

Application: A.25-11-XXX
(U 39 M)
Exhibit No.: _____
Date: November 14, 2025
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

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

PREPARED TESTIMONY

VOLUME 1 OF 2



PACIFIC GAS AND ELECTRIC COMPANY
KINCADE AND DIXIE AB 1054 WILDFIRE COST REVIEW AND RECOVERY
PROCEEDING
PREPARED TESTIMONY

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CHAPTER 1
POLICY

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POLICY

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
POLICY

A. Introduction

Through this Application and supporting testimony, Pacific Gas and Electric Company (PG&E or the Company) demonstrates that the California Public Utilities Commission (Commission) should authorize recovery of costs related to the 2019 Kincade Fire and the 2021 Dixie Fire. PG&E seeks to recover in rates approximately \$1.59 billion in costs recorded in its Wildfire Expense Memorandum Account (WEMA) and approximately \$71.6 million in capital costs and \$242 million in operation and maintenance (O&M) costs recorded in its Catastrophic Event Memorandum Account (CEMA) related to these fires. PG&E also seeks a determination by the Commission that costs related to these fires that are being paid by the California Wildfire Fund and credited to the WEMA need not be reimbursed.

This Application is the first catastrophic wildfire proceeding that involves the presumption of prudence enacted by the Legislature as part of Assembly Bill 1054 (AB 1054) and codified in Public Utilities Code Section 451.1.¹ By statute, PG&E is entitled to that presumption of prudence because it had a valid safety certification at the time of the ignition of each fire.² The Commission should allow PG&E to recover its costs at issue in this proceeding because PG&E was presumptively prudent under AB 1054, and (even setting aside the presumption) the costs are not attributable to any imprudence by PG&E.

The Commission's application of the presumption and the AB 1054 framework in this proceeding will set an important precedent. Authorizing PG&E's recovery of its costs would promote investor confidence and foster utility financial stability. By demonstrating a predictable and fair California regulatory environment, it would help to ensure utilities have access to capital at

¹ All statutory references are to the Public Utilities Code (Pub. Util. Code) unless otherwise stated.

² Pub. Util. Code § 451.1(c).

1 reasonable cost, which is necessary to meet the State’s clean energy, reliability,
2 electrification, and safety goals at an affordable cost to customers.

3 Before AB 1054’s passage, the credit ratings for PG&E and other electrical
4 utilities had plummeted due to the increasing frequency and severity of wildfires
5 in California, the exposure of electrical utilities to inverse-condemnation claims
6 for wildfires caused by utility equipment, and uncertainty about utilities’ ability to
7 recover in rates the costs of wildfire liability.³ In 2017, the Commission issued a
8 watershed decision denying the application of San Diego Gas & Electric
9 Company (SDG&E) to recover certain wildfire costs in rates.⁴ Perceptions of
10 that decision contributed to credit downgrades, high borrowing costs for utilities,
11 and resulting increased costs to customers.⁵ In a concurrence to that decision,
12 two members of the Commission “respectfully urge[d] the California Legislature
13 to affirmatively address” utility wildfire liability and its unsustainable effects on
14 access to capital and ratepayer costs.⁶ AB 1054 was the Legislature’s response
15 to that call, and it was expressly designed to create “more certainty in the cost
16 recovery process in order to restore the regulatory compact.”⁷

17 Under AB 1054, the utility’s “conduct shall be deemed to have been
18 reasonable” under the codified prudence standard set forth in Section 451.1(b),
19 if a utility had a valid safety certification at the time that a covered wildfire
20 ignited.⁸ To obtain a safety certification, the utility must have and implement a
21 Commission-approved Wildfire Mitigation Plan (WMP) and satisfy numerous

3 Pub. Util. Code § 854.2(a)(6).

4 See D.17-11-033.

5 Governor’s Office of Planning and Research, Final Report of the Commission on Catastrophic Wildfire Cost and Recovery (June 17, 2019) (SB 901 Commission Report), p. 7, available at: <https://lci.ca.gov/docs/20190618-Commission_on_Catastrophic_Wildfire_Report_FINAL_for_transmittal.pdf> (accessed Oct. 27, 2025).

6 D.17-11-033, Joint Concurrence of President Michael Picker and Commissioner Martha Guzman Aceves, pp. 6-7.

7 Assembly Committee on Utilities and Energy, Summary of AB 1054 - as amended July 5, 2019 (Summary of AB 1054), p. 13. See also SB 901 Commission Report, p. 7 (“The current process for determining prudence and cost-recovery contributes to the uncertainty that utilities face, ultimately increasing costs to ratepayers while resulting in insufficient investment in wildfire mitigation.”).

8 Pub. Util. Code § 451.1(c).

1 other criteria promoting safety.⁹ Section 451.1(b) provides for recovery if the
2 utility's conduct "related to the ignition was consistent with actions that a
3 reasonable utility would have undertaken in good faith under similar
4 circumstances, at the relevant point in time, and based on the information
5 available to the electrical corporation at the relevant point in time."¹⁰ The
6 standard also elaborates that reasonable conduct "encompasses a spectrum" of
7 "practices, methods, or acts."¹¹ Finally, it specifies that cost recovery "tak[es]
8 into account factors both within and beyond the utility's control."¹²

9 The Commission should authorize recovery of PG&E's WEMA and CEMA
10 costs related to the Kincade and Dixie Fires. The testimony supporting this
11 Application demonstrates that neither the Kincade Fire nor the Dixie Fire was
12 attributable to any imprudence by PG&E, and that PG&E was a prudent operator
13 of its electrical system. The destructive 2017 and 2018 wildfire seasons
14 evidenced a grave increase in wildfire risk across the State. Consistent with
15 Senate Bill (SB) 901, PG&E responded to this evolving risk by developing a
16 comprehensive WMP, in coordination with the Commission, the Office of Energy
17 Infrastructure Safety (Energy Safety), and other stakeholders.¹³ The WMP and
18 the encompassed programs were a foundational part of PG&E's safety
19 certification, giving rise to the presumption of prudence in this proceeding.
20 Through its WMP, PG&E implemented policies and programs to mitigate the risk
21 of utility-caused ignitions in its service area. It was diligently executing those
22 programs at the time of the Kincade and Dixie Fires.

23 With respect to the Kincade Fire, the California Department of Forestry and
24 Fire Protection (Cal Fire) determined that the ignition resulted from a jumper
25 conductor associated with PG&E's Geysers #9-Lakeville 230kV transmission

⁹ Pub. Util. Code § 8389(a).

¹⁰ Pub. Util. Code § 451.1(b).

¹¹ *Id.*

¹² *Id.*

¹³ In 2019 (via AB 1054), the Legislature created the Wildfire Safety Division (WSD) within the Commission and gave the WSD authority to review and approve WMPs. In July 2021, Energy Safety was established as a new state department to review and audit compliance with WMPs. This testimony uses "Energy Safety" to refer to WSD and/or Energy Safety, depending on the relevant time frame.

1 line (Geysers #9 Line) breaking and coming into contact with a metal tower. The
2 jumper separated at a location obscured from view by a solid metal clamp,
3 called a shoe. PG&E had no prior indication the jumper would fail in this
4 manner. In the years before the fire, these facilities were regularly inspected
5 and maintained, and no damage to the conductor was identified. In particular, in
6 May 2019—less than six months before the fire—PG&E performed a drone
7 inspection of the facilities at issue, and the high-resolution photographs from that
8 inspection showed no indication that the jumper would fail. These facilities
9 previously connected a customer-owned geothermal power plant known as
10 Geysers Units 9/10 to the Geysers #9 Line. After the owner requested that
11 PG&E disconnect the power plant, which was in a standby state, from the
12 Geysers #9 Line, the jumper conductors were configured in a way that would
13 support safe reconnection in the future.

14 With respect to the Dixie Fire, Cal Fire determined that the ignition resulted
15 from a Douglas fir tree falling onto PG&E's Bucks Creek 1101 12kV distribution
16 circuit (Bucks Creek 1101 Circuit). Post-incident examination of the tree
17 revealed a wound at the base of the tree that likely contributed to its failure.
18 PG&E performed numerous vegetation management patrols of the circuit in the
19 years prior to the Dixie Fire, and the tree was not identified as a potential
20 hazard. A photograph taken just a few months prior to the fire shows that the
21 tree appeared healthy, had a green canopy, and did not have an obvious defect
22 or significant lean. Cal Fire's retained arborist acknowledged that the subject
23 tree was alive and vital when it failed and in fact suggested the immediate cause
24 of the failure may have been a second tree that failed and fell into the subject
25 tree. PG&E responded diligently and appropriately to the reported outage on the
26 day of the fire, consistent with its procedures. PG&E was not aware of any
27 continuing hazard on the line until its experienced troubleshooter was able to
28 access the site on the afternoon of ignition—at which point the troubleshooter
29 took immediate action to ensure the line was de-energized and even attempted
30 to fight the fire himself.

31 PG&E's testimony also will show that external factors beyond PG&E's
32 control contributed to the progression of each fire, including climate change,

1 strong winds and fuel conditions for the Kincade Fire, and extreme drought and
2 fire-suppression challenges for the Dixie Fire.

3 PG&E incurred reasonable costs to defend and resolve the litigation arising
4 from the Kincade and Dixie Fires. The Wildfire Fund Administrator has already
5 determined that PG&E's process for resolving claims related to these fires and
6 the amounts it paid to settle those claims were consistent with the exercise of
7 reasonable business judgment. PG&E also prudently repaired and
8 reconstructed its facilities that were destroyed and damaged by the fires.

