4 Transmission Vegetation Management.

Level of Use: Informational Use

TARGET AUDIENCE

Vegetation management (VM) operations

VM pre-inspection (PI), tree crew (TC), and quality management contractors

SAFETY

NA

BEFORE YOU START

1. ESTABLISH an understanding on how to use Excel spreadsheets or manual mathematical calculations.
2. ESTABLISH an understanding of the following VM utility standards and procedures:
 - [Utility Standard TD-7102S, "Distribution Vegetation Management Standard"](#)
 - [Utility Procedure TD-7102P-01, "Vegetation Management Distribution Routine Patrol Procedure"](#)
 - [Utility Standard TD-7103S, "Transmission Vegetation Management Standard"](#)
 - [Utility Procedure TD-7103P-01, "Vegetation Management Transmission Routine Non-Orchard Patrol Procedure"](#)

Vegetation Management Hazard Tree Rating and Scoring Procedure

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PROCEDURE STEPS

Overview of Evaluation Process

Each HTRS spreadsheet can be used to record the results of up to three assessments, where an assessment is an evaluation of a whole tree, a part of a tree, or both.

There are three components to using the HTRS and Scoring Matrix tool:

- Determine whether the tree or tree part is likely to strike a facility.
- Determine whether the tree or tree part is likely to fail.
- Determine what impacts could occur if the tree or tree part fails and/or strikes a facility.

This is accomplished by doing the following:

1. Rating the Likelihood for Strike and Likelihood of Failure.
2. Adding the resultant Likelihood of Strike and Likelihood of Failure Scores into a single Tree Matrix Score within the HTRS.

The Impacts rating is directly derived from these combined scores.

3. Plotting the Tree and Impacts scores in the Scoring Matrix.

Vegetation Management Hazard Tree Rating and Scoring Procedure

The Procedure Steps are divided into the following sections:

- **Section 1 for Strike Likelihood:** Determine whether a tree or part of a tree has the potential to make contact with electrical facilities by using the first section of the HTRS spreadsheet.
- **Section 2 for Failure Likelihood:** Determine the condition of a tree or part of a tree and evaluate the surrounding environment by using the second section of the HTRS spreadsheet.
- **Section 3 for Impacts:** Determine the impacts that could occur if a tree or part of a tree makes contact with electrical facilities by using the third section of the HTRS spreadsheet.
- **Section 4 for Plotting Matrix Scores:** Plot Tree Matrix Scores and Impacts Matrix Scores on the Scoring Matrix

All steps in the Procedure Steps section must be performed to obtain an accurate HTRS evaluation.

1 Calculate Strike Likelihood in First Section of HTRS Spreadsheet

- 1.1 Review Appendix A, Overview for Scoring Likelihood of Strike, AND then RETURN to this section to perform the steps below.
- 1.2 OPEN [Utility Form TD-7102P-07-F01, "Vegetation Management Hazard Tree Rating and Scoring Form"](#). The form can be used in electronic or print format.
- 1.3 READ the instruction at the top of the spreadsheet, which states:

"Decide if the assessment will evaluate a tree or part of a tree that has the potential to make contact with electrical facilities.

More than one assessment can be completed on a single tree."

Decide if the assessment will evaluate a tree or part of a tree that has the potential to make contact with electrical facilities. More than one assessment can be completed on a single tree.										
ELEMENT	CONDITION (RATING IN BLUE)							Assessment		
								A	B	C
STRIKE LIKELIHOOD										
Total height & distance to the conductor of the part that is most likely to fail	Tree height < conductor (STOP)	Distance > than tree height (STOP)	Distance = Tree Height (0)	Distance ≤ 90% of tree height (1)	Distance ≤ 75% of tree height (3)	Distance ≤ 50% of tree height (5)	Distance ≤ 25% of tree height (7)			
Path (part most likely to fail)					No path to facility (0)	Possible path or domino to facility (1)	Likely path or domino to facility (3)			
Lean (part most likely to fail)			Severe away from facility (-7)	Mod away from facility (-5)	Slight away from facility (-3)	Vertical or slight to facility (3)	Mod to facility (5)	Severe to facility (7)		
Weight (part most likely to fail)			Severe away from line (-5)	Mod away from line (-3)	Slight away from line (-1)	Neutral or slight line side (1)	Mod line side (3)	Severe line side (5)		
STRIKE TOTAL								0	0	0
<1=None; STOP	1-4= Very Low (VL)	5-6= Low (L)	7-11= Mod (M)	12-16= High (H)	>16 Very High (VH)	Strike Likelihood Level		STOP	STOP	STOP
Very Low= 0	Low=0	Mod=1	High=2	Very High=3	Strike Matrix Score		0	0	0	

Vegetation Management Hazard Tree Rating and Scoring Procedure

NOTE

When using an electronic version of the HTRS spreadsheet, Excel automatically calculates totals and levels, and displays the results in the rows at the bottom of each section.

When using a printed version of the HTRS spreadsheet, it is necessary to manually compute and write the assessment values, totals, and levels on the paper spreadsheet.

- 1.4 The first section of the spreadsheet lists the Elements to be evaluated for strike likelihood, with conditions that could apply and the number of points assigned to each condition.

Decide if the assessment will evaluate a tree or part of a tree that has the potential to fail. More than one assessment can be completed on a tree.				
ELEMENT	CONDITION (RATING IN PARENTHESES)			
STRIKE LIKELIHOOD				
Total height & distance to the conductor of the part that is most likely to fail	Tree height < conductor (STOP)	Distance > than tree height (STOP)	Distance = Tree Height (0)	Distance ≤ 90% of tree height (1)
Path (part most likely to fail)				
Lean (part most likely to fail)				
	Severe away from facility (-7)	Mod away from facility (-5)	Slight away from facility (-3)	
Weight (part most likely to fail)				
	Severe away from line (-5)	Mod away from line (-3)	Slight away from line (-1)	

- 1.5 For each of the four Elements in the left-hand column, DETERMINE the applicable condition(s).

The blue numbers in parenthesis (#) show the number of points assigned to each condition.

ELEMENT	CONDITION (RATING IN BLUE)						
STRIKE LIKELIHOOD							
Total height & distance to the conductor of the part that is most likely to fail	Tree height < conductor (STOP)	Distance > than tree height (STOP)	Distance = Tree Height (0)	Distance < 90% of tree height (1)	Distance < 75% of tree height (3)	Distance < 50% of tree height (5)	Distance < 25% of tree height (7)

Vegetation Management Hazard Tree Rating and Scoring Procedure

1.5 (continued)

The columns A, B, and C are used to rate the assessment.

For example, if the condition "Distance $\leq$ 25% of tree height" applies to the "Total height & distance..." element, enter or write a **7** in column A.

	Assessment		
	A	B	C
Distance $\leq$ 25% of tree height (7)	7		

- 1.6 RATE the whole tree, part of tree, or both that, might strike by entering or writing one assessment per rating column (A, B, C), using only the **whole numbers** in parenthesis (#) provided in the spreadsheet.

1.7 For printed version of HTRS spreadsheet:

1. ADD the numbers in a rating column (A or B or C) AND WRITE the sum in the appropriate STRIKE TOTAL column on the spreadsheet. Repeat for each rating column.

	Assessment		
	A	B	C
Distance $\leq$ 25% of tree height (7)	7		
Likely path or domino to facility (3)	3		
Severe to facility (7)	5		
Severe line side (5)	3		
STRIKE TOTAL	18	0	0

Vegetation Management Hazard Tree Rating and Scoring Procedure

1.7 (continued)

2. Based on the Strike Total, WRITE the HTRS Likelihood of Strike rating recommendation for the tree in the appropriate rating column (A or B or C).

a. For a Strike Total of zero (0), WRITE "STOP."

For example, if the Strike Total for a tree is 18, its Strike Likelihood Level is greater than 16, so equal to VH for Very High.

		STRIKE TOTAL	18	0	0
12-16= High (H)	>16 Very High (VH)	Strike Likelihood Level	VH	STOP	STOP

3. WRITE the letter(s) for the Strike Likelihood Level under the appropriate rating column (A or B or C).
4. WRITE the number for the matching Strike Matrix Score in the gray cell under the appropriate rating column (A or B or C).

For example, the Strike Matrix Score for Very High equals 3.

		STRIKE TOTAL	18	0	0
12-16= High (H)	>16 Very High (VH)	Strike Likelihood Level	VH	STOP	STOP
Very High=3	Strike Matrix Score		3	0	0

1.8 LOOK at the Strike Total for each rating column.

1. IF the Strike Total is less than 1,

THEN the whole tree, part of tree, or both is **not** likely to strike facilities; EXIT this procedure;

OTHERWISE continue to the Section below.

Vegetation Management Hazard Tree Rating and Scoring Procedure

2 Calculate Failure Likelihood in Second Section of HTRS Spreadsheet

The second section of the spreadsheet lists the Elements to be evaluated for failure likelihood, with conditions that could apply and the number of points assigned to each condition.

FAILURE LIKELIHOOD						
Tree species, age, condition (health, vigor, insect/disease & pests, fire, and mechanical injury, deformity, decay, etc.) & environmental influences						
Tree age (whole tree)		Immature (1)	Mature (3)	Over Mature (7)	Dead (20)	
Disease (whole or part most likely to fail)	None (0)	Nuisance-does not cause defects (3)	Pathogen-does not cause defect (3)	Nuisance-Causes defect (5)	Pathogen-Causes defect (5)	
Insects (whole tree)	None (0)	Nuisance-does not cause defects (3)	Pathogen-does not cause defect (3)	Nuisance-Causes defect (5)	Pathogen-Causes defect (5)	
Oldest defects present for what % of trees life?	Very Low (0)	Low (1)	Moderate (3)	High (5)	Very High (7)	

2.1 Review Appendix B, Overview for Scoring Likelihood of Failure, AND then RETURN to this section to perform the steps below.

2.2 Refer to Appendix D, Recommended Species-Specific Ratings for the ratings (bandwidths) to use for the following two Elements:

- Species Failure
- Whole or Partial Failure

1. IF the tree species for the Species Failure or Whole or Partial Failure Element is listed in Appendix D, Recommended Species-Specific Ratings,

THEN use the condition rating from Appendix D, Recommended Species-Specific Ratings;

OTHERWISE, use the condition rating stated in the HTRS spreadsheet.

Species failure potential (unknown = 3)	Very Low (0)	Low (1)	Moderate (3)	High (5)	Very High (7)	Unknown (3)	1		
Whole or partial failure most likely?			Partial (5)	Whole tree (7)	Equally Likely (9)	Unknown (3)	5		

2.3 For each of the 15 Elements in the left-hand column, DETERMINE the applicable condition(s).

FAILURE LIKELIHOOD						
Tree species, age, condition (health, vigor, insect/disease & pests, fire, and mechanical injury, deformity, decay, etc.) & environmental influences						
Tree age (whole tree)		Immature (1)	Mature (3)	Over Mature (7)	Dead (20)	
Disease (whole or part most likely to fail)	None (0)	Nuisance-does not cause defects (3)	Pathogen-does not cause defect (3)	Nuisance-Causes defect (5)	Pathogen-Causes defect (5)	
Insects (whole tree)	None (0)	Nuisance-does not cause defects (3)	Pathogen-does not cause defect (3)	Nuisance-Causes defect (5)	Pathogen-Causes defect (5)	
Oldest defects present for what % of trees life?	Very Low (0)	Low (1)	Moderate (3)	High (5)	Very High (7)	

Vegetation Management Hazard Tree Rating and Scoring Procedure

2.3 (continued)

The **blue** numbers in parenthesis (#) show the number of points assigned to each condition.