9 **B. Summary of Requested Relief**

10 Through this Application and supporting testimony, PG&E respectfully
11 requests the following relief from the Commission related to costs paid in
12 connection with the Kincade and Dixie Fires:

- 13 • Approve as reasonable the costs recorded in PG&E's WEMA, net of
14 insurance, to resolve third-party claims arising from the Kincade Fire,
15 including claims filed by individual plaintiffs, subrogated insurers, and
16 public entities.
 - 17 ○ As of September 30, 2025, the Kincade Fire claims costs recorded
18 in PG&E's WEMA total approximately \$765.7 million of CPUC-
19 jurisdictional costs, which excludes \$430 million in claims costs
20 covered by insurance.
 - 21 ○ Of the \$765.7 million amount, PG&E seeks to recover
22 approximately \$700.9 million in rates, consistent with PG&E's cost
23 recovery proposal in Chapter 7: Cost Recovery and Revenue
24 Requirements.
 - 25 ○ The remaining approximately \$64.8 million has already been paid
26 by the Wildfire Fund.¹⁴ PG&E anticipates receiving additional
27 payments from the Wildfire Fund for Kincade Fire claims paid to
28 date, which would reduce the \$700.9 million that PG&E seeks to
29 recover in rates.

¹⁴ Pursuant to Section 3292(e), the Wildfire Fund is paying 40 percent of eligible claims related to the Kincade Fire, which occurred while PG&E was in bankruptcy. See Pub. Util. Code § 3292(e) ("[T]he fund shall not pay more than 40 percent of the allowed amount of a claim arising between [the effective date] and the date the electrical corporation exits bankruptcy . . .").

- PG&E will update these costs and provide an updated WEMA balance in its rebuttal testimony. This will include additional payments received from the Wildfire Fund, which will be credited to PG&E's WEMA, as well as any additional claims paid after September 30, 2025.
- Approve as reasonable the costs recorded in PG&E's WEMA, net of insurance, to resolve third-party claims arising from the Dixie Fire, including claims filed by individual plaintiffs, subrogated insurers, and public entities.
 - As of September 30, 2025, the Dixie Fire claims costs recorded in PG&E's WEMA total approximately \$1.3 billion of CPUC-jurisdictional costs, which excludes \$500 million in claims costs covered by insurance.
 - Of the \$1.3 billion amount, PG&E seeks to recover approximately \$691.2 million in rates, consistent with PG&E's cost recovery proposal in Chapter 7.
 - The remaining approximately \$609 million has already been paid by the Wildfire Fund. PG&E anticipates receiving additional payments from the Wildfire Fund for Dixie Fire claims paid to date, which would reduce the \$691.2 million that PG&E seeks to recover in rates.
- Approve as reasonable the costs recorded in PG&E's WEMA to defend and resolve claims arising from the Kincade and Dixie Fires, including costs for outside counsel, mediations, experts and consultants, e-discovery, and other litigation costs.
 - As of September 30, 2025, the Kincade and Dixie Fire litigation costs recorded in PG&E's WEMA total approximately \$199.8 million of CPUC-jurisdictional costs. PG&E will update these costs and provide an updated WEMA balance in its rebuttal testimony.
- The WEMA costs described above include financing costs accrued on the balance in PG&E's WEMA at the authorized interest rate for this memorandum account.

- 1 • PG&E will update its WEMA costs and provide an updated WEMA
2 balance in its rebuttal testimony. This will include additional payments
3 received from the Wildfire Fund, which will be credited to PG&E's
4 WEMA, as well as additional claims and litigation costs paid after
5 September 30, 2025.
- 6 • Approve as reasonable approximately \$71.6 million in capital costs and
7 \$242 million in O&M costs recorded in PG&E's CEMA as of February 28,
8 2025, and incurred by PG&E to restore service to customers and to
9 repair or replace facilities damaged by the Kincade and Dixie Fires; and
10 authorize the associated capital revenue requirement of approximately
11 \$64.5 million and O&M revenue requirement of approximately \$296.9
12 million.
- 13 • The CEMA costs described above include financing costs accrued on the
14 balance in PG&E's CEMA at the authorized interest rate for this
15 memorandum account.
- 16 • PG&E will update its CEMA costs and provide an updated CEMA
17 balance in its rebuttal testimony, including additional CEMA costs paid
18 after February 28, 2025.
- 19 • Approve as reasonable PG&E's proposals for updating its WEMA and
20 CEMA costs and for addressing WEMA and CEMA costs paid after
21 PG&E's rebuttal testimony. While PG&E has resolved substantially all
22 filed claims related to the Kincade and Dixie Fires, certain claims remain
23 outstanding and reimbursements from the Wildfire Fund are ongoing as
24 described above. Restoration efforts also remain ongoing. In Chapter 7,
25 PG&E explains that it will update its WEMA and CEMA costs in its
26 rebuttal testimony and proposes processes to address WEMA and
27 CEMA costs paid after its rebuttal testimony.

TABLE 1-1
WEMA COSTS AS OF SEPTEMBER 30, 2025
(THOUSANDS OF DOLLARS)

Line No.	Costs	Kincade	Dixie	Both Fires
1	Claims Payments <\$1 billion	1,000,000	1,000,000	2,000,000
2	Insurance Reimbursements	(430,000)	(500,000)	(930,000)
3	Claims Payments >\$1 billion	276,001	858,614	1,134,615
4	Wildfire Fund Reimbursements	(64,771)	(609,082)	(673,853)
5	FERC Jurisdictional Costs	(126,302)	(120,864)	(247,166)
6	Interest	45,995	62,525	108,520
7	<i>Net Claims</i>	700,923	691,193	1,392,116
8	Litigation Costs	64,228	136,133	200,361
9	FERC Jurisdictional Costs	(6,180)	(12,803)	(18,983)
10	Interest	7,621	10,843	18,464
11	<i>Net Litigation Costs</i>	65,669	134,173	199,842
12	<i>WEMA Balance (September 30, 2025) (lines 7 and 11)</i>	766,592	825,366	1,591,958
13	<i>Total WEMA Costs under Review (lines 4 and 12)</i>	831,363	1,434,448	2,265,811

TABLE 1-2
CEMA COSTS AND REVENUE REQUIREMENTS
(THOUSANDS OF DOLLARS)

Line No.	Costs and Revenue Requirements	Expense	Capital
1	Total CEMA Costs	242,018	71,647
2	CEMA Revenue Requirement (without interest)	241,810	61,436
3	Interest (2019-2027)	55,129	3,037
4	CEMA Revenue Requirement (with interest)	296,939	64,473

1 C. The Kincade and Dixie Fires

2 *The Kincade Fire.* The Kincade Fire ignited on the evening of October 23,
3 2019, east of Geyserville in Sonoma County, in a geothermal field known as the
4 Geysers. The area was under a Red Flag Warning at the time, meaning that
5 conditions included warm temperatures, very low humidity, and strong winds that
6 combined to increase the risk of wildfires. These conditions—addressed in

1 detail in Chapter 4: External Factors—caused the Kincade Fire to spread rapidly,
2 resulting in the largest mandatory evacuation in the history of Sonoma County.

3 Cal Fire conducted an investigation into the origin and cause of the Kincade
4 Fire and issued a report (referred to herein as the Kincade fire agency report)
5 concluding that the ignition resulted from a broken jumper conductor associated
6 with the Geysers #9 Line.¹⁵ PG&E does not dispute that causal conclusion.
7 The evidence shows that PG&E had no prior indication the jumper conductor
8 would break as it did, as described below and in more detail in Chapter 3A: The
9 Kincade Fire.

10 According to Cal Fire, the Kincade Fire ultimately burned approximately
11 77,758 acres, destroyed 374 structures, damaged 60 structures, and caused
12 four injuries. Following the fire, individual claimants, subrogated insurers, and
13 public entities filed civil lawsuits against PG&E for damages caused by the
14 Kincade Fire based on inverse condemnation and other claims. PG&E has
15 prudently defended against and resolved these claims, as summarized below
16 and described in detail in Chapter 5: Litigation and Claims Costs. PG&E
17 submitted eligible claims—i.e., third-party claims exceeding the \$1 billion
18 threshold amount—to the Wildfire Fund for payment, and the Wildfire Fund
19 Administrator determined that the resolution of claims was consistent with the
20 exercise of reasonable business judgment, including for claims under the
21 \$1 billion threshold.¹⁶

22 Following the Kincade Fire, PG&E restored service to customers and
23 repaired and rebuilt PG&E's facilities damaged or destroyed by the fire. PG&E
24 recorded these incremental costs related to restoring service to customers and
25 repairing or replacing facilities damaged by the fire in its CEMA. These rebuilt
26 and repaired facilities continue to provide service to PG&E's customers today.

¹⁵ See Chapter 3A: The Kincade Fire, Attachment 1.

¹⁶ While only eligible claims are paid by the Wildfire Fund, the Wildfire Fund Administrator reviews *all* claims—including claims under the \$1 billion threshold amount—to confirm that PG&E reached the eligible claim threshold based on claims payments consistent with reasonable business judgment. See Pub. Util. Code § 3292(f)(1); California Earthquake Authority, Wildfire Fund Administrator, Claims Administration Procedures (dated July 22, 2021, amended May 4, 2023), available at: <<https://tinyurl.com/ClaimsAdministrationProcedures>> (accessed Nov. 11, 2025), § II.A.

1 *The Dixie Fire.* The Dixie Fire ignited in the late afternoon of July 13, 2021,
2 in a remote area of the Feather River Canyon above PG&E's Cresta Dam in
3 Plumas County. Despite igniting under fair weather conditions and without a
4 Red Flag Warning in effect, the remote location of the ignition complicated the
5 fire-suppression response. Firefighters were hindered in their initial suppression
6 efforts by the remote and inaccessible terrain and by a sighting of an unmanned,
7 unidentified drone that forced air resources to be grounded for their safety.¹⁷
8 After the initial containment efforts were unsuccessful, the fire spread rapidly
9 due to factors including an unprecedented amount of dry fuel caused by severe
10 drought conditions. The impact of these factors is discussed in detail in
11 Chapter 4: External Factors. The Dixie Fire ultimately grew to become the
12 largest single-origin wildfire in California history, burning through five counties
13 over the course of nearly two months.

14 Cal Fire investigated the origin and cause of the Dixie Fire and issued a
15 report (referred to herein as the Dixie fire agency report) concluding that the
16 ignition resulted from a Douglas fir tree (the Subject Tree) falling onto a PG&E
17 distribution line.¹⁸ PG&E does not dispute that causal conclusion. The
18 evidence shows that PG&E performed numerous vegetation management
19 patrols of this area in the years preceding the fire. The Subject Tree appeared
20 healthy and was not identified as a potential hazard, as described below and in
21 more detail in Chapter 3B: The Dixie Fire.

22 According to the Dixie fire agency report, the Dixie Fire ultimately burned
23 approximately 963,309 acres, destroyed 1,311 structures, damaged 94
24 structures, and resulted in four firefighter injuries. Following the fire, individual
25 claimants, subrogated insurers, and public entities filed civil lawsuits against
26 PG&E for damages caused by the Dixie Fire based on inverse condemnation
27 and other claims. PG&E has prudently defended against and resolved these

17 Local and federal agencies investigated the drone and concluded it was not associated with PG&E. See Jiang, J, North State Public Radio, More than a year later, the investigation into the drone that hampered the Dixie Fire air attack was still in progress (Aug. 18, 2022), available at: <<https://www.myspr.org/news/2022-08-18/more-than-a-year-later-the-investigation-into-the-drone-that-hampered-the-dixie-fire-air-attack-is-still-in-progress>> (accessed Oct. 27, 2025).

18 See Chapter 3B: The Dixie Fire, Attachment 1.

claims, as summarized below and described in detail in Chapter 5: Litigation and Claims Costs. PG&E has submitted eligible claims to the Wildfire Fund for payment, and the Wildfire Fund Administrator determined that the resolution of claims was consistent with the exercise of reasonable business judgment, including for claims under the \$1 billion threshold. This review has confirmed that the process and payments are consistent with the exercise of reasonable business judgment. The Wildfire Fund Administrator continues to review and approve eligible claims related to the Dixie Fire. As of September 30, 2025, PG&E has resolved substantially all of the claims filed by individual plaintiffs with respect to the Dixie Fire.¹⁹ PG&E has resolved all claims with the subrogation plaintiffs and nearly all claims with public entities.²⁰

PG&E facilities were also damaged or destroyed in the fire. PG&E worked to restore service to customers and repaired and rebuilt PG&E's facilities damaged in the fire. PG&E recorded these incremental costs related to restoring service to customers and repairing or replacing facilities damaged by the fire in its CEMA. These rebuilt and repaired facilities continue to provide service to PG&E's customers today.

D. AB 1054 Establishes a New Framework and Standard for Catastrophic Wildfire Proceedings

This Application is subject to the framework established through AB 1054 in 2019 for costs associated with a "covered wildfire," defined as a wildfire that "ignited on or after July 12, 2019," and was caused by electrical facilities.²¹

¹⁹ PG&E also is continuing to resolve claims for more minor damage.

²⁰ The claim for fire-suppression costs filed by Cal Fire remains outstanding, as discussed in Chapter 5: Litigation and Claims Costs.

²¹ Pub. Util. Code § 1701.8(a)(1). AB 1054 originally defined a "covered wildfire" as a wildfire on or after July 12, 2019, that is "caused by an electrical corporation as determined by the governmental agency responsible for determining causation." Stats 2019, ch. 79, § 15 (AB 1054), effective July 12, 2019, until January 1, 2020. In 2021, the Legislature broadened the definition to also include a wildfire that "a court of competent jurisdiction determines . . . was caused by an electrical corporation," Pub. Util. Code § 1701.8(a)(1)(A), or that is "[a]sserted to have been caused by an electrical corporation and results in a court-approved dismissal resulting from the settlement of third-party damage claims." *Id.* § 1701.8(a)(1)(B). As discussed below, the responsible government agency (Cal Fire) found that both the Kincade and Dixie Fires were caused by PG&E facilities.

1 AB 1054 enacted a broad set of reforms to address the challenges associated
2 with catastrophic wildfires that involve utility equipment.

3 1. AB 1054 was enacted to remedy “an unprecedented state of instability”
4 faced by California utilities, caused principally by “destructive and deadly
5 wildfires.”²² Before AB 1054’s passage, the credit ratings for PG&E and
6 other electrical utilities had plummeted due to the increasing frequency and
7 severity of wildfires in California.²³ Those credit downgrades increased
8 borrowing costs for utilities, which costs were “passed directly to
9 customers.”²⁴ The high costs and uncertainty of access to capital
10 “jeopardize[d] the ability of these corporations to provide safe and reliable
11 electric and gas service, to reduce the risk of future catastrophes, to provide
12 service at just and reasonable rates, to meet the state’s mandates to reduce
13 carbon emissions, and to address the risks of climate change.”²⁵

14 The challenge of increasing wildfire risk was amplified by tensions in
15 the legal landscape. On the one hand, judicial decisions applied a strict-
16 liability, no-fault standard to inverse condemnation claims—on the premise
17 that the cost of damage “can be better absorbed, and with infinitely less
18 hardship, by the taxpayers as a whole than by the owners of the individual
19 parcels damaged.”²⁶ On the other hand, utilities faced regulatory
20 uncertainty about the ability to recover wildfire-related costs. A pivotal
21 moment came in 2017, with the Commission’s decision to deny the
22 application of San Diego Gas & Electric Company (SDG&E) to recover
23 \$379 million in costs arising from 2007 wildfires.²⁷ As the legislatively-
24 directed Commission on Catastrophic Wildfire Cost and Recovery explained,
25 that decision highlighted the failure of the existing regime to “equitably

22 Pub. Util. Code § 854.2(a)(6).

23 *Id.*

24 SB 901 Commission Report, p. 2, available at: <[https://lci.ca.gov/docs/20190618-Commission on Catastrophic Wildfire Report FINAL for transmittal.pdf](https://lci.ca.gov/docs/20190618-Commission%20on%20Catastrophic%20Wildfire%20Report%20FINAL%20for%20transmittal.pdf)> (accessed Aug. 26, 2025).

25 Pub. Util. Code § 854.2(a)(6).

26 *Albers v. County of Los Angeles* (1965) 62 Cal.2d 250, 263; see also, e.g., *Holtz v. Superior Ct.* (1970) 3 Cal.3d 296, 303.

27 D.17-11-033.

1 socialize the costs of utility-caused wildfires.”²⁸ It also “raised questions as
2 to whether a more predictable standard of review for wildfire claims is
3 warranted, and whether it should be more permissive given the nature of the
4 risk, size of potential liabilities, and assumptions of cost socialization
5 assumed in ‘no-fault’ liability.”²⁹ In the meantime, “[t]he increasing costs of
6 capital and the risk of bankruptcy associated with the application of strict
7 liability inverse condemnation doctrine to . . . investor-owned utilities is
8 harmful to wildfire victims, ratepayers, and the utilities themselves.”³⁰
9 Recognizing similar principles, two members of the Commission, in a
10 separate joint concurrence in the SDG&E decision, “respectfully urge[d] the
11 California Legislature to affirmatively address” the cost recovery standards
12 applied by the Commission.³¹

13 Against this backdrop, the 2019 Legislature designed AB 1054 as “a
14 new approach to address the calls for more certainty in the cost recovery
15 process in order to restore the regulatory compact.”³² The Legislature
16 sought to “support[] the credit worthiness” of participating utilities and
17 “provide[] a mechanism to attract capital for investment in safe, clean, and
18 reliable power for California at a reasonable cost to utility customers.”³³

- 19 **2.** AB 1054 changed the framework for wildfire cost recovery by adopting a
20 presumption of prudence in favor of an electric utility that had a valid safety
21 certificate when the wildfire ignited, and shifting the burden to other parties

28 SB 901 Commission Report, p. 4.

29 SB 901 Commission Report, p. 6.

30 SB 901 Commission Report, p. 5.

31 D.17-11-033, Joint Concurrence of President Picker and Commissioner Guzman Aceves, pp. 6-7. The Commissioners advocated for a cost recovery standard that would “explicitly allow a more nuanced assessment of fault” and reject “a binary choice of determining prudence in the aggregate.” *Id.* at p. 6. In addition to calling on the Legislature, they “respectfully urge[d] the California Courts of Appeal to carefully consider the rationale for applying inverse condemnation in these types of cases.” *Id.* at pp. 6-7.

32 Summary of AB 1054, p. 13.

33 AB 1054 (2019-2020 Reg. Session), Sec. 1(a)(5).

1 to raise “serious doubt” to overcome that presumption.³⁴ The legislative
2 analyses of AB 1054 highlighted the “similarity” of the presumption “to what
3 is afforded in the Federal Energy Regulatory Commission Process.”³⁵

4 In other words, under AB 1054, a utility that underwent the rigorous
5 process of obtaining a valid safety certification is presumed to have acted
6 reasonably under the codified prudence standard in Section 451.1(b). So
7 the utility’s presumption of prudence is tied to its safety certification, which in
8 turn depends in part on a WMP approved by Energy Safety and ratified by
9 the Commission *prior to* the ignition of that wildfire. That criterion reflects
10 AB 1054’s focus on managerial policies and decision making, not individual
11 conduct in the moment. It also reflects the statute’s reliance on a process in
12 which a utility’s management of wildfire risks can be objectively measured
13 *before* the occurrence of a catastrophic wildfire.

14 As economist Dr. Debra Aron explained in testimony on behalf of
15 Southern California Edison (SCE) in prior cost recovery proceedings, this
16 framework is “conducive to regulatory consistency” because it “establish[es]
17 objective criteria that, if met, create an expectation of cost recovery.”³⁶ It is
18 also good public policy: “When a rate-of-return regulated utility is authorized
19 by the regulator to incur a certain level of expenditures on fire precaution, it
20 creates an expectation as to whether the expenditures—and wildfire costs
21 that may occur as a result of the residual risks associated with that level of
22 expenditures—will be recoverable.”³⁷ “Consumers are best served” when
23 the utility’s later ability to recover wildfire costs is consistent with the
24 prospective analysis of “precautionary expenditures,” which supports “the
25 ability of the utility to attract capital and [its] cost of capital.”³⁸

³⁴ Section 451.1(c) provides: “An electrical corporation bears the burden to demonstrate, based on a preponderance of the evidence, that its conduct was reasonable pursuant to subdivision (b) unless it has a valid safety certification pursuant to Section 8389 for the time period in which the covered wildfire that is the subject of the application ignited.”