- 2.4 RATE the tree or part of the tree that might fail by entering or writing one assessment per rating column (A, B, C), using only the **whole numbers** in parenthesis (#) provided in the spreadsheet.

For example, if the condition "Pathogen—does not cause defect (3)" applies to the Element "Insects (whole tree)", enter or write a 3 in column A for that element.

Insects (whole tree)	None (0)	Nuisance-does not cause defects (3)	Pathogen-does not cause defect (3)	Nuisance-Causes defect (5)	Pathogen-Causes defect (5)	3
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2.5 For printed version of HTRS spreadsheet:

1. ADD the numbers in rating column A, AND WRITE the sum in the appropriate FAILURE TOTAL box on the spreadsheet. Repeat for rating columns B and C.

FAILURE TOTAL	31	0	0
---------------	----	---	---

2. Follow the HTRS Likelihood of Failure rating recommendation for the tree, based on the Failure Total.

- a. WRITE the letter for the Failure Likelihood Level and the number for the Failure Matrix Score in the appropriate boxes under the appropriate rating column (A or B or C).

For example, if the Failure Total for a tree is 31,

<24=Very Low (VL)	24-37= Low (L)	38-55=Mod (M)	56-82= High (H)	>82= Very High (VH)
Very Low= 0	Low=1	Mod=2	High=3	Very High=4

Then its Failure Likelihood Level is L for Low, and its Failure Matrix Score is 1 for Low.

FAILURE TOTAL	31	0	0
Failure Likelihood Level	L	VL	VL
Failure Matrix Score	1	0	0

3. ADD the resultant Strike Matrix Score (see Section 1, above) and the Failure Matrix Score into a single Tree Matrix Score AND WRITE the sum in the appropriate gray box.

Vegetation Management Hazard Tree Rating and Scoring Procedure

2.5 (continued)

For example, add the Strike Matrix Score of 3 to the Failure Matrix Score of 1 to obtain the Matrix Tree Score of 4.

FAILURE TOTAL	31	0	0
Failure Likelihood Level	L	VL	VL
Failure Matrix Score	1	0	0
Tree Matrix Score	4	0	0

3 Calculate Impacts in Third Section of HTRS Spreadsheet

The third section of the spreadsheet lists the Elements to be evaluated for impacts, with conditions that could apply and the number of points assigned to each condition.

IMPACTS							
Roads (below conductor)	None or local low volume (0)	Residential street (1)	Local high volume (3)	Dead end or blocked (4)	2 lane highway (4)	4 lane highway (5)	Interstate (6)
Structures (below conductor)	None (0)		Fence or shed (1)	Garage (3)	House (5)	Care facility or school (7)	
Population density (general vicinity)	Low (1)		Moderate (3)	High (5)			
Emergency response time (in minutes)	<30 = Short (1)		<45 = moderate (5)	>45 min=Long (7)			

- 3.1 Review Appendix C, Overview for Scoring Impacts: Safety, Fire, and Reliability, AND then RETURN to this section to perform the steps below.
- 3.2 Refer to Appendix D, Recommended Species-Specific Ratings for the ratings (bandwidths) to use for the following Element:

- Time of Year Species Likely to Fail
 1. IF the tree species for the Time of Year Species Likely to Fail is listed in Appendix D, Recommended Species-Specific Ratings,

THEN use the condition rating from Appendix D, Recommended Species-Specific Ratings;

OTHERWISE, use the condition rating stated in the HTRS spreadsheet.

Time of year species likely to fail	Nov-March (1)	Nov-June (5)	July-Oct (11)	Equally in winter & summer (7)	Unknown (7)			
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Vegetation Management Hazard Tree Rating and Scoring Procedure

3.3 For each of the 15 Elements in the left-hand column, DETERMINE the applicable condition(s).

IMPACTS							
Roads (below conductor)	None or local low volume (0)	Residential street (1)	Local high volume (3)	Dead end or blocked (4)	2 lane highway (4)	4 lane highway (5)	Interstate (6)
Structures (below conductor)	None (0)		Fence or shed (1)	Garage (3)	House (5)	Care facility or school (7)	
Population density (general vicinity)					Low (1)	Moderate (3)	High (5)
Emergency response time (in minutes)					<30 = Short (1)	<45 = moderate (5)	>45 min=Long (7)

The blue numbers in parenthesis (#) show the number of points assigned to each condition.

3.4 RATE the type of impacts that might occur due to whole tree or partial tree failure by entering or writing one assessment per rating column (A, B, C), using only the **whole numbers** in parenthesis (#) provided in the spreadsheet.

For example, if the condition "Care facility or school (7)" applies to the "Structures (below conductor)" element, enter or write a **7** in column A for that element.

Structures (below conductor)	None (0)	Fence or shed (1)	Garage (3)	House (5)	Care facility or school (7)	7
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3.5 For printed version of the spreadsheet:

1. ADD the numbers in rating column A AND WRITE the sum in the appropriate Impacts Total box on the spreadsheet. Repeat for rating columns B and C.

IMPACTS TOTAL	63	0	0
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2. Follow the HTRS Impacts rating recommendation for the tree, based on the Impacts Total.

For example, if the Impacts Total for a tree is 63, its Impacts Matrix Level is H for High.

		IMPACTS TOTAL	63	0	0
50-66 High (H)	>66 Very High (VH)	Impacts Level	H	VL	VL

3. WRITE the Impacts Level in the cell under the appropriate rating column (A or B or C).

For example, an Impacts Level of Very High (VH) equals an Impacts Matrix Score of 4.

		IMPACTS TOTAL	63	0	0
50-66 High (H)	>66 Very High (VH)	Impacts Level	H	VL	VL
High=3	Very High=4	Impacts Matrix Score	3	0	0

Vegetation Management Hazard Tree Rating and Scoring Procedure

4 Plot Tree and Impacts Matrix Scores on Scoring Matrix

PG&E recommends that trees scoring in the:

- Dark-grey shaded cells should be abated.
- Light-grey shaded cells might not require abatement.
- Un-shaded cells may be abated, if prudent, based on professional judgement.

Tree Score	7 (Very High)					
	6 (High)					
	5 (High)					
	4 (Mod)					
	3 (Mod)					
	1, 2 (Low)					
	0 (Very Low)					
		0 (Very Low)	1 (Low)	2 (Mod)	3 (High)	4 (Very High)
		Impact Score				

Diagonal labels: Don't Work, Professional Judgement, Work

4.1 VIEW the Scoring Matrix by clicking on the **Scoring Matrix** tab at the bottom of the HTRS spreadsheet.

1. PLOT the Tree Matrix Score and the Impacts Matrix Score for each tree on the Scoring Matrix by writing an "xx" in the box where these two values intersect.

For example, if the Tree Score is 4 for Moderate, and the Impact Score is 3 for High, write "XX" as shown below.

Tree Score	7 (Very High)					
	6 (High)					
	5 (High)					
	4 (Mod)				XX	
	3 (Mod)					
	1, 2 (Low)					
	0 (Very Low)					
		0 (Very Low)	1 (Low)	2 (Mod)	3 (High)	4 (Very High)
		Impact Score				

END of Instructions

Vegetation Management Hazard Tree Rating and Scoring Procedure

DEFINITIONS

Hazard Tree Rating System (HTRS): A spreadsheet designed to be used as a decision making tool for computing the Tree Score and Impact values for entering into the Scoring Matrix.

IMPLEMENTATION RESPONSIBILITIES

The Document Owner is responsible for the implementation, communication, and maintenance of this procedure. The Document Owner issues training and compliance materials annually.

VM contractors are responsible for training all employees before they perform PG&E VM work and for providing documentation of this training.

All PG&E VPMs and VM contractors are responsible for knowing and complying with this procedure.

GOVERNING DOCUMENT

[Utility Standard TD-7102S, "Distribution Vegetation Management Standard"](#)

[Utility Standard TD-7103S, "Transmission Vegetation Management Standard"](#)

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

ANSI Standard, NCA 300, Part 7

[CPUC General Order 95, Rule 35](#)

Federal Energy Regulatory Commission (FERC) Order No. 777

[Public Resource Code \(PRC\) 4292](#)

[Public Resource Code \(PRC\) 4293](#)

North American Electric Reliability Council (NERC) Standards for Vegetation Management, FAC-003-04

REFERENCE DOCUMENTS

Developmental References:

NA

Vegetation Management Hazard Tree Rating and Scoring Procedure

Supplemental References:

[Utility Procedure TD-7102P-01, "Vegetation Management Distribution Routine Patrol Procedure"](#)

[Utility Form TD-7102P-07-F01, "Vegetation Management Hazard Tree Rating and Scoring Form"](#)

[Utility Procedure TD-7103P-01, "Vegetation Management Transmission Routine Non-Orchard Patrol Procedure"](#)

APPENDICES

Appendix A, Overview for Scoring Likelihood of Strike

Appendix B, Overview for Scoring Likelihood of Failure

Appendix C, Overview for Scoring Impacts: Safety, Fire, and Reliability

Appendix D, Recommended Species-Specific Ratings

ATTACHMENTS

[Utility Form TD-7102P-07-F01, "Vegetation Management Hazard Tree Rating and Scoring Form"](#)

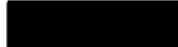
DOCUMENT RECISION

TD-7102P-07, "Vegetation Management Hazard Tree Rating and Scoring," Rev. 2, 11/28/2017

DOCUMENT APPROVER

 Senior Manager, Vegetation Management

DOCUMENT OWNER

 Senior Vegetation Program Manager

DOCUMENT CONTACT

 Senior Vegetation Program Manager

 Supervising Vegetation Program Manager

Vegetation Management Hazard Tree Rating and Scoring Procedure**REVISION NOTES**

Where?	What Changed?
Target Audience	Removed "governance & support operations", changed "quality control" to "quality management" contractors.
Safety	Removed boilerplate language to review best management practices.
Before You Start	Clarified.
Section 4	Clarified bullet points specific to tree scoring and the color reference in the matrix.
Throughout	Updated document titles and links
Document Owner and Contact	Updated.
Appendix D	Recommendations changed for more than half of the ratings. Table reformatted.
TD-7102P-01-F01	Updated auto-calculations, clarified legend for matrix, corrected duplicate "Low" score in Line 26.

Vegetation Management Hazard Tree Rating and Scoring Procedure

Appendix A, Overview for Scoring Likelihood of Strike

Page 1 of 1

1. READ the "Overview for Scoring Likelihood of Strike" in the table below,

THEN RETURN to Section 1. Calculate Strike Likelihood in First Section of HTRS Spreadsheet to perform the steps. Do **not** take action on the instructions in the table below.