³⁵ AB 1054 Senate Floor Analysis, p. 8.

³⁶ A.23-08-013, SCE-01 (Opening Testimony), Vol. 02, Economic Policy Testimony (sponsored by witness Dr. Debra Aron of Charles River Associates), p. 57.

³⁷ *Id.* at p. 21.

³⁸ *Id.*

1 Only if a party to the proceeding creates a “serious doubt” as to
2 whether the utility acted reasonably does the burden shift to the utility to
3 establish that its conduct was prudent.³⁹ This statutory presumption was
4 intended to adopt the standard used by the Federal Energy Regulatory
5 Commission (FERC),⁴⁰ which makes clear that the “presumption of
6 prudence is not easily refuted,” and challenging parties face a high bar to
7 create “serious doubt.”⁴¹ That standard recognizes the “broad discretion” of
8 “managers of a utility,” and maintains that “a mistake” or an error “in
9 hindsight” does not establish imprudence.⁴²

10 **3.** AB 1054 codified the prudence standard to be applied by the Commission in
11 catastrophic wildfire cost recovery proceedings.⁴³ That standard includes
12 several features worth highlighting here.

13 By referencing the “conduct of the electrical corporation,” the
14 reasonableness standard reinforces the importance of the utility’s

39 Section 451.1(c) provides: “If the electrical corporation has received a valid safety certification for the time period in which the covered wildfire ignited, an electrical corporation’s conduct shall be deemed to have been reasonable pursuant to subdivision (b) unless a party to the proceeding creates a serious doubt as to the reasonableness of the electrical corporation’s conduct. Once serious doubt has been raised, the electrical corporation has the burden of dispelling that doubt and proving the conduct to have been reasonable.”

40 See Senate Committee on Energy, Utilities and Communications (July 8, 2019), p. 13 (equating the AB 1054 presumption to the presumption “afforded in the Federal Regulatory Commission (FERC) process”).

41 San Diego Gas & Electric Company, 146 FERC ¶ 63,017, P 57 (2014).

42 Entergy Services, Inc., 130 FERC ¶ 61,023, PP 51, 52 (2010).

43 Section 451.1(b) provides: “When determining an application by an electrical corporation to recover costs and expenses arising from a covered wildfire, the commission shall allow cost recovery if the costs and expenses are just and reasonable. Costs and expenses arising from a covered wildfire are just and reasonable if the conduct of the electrical corporation related to the ignition was consistent with actions that a reasonable utility would have undertaken in good faith under similar circumstances, at the relevant point in time, and based on the information available to the electrical corporation at the relevant point in time. Reasonable conduct is not limited to the optimum practice, method, or act to the exclusion of others, but rather encompasses a spectrum of possible practices, methods, or acts consistent with utility system needs, the interest of the ratepayers, and the requirements of governmental agencies of competent jurisdiction. Costs and expenses in the application may be allocated for cost recovery in full or in part taking into account factors both within and beyond the utility’s control that may have exacerbated the costs and expenses, including humidity, temperature, and winds.”

1 managerial decision-making process, meaning its operational programs,
2 policies, and procedures.⁴⁴ That makes good sense, as underscored by
3 Dr. Aron’s prior testimony: A utility *can* establish programs, policies, and
4 procedures to carry out its operations and priorities, and to govern hiring and
5 training of qualified employees. But it *cannot* control every decision of its
6 employees and representatives to ensure that no errors are ever made.⁴⁵
7 Indeed, utilities (like other firms) face a “principal agent problem” in “inducing
8 their workers . . . to act in accordance with the objectives of the firm,”
9 because “the worker has information that the company does not have” but
10 “the worker’s self-interest is not perfectly aligned with the interests of the
11 company.”⁴⁶ Evaluation of prudence should therefore be based on
12 operational programs, policies, and procedures established at the enterprise
13 level, and not one-off errors or missteps of specific individuals.⁴⁷

14 The inquiry considers whether the utility’s conduct “was consistent with
15 actions that a reasonable utility would have undertaken in good faith under
16 similar circumstances . . . based on the information available to the electrical
17 corporation at the relevant point in time,” which is the time leading up to the
18 fire in question. The standard recognizes, however, that prudent conduct
19 “encompasses a spectrum of possible practices, methods, or acts,” rather
20 than a single optimal practice or policy.⁴⁸

21 Finally, relevant conduct must be “related to the ignition,” such that any
22 allegedly imprudent policy, program, or practice must have a clear causal

⁴⁴ That aligns with the Commission’s pre-AB 1054 precedent focusing on whether a utility’s “managers” acted within the bounds of reasonableness. See, e.g., D.09-07-021, pp. 64-65.

⁴⁵ A.23-08-013, SCE-01, Vol. 02, p. 32 (“No utility can achieve perfection in its workers’ operational decisions—indeed, the utility must afford its workers discretion to make operational judgments given facts known at the time.”).

⁴⁶ *Id.* at p. 35.

⁴⁷ *Id.* at p. 32; see also *id.* at p. 37 (“If the company has established policies and systems for hiring, training, monitoring, and providing incentives that rigorously and in good faith are designed to induce conduct that advances the company’s goals in accordance with the Commission’s rules —i.e., is ‘prudent’—incorrect judgments, errors, and malfeasance may occur. This should not be treated by the Commission as imprudence by the company.”).

⁴⁸ Pub. Util. Code § 451.1(b).

nexus to the ignition.⁴⁹ That too makes sense: “[A]pplying a causation requirement for denial of cost recovery in addition to a finding of imprudence aligns the incentives of the utility with those of the Commission to invest the socially optimal amount in fire precautions.”⁵⁰ Otherwise, “imposing liability for the costs of a wildfire as a result of even a small deviation from the Commission’s prudence standard imposes significant regulatory risk on the utility that is disproportionate to and not necessarily related at all to the harm.”⁵¹

4. AB 1054 explicitly affirmed that the Commission may allocate costs “for cost recovery in full or in part [by] taking into account factors both within and beyond the utility’s control that may have exacerbated the costs, . . . including humidity, temperature, and winds.”⁵² This provision reflects the Legislature’s judgment that the extent of damage resulting from a utility-caused fire is influenced by a range of factors, including environmental and other factors beyond the utility’s control, and that the utility should not bear all of those costs. Regardless of the Commission’s determination regarding prudence, the statute specifically empowers the Commission to allow rate recovery to the extent the damages resulted from external factors.

5. AB 1054 set timelines to facilitate expeditious resolution of cost recovery applications for costs arising from covered wildfires. Specifically, Section 1701.8 provides that the scoping memorandum shall establish a schedule that provides for a date of issuance of a proposed decision “no later than 12 months after the filing date of the application.”⁵³

⁴⁹ Pub. Util. Code § 451.1(b).

⁵⁰ A.23-08-013, SCE-01, Vol. 02, p. 51.

⁵¹ *Id.*

⁵² Pub. Util. Code § 451.1(b). Members of the Commission supported revising the prudency standard “to explicitly allow a more nuanced assessment of fault,” and criticized the prior standard for allowing only “a binary choice of determining prudency in the aggregate.” D.17-11-033, Joint Concurrence of President Michael Picker and Commissioner Martha Guzman Aceves, p. 6.

⁵³ Pub. Util. Code § 1701.8(b)(4)(B). The statute further provides that the assigned commission may extend this timeline by “up to six months upon a showing of good cause.” *Id.* § 1701.8(b)(4)(C).

1 Section 1701.8 also provides for a prehearing conference to be held within
2 25 days of the filing date of the application and a scoping memorandum to
3 be issued within 30 days of the filing date of the application.⁵⁴

4 **6.** AB 1054 established the Wildfire Fund to provide a source of funds to pay
5 eligible claims arising from a covered wildfire for participating utilities that
6 assist in capitalizing the Wildfire Fund. To qualify for the Wildfire Fund,
7 PG&E was required to make an initial contribution of \$4.8 billion and annual
8 contributions of \$193 million, equating to nearly two-thirds of the Wildfire
9 Fund contributions by California's large investor-owned utilities (IOU).⁵⁵
10 Because AB 1054 did not permit PG&E to recover these costs from its
11 customers, these contributions were effectively borne by PG&E's
12 shareholders. This is a major departure from the cost-of-service ratemaking
13 principles that traditionally govern PG&E's expenditures, in which PG&E can
14 recover its costs from customers unless those costs resulted from
15 imprudence. PG&E's customers also have made substantial contributions
16 to the Wildfire Fund through the extension of the fixed recovery charge
17 under Section 8389 and Water Code Section 80524.⁵⁶

18 AB 1054 also barred PG&E from recovering a return on equity from its
19 initial \$3.21 billion in wildfire safety investments.⁵⁷ That is a further
20 departure from ordinary cost-of-service ratemaking: PG&E has traditionally
21 been permitted to recover a reasonable rate of return on reasonable capital
22 investments in safety projects. As the Commission has explained in

54 Pub. Util. Code § 1701.8(b)(3), (b)(4)(A).

55 The costs of the initial and annual contributions are allocated among the three IOUs pursuant to a "Wildfire Fund allocation metric" set forth in AB 1054. PG&E's initial Wildfire Fund allocation metric was 64.2 percent. See Pub. Util. Code § 3280(n).

56 See [R.19-07-017](#); R.23-03-007.

57 See Pub. Util. Code § 8386.3(e) ("The commission shall not allow a large electrical corporation to include in its equity rate base its share, as determined pursuant to the Wildfire Fund allocation metric specified in Section 3280, of the first five billion dollars (\$5,000,000,000) expended in aggregate by large electrical corporations on fire risk mitigation capital expenditures included in the electrical corporations' approved wildfire mitigation plans."); AB 1054 (2019-2020 Reg. Session), Sec. 2(g) ("The first \$5 billion in safety investments in the aggregate by the large electrical corporations must be made under this act without return on equity that would have otherwise been borne by ratepayers.").

1 applying longstanding legal precedent, public utilities are entitled to a return
2 on equity that is “reasonably sufficient to ensure confidence in the financial
3 soundness of the utility, and adequate, under efficient management, to
4 maintain and support its credit and to enable it to raise the money necessary
5 for the proper discharge of its public duties.”⁵⁸ The return on investment
6 “should be sufficient to cover capital costs of the business.”⁵⁹ But under
7 AB 1054, PG&E’s investors must forgo compensatory returns on a large
8 share of PG&E’s wildfire safety investments.

9 In exchange for the increased financial costs and risk borne by PG&E’s
10 shareholders, AB 1054 provided a more stable regulatory framework for
11 wildfire cost recovery through the reforms discussed in this section,
12 including the presumption of prudence for utilities with safety certifications.
13 Even though PG&E’s participation in the Wildfire Fund requires
14 shareholders to absorb significant costs, the bargain embodied in AB 1054
15 helped restore investor confidence by increasing certainty that PG&E would
16 recover costs for any covered wildfires if it adhered to the law’s
17 requirements, as PG&E has done with respect to the Kincade and Dixie
18 Fires.⁶⁰ And by promoting the financial stability of PG&E and the other
19 IOUs in California, AB 1054 benefits customers and the general public by
20 enabling continued service, alongside investments in safety and climate
21 goals, while limiting rate increases.

- 22 7. The Wildfire Fund pays eligible claims in excess of a threshold amount of
23 \$1 billion. Before approving payments to the utility, the Wildfire Fund

⁵⁸ D.19-12-056, p. 16 (citing *Bluefield Water Works & Improvement Company v. Public Service Commission of the State of Virginia*, 262 U.S. 679 (1923)).

⁵⁹ D.19-12-056, p. 16 (citing *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591 (1944)).

⁶⁰ See, e.g., S&P Global Ratings, Pacific Gas & Electric Co.: Ratings Score Snapshot (Feb. 13, 2023), p. 5 (“[PG&E’s] credit quality significantly benefits from the Wildfire Fund as a liquidity source, and we believe the revised standards will likely allow [it] to recover future wildfire costs from ratepayers.”); Moody’s Investors Service, Pacific Gas & Electric Company: Credit Opinion (Feb. 16, 2023), p. 13 (analyzing “credit supportive mechanisms” adopted by AB 1054, including access to Wildfire Fund and revised cost recovery standards, and noting that “[o]ne of the more important changes is that the burden of proof” in cost recovery proceedings “has shifted from the utility to the intervenors”).

1 Administrator reviews both the threshold claims (claims under \$1 billion) and
2 the eligible claims to ensure that all claims were paid consistent with the
3 exercise of “reasonable business judgment.”⁶¹

4 After a utility has received payment from the Wildfire Fund for eligible
5 claims, the utility must file an application with the Commission to initiate
6 review of the underlying costs in a catastrophic wildfire proceeding. The
7 Commission reviews the amounts previously paid by the Wildfire Fund and
8 other costs related to the wildfire pursuant to Section 451.1. If the
9 Commission determines that the costs are just and reasonable, the
10 Commission “shall allow cost recovery.”⁶² If the Commission reviews “the
11 conduct of the electrical corporation related to the ignition” and finds costs
12 unreasonable,⁶³ the utility’s obligation to reimburse the Wildfire Fund is
13 capped at the lesser of two amounts: (i) the disallowed amount that the
14 Commission determined was not just and reasonable; or (ii) 20 percent of
15 the utility’s transmission and distribution equity rate base, calculated on a
16 three-year rolling basis.⁶⁴ PG&E has sought and obtained payment from
17 the Wildfire Fund for eligible claims related to the Kincade and Dixie Fires.

18 As described in detail in Chapter 5, PG&E has resolved nearly all filed
19 claims related to the Kincade Fire and the vast majority of filed claims
20 related to the Dixie Fire. On October 3, 2025, the Wildfire Fund
21 Administrator requested, pursuant to Section 1701.8(b)(1)(B)(ii), that PG&E
22 “commence a catastrophic wildfire proceeding concerning the 2019 Kincade

⁶¹ See Pub. Util. Code § 3292(f). “Reasonable Business Judgment” is defined as “[t]he judgment by the Participating Utility of the validity and value of a claim that is based on the process employed by the Participating Utility and the types of information and documentation generally relied upon by the Participating Utility to reach a fair evaluation of the Participating Utility’s liability for, and amount of, the claim.” California Earthquake Authority, Wildfire Fund Administrator, Claims Administration Procedures (as amended May 4, 2023), p. 12.

⁶² Pub. Util. Code § 451.1(b).

⁶³ *Id.*

⁶⁴ See Pub. Util. Code § 3292(h)(2). The Commission has noted this element of AB 1054, explaining that “[s]hareholders are only required to repay the [Wildfire] [F]und for imprudent wildfire costs, and only up to a cap.” D.19-12-056, Decision on Test Year 2020 Cost of Capital for the Major Energy Utilities, p. 36 and p. 51, Findings of Fact 28-29.

1 Fire and the 2021 Dixie Fire.”⁶⁵ The Administrator emphasized the need for
2 timely resolution as to these earlier covered wildfires in light of the 2025
3 Eaton Fire. Expeditious resolution of the Application also benefits
4 customers given the ongoing financing costs associated with the WEMA and
5 CEMA costs and the significance of cost recovery to PG&E’s financial
6 health.

7 **E. PG&E Has a Statutory Presumption of Prudence and Operated Its**
8 **System Prudently**

9 PG&E had valid safety certifications in 2019 and 2021 when the Kincade
10 and Dixie Fires ignited, and is therefore entitled to the presumption of
11 prudence.⁶⁶ Specifically, at the time of the Kincade Fire, PG&E had an Initial
12 Safety Certification issued by the Commission on August 23, 2019; and at the
13 time of the Dixie Fire, PG&E had a subsequent safety certification issued by the
14 Commission on January 14, 2021.⁶⁷ Thus, PG&E’s application is subject to the
15 statutory presumption that its conduct was reasonable with respect to both fires.

16 This presumption represents a “fundamental distinction” between the
17 AB 1054 framework and the Commission’s typical review process under
18 Section 451, where a utility-applicant bears the burden.⁶⁸ In particular, the
19 “approach” enacted in AB 1054 was designed “to address the calls for more
20 certainty in the cost recovery process in order to restore the regulatory
21 compact.”⁶⁹ Only if the Commission determines that another party has raised
22 “serious doubt” would the burden shift to the utility to dispel that doubt and prove

⁶⁵ See Application Exhibit A.

⁶⁶ Pub. Util. Code § 451.1(c).

⁶⁷ Initial Safety Certification (Aug. 23, 2019), available at: <https://energysafety.ca.gov/wp-content/uploads/docs/safety-certificates/news/pge-safety-certificate_signed-20190823.pdf> (accessed Aug. 27, 2025); Wildfire Safety Division Issuance of Pacific Gas and Electric Company’s 2020 Safety Certification (Jan. 14, 2021), available at: <<https://energysafety.ca.gov/wp-content/uploads/docs/misc/wsd/wsd-to-pge-safety-certificate-20210114.pdf>> (accessed Aug. 27, 2025).

⁶⁸ Summary of AB 1054, p. 13. *Compare* Pub. Util. Code § 451.1(c) *with* D.18-07-025, p. 6 (“The burden rests heavily upon a utility to prove . . . that it is entitled to the requested rate relief and not upon the Commission, its staff, or any interested party to prove the contrary.”) (quoting D.02-08-064) (ellipsis in original).

⁶⁹ Summary of AB 1054, p. 13.

1 its conduct was reasonable under the standard set forth in Section 451.1(b).
2 Thus, raising “serious doubt as to the reasonableness of” PG&E’s conduct under
3 Section 451.1 is a high bar, as shown by relevant FERC precedents addressing
4 that standard. And even if “serious doubt” could be raised, as would shift the
5 burden back to PG&E to establish prudence, PG&E demonstrates through this
6 Application and supporting testimony that the WEMA and CEMA costs incurred
7 in connection with the Kincade and Dixie Fires are reasonable and should be
8 authorized for recovery.⁷⁰

9 **1. The Presumption of Prudence**

10 **a. PG&E Went Through a Rigorous Review to Qualify for the** 11 **Presumption**

12 AB 1054 prescribes a rigorous process to qualify for the
13 presumption of prudence. To obtain a safety certification under
14 AB 1054, a utility must meet standards prescribed by the Legislature
15 and undergo a robust review of its wildfire mitigation, safety, and other
16 policies and practices. The first requirement is having an approved
17 WMP.⁷¹ The utility’s plan must contain an extensive list of elements as
18 defined by statute, including detailed descriptions of strategies and
19 programs to minimize the risk of utility-equipment-involved ignitions,
20 measurable performance metrics, prioritized lists of wildfire risks and
21 drivers, and plans for vegetation management, equipment inspections,
22 system hardening, and workforce development, among many other
23 requirements.⁷²

24 To obtain an *initial* safety certification in 2019, a utility had to satisfy
25 additional requirements to: implement the findings of its most recent
26 safety-culture assessment, establish a safety committee of its board of

⁷⁰ PG&E also pursued recovery of FERC-jurisdictional costs arising from the Kincade Fire and Dixie Fire. FERC recently approved a settlement allowing PG&E to collect from its transmission customers 77 percent of the value of wildfire costs attributable to the Kincade Fire and the Dixie Fire, as well as the Zogg Fire and several other wildfires. See FERC Dkt. No. ER19-13-000, *et al.*, Offer of Settlement and Stipulation (Mar. 21, 2025), pp. 13-14, 16.

⁷¹ Pub. Util. Code § 8389(a)(1).

⁷² See Pub. Util. Code § 8386(b)-(c).

1 directors composed of members with relevant safety experience, and
2 establish board-level reporting to the Commission on safety issues.⁷³
3 To renew its safety certification in subsequent years, a utility had to
4 continue meeting these requirements and comply with additional
5 requirements, including obtaining Commission approval of an executive
6 incentive-compensation structure designed to promote safety.⁷⁴ A utility
7 also needed to submit quarterly reports on wildfire mitigation plan
8 implementation, independent third-party safety-culture assessment
9 recommendations, and board of director safety committee
10 recommendations, which were subject to discretionary audits by Energy
11 Safety.⁷⁵

12 PG&E fully complied with AB 1054's requirements in order to obtain
13 safety certifications for the periods that encompass the Kincade and
14 Dixie Fires. Each step required sustained attention from key members
15 of PG&E's executive management team and deliberate decision making
16 about investments and spending to optimize wildfire mitigation and
17 safety practices. Because the process to obtain a safety certification
18 centers on enterprise-based decisions at the executive level, it
19 underscores and is consistent with AB 1054's focus on managerial
20 conduct in assessing prudence.