Overview for Scoring Likelihood of Strike	
Element	Description
Total height & distance to the conductor or the part that is most likely to fail	1. WHEN the tree is shorter than the facilities, OR the distance to the conductor is more than the height of the tree or the part most likely to fail, THEN the tree cannot strike; EXIT this procedure. - As the distance from the tree to the conductor decreases in relation to the tree's height, the ratings increase. 2. INCLUDE slope. 3. EVALUATE height and distance from the conductors of that part from where it will "hinge."
Path (part most likely to fail)	1. Some trees are tall enough to strike, but are not likely to, because the path is blocked. 2. Have conditions changed since the last inspection such that the tree currently has a path to strike?
Lean (part most likely to fail)	1. EVALUATE the lean of the main stem(s) or portions of the tree most likely to fail regardless of weight distribution. 2. IF a nearly horizontal branch is being evaluated, AND it occurs perpendicularly and directly over the lines, THEN USE the Severe to Facility rating for lean.
Weight (part most likely to fail)	1. EVALUATE the weight distribution of the tree or portion most likely to fail regardless of lean. 2. IF a nearly horizontal branch is being evaluated AND it occurs perpendicularly and directly over the lines, THEN USE the Severe Line Side rating for weight.
Strike Total	The total of the height/distance, path, lean, and weight ratings.
Strike Likelihood Level	1. FIND the corresponding bandwidth that the strike total matches. This is the Strike Likelihood rating, signified by letter: VL, L, M, H or VH.
Strike Matrix Score	1. TRANSLATE the rating (VL, L, M, H, VH) from the Strike Likelihood line into a Matrix score (0, 1, 2, 3, or 4).

Vegetation Management Hazard Tree Rating and Scoring Procedure

Appendix B, Overview for Scoring Likelihood of Failure

Page 1 of 3

1. READ the "Overview for Scoring Likelihood of Failure" in the table below,

THEN RETURN to Section 2. Calculate Failure Likelihood in Second Section of HTRS Spreadsheet to perform the steps. Do **not** take action on the instructions in the table below.

Overview for Scoring Likelihood of Failure	
Element	Description
Tree Age (whole tree)	Exact age is not required. 1. ESTIMATE age, taking species into consideration. Tree size is only an indicator of age. 2. INCLUDE dead trees in this line item. 3. Evaluate age regardless of condition. Distinguish DEAD from DEFECTIVE (see below).
Disease (whole or part most likely to fail)	Some diseases are fatal to a tree; others are nuisances, but when combined with other agents, might be a problem.
Insects (whole tree)	Some insects are fatal to a tree; others are nuisances, but when combined with other agents, might be a problem.
Oldest defect present for what % of tree's life	A Defect is a reduction of wood strength (structural integrity). Lean is not necessarily a defect. "Dead" is not necessarily a defect. The longer amount of time an agent of decline has to work on a tree, the more effect it can have. 1. EVALUATE Defect Severity.
Severity caused by combination of defects (≤ 1 defect use 0)	1. IF there appears to be a combination of defect(s) or disease and insects, THEN evaluate the indications of the defect(s), including combined defects, to determine Severity.
Defect extent (worst radially in the log)	1. INDICATE the proportion of the log, radially (two dimensionally) affected by defect(s).
Defect distribution (worst vertically in the tree)	What proportion of the tree vertically is affected by defect(s)? Is there downward moving rot from an entry point further up the tree? Is the decay uniform along its vertical distribution?
Clues from surrounding trees/stand	What types of indications of overall tree or stand health are visible in the surrounding trees? Are others of the same species in similar or worse condition? Have stand conditions changed since the last inspection that exposed the tree to new environmental pressures?

Vegetation Management Hazard Tree Rating and Scoring Procedure

Overview for Scoring Likelihood of Failure	
Element	Description
Tree condition (of whole tree or part most likely to fail)	- IF a tree is failing when the inspector arrives (Already failing), THEN immediately call for tree crew. - EVALUATE the tree's overall condition and circumstances: - Vigorous? Well growing? Healthy? - Good taper (height to diameter ratio)? - Does the tree have good color; needle length or leaf shape & size; and inter-node length, etc.? - Are there wounds, die back, conks, splits, dead limbs, seepage, included bark, swellings, cat-faces, etc.? - Are roots buried or severed? - Are there other adverse environmental influences? - Have there been changes due to adjacent tree work or any other kind of work since the last inspection that would increase a tree's failure likelihood? - Is the tree wind-firm? - GIVE a dead tree or dead part of the tree its own category. - Evaluate co-dominance in the tree. - Is co-dominance in the lower part of the tree (lowest 25% of total height)? - Is co-dominance in the middle part of the tree (up to 75% of total height)? - Is co-dominance in the top part of the tree? - Is there included bark? If yes, how severe?
Species failure potential (unknown = 3)	Appendix D, Recommended Species-Specific Ratings contains recommended ratings for the top 20 species that cause outages within the PG&E service territory.
Whole or partial failure most likely?	Appendix D, Recommended Species-Specific Ratings contains recommended ratings for the top 20 species that cause outages within the PG&E service territory.
Tree canopy size or sail (part most likely to fail)	EVALUATE the amount of canopy the tree has (sail or wind resistance) relative to the trees surrounding trees.
Wind exposure (topography & position in stand)	- CONSIDER the tree's exposure to wind: - Where on the slope is the tree located? On the ridge (high winds), mid slope (moderate winds) or gulch bottom (low)? - Is the tree is fully exposed or sheltered by other trees?
Winter storm severity (geography and/or elevation: unknown = 2)	Geography and/or elevation issues: if the tree is along the immediate coast or along high ridges near the coast, or above about 5,000 ft. in the Sierra, then storms are more severe than in sheltered valleys or in the central valley.
Soil support (whole tree)	DETERMINE whether likelihood of failure is related to soil failure rather than a tree failure. This is an evaluation of the soil's ability to hold the tree up and is not applicable if

Vegetation Management Hazard Tree Rating and Scoring Procedure

Overview for Scoring Likelihood of Failure	
Element	Description
	evaluating partial tree failure.
Failure Total	The sum of individual element ratings for the tree.
Failure Likelihood Level	The sum of the tree elements will fall within a bandwidth that corresponds to a Failure Likelihood rating VL, L, M, H or VH. (Excel files do this automatically.)
Failure Matrix Score	1. TRANSLATE the Failure Likelihood (VL, L, M, H, VH) from the Failure Likelihood line into a Matrix score (0, 1, 2, 3, or 4). (Excel files do this automatically.)
Tree Matrix Score	1. CREATE a combined Tree rating by adding the strike and failure likelihood numbers. 2. ENTER that number in the corresponding box. (Excel files do this automatically.)

Vegetation Management Hazard Tree Rating and Scoring Procedure

Appendix C, Overview for Scoring Impacts: Safety, Fire, and Reliability

Page 1 of TYPE total page count for this appendix

1. READ the "Overview for Scoring Impacts: Safety, Fire, and Reliability " in the table below,

THEN RETURN to Section 3. Calculate Impacts in Third Section of HTRS Spreadsheet to perform the steps. Do **not** take action on the instructions in the table below.

Overview for Scoring Impacts: Safety, Fire, and Reliability	
Element	Description
Roads (below conductor)	Onto what type of road will conductors fall if a tree/limb collapses? Will roads be blocked so that access for emergency crews or evacuations is affected?
Structures (below conductor)	1. EVALUATE the presence of property improvements.
Population density (general vicinity)	1. REVIEW whether the location occurs within a rural (low), sub-urban (moderate), or an urban (high) area.
Emergency response time (in minutes)	1. CONSIDER response times by fire department, law enforcement, and PG&E. • Less than 30 minutes as short (1). • Less than 45 minutes as moderate (3). • More than 45 minutes as long (9).
Summer temp (unknown = 3)	1. CONSIDER local, average temperatures. Low: Areas with summer temperatures about 75 - 80°. Moderate: Areas with summer temperature about 80 - 90°. High: Areas with summer temperatures in the 90 - 110°+ range.
Summer and fall winds (unknown = 3)	1. CONSIDER winds of at least 10 mph. Infrequent means less than once a week. 2. CHOOSE annual fall winds (Chinook, Santa Ana) only in areas where these winds occur regularly , as opposed to occasionally.
Slope (general vicinity)	1. DO NOT CONSIDER only the immediate location of the tree; also EVALUATE where the lines are likely to contact fuel if the tree should fail. 2. MEASURE slope in percentage (%), perpendicular to the contour.
Development & land use (general vicinity)	Industrial areas have less vegetation fuel, and might have more security or fire suppression. More weight is allocated toward commercial use of open lands and to housing. Non-residential development includes schools, shopping centers, warehouses, libraries, business centers, etc. High density means condominiums or multiple story apartments. Medium density means greater than 1/10 acre lot. Low density means lots that are greater than 1 acre.

Vegetation Management Hazard Tree Rating and Scoring Procedure

Overview for Scoring Impacts: Safety, Fire, and Reliability	
Element	Description
Fuel type (general vicinity)	What is the pre-dominant vegetation type of the area? Irrigated/landscaped areas will likely be in an urban or developed area; other fuel types are likely to be in open space areas.
Fuel continuity (general vicinity)	Anything that can burn should be considered fuel. Open fuel refers to low-lying grasses. Patchy fuel is a combination of fuel types, without continuity, as indicated by a significant break like a road, driveway, lawn etc. Horizontal fuels are contiguous along or near the ground. Vertical fuels (fuel ladder) are contiguous vertically. Both a horizontal and vertical fuel ladder might be present. 1. CONSIDER whether the tree canopy is contiguous as well.
Fuel moisture content (summer)	Where is the location in relation to the coast? Is the location irrigated and how frequently? Are fuels large (retain moisture) or small (dry quickly) in size? Is the site subject to wind drying?
Time of year species likely to fail (unknown = 7)	What time of year is the species likely to fail, or is it equally likely to fail during winter and summer? Appendix D, Recommended Species-Specific Ratings contains recommended ratings for the top 20 species that cause outages within the PG&E service territory.
PG&E assets	If the tree fails, what will happen to PG&E assets such as poles, cross arms, equipment excluding transformers, and fuses?
Line	What type of line will be affected if the tree fails?
No. of customers	How many customers would be impacted if a failure interrupted service?
Impacts Total	Sum of individual element ratings for impacts.
Impacts Level	The total of the impacts elements will fall within a bandwidth that corresponds to an Impacts rating of VL, L, M, H or VH. (Excel files do this automatically.)
Impacts Matrix Score	1. TRANSLATE the Impacts rating (VL, L, M, H, VH) into an Impacts Matrix score (0, 1, 2, 3, or 4). (Excel files do this automatically.)