21 Starting in 2019, and thereafter throughout the periods that
22 encompass the Kincade and Dixie Fires, PG&E prepared and submitted
23 a WMP, or WMP update, for approval each year. PG&E's plans are
24 developed, reviewed, and approved through an open process with
25 engagement from Energy Safety and various stakeholders, including

73 See Pub. Util. Code §§ 8389(a)(2)-(3), (5), 8389(b)(1) (setting forth requirements for an initial safety certification).

74 See Pub. Util. Code § 8389(a)(4)-(6).

75 See Pub. Util. Code § 8389(a)(7). In 2021, the Legislature amended Pub. Util. Code Section 8389(f) to shift responsibility for discretionary audits of quarterly reports from the Wildfire Safety Division to Energy Safety. See Stats 2021, Ch. 115, § 82 (AB 148), effective July 22, 2021.

1 other local and state agencies.⁷⁶ Before approving each plan, Energy
2 Safety “verif[ied] that the plan complie[d] with all applicable rules,
3 regulations, and standards”⁷⁷ On May 30, 2019, the Commission
4 approved PG&E’s first WMP.⁷⁸

5 PG&E’s activities under its WMPs were subject to strict oversight by
6 Energy Safety.⁷⁹ At the direction of Energy Safety, a qualified
7 independent evaluator prepared annual reports on PG&E’s WMP
8 activities, including funding commitments.⁸⁰ Energy Safety specifically
9 audited the vegetation management requirements contained in PG&E’s
10 WMP and had the ability to order remediation of any identified
11 deficiencies.⁸¹ Additionally, Energy Safety completed its own annual
12 reviews of PG&E’s activities under its WMP, which were informed by
13 findings from Energy Safety’s audits and field inspections, the
14 independent evaluator’s report, and PG&E’s self-assessment, among
15 other data.⁸²

16 **b. The Presumption of Prudence Allows Considerable Latitude and**
17 **Serious Doubt Is a Steep Hurdle**

18 AB 1054’s presumption of prudence and requirement of “serious
19 doubt” to overcome that presumption are consistent with the cost
20 recovery standard applied by FERC.⁸³ As FERC has explained: “[A]

⁷⁶ See Pub. Util. Code § 8386(d). Before Energy Safety was established on July 1, 2021, the Wildfire Safety Division reviewed and approved the utilities’ WMPs. See Cal. Gov. Code, § 15475; Pub. Util. Code § 8389.

⁷⁷ See Pub. Util. Code § 8386(d).

⁷⁸ D. 19-05-037, p. 58.

⁷⁹ Cf. Pub. Util. Code § 8389(b) (requiring Commission to adopt and approve a WMP compliance process).

⁸⁰ See Pub. Util. Code § 8386.3(c)(2).

⁸¹ See Pub. Util. Code § 8386.3(c)(5).

⁸² See Chapter 2: Prudence of Operations, Section 2.B, which discusses Energy Safety’s annual reports addressing PG&E’s execution of its 2020 and 2021 WMPs. There was not an annual compliance report framework for 2019 WMPs.

⁸³ See Senate Committee on Energy, Utilities and Communications (July 8, 2019), p. 13 (“The Governor’s Office notes this is a presumption with similarity to what is afforded in the Federal Energy Regulatory Commission (FERC) process.”).

1 utility does not have the burden of demonstrating that expenditures are
2 prudent. Rather, a challenger to prudence must create a ‘serious doubt’
3 as to the prudence of an expenditure”⁸⁴ Costs are reviewed to
4 determine whether they would have been incurred by “a reasonable
5 utility management . . . , in good faith, under the same circumstances,
6 and at the relevant point in time.”⁸⁵ The standard “permits considerable
7 latitude,” so that the Commission “does not look for a single correct
8 result or require that every possible alternative be evaluated.”⁸⁶

9 Under that standard, the “presumption of prudence is not easily
10 refuted,” and challenging parties rarely succeed in creating serious
11 doubt.⁸⁷ “It does not suffice to make general, sweeping allegations of
12 imprudence”; rather, a challenge must “raise discrete issues and present
13 specific evidence raising doubts pertaining to the prudence” of particular
14 costs.⁸⁸ Moreover, a party “must do more than, in hindsight, second
15 guess utility management decisions.”⁸⁹ Instead the focus is on whether
16 “management decisions were imprudent at the time” of the incident.⁹⁰
17 “Even if a decision turns out to be incorrect in hindsight, [FERC]’s task is
18 to review the prudence of a utility’s actions and the costs resulting from
19 the particular circumstances existing . . . at the time the costs were
20 incurred”⁹¹

21 Mistakes alone are generally insufficient to raise serious doubt, as
22 “[f]lawed or even wrong decision-making does not equate to

⁸⁴ See, e.g., *Entergy Services, Inc.*, 130 FERC ¶ 61,023, P 52 (2010).

⁸⁵ *San Diego Gas & Electric Company*, 146 FERC ¶ 63,017, P 56 (2014).

⁸⁶ *Id.*

⁸⁷ *Id.*, P 57.

⁸⁸ *Pacific Gas and Electric Company*, 173 FERC ¶ 61,045, P 181 (2020) (Initial Decision).

⁸⁹ *Core Elec. Coop. Grand Valley Rural Power Lines, Inc. et al.*, 184 FERC ¶ 61,084, P 47 (2023) (quoting *J. William Foley Inc. v. United Illuminating Co.*, 142 FERC ¶ 61,125, P 19 (2013)); see also *Ind. & Mich. Mun. Distributions Ass’n & Auburn*, 62 FERC ¶ 61,189, at *62239 (1993) (explaining that FERC’s “prudence standard is based on the principle that [FERC] should not, using the benefit of hindsight, replace the business decisions of a utility with its own”).

⁹⁰ *TransCanada Keystone Pipeline*, 188 FERC ¶ 61,077, P 116 (2024).

⁹¹ *Pacific Gas and Electric Company*, 173 FERC ¶ 61,045, P 179 (2020).

1 imprudence.”⁹² In one example, FERC found that PG&E’s capital
2 expenditures for a cable project were prudent, although final costs
3 exceeded those forecast by over \$90 million.⁹³ It acknowledged the
4 concerns about cost, “particularly the cost overruns from [PG&E’s] initial
5 forecast,” but held that “any mistakes made by PG&E in developing this
6 significant transmission project ‘do not constitute the kind of
7 mismanagement that should raise serious doubts about the prudence of
8 their expenditures.’”⁹⁴

9 Regulatory violations likewise do not necessarily establish serious
10 doubt. In the course of FERC’s review of SDG&E’s costs from 2007
11 wildfires, it explained that “one [regulatory] violation by a utility does not
12 necessarily constitute imprudence, as utilities are not expected to be
13 infallible.”⁹⁵ Accordingly, “even if SDG&E had been found to have
14 violated [General Order] 95, that alone is insufficient to cast serious
15 doubt on the prudence of [the company’s] Wildfire Costs.”⁹⁶

16 This Commission has recognized that the FERC standard is “very
17 different” from the Section 451 standard that previously governed review
18 of wildfire-related costs.⁹⁷ Along the same lines, the Commission has
19 also noted that AB 1054 “altered the Commission’s standard of review”

⁹² TransCanada Keystone Pipeline, 188 FERC ¶ 61,077, P 112 (2024); see, e.g., Pacific Gas and Electric Company, 173 FERC ¶ 61,045, P 180 (2020) (Initial Decision) (“[A]ny mistakes made by PG&E in developing this significant transmission project ‘do not constitute the kind of mismanagement that should raise serious doubts about the prudence of their expenditures.’”).

⁹³ Pacific Gas and Electric Company, 173 FERC ¶ 61,045, P 163 (2020).

⁹⁴ *Id.* at P 180.

⁹⁵ San Diego Gas & Electric Company, 146 FERC ¶ 63,017, PP 55-56 (2014).

⁹⁶ *Id.* at P 55.

⁹⁷ D.18-07-025, Order Denying Rehearing of D.17-11-033 (Application of SDG&E for Authorization to Recover Costs Related to the 2007 Southern California Wildfires Recorded in the WEMA), p. 30. The Commission explained that under the FERC standard, “FERC presumes all costs requested by an IOU are reasonable and prudent, and its analysis stops there unless there is a specific challenge to the utility’s request.” *Id.* (citing San Diego Gas & Electric Company, 146 FERC ¶ 63,017, PP 37-38 (2014)).

1 of wildfire costs “for a utility with a valid safety certification, by creating a
2 presumption that a utility’s conduct was reasonable.”⁹⁸

3 **2. PG&E Was a Prudent Operator of its Electrical System**

4 As described in detail in Chapter 2 (Prudence of Operations), in the
5 years preceding the Kincade and Dixie Fires, PG&E implemented a robust
6 suite of policies and programs to mitigate and respond to increased wildfire
7 risk in its service area.

8 *Fire risk in PG&E’s service area.* PG&E is the largest combined natural
9 gas and electric utility in the United States and the largest utility in California.
10 Under the Commission’s 2018 Fire-Threat Map, more than 50 percent of
11 PG&E’s service area was within an area of elevated or extreme wildfire risk,
12 representing a massive increase (over 300 percent) from the Commission’s
13 prior maps (in effect from 2012 to 2017). The destructive 2017 and 2018
14 wildfire seasons, including the North Bay Fires and the Camp Fire that
15 ignited in PG&E’s service area, demonstrated a fundamental shift in the
16 wildfire risk landscape across the State and particularly in Northern
17 California. Climate change has been “a core driver” of this heightened
18 wildfire risk, fueling more frequent and destructive wildfires.⁹⁹

19 *PG&E’s wildfire mitigation efforts.* Wildfire risk cannot be fully
20 eliminated.¹⁰⁰ But PG&E has implemented a suite of measures with layers
21 of protection to reduce the risk of utility-caused wildfires across its service
22 area in response to this changing reality. PG&E’s efforts have included
23 significant infrastructure investments to harden its system, changes to its
24 inspection and maintenance programs, and new and expanded operational
25 mitigations, such as programs to disable reclosers and proactively de-
26 energize lines when warranted.

⁹⁸ D.19-12-056, Decision on Test Year 2020 Cost of Capital for the Major Energy Utilities, p. 35.

⁹⁹ 2019 Strike Force Report, p. 2.

¹⁰⁰ See, e.g., D.23-11-069, Decision on Test Year 2023 General Rate Case for PG&E, p. 256 (recognizing that “it is not possible to eliminate all risk” and discussing “the appropriate balance of risk reduction and costs”); *id.* at p. 798 (“Risk reduction alone is not a sufficient metric to judge the prudence of the proposed mitigations.”).

1 To capture and document these efforts, PG&E annually developed and
2 submitted its WMP to the Commission and Energy Safety for approval. As
3 noted, PG&E's WMP was an important element supporting the safety
4 certification that establishes the presumption of prudence in this proceeding.
5 PG&E has revised and updated its WMP over time based on input from the
6 Commission, Energy Safety, various third parties, and learnings by PG&E
7 and other utilities. In developing its WMPs, PG&E weighed risk reduction
8 and the costs of mitigation, including impacts on customer affordability and
9 reliability.¹⁰¹ Energy Safety issued detailed statements approving PG&E's
10 WMPs during the relevant time period, and the Commission ratified those
11 statements by resolution.¹⁰²

12 PG&E's effort to reduce wildfire risk is an evolving process. The
13 Commission's review of this application under Section 451.1, however, must
14 focus on "the tools and knowledge available during that snapshot in time"—
15 i.e., 2019 for the Kincade Fire and 2021 for the Dixie Fire—not what may be
16 known today with the benefits of hindsight and additional developments
17 across the industry in the time since the Fires.¹⁰³

18 *Design and construction.* PG&E provided safe and reliable service to its
19 customers in this time period. PG&E designed and constructed its system
20 to meet or exceed the CPUC's regulatory requirements for overhead
21 powerlines under General Order 95.

22 PG&E also employed advanced risk modeling to prioritize system-
23 hardening efforts on the most fire-prone segments of its electric grid. These
24 hardening strategies included replacing bare overhead conductors with
25 covered conductors and undergrounding lines entirely.

¹⁰¹ See, e.g., Pub. Util. Code § 8386(c)(12) (requiring that WMPs describe and prioritize the wildfire risks that are part of the utility's Risk Assessment Mitigation Phase filings, which include risk-spend efficiency modeling that attempts to maximize the effectiveness of safety investments while minimizing customer impacts).

¹⁰² E.g., Res. WSD-021 (Oct. 21, 2021).

¹⁰³ *Id.* (comments of Commissioner John Reynolds); D.05-08-037, p. 10 ("[T]he reasonableness of a particular management action depends on what the utility knew or should have known at the time that the managerial decision was made, not how the decision holds up in light of future developments. The Commission has affirmed this standard of review in numerous decisions over many years.").

1 PG&E utilized protection devices throughout its system to isolate faults
2 and reduce wildfire risk, including by disabling automatic reclosing during
3 periods of elevated wildfire risk. PG&E also deployed technology to enable
4 remote monitoring and control of reclosing devices and other equipment,
5 enhancing its ability to respond quickly to system conditions.

6 *Inspection and maintenance.* PG&E's comprehensive inspection and
7 maintenance programs exceeded regulatory requirements under General
8 Order 165 and focused on addressing growing wildfire risks. At the start of
9 2019, PG&E launched the Wildfire Safety Inspection Program (WSIP) to
10 accelerate and enhance inspections across its electric infrastructure. This
11 shift marked a transition from general asset inspections to a program
12 specifically focused on wildfire risk mitigation—emphasizing more frequent,
13 detailed, standardized, and digitally documented inspections, especially in
14 High Fire-Threat Districts. PG&E also expanded its existing inspection
15 efforts through specialized programs, including detailed and patrol
16 inspections, infrared inspections, and extensive vegetation management, all
17 backed by rigorous quality control and internal audits to ensure effective
18 implementation.

19 *System operation.* PG&E relied on a suite of operational policies,
20 programs, and equipment designed to address potential safety hazards and
21 reduce the risk of ignitions caused by PG&E's electrical equipment. PG&E
22 used control centers and other facilities to continuously monitor its systems
23 and respond to outages, protective relay operations, and other anomalies
24 that could indicate potential abnormal conditions on its electrical grid. PG&E
25 deployed tools and models for enhanced situational awareness, including
26 through real-time analysis of fire-weather conditions. PG&E used reclosing
27 devices to protect and de-energize its system. Its Public Safety Power
28 Shutoff (PSPS) program also served as a wildfire mitigation measure of last
29 resort. Finally, PG&E followed formal and comprehensive emergency
30 response protocols to facilitate dynamic responses and coordinate with
31 external stakeholders.

3. The Ignitions Were Not Caused By Any Imprudence and Do Not Raise Serious Doubt

a. The Kincade Fire

As described in detail in Chapter 3A: The Kincade Fire, the available evidence shows that the Kincade Fire was not attributable to any imprudence on the part of PG&E. The Kincade Fire ignited during an extreme wind event after a jumper conductor on a PG&E transmission line broke and contacted the metal tower. The facilities at issue were inspected numerous times in the years preceding the fire—including a detailed inspection using high-resolution drone imagery, a climbing inspection, and a ground inspection in 2019 alone—and no damage to the jumper conductor was identified. Post-incident examination by PG&E’s metallurgical expert showed that the jumper conductor separated due to fatigue, a type of mechanical failure, at a location within a solid metal clamp known as a “shoe.” PG&E’s expert explains that the shoe obscured the failure location prior to separation, and there was no visible indication of fatigue prior to the incident. PG&E’s expert further explains that based on his review, fatigue failure of a short, low-tension wire like the jumper conductor at issue is rare.

The facilities at issue previously connected a customer-owned geothermal power plant to the Geysers #9 Line. In response to a request from the plant owner advising that the plant was in a standby state, PG&E disconnected its transmission line from the neighboring Geysers Units 9/10 switchyard and placed the jumper conductors on the transmission tower at issue in an “open configuration.” This open configuration was intended to make expected future reconnection work safer and was not inconsistent with PG&E or industry standards. Moreover, PG&E installed several wind mitigation measures on the facilities, such as dampers, spacers, and heavy insulator strings, which were recommended by industry standards at the time to guard against the potential for damage.

1 **b. The Dixie Fire**

2 As described in detail in Chapter 3B: The Dixie Fire, the Dixie Fire
3 ignited in the late afternoon on July 13, 2021, after the Subject Tree
4 failed and fell onto overhead conductors on PG&E's Bucks Creek 1101
5 Circuit. Post-incident analysis showed that PG&E's system protection
6 on the Bucks Creek 1101 Circuit operated as expected. The impact of
7 the Subject Tree triggered a fault between two of the three phases of the
8 circuit, causing fuses on those two phases to operate and cause an
9 outage at the nearby Cresta Dam. Because the third phase was not
10 involved in the fault, the fuse on that phase did not operate, leaving that
11 phase energized. This resulted in a "high-impedance fault" from the
12 Subject Tree's contact that eventually, over many hours, led to an
13 ignition. Unlike a phase-to-phase fault that generates a significant surge
14 in current, high-impedance faults are difficult to detect because they are
15 low-current faults that appear indistinguishable from regular customer
16 load.

17 After receiving notice of the outage at Cresta Dam, PG&E
18 responded quickly. Early assessments did not indicate a continuing
19 safety hazard that would have required de-energizing the line. PG&E
20 deployed field personnel to investigate the outage and fault alarm. A
21 roving operator associated with hydroelectric operations was dispatched
22 to investigate the conditions at Cresta Dam but found no safety hazards.

23 Consistent with PG&E's policies and procedures, a troubleshooter
24 for PG&E's overhead electric system was assigned to investigate the
25 outage. The troubleshooter first inspected the equipment near the dam
26 and used binoculars to visually inspect the Bucks Creek 1101 Circuit,
27 which was located in a remote area upslope from the dam. He noticed
28 what appeared to be at least one open fuse on the line but did not see
29 any safety hazards such as vegetation contacting the line or smoke
30 indicating fire. After examining the line from the dam, he traveled a
31 lengthy route to access the fuse. His initial attempt to access the site
32 was blocked by a closed bridge approximately two miles from the fuse's
33 location. A Butte County road crew performing repair work on the bridge

1 informed the troubleshooter that it would be a few hours before he could
2 pass. The troubleshooter returned later that afternoon after the road
3 crew had left for the day and, ignoring a “road closed” sign, crossed the
4 bridge and continued on the road to access the fuse.

5 When the troubleshooter reached the involved facilities, he
6 discovered two open fuses on a pole, observed that a tree was resting
7 on the line, and saw a fire burning downhill from the pole. PG&E was
8 not aware of any safety hazard related to the facilities until this time.
9 The troubleshooter acted immediately: He de-energized the remaining
10 phase, radioed for assistance, and attempted to extinguish the fire
11 himself using equipment from his truck. He remained on site to offer
12 assistance to Cal Fire crews until they told him he was no longer
13 needed.

14 PG&E has not identified any information to suggest any prior
15 indication that the Subject Tree would fail. PG&E performed numerous
16 vegetation management patrols in the area in the years preceding the
17 fire, including a routine patrol in November and December 2020 and a
18 second patrol in January 2021, and the tree was not identified for work
19 because the tree appeared healthy and did not have a significant lean or
20 visible wound. A photo of the Subject Tree taken just two months before
21 the fire during a pole inspection shows that the tree appeared healthy
22 and did not have a significant lean or obvious defect.