Vegetation Management Hazard Tree Rating and Scoring Procedure

Appendix D, Recommended Species-Specific Ratings

Page 1 of 1

Species	Species Failure Potential	Whole or Partial Failure Most Likely?	Time of Year Species Likely to Fail
Coast Redwood	Very High (7)	Partial (5)	Nov-March (1)
Douglas Fir	Very High (7)	Equally Likely (9)	Nov-March (1)
Black Oak	Very High (7)	Equally Likely (9)	Species equally likely to fail in winter as summer (7)
Tan Oak	Very High (7)	Whole Tree (7)	Nov-June (5)
Monterey Pine	High (5)	Equally Likely (9)	Nov-March (1)
Ponderosa Pine	Very High (7)	Whole Tree (7)	Nov-March (1)
Valley Oak	Very High (7)	Equally Likely (9)	July-Oct (18)
Live Oak	High (5)	Equally Likely (9)	Nov-June (5)
Gray Pine	Very High (7)	Equally Likely (9)	July-Oct (18)
Blue Gum	Very High (7)	Partial (5)	Species equally likely to fail in winter as summer (7)
Calif. Bay	Mod (3)	Whole Tree (7)	Nov-June (5)
Coast Live Oak	High (7)	Equally Likely (9)	Nov-June (5)
Madrone	Mod (3)	Whole Tree (7)	Nov-June (5)
Incense Cedar	High (5)	Whole Tree (7)	Nov-March (1)
Cottonwood	Mod (3)	Partial (5)	Species equally likely to fail in winter as summer (7)
Monterey Cypress	High (7)	Partial (5)	Nov-June (5)
Deodar Cedar	Mod (3)	Partial (5)	Species equally likely to fail in winter as summer (7)
Bishop Pine	Mod (3)	Whole Tree (7)	Nov-June (5)
Alder - Red	Low (1)	Whole Tree (7)	Nov-June (5)
Liquidambar	Low (1)	Partial (5)	Species equally likely to fail in winter as summer (7)
Sycamore	Low (1)	Partial (5)	July-Oct (18)

PACIFIC GAS AND ELECTRIC COMPANY
REBUTTAL TESTIMONY SUPPORTING ATTACHMENTS
ATTACHMENT 16
PG&E'S RESPONSE TO SED DATA REQUEST DIXIE FIRE –
SED-005, QUESTION 32

PACIFIC GAS AND ELECTRIC COMPANY
CPUC – SED Data Request
Dixie Fire – SED-005

Requesters: Henry Sweat, Samuel Mandell, Emily Fisher

Request Date: January 31, 2022

Response Date: March 14, 2022

Question 32:

Exhibit QQQ-2 from Case 3:14-cr-00175-WHA states:

Uni-grounded and ungrounded distribution systems have their loads connected phase-to-phase with rare exceptions. Phase-to-phase connected loads do not generate residual unbalance currents. Any standing unbalance current that comes from asymmetries of feeder construction, power equipment such as transformers, and mismatched phase CTs is typically a few amperes. This allows for much lower ground relay settings that result in more sensitivity than is possible on multigrounded systems. With today's sensitive current inputs of digital relays, flux summation CTs to eliminate phase CT imbalances, and low CT ratios, it is possible to detect more high-impedance faults.

The same paper also states:

The sensitivity of ground fault detection without considering time coordination is limited by the standing ground current of the system. In the example shown in Fig. 8, one can set the fault detection threshold at 3 A, the 2 A standing ground current plus a 50 percent margin. This ground fault pickup provides an equivalent of 2400 Ω fault resistance coverage.

Please answer the following questions based on that paper:

- a. Explain the decision of setting the Minimum To Trip (MTT) for the sensitive earth fault to 20 amps, and for the ground fault to 50 amps in the context of these two statements.
- b. What is the anticipated peak standing ground current of the system?
- c. What is the peak measured standing ground current of the system for the past year?
- d. Based on the criteria discussed in the paper, what should PG&E have set the recloser's setting for Sensitive Earth Fault and Ground settings to?

Response to Question 32:

a. As set forth in our response to SED's Dixie Fire Data Request SED-005, Question 12, in making changes to or generating new protection settings, our engineers use their best judgment, based on their knowledge of the relevant device, our standards and guidelines, and the protection needs of the area at the time they make the changes. We do not require our engineers to record a detailed justification for each setting change that they make.

b.-c. We typically anticipate peak ground current based on historical values. Looking at the time period from February 1, 2021 to February 1, 2022, the peak ground current recorded in PG&E's Process Information (PI) Historian database for the line recloser for the Bucks Creek 1101 12kV distribution line ("Bucks Creek 1101 Line") was 1.6A.

d. We do not understand this question as framed. Exhibit QQQ-2, ECF No. 1515-14 in Case 3:14-cr-00175-WHA, is a technical article that was cited for the notion that it is widely recognized in the industry that it is difficult to detect high-impedance ground faults based on load data. Our engineers follow our standards and guidelines when making changes to or generating new protection settings, as described above. While our standards and guidelines are informed by our awareness of technical papers such as this, technological developments, industry benchmarking, and internal testing, we do not design to external criteria.

PACIFIC GAS AND ELECTRIC COMPANY
REBUTTAL TESTIMONY SUPPORTING ATTACHMENTS
ATTACHMENT 17
PG&E'S RESPONSE TO KINCADEDIXIEAB1054_
DR_CALADVOCATES_D01-Q020SUPP01 AND ATTACHMENT

(REDACTED)

PACIFIC GAS AND ELECTRIC COMPANY
Kincade and Dixie AB1054-Wildfire Cost Review and Recovery
Application 25-11-001
Data Response

PG&E Data Request No.:	CalAdvocates_D01-Q020
PG&E File Name:	KincadeDixieAB1054_DR_CalAdvocates_D01-Q020Supp01
Request Date:	December 18, 2025
Requester DR No.:	D01
Requesting Party:	Public Advocates Office
Requester:	Holly Wehrman
Date Sent:	January 6, 2026 (Original) February 4, 2026 (Supplemental)
PG&E Witness(es):	Andrew Paul Abranches – Electric Operations

Fast Trip

QUESTION 020

- a) Prior to July 13, 2021, did PG&E research or examine the practices of other utilities, or industry best practices, with respect to fast-trip settings?
- b) If the answer to part (a) is no, why not?
- c) If the answer to part (a) is yes, please describe the findings of PG&E’s research, examination, or analysis.
- d) If the answer to part (a) is yes, please provide a copy of any resulting reports or studies.

ANSWER 020

PG&E objects to this Question as vague, ambiguous and overbroad as framed. Subject to and without waiving its objections, PG&E responds as follows:

- a) PG&E refers Cal Advocates to its responses to CalAdvocates_D01, Question 19(a) and Question 21, of this proceeding. In around 2019, PG&E learned of Southern California Edison Company’s “Fast Curve” protection and San Diego Gas & Electric Company’s “Sensitive Relay Settings.” In the 2019-2021 time period, PG&E began exploring more sensitive settings for protection devices as a wildfire mitigation measure. PG&E piloted such settings on select devices on the Calistoga 12kv circuit in the North Bay Division in December 2020. During this period, PG&E further sought to understand the nature of reliability impacts associated with widespread use of more sensitive settings for protection devices as a wildfire mitigation measure.
- b) N/A.
- c) See response to subpart (a).
- d) PG&E is continuing to search for any reports or studies from prior to July 13, 2021 and will supplement this response.

ANSWER 020 SUPPLEMENTAL

The attachments to this response contain CONFIDENTIAL information as described in the accompanying confidentiality declaration.

Subject to and without waiving its objections in its original response, PG&E supplements its response as follows:

- d) PG&E is providing the attached document related to PG&E's piloting of more sensitive settings as described in PG&E's response to KincadeDixieAB1054_DR_CalAdvocates_D01-Q019, see *"KincadeDixieAB1054_DR_CalAdvocates_D01-Q020Supp01Atch01CONF"*.

Description of Operation

Fast Tripping Scheme (FTS)

December 2020

Background

PG&E operates in an unprecedented environment with an increasing risk of wildfire. Wildfires can be caused by faulted electrical equipment combined with high winds, dry conditions and abundant fuel. The energy released during an electrical fault can be in the order of several million joules per second. Limiting the energy released from faulted electrical equipment may reduce the probability to start wildfires. This energy is proportional to I^2T (Fault amps squared times seconds). Faster protection schemes on electric distribution lines will de-energize (trip) a faulted line faster than conventional time delayed protection schemes. Faster tripping means less energy released during a fault resulting in a reduced probability to start wildfires.

PG&E will Pilot FTS on Calistoga 12kv circuits in North Bay Division in 2021, as a result of equipment changes due to REFCL system, that enables availability of Feeder Breaker – Group 3, and Line Recloser – REC mode 3, as designated FTS group settings. Note that on the Pilot, all mainline Reclosers are G&W Vipers with Beckwith M7679 Controllers with SCADA.

Description of Operation

FTS consists of implementing a lower phase and ground instantaneous relay or recloser settings with a very short time delay. A portion of the line is already covered by instantaneous settings; however reduce the instantaneous settings to cover 100 % of the mainline to the next line recloser and **SET to 100% of duty levels as listed in template below**. The new FTS setting will be done by implementing an alternative setting group 3 on feeder breakers, On line reclosers, F6 controllers are set with Alternate 2 – LS mode set to 1 operation, while Beckwith are set with Recloser Mode 3 set to 1 operation, enabled via SCADA or manually done in the field. FTS will result in intentional miscoordination of most tap line protection devices when FTS is enabled. i.e. Tap line fuses and the feeder breaker may operate at the same time or the fuse will not

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operate before the feeder or line recloser. However, FTS should minimize miscoordination between the feeder breakers and line reclosers.

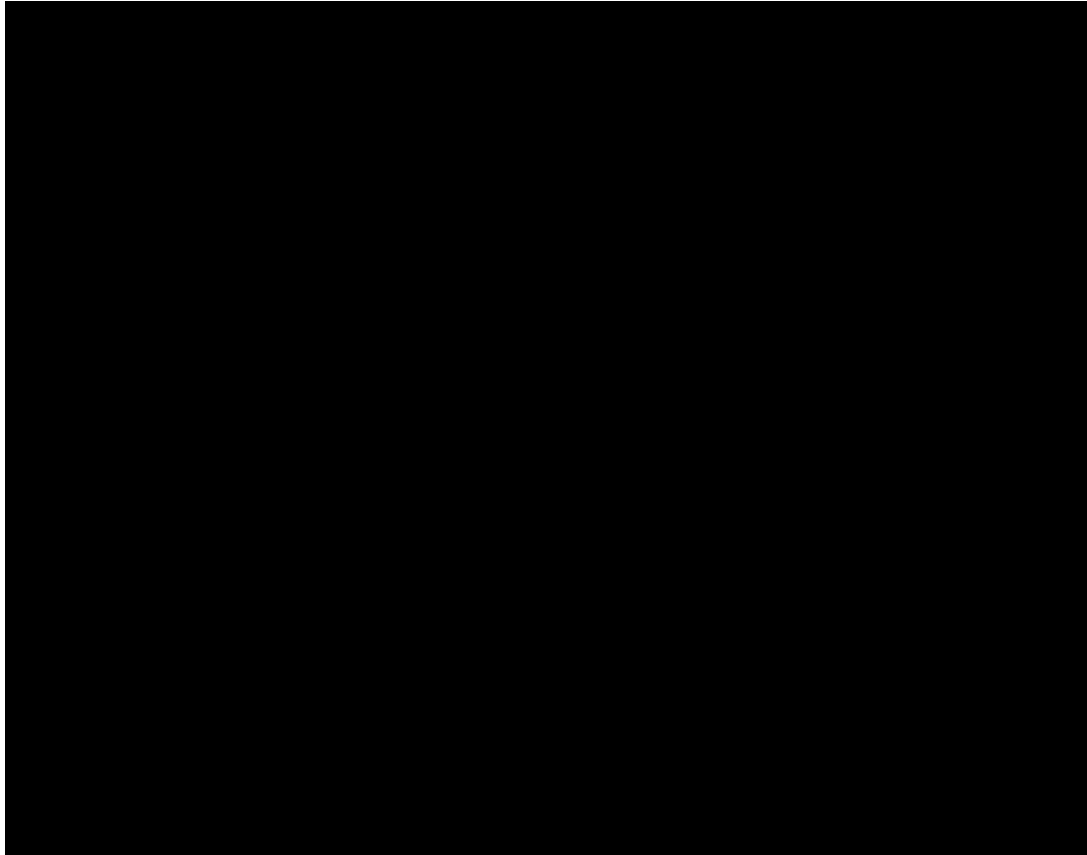
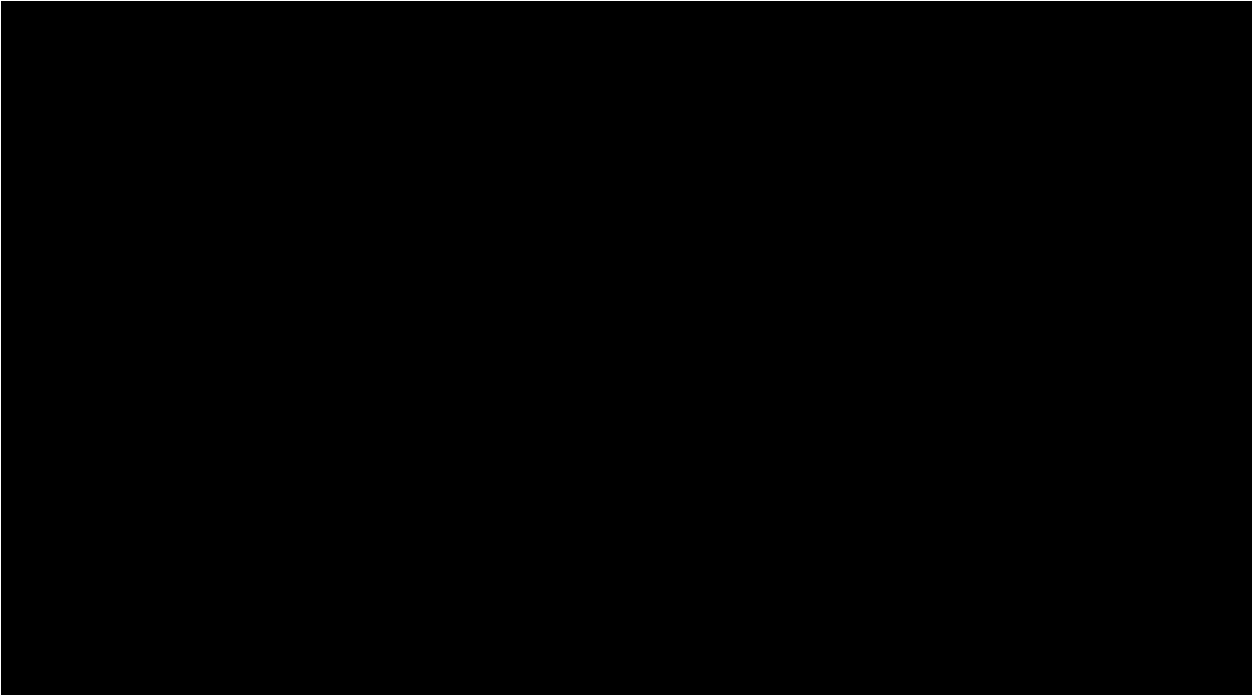


Diagram below illustrates existing settings in dark shade – smaller circle (limited reach/coverage), and proposed FTS settings in lighter shade – larger circle (expanded reach/coverage).



PILOT Implementation

During conditions where our daily - Utility Fire Potential Index (FPI) rating is forecasted R5 or R5+ in FIA 180, enable FTS on selected devices as listed below for Calistoga 1101 and 1102 circuits.

Access each device via SCADA and SELECT Group 3 or REC mode 3; enable setting mode and tag caution. Note that FTS setting mode has NO reclosing, and upon overcurrent will trip immediately to lockout, however due to fire season, the device should already have reclosing cutout (blocked) per operating standards.

Restoration - When FTS is enabled and device lockout occurs, implement existing patrolling and restoration protocols. Follow established operating procedures TD 1464P-01, Patrolling and Testing/Energizing requirements for Automatic Protective Devices for active FPI ratings of “R4 and R5”, specifically application of 2.3 – item 1:

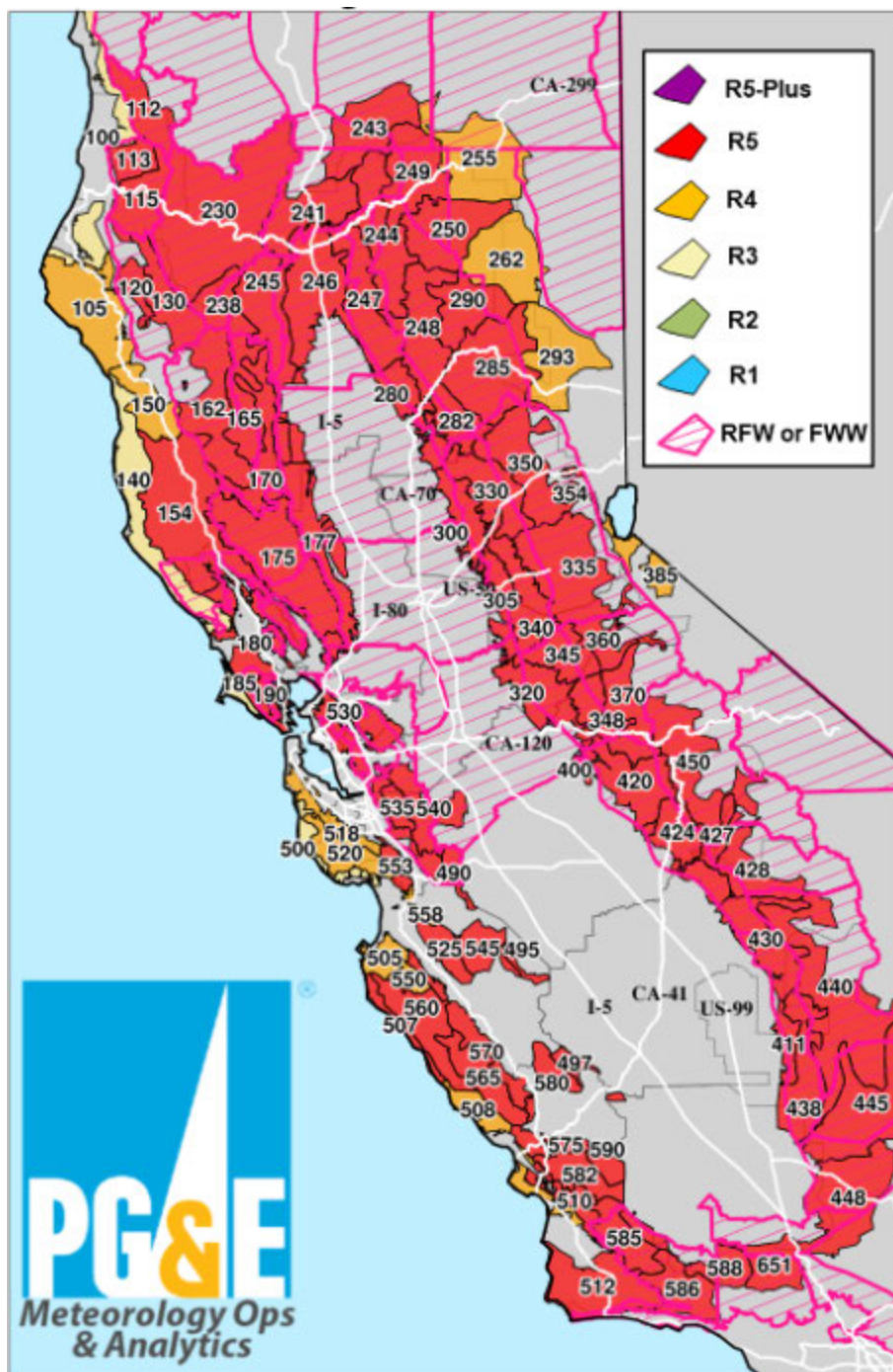
2.3 (continued)

1. IF "R4" or "R5" FPI ratings are active and a device tests to lockout or open/de-energized,

THEN the overhead (OH) line in the involved protection zone must be PATROLLED in its entirety and all found trouble ISOLATED or CLEARED regardless of found fault location. (Refer to "Protection Zone" definition and [Figure 2](#)).

- a. Fault targets/targeting devices (including line sensors and OH fault indicators OBSERVED within 4 hours of the first no light) may be USED to reduce patrolling (e.g. would not have to patrol beyond fault indicators that are not tripped or devices that have not targeted).

Device List

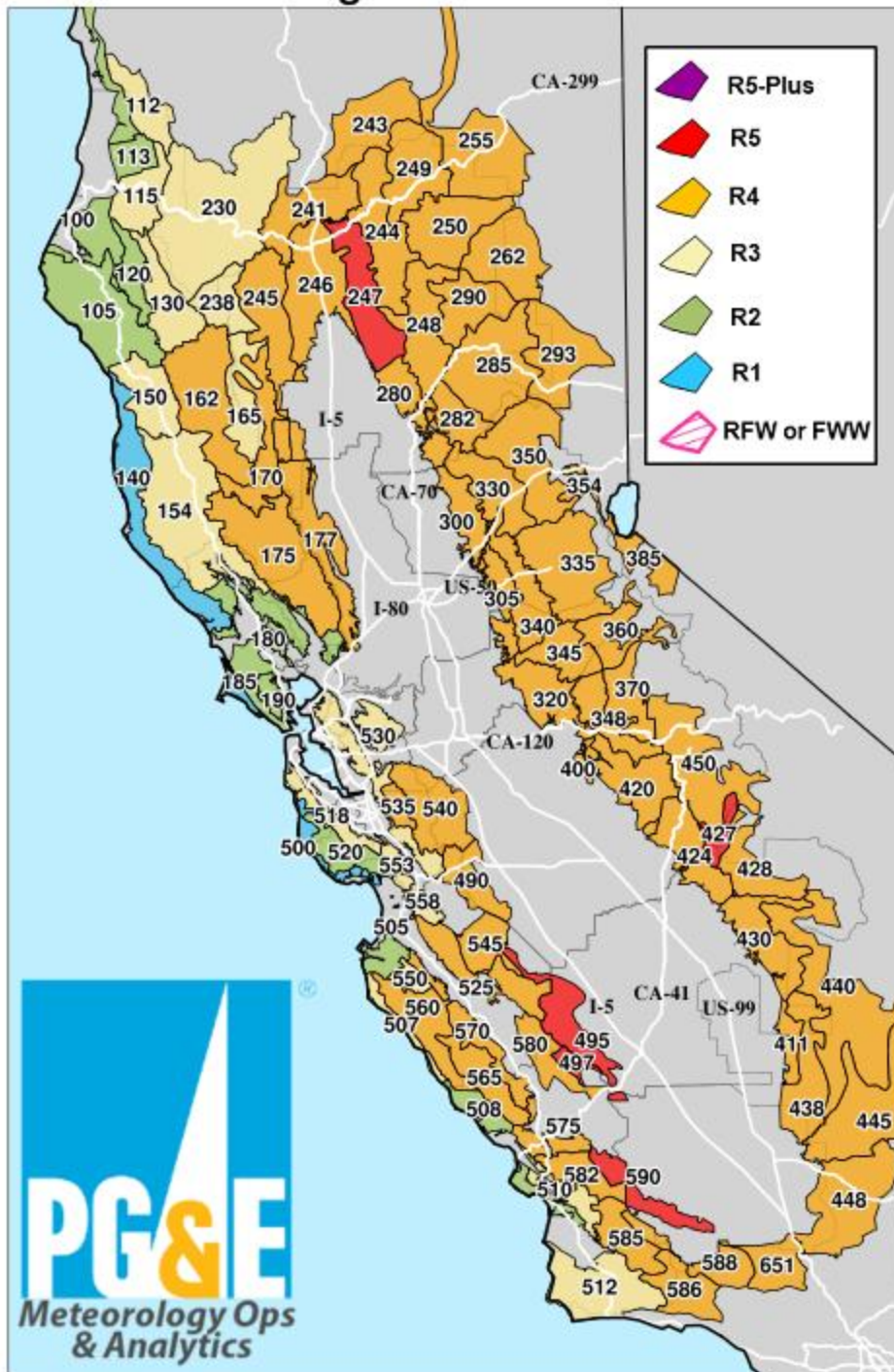


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Atch17-7

PACIFIC GAS AND ELECTRIC COMPANY
REBUTTAL TESTIMONY SUPPORTING ATTACHMENTS
ATTACHMENT 18
FPI FORECAST FOR PG&E SERVICE AREA – JULY 13, 2021

Utility Fire Potential Index Ratings for 07/13/2021



This forecast is intended and has been customized for PG&E utility operations and should not be used for any other purpose or by any other entity. Do not share this information without authorization.

**PACIFIC GAS AND ELECTRIC COMPANY
REBUTTAL TESTIMONY SUPPORTING ATTACHMENTS
ATTACHMENT 19
SDG&E'S RESPONSE TO CALPA-SDGE-A2511001-004
AND ATTACHMENT**

CALPA DATA REQUEST: CALPA-SDGE-A2511001-004
SDG&E RESPONSE

Date Received: 02-27-2026
Date Submitted: 03-13-2026

III. RESPONSES

QUESTION 1

- a) Please provide a copy of SDG&E policies, procedures, standards, and guidelines related to its fast-trip or Sensitive Relay Profile (SRP) program that were in effect during July of 2021.
- b) Given the following environmental conditions listed below, would SDG&E have activated or enabled its fast-trip or SRP program along its electrical distribution lines?
- i. Temperature: 76-80 degrees Fahrenheit
 - ii. Wind: 20-22 mile per hour winder from the North East
 - iii. Relative Humidity: 16 percent
- c) If the answer to (b) is no, explain why not.
- d) If SDG&E is unable to respond to part (b) without additional information, please list what such information would be required.
- e) On July 13, 2021, please provide the environmental conditions (ex. temperature, wind speed and direction, and relative humidity) during which SDG&E would have activated or enabled its fast-trip or SRP program along its electrical distribution lines?

RESPONSE 1

SDG&E objects to the request on the grounds set forth in General Objections Nos. 2, 3, and 9. Further, the request calls for speculation based on facts unavailable to SDG&E. Subject to and without waiving the foregoing objections, SDG&E responds as follows:

- a) See attached document titled “DOP3017 - EDO Requirements During SDGE Fire Conditions (2021-02-24_12-45-50_74927).pdf”. Please note that certain information irrelevant to the purpose of this question was redacted. Moreover, this document has been updated since 2021 and is no longer applicable to SDG&E’s current operating procedures.
- b) Per the attached Distribution Operating Procedure (DOP) 3017 that was in effect in July 2021, SDG&E’s activation of the Sensitive Relay Profile (SRP) program was based on the Extreme Fire Potential Index (FPI) or the presence of a Red Flag Warning (RFW). It is not determined solely by the environmental conditions listed in question 1c of this data request (temperature, wind speed/direction, and relative humidity). SDG&E also notes that the broad use of “electrical distribution lines” is not applicable to SDG&E’s SRP enablement

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practices, which are generally targeted to specific areas and enabled on devices where these conditions are present.

c) SDG&E cannot provide an answer to this question. Please see SDG&E's response to 1b and 1d below.

d) Additional information necessary to calculate SDG&E's Fire Potential Index is required. The formula for the FPI is:

$$FPI = Wx + G + \frac{DFM}{LFM}$$

where Wx is the weather component comprised of wind speed and dewpoint depression as defined by the following matrix,

WX Matrix	≤ 5 mph	6 to 10	11 to 16	17 to 22	23 to 28	≥ 29 mph
≥ 50 F	3	3	4	5	5	6
40 to 49	3	3	3	4	5	5
30 to 39	3	3	3	3	4	5
20 to 29	3	3	3	3	3	4
10 to 19	2	2	2	2	2	3
< 10 F	0	1	1	1	1	2

G is grass greenness, derived from satellite observations of the Normalized Difference Vegetation Index (NDVI) and translated to values of 0-5 using the following scale,

Planet NDVI	G	Description
NDVI > 0.75	0	Fully Green
0.70 < NDVI ≤ 0.75	1	
0.65 < NDVI ≤ 0.70	2	
0.60 < NDVI ≤ 0.65	3	
0.50 < NDVI ≤ 0.60	4	
NDVI ≤ 0.50	5	Cured

DFM represents 10-hour dead fuel moistures categorized on a scale of 1-3 using the definition below, and LFM represents the live fuel moisture of chamise, taken as a decimal (% x 0.01).

10 hr DFM	Score
>10%	1
10-6.5%	2
0-6.5%	3

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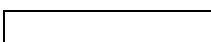
Date Received: 02-27-2026
Date Submitted: 03-13-2026

e) As stated in response to question 1b, Activation of SDG&E's Fast-Trip / Sensitive Relay Profile (SRP) program is based on the Extreme Fire Potential Index (FPI) or the presence of a Red Flag Warning (RFW). It is not determined solely by the environmental conditions listed in question 1c of this data request (temperature, wind speed/direction, and relative humidity). SDG&E also notes that the broad use of "electrical distribution lines" is not applicable to SDG&E's SRP enablement practices, which are generally targeted to specific areas where these conditions are present.

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SDG&E RESPONSE

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END OF REQUEST

 A Sempra Energy utility™	DEPARTMENT ELECTRIC DISTRIBUTION OPERATIONS	DIVISION ELECTRIC OPERATIONS	DOCUMENT SECURITY INTERNAL
	SECTION 3000 – EMERGENCIES		2/24/2021
TITLE EDO REQUIREMENTS DURING SDG&E FIRE CONDITIONS			DOCUMENT NUMBER 3017

Yellow highlight indicates change since last publication.

1. REVISION HISTORY

- 1.3. 2009 - 2016 – Yearly
- 1.4. 07/20/2017 – Annual Review, formatting and updated to section 2 and section 7.3.3 and added Appendix A. Change wind speed for EDO/EOC staffing from 45 to 50 mph and Volcan Mountain Operating Procedure.
- 1.5. 05/29/2018 – Annual Review; updated to remove referenced to FTZ and HRFA and add HFTD, Zone 1, Tier 2 and Tier 3. Updated section 8.1 regarding reclosing.
- 1.6. 05/06/2019 - Annual Review; updated changes to the enablement of Sensitive Relay Profiles and added the ATO policy.
- 1.7. 05/18/2020 - Annual Review, minor changes
- 1.8. 09/15/2020 - Minor changes to extreme and RFW testing and re-energizing section.
- 1.9. 10/02/2020 - Language revisions to Sections 7.4.1.2; 8.2; 8.4.5; 8.4.1.2; 8.4.1.3; 9.9.1; 9.9.2; 9.9.3; 9.13.1; 11.1.1, 11.1.2

2. PURPOSE

DOP 3017 outlines the distribution operating restrictions and notifications required for overhead facilities during various operating condition levels, such as when Electric Distribution Operations (EDO) declares an Elevated Operating Condition or when the [National Weather Service](#) issues a Red Flag Warning. The restrictions shall apply to the SDG&E Highest Fire Threat Districts (HFTD), which include Tier 2 and Tier 3. within SDG&E's service territory, excluding facilities in Imperial Valley and Borrego Springs.

3. REFERENCES & APPENDICES

- [Appendix A](#) - Q&A on Different Scenarios under Elevated Conditions or higher conditions
- [Appendix B](#) Reclosing/Line Testing Recommended Procedure Summary
- [DOP 1001](#) Distribution System Operator Responsibility and Authority
- [DOP 1002](#) Dispatching Employees for Routine and Emergency Switching
- [DOP 2006](#) 12kV Throw-Over Substation

DOP 3013	SDG&E Fire Preparedness
DOP 3017B	Distribution Circuits and Service Restorers Associated with SDG&E Fire Conditions
DOP 3021	EDO Requirements During SDGE Fire Conditions & Pandemic
DOP 3507	Falling Conductor Protection – Advanced SCADA
ESP 113.1	Wildland Fire Prevention & Fire Safety
TMC1320	SDG&E Fire Preparedness

4. ACRONYMS & DEFINITIONS

CB	Circuit Breaker
CFR	Contract Fire Resources
DSO	Distribution System Operator
EDO	Electric Distribution Operations
EGO	Electric Grid Operations
Elevated Condition	SDG&E Meteorologists Declaration due to the FPI falling between 12-14
ETS	Electric Troubleshooter
Extreme Condition	SDG&E Meteorologists Declaration due to the FPI falling between 15-17
FC	Fire Coordinator
FPI	Fire Potential Index developed by SDG&E Meteorology
HFTD	High Fire Threat District consisted of Zone 1, Tier 2 and Tier 3 areas.
High Wind Warning	The NWS will issue a High Wind Warning for the following conditions in the SDG&E service territory: • NWS Zones 242 (OC Coastal), 243 (Coastal), and 250 (Inland): Sustained 40 mph or more and/or gust 56 mph or more • NWS Zones 258 (Mountains) and 262(Desert): Sustained 45 mph or more and/or gust of 56 mph or more
HLT	Hot Line Tag – Device setting is set to Fast (no delay), also turns OFF Reclosing
IR	IntelliRupter PulseCloser SCADA switch
NWS	National Weather Service
PC	Pulse Close operation. A capability of the IntelliRupter switch
Sensitive Relay Settings	Device setting are set to Fast (no delay) and Sensitive (lower current pick-up); also known as “Profile 3”
RAWS	Remote Automated Weather Station
RFW	Red Flag Warning. The NWS will declare an RFW for the following conditions:

	• High Wind – the relative humidity is $\leq 15\%$ with sustained winds of ≥ 35 mph and/or frequent wind gusts of ≥ 35 mph for a duration ≥ 6 hours • Dry Lightning – A lightning event that is not accompanied by enough precipitation to significantly wet fuels that have been identified as critically dry. (Significant precipitation is defined as ranging from .05 inches for grass or brush fuels to .15 inches for closed-canopy timber/heavy fuels.)
SAWTI	Santa Ana Wildfire Threat Index. The US Forest Service department of Predictive Services will issue the SAWTI.
SGF	Sensitive Ground fault
SR	Service Restorer
Tier 2	Tier 2 consists of areas on the California Public Utilities Commission’s Fire-Threat Map (“CPUC Fire-Threat Map”) where there is an elevated risk for destructive utility-associated wildfires. The CPUC Fire-Threat Map is currently in an advanced stage of development.
Tier 3	Tier 3 consists of areas on the CPUC Fire-Threat Map where there is an extreme risk for destructive utility-associated wildfires.
TSO	Transmission System Operator
TST	Technical Support Team
WF-DSO	Working Foreman – Distribution System Operator
Wind Advisory	The NWS will issue a Wind Advisory for the following conditions: • NWS Zones 552 (OC Coastal), 554 (OC Inland), 243 (Coastal), and 250 (Inland): Sustained 30 mph or more and/or gust 35 mph or more • NWS Zones 258 (Mountains) and 262 (Desert): Sustained 35 mph or more and/or gust of 45 mph or more
Zone 1	High Hazard Zones on the U.S Forest Service-California Department of Forestry and Fire Protection joint map of Tree Mortality High Hazards Zones. Note: for SDG&E, Zone 1 is encompassed within Tiers 2 and 3.

5. GENERAL

This DOP provides guidelines for the electric distribution system during all operating conditions, as specified in [TMC1320/DOP3013](#), within SDG&E’s service territory, excluding Borrego Springs and Imperial County. These procedures are implemented seasonally to balance electric reliability with risks associated with fire threat.

8. EXTREME OPERATING CONDITION (FPI 15-17)

An extreme operating condition will be declared when the burn environment of a specific area or district has become conducive for a catastrophic wildfire within the SDG&E service territory.

- 8.1. **Reclosing / Protection Policy** – All distribution reclosing relays shall be disabled on circuits (may include CB, SR and IR devices) located in or that feed into the HFTD, and in Coastal Circuits with Fire Risk as outline in section 8.2.1 of [DOP 3017B](#). When the Santa Ana Wildfire Threat Index (SAWTI) for San Diego County reaches “High” or “Extreme” level in conjunction with an “Extreme” FPI rating in one or more coastal operating districts, reclosing may be disabled for the entire SDG&E service territory on circuits and Fault Interrupting Devices which feed overhead. The following templates can be used to perform these:

8.2.

Switch Plan Template	Reclosing Coverage
TBD	HFTD
216695	Coastal Circuits with Fire Risk
TBD	All Other Station A
TBD	All Other Station L

Note: These switch plans must be reviewed and updated before any significant event to add or remove new devices.

- 8.3. **4 kV Auto-Throw-Over Policy** – All 4kV auto-throwers in the HFTD and in Coastal Circuits with Fire Risk shall be set to Manual.

4 kV Substations with Auto-Throw-Over		
4KV Substation	Preferred Circuit	Alternate Circuit
Adams	703*	361
Ramona	235**	237**

* Circuit is in a Coastal Circuits with Fire Risk

** Circuit is in the HFTD

- 8.4. The Sensitive Relay Settings will be enabled for defined SR and IR devices as described below.

8.4.1. If the FPI is Extreme in Mountain Empire and/or Ramona all of Tier 3 should have Sensitive Relay Settings enabled.

8.4.2. If the FPI is Extreme in Eastern and/or Northeast, the entire HFTD should have Sensitive Relay Settings enabled.

8.4.3. If the FPI is Extreme in Orange County, then the HFTD in Orange County should have Sensitive Relay Settings enabled.

8.4.4. If the FPI is Extreme in any of the San Diego County coastal districts (North Coast, Beach Cities, Metro) all the Coastal Circuits with Fire Risk as defined in 3017B should have Sensitive Relay Settings enabled.

8.4.5. The following templates can be used to enable these per above:

Switch Plan Template	Sensitive Relay Coverage
208862	Tier 3
208860	Tier 2
208875	Orange County
216965	Coastal Circuits with Fire Risk
TBD	All Other Station A
TBD	All Other Station L

Note: These switch plans must be reviewed and updated before any significant event to add or remove new devices.

- 8.5. Any time the FPI merits significant long-term operational changes, Meteorology will issue notifications throughout SDG&E (via the FPI_PM or normal weather update distribution lists) to communicate when an Extreme Condition has terminated.

8.4 Testing Procedure

- 8.4.1. For HFTD, Coastal Circuits with Fire Risk ([DOP 3017B](#) Sect. 8.2.1) and any circuit with reclosing turned off due to “High” or “Extreme” SAWTI (section 8.1). An outage cause **must** be found during extreme FPI **prior** to re-energizing any portion of the tripped circuit. Upon completion of a patrol, as outlined under sections 8.4.1.1 – 8.4.1.4, if no cause is found, at the discretion and direction of EDO Leadership, step-wise restoration may occur.
- 8.4.1.1. A patrol must be completed until a cause is identified prior to energizing. If no cause is found, at the discretion and direction of EDO Leadership, step-wise restoration may occur.
- 8.4.1.2. **Unless exempted by Deputy Operations Chief Electric,** Independent of the target type (ex: SGF or hard targets) a patrol of the entire distribution line is required, even if damage is found. Prior to energizing, at the discretion and direction of EDO Leadership, step-wise restoration may occur.
- 8.4.1.3. Due to circuit relay abnormal configuration **unless exempted by Deputy Operations Chief,** Electric Distribution Operations **will** not consider the possibility of operating devices miscoordination, regardless of trip target types. If multiple devices trip open, a patrol must be completed.
- 8.4.1.4. If distribution overhead is deenergized due to any transmission operations, the distribution overhead will be isolated, and a patrol of the entire line must be conducted prior to energizing distribution lines, unless otherwise directed by EDO leadership. Field personnel/CFR shall be placed in strategic locations as needed along the affected circuit(s). At the discretion and direction of EDO leadership.
- 8.4.1.5. EDO may re-energize without a full patrol at the direction of Deputy Operations Chief-Electric in consultation with the Utility Incident Commander.

8.5. Field Restrictions for District(s) identified for Extreme Operating Condition

- 8.5.1. Actions that apply to the SDG&E HFTD (Tier 2 and Tier 3) – Refer to Section in [ESP 113.1](#) and/or Section 10.3 in [TMC1320 \(AKA: DOP3013, ESP 109\)](#)
- 8.5.2. Discretionary Overhead energized work will be prohibited in, but not limited to, the areas of critical fire weather in the SDG&E HFTD (Tier 2 and Tier 3). Work requiring a “Hot Line Order” will be cancelled on circuits that are potentially at risk due to the critical fire weather in that area. Work will be allowed to proceed if the Electric Construction Supervisor does not see a fire risk, has had the job field verified that there is no fire risk, CFR is on scene with the crew and the job has been reviewed with Fire Coordination or where not performing the work creates a greater risk than doing so.

8.6. Terminating Condition

- 8.6.1. EDO will issue notifications throughout SDG&E (via the Deputy Operations Chief Distribution List for Operational Calls) to communicate when an Extreme Operating Condition has terminated.

9. RED FLAG WARNING

A Red Flag Warning is issued by the NWS for fire-conducive weather, including relative humidity $\leq 15\%$ with sustained winds ≥ 25 mph and/or frequent gusts ≥ 35 mph (for a duration ≥ 6 hours). This condition may be declared when SDG&E is in any of the previously defined operating conditions.

- 9.1. An operational conference call will be initiated with by Deputy Operations Chief to include Safety, Meteorology, Fire Coordination, Construction & Operations Centers, Kearny Operations, Design Construction Management, Grid Control, Service Dispatch, ARSO and the EOC at the start of the Red Flag Warning.
- 9.2. The Deputy Operations Chief position may be activated at the start of the RFW and remain open until the RFW is terminated, or fire weather conditions subside as defined by SDG&E Meteorology or Fire Coordination.
 - 9.2.1. Staffing of the Deputy Operations Chief and supporting staff will be at the discretion of EDO Director or delegate.
- 9.3. SDG&E Meteorologist will provide timely and periodic weather updates.
- 9.4. There may be an open conference call line with the EOC and Grid Control at the start of an RFW with forecasted winds of ≥ 50 mph and remain open until the RFW is terminated, or at the direction of SDG&E management.
- 9.5. See DOP 3021 for RFW procedures during a pandemic.
- 9.6. **Reclosing / Protection Policy** – All distribution reclosing relays shall be disabled on specified circuits (may include CB, SR and IR devices) located within the NWS weather zone for which the RFW has been declared. These areas will include, but are not limited to, circuits within or feed into the HFTD and may include circuits outside the HFTD if the burn environment is conducive to large fires as defined by Fire Coordination. When

the Santa Ana Wildfire Threat Index (SAWTI) for San Diego County reaches “High” or “Extreme” level in conjunction with an “Extreme” FPI rating in one or more coastal operating districts, reclosing may be disabled for the entire SDG&E service territory.

- 9.7. **4 kV Auto-Throw-Over Policy** – All 4kV auto-throwers in the HFTD and in Coastal Circuits with Fire Risk shall be set to Manual.

4 kV Substations with Auto-Throw-Over		
4KV Substation	Preferred Circuit	Alternate Circuit
Adams	703*	361
Ramona	235**	237**

* Circuit is in a Coastal Circuits with Fire Risk

** Circuit is in the HFTD

NOTE: when SAWTI for San Diego County reaches “High” or “Extreme” level in conjunction with an “Extreme” ALL 4kV auto-throwers outlined in [DOP 2006](#), are required to be set to Manual.

- 9.8. The Sensitive Relay Settings will be enabled for defined SR and IR devices as described below.

9.8.1. If a zone for the RFW impacts Mountain Empire and/or Ramona, all of Tier 3 should have Sensitive Relay Settings enabled.

9.8.2. If a zone for the RFW impacts Eastern and/or North East, the entire HFTD should have Sensitive Relay Settings enabled.

9.8.3. If a zone for the RFW impacts Orange County, then the HFTD in Orange County should have Sensitive Relay Settings enabled.

9.8.4. If a zone for the RFW impacts any of the San Diego County coastal districts (North Coast, Beach Cities, Metro) all the Coastal Circuits with Fire Risk as defined in 3017B should have Sensitive Relay Settings enabled.

- 9.9. Testing Procedure

9.9.1. Due to circuit relay abnormal configuration **unless exempted by Deputy Operations Chief**, Electric Distribution Operations **will** not consider the possibility of operating devices miscoordination, regardless of trip target types. If multiple devices trip open, a patrol must be completed.

9.9.2. **Unless exempted by Deputy Operations Chief Electric**, Independent of the target type (ex: SGF or hard targets) a patrol of the entire distribution line is required, even if damage is found. Prior to energizing, at the discretion and direction of EDO Leadership, step-wise restoration may occur.

9.9.3. A full patrol must be completed with the cause of the outage identified. If no cause is found, Kearny SCADA techs will download the event records for System Protection to analyze to help determine the potential cause of the outage. Re-patrol may be required. At the discretion and direction of EDO Leadership in consultation with Meteorology and EOC, step-wise restoration may occur.

- 9.9.4. If distribution overhead is deenergized due to any transmission operations, the distribution overhead will be isolated, and a patrol of the entire line must be conducted prior to energizing distribution lines, unless otherwise directed by EDO leadership. Field personnel and CFR shall be placed in strategic locations as needed along the affected circuit(s).
- 9.9.5. EDO may re-energize without a full patrol at the direction of Deputy Operations Chief-Electric in consultation with the Utility Incident Commander.

9.10. Field Resources

- 9.10.1. Personnel shall be placed in the field at specific locations to monitor real-time conditions, such as hazards to the SDG&E electrical infrastructure and report such hazards to EDO. These locations will be determined based upon adverse weather forecasts and affected system equipment.

9.11. Field Restrictions

- 9.11.1. Actions that apply to the SDG&E HFTD – Refer to [ESP 113.1](#) and/or Section 10.3 in [TMC1320 \(AKA: DOP3013, ESP 109\)](#)
- 9.11.2. All Discretionary Overhead energized work will be prohibited in, but not limited to, the areas of critical fire weather in the SDG&E HFTD. Work requiring a “Hot Line Order” will be cancelled for circuits that are potentially at risk due to the critical fire weather in that area. Work may only be performed to remedy a greater risk or hazard.

9.12. Safety Protocols

- 9.12.1. SDG&E has an obligation to operate its system safely and within its design criteria. Therefore, EDO may de-energize circuits to protect public safety due to field observations that could damage the electric infrastructure and/or strong winds that exceed the design criteria of SDG&E’s overhead structures.
- 9.12.2. When winds reach critical speeds the SDG&E Meteorologist will validate anemometer or RAWS data prior to any operating decisions being made, unless field observers report an imminent safety hazard.
- 9.12.3. Any decisions to de-energize circuits for public safety will be made in consultation with the EOC, SDG&E Meteorology and EDO leadership. It is expected, but not required, that an RFW will be in effect when such a decision to de-energize a circuit is made.

9.13. Terminating an RFW Condition

- 9.13.1. Upon termination of the RFW, the operating condition either returns to the Normal Operating Condition, Elevated Operating Condition, **or Extreme Operating Condition.**
- 9.13.2. EDO will issue notifications throughout SDG&E (via the EDO – Storm Desk distribution list) to communicate when a Red Flag Operating Condition has terminated.

**PACIFIC GAS AND ELECTRIC COMPANY
REBUTTAL TESTIMONY SUPPORTING ATTACHMENTS
ATTACHMENT 20
SCE'S RESPONSE TO CALADVOCATES-SCE-A2511001-004
AND ATTACHMENT**

(REDACTED)

Southern California Edison
A.25-11-001 – APGE-Fire1054

DATA REQUEST SET CalAdvocates-SCE-A2511001-004

To: Cal Advocates
Prepared by: Curtis Sanden
Job Title: Senior Engineer
Received Date: 2/27/2026

Response Date: 3/13/2026

Question 01.a:

a) Please provide a copy of SCE policies, procedures, standards, and guidelines related to its fast-trip or Fast-Curve settings that were in effect during July of 2021.

Response to Question 01.a:

CONFIDENTIAL

The Attachment(s) Are Marked Confidential In Accordance With Applicable Law and Regulation.

Basis for Confidentiality In Accompanying Confidentiality Declaration.

Public Disclosure Restricted.

Please see attached SCE Fast Curve setting methodology document titled “Fast Curves for Substation Flow Diagram 2018.pdf” which was the guideline used to program Fast Curves into substation CB relays and was in effect during July 2021. Also attached is “CONFIDENTIAL_SOB 322 - 11_12_2020_Redacted.pdf” which is SCE’s operational guideline in effect during July 2021.

CONFIDENTIAL ATTACHMENT OMITTED

PACIFIC GAS AND ELECTRIC COMPANY
REBUTTAL TESTIMONY SUPPORTING ATTACHMENTS
ATTACHMENT 21
CONFIDENTIALITY DECLARATION

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

**DECLARATION SUPPORTING CONFIDENTIAL DESIGNATION
ON BEHALF OF
PACIFIC GAS AND ELECTRIC COMPANY (U 39 E)**

1. I, Joel B. Crane, am a Chief Counsel of Pacific Gas and Electric Company (“PG&E”), a California corporation. William Manheim, the Vice President, Deputy General Counsel & Law Utility Strategy & Operations of PG&E, delegated authority to me to sign this declaration. My business office is located at:

Pacific Gas and Electric Company
300 Lakeside Dr.
Oakland, CA 94612

2. PG&E will produce the information identified in Paragraph 3 of this Declaration to the California Public Utilities Commission (“CPUC”) or departments within or contractors retained by the CPUC in response to a CPUC audit, data request, proceeding, or other CPUC request.

Name or Docket No. of CPUC Proceeding (if applicable): A.25-11-001: Cost Recovery for 2019 Kincade Fire and 2021 Dixie Fire

3. Title and description of document(s):

Attachment	Title	Description
	Please refer to details starting on Page 4 of this declaration	

4. These documents contain confidential information that, based on my information and belief, has not been publicly disclosed. These documents have been marked as confidential, and the basis for confidential treatment and where the confidential information is located on the documents are identified on the following chart:

Check	Basis for Confidential Treatment	Where Confidential Information is Located on the Documents
☐	Customer-specific data, which may include demand, loads, names, addresses, and billing data. (Protected under Pub. Util. Code § 8380; Civ. Code §§ 1798 <i>et seq.</i>; CPUC Decisions (D.) 14-05-016)	
☐	Personal information that identifies or describes an individual (including employees), which may include home address or phone number; SSN, driver's license, or passport numbers; education; financial matters; medical or employment history (not including PG&E job titles); and statements attributed to the individual. (Protected under Civ. Code §§ 1798 <i>et seq.</i>; Gov. Code § 7927.400; 42 U.S.C. § 1320d-6; General Order (G.O.) 77-M; see also CPUC D. 04-08-055, 06-12-029)	
☒	Physical facility, cyber-security sensitive, or critical infrastructure data, including without limitation critical energy infrastructure information (CEII) as defined by the regulations of the Federal Energy Regulatory Commission at 18 C.F.R. § 388.113 and/or General Order 66-D ("The subject information: (1) is not customarily in the public domain by providing a declaration in compliance with Section 3.2(c) stating that the subject information is not related to the location of a physical structure that is visible with the naked eye or is available publicly online or in print; and (2) the subject information either: could allow a bad actor to attack, compromise or incapacitate physically or electronically a facility providing critical utility service; or discusses vulnerabilities of a facility providing critical utility service"). (Protected under Gov. Code § 7927.705, 7929.205; 6 U.S.C. § 671; 6 CFR § 29.2)	Confidential information is outlined red, please refer to details starting on Page 5 of this declaration
☐	Proprietary and trade secret information or other intellectual property and protected market sensitive/competitive data. (Protected under Civ. Code §§ 3426 <i>et seq.</i>; Gov. Code §§ 7927.300, 7927.705, 7929.420, 7927.605, 7930.205; Evid. Code § 1060; CPUC D.11-01-036)	
☐	Corporate financial records. (Protected under Gov. Code §§ 7927.705, 7927.605)	



Third-Party information subject to non-disclosure or confidentiality agreements or obligations.
(Protected under Gov. Code § 7927.705; see, e.g., CPUC D.11-01-036)

Confidential information is grey shaded or outlined red, please refer to details starting on Page 5 of this declaration



Other categories where disclosure would be against the public interest.
(Gov. Code § 7922.000)

Confidential information is outlined red, please refer to details starting on Page 5 of this declaration

: In light of risks to employee safety and privacy, the public interest in maintaining the confidentiality of the employee information outweighs the public interest in disclosure.

5. The importance of maintaining the confidentiality of this information outweighs any public interest in disclosure of this information. This information should be exempt from the public disclosure requirements under the Public Records Act and should be withheld from disclosure.
6. I declare under penalty of perjury that the foregoing is true, correct, and complete to the best of my knowledge.
7. Executed on this 19th day of June, 2026 at El Dorado Hills, California.

/s/ Joel B. Crane

Joel B. Crane
Chief Counsel
Pacific Gas and Electric Company

Rebuttal Testimony of Pacific Gas and Electric Company for Review and Recovery of Costs Associated with the 2019 Kincade Fire and 2021 Dixie Fire Under AB 1054
ATTACHMENT TO DECLARATION
 June 19, 2026

BOOK NAME	DOCUMENT NAME	CATEGORY OF CONFIDENTIALITY	LOCATION
REBUTTAL TESTIMONY	CHAPTER 3A REBUTTAL TESTIMONY ON THE KINCADE FIRE	Third-Party information subject to non-disclosure or confidentiality agreements or obligations. (Protected under Gov. Code § 7927.705; see, e.g., CPUC D.11-01-036)	Chapter 3A Pages 3A-6, 3A-7, 3A-8
REBUTTAL TESTIMONY SUPPORTING ATTACHMENTS	ATTACHMENT 5 ETPM TABLE 6 BULLETIN	Other categories where disclosure would be against the public interest.	Page Atch5-6
REBUTTAL TESTIMONY SUPPORTING ATTACHMENTS	ATTACHMENT 15 PG&E'S RESPONSE TO KINCADE DIXIE AB1054 DR CALADVOC ATES_D01-Q011 SUPP01REV01 AND SELECT ATTACHMENTS	Physical facility, cyber-security sensitive, or critical infrastructure data, including without limitation critical energy infrastructure information (CEII) as defined by the regulations of the Federal Energy Regulatory Commission at 18 C.F.R. § 388.113 and/or General Order 66-D.	Pages Atch15-22, Atch15-34, Atch15-43, Atch15-60

BOOK NAME	DOCUMENT NAME	CATEGORY OF CONFIDENTIALITY	LOCATION
REBUTTAL TESTIMONY SUPPORTING ATTACHMENTS	ATTACHMENT 17 PG&E'S RESPONSE TO KINCADEDIXIEAB1054_ DR_CALADVOCATES_D01-Q020SUPP01 AND ATTACHMENT	Other categories where disclosure would be against the public interest. Physical facility, cyber-security sensitive, or critical infrastructure data, including without limitation critical energy infrastructure information (CEII) as defined by the regulations of the Federal Energy Regulatory Commission at 18 C.F.R. § 388.113 and/or General Order 66-D.	Pages Atch17-4, Atch17-5, Atch17-6
REBUTTAL TESTIMONY SUPPORTING ATTACHMENTS	ATTACHMENT 20 SCE'S RESPONSE TO CALADVOCATES- SCE-A2511001-004 AND ATTACHMENT	Third-Party information subject to non-disclosure or confidentiality agreements or obligations. (Protected under Gov. Code § 7927.705; see, e.g., CPUC D.11-01-036)	Pages Atch20-2 through Atch20-48