23 **c. Agency Reports and Resolutions Do Not Raise Serious Doubt**

24 Section 451.1 establishes the legal standard that “shall direct” this
25 Commission’s “evaluation of applications for recovery of costs and
26 expenses arising from a covered wildfire.”¹⁰⁴ The reports and
27 resolutions of other agencies that investigated the Kincade and Dixie
28 Fires did not address or apply that legislatively directed standard for
29 evaluating prudence. In particular, they did not purport to address
30 whether there is any “serious doubt as to the reasonableness of

¹⁰⁴ Pub. Util. Code § 451.1(e).

1 [PG&E's] conduct.”¹⁰⁵ As described above, “serious doubt” is a high
2 bar that is not satisfied by alleged regulatory violations, claimed
3 mistakes, or hindsight judgments.

4 PG&E describes these investigations and reports as part of the
5 factual background relating to these fires. They do not address or bear
6 directly on the principal issue in this proceeding: whether PG&E’s costs
7 that it seeks to recover are reasonable under Section 451.1. Ultimately,
8 it is the Commission, and not any other public entity in any prior
9 investigation, report, or forum, that holds the duty to review the costs
10 requested in this Application and to approve just and reasonable rates
11 consistent with the AB 1054 framework.

12 *Cal Fire*. As to each of the Kincade and Dixie Fires, Cal Fire issued
13 a report concluding that the fire was caused by PG&E’s electrical
14 equipment, which makes them “covered wildfires” as described above.
15 Cal Fire holds a broad mandate with respect to fire prevention,
16 protection, and stewardship in California, and provides critical
17 emergency response services in case of fire.¹⁰⁶ In particular, Cal Fire
18 investigates and issues reports with respect to wildfires and their
19 causes.¹⁰⁷ Cal Fire does not, however, regulate utilities and rates,
20 evaluate and approve utility wildfire mitigation efforts, or determine the
21 prudence of utility conduct under the applicable legal standard for cost
22 recovery purposes. Those roles and responsibilities belong exclusively
23 to the Commission.¹⁰⁸ For purposes of this proceeding, PG&E does
24 not dispute Cal Fire’s determination that the Kincade and Dixie Fires

¹⁰⁵ Pub. Util. Code § 451.1(c).

¹⁰⁶ See Memorandum of Understanding between the California Public Utilities Commission and the California Department of Forestry and Fire Protection (Aug. 23, 2017), p. 1.

¹⁰⁷ Under California law, Cal Fire can recover costs of fire suppression and investigation, as well as administrative and other costs, from “[a]ny person . . . who negligently, or in violation of the law, sets a fire, allows a fire to be set, or allows a fire kindled or attended by the person to escape onto any public or private property.” Health & Safety Code §§ 13009, 13009.1.

¹⁰⁸ See Memorandum of Understanding between the California Public Utilities Commission and the California Department of Forestry and Fire Protection (Aug. 23, 2017), pp. 1, 3-4.

1 were attributable to PG&E electrical equipment. But the Commission is
2 best positioned, based on its mandate and expertise, to assess PG&E's
3 showing on the relevant programs, policies, and conduct supporting
4 PG&E's prudence, as demonstrated through this Application and
5 supporting testimony.

6 *Safety and Enforcement Division (SED)*. The Commission's Safety
7 and Enforcement Division conducted a staff investigation of each of the
8 Kincade and Dixie Fires and issued a report alleging violations of
9 Commission rules and regulations, as described in more detail in
10 Chapter 3A and Chapter 3B, respectively. SED's reports are not legal
11 documents; they do not apply Section 451.1 or address the standards
12 therein; and they do not represent decisions or judgments of the
13 Commission. PG&E and SED resolved each investigation through an
14 Administrative Consent Order (ACO), which reflected a settled outcome
15 with no admission of imprudence that was approved by the Commission.
16 PG&E expressly disputed all of the alleged violations related to ignition
17 of the fires, and each ACO explicitly stated that it is not admissible as
18 evidence of fault or liability in any Commission proceeding (or any other
19 proceeding).¹⁰⁹

20 With respect to the Kincade Fire, SED's report alleged three
21 violations of Commission rules. PG&E disputed each of the three
22 alleged violations.¹¹⁰ To resolve the investigation, PG&E agreed to pay
23 \$40 million in fines and to waive its right to seek recovery of up to
24 \$85 million spent to remove permanently abandoned transmission
25 conductors and structures.

26 With respect to the Dixie Fire, SED's report alleged seven total
27 violations of Commission rules. PG&E disputed all three alleged
28 violations related to the cause of the Dixie Fire and disputed one
29 additional alleged violation; it did not dispute the three remaining alleged
30 violations, relating to recordkeeping and documentation, only for

¹⁰⁹ Kincade Settlement Agreement, p. 7; Resolution SED-8 at 6-7.

¹¹⁰ Kincade Settlement Agreement, pp. 3-4.

1 purposes of the ACO.¹¹¹ To resolve the investigation, PG&E agreed to
2 (i) pay \$2.5 million to California’s General Fund; (ii) pay \$2.5 million to
3 tribes impacted by the Dixie Fire; and (iii) implement a shareholder-
4 funded project to transition hard-copy records to electronic records for
5 certain patrols and inspections of distribution facilities, costing
6 approximately \$40 million over five years.¹¹²

7 *District Attorneys.* PG&E entered into a stipulated civil judgment
8 with the Sonoma County District Attorney, which led to the dismissal of a
9 criminal enforcement action related to the Kincade Fire without any
10 admission of wrongdoing.¹¹³ PG&E also entered into a stipulated civil
11 judgment with local district attorneys related to the Dixie Fire, which
12 resolved an investigation without any admission of wrongdoing.¹¹⁴

¹¹¹ Dixie Settlement Agreement, p. 16; *id.* at pp. A-4 to A-5.

¹¹² The Dixie Fire merged soon after its ignition with the Fly Fire, which ignited on July 22, 2021, in Plumas County, California. The Fly Fire resulted from a white fir tree uprooting and falling onto a PG&E distribution line known as the Gansner 1101 circuit. SED investigated the Fly Fire and concluded “that PG&E’s actions related to the Fly Fire incident did not result in violations of the Commission’s General Orders.” SED Fly Fire Report, p. 1 (Apr. 17, 2023).

¹¹³ On April 8, 2022, the Sonoma County District Attorney dismissed all previously filed criminal charges and agreed to a long-term civil settlement designed to strengthen wildfire safety and response programs in the county and support local organizations affected by the fire to help rebuild impacted communities. As part of the settlement, PG&E agreed, among other things, to: (1) make certain monetary payments to local organizations, including Santa Rosa Junior College’s Fire Technology Program; (2) implement various performance commitments in the region, such as adding 80-100 new PG&E jobs based in Sonoma County; and (3) commit to a five-year monitorship of vegetation and system inspection work in the county. The stipulated judgment provides that it may not be deemed an admission or evidence of the validity of any allegations or claims arising from the underlying complaints.

¹¹⁴ On April 11, 2022, PG&E entered into a stipulated civil judgment with the district attorneys of Plumas, Lassen, Tehama, Shasta, and Butte Counties to resolve their investigation related to the Dixie Fire. The agreement called for the creation of the Direct Payments for Community Recovery program, which has enabled individuals who lost their homes in the Dixie Fire to submit claims for expedited review, approval, and payment. As part of the agreement, PG&E also committed, among other things, to: (1) make certain payments to local nonprofits assisting in rebuild efforts; (2) implement various performance commitments in the region, such as adding a minimum of 100 new PG&E jobs based in the five counties; and (3) commit to a five-year monitorship of vegetation and system inspection work.

F. Factors Outside of PG&E's Control Caused the Kincade and Dixie Fires to Spread and Exacerbated Their Destructiveness

Section 451.1(b) provides that “factors both within and beyond the utility’s control . . . may have exacerbated the costs and expenses, including humidity, temperature, and winds,” and therefore “[c]osts and expenses in the application [to recover costs and expenses arising from a covered wildfire] may be allocated for cost recovery in full or in part.” As described in detail in Chapter 4, several such external factors exacerbated the destructiveness of the Kincade and Dixie Fires. PG&E also provides some estimates of certain costs attributable to these external factors.

First, the effects of climate change have increased wildfire risk and the severity of wildfires in California. It is well established that climate change has caused a global rise in temperatures, a long-term drying trend, and more variability in precipitation. In Northern California, these climatological trends have extended the fire season into windier months, contributed (along with insect outbreaks) to tree mortality and fuel buildup, and increased the frequency of “critical fire weather” days. The Kincade and Dixie Fires exemplify the destructiveness of wildfires driven by climate change. The Kincade Fire was the largest October fire in Northern California in at least 35 years, driven primarily by extreme winds in a year when autumn precipitation was insufficient to extinguish the risk of large fires during the windy season. The Dixie Fire—the largest single-origin fire in the state’s history—ignited during a historically hot and dry summer and burned through significant areas of cumulative tree mortality.

Second, other external factors exacerbated the size and destructiveness of each fire. The Kincade Fire’s progression and destruction was driven primarily by two extreme wind events, one on the day of ignition and one four days into the fire. The second wind event was particularly destructive, causing the fire to grow by roughly 40,000 acres in just over a day. The extreme winds that propelled the Kincade Fire’s growth also complicated emergency responders’ suppression efforts. The relative lack of recent wildfires in the area, contributing to the accumulation of fuel, also contributed to the fire’s rapid spread during the two wind events. Based on analysis of claims data and fire-spread modeling based on reduced wind scenarios, PG&E’s expert estimates that the Kincade

1 Fire's growth during and after the October 27 wind event accounted for
2 approximately \$741 million in total damages. This amount represents one
3 estimate of costs exacerbated by wind—a factor beyond PG&E's control.

4 With respect to the Dixie Fire, a closed bridge impeded the troubleshooter's
5 access to the site earlier in the day. The difficulty in accessing the remote site,
6 delays in the arrival of ground resources, and the premature grounding of aerial
7 suppression resources impeded early fire-suppression efforts, enabling a
8 relatively small fire to spread out of control. The Dixie Fire also ignited during a
9 historically dry and hot summer. Extreme drought conditions helped propel the
10 fire's progression, resulting in the Dixie Fire becoming the first fire in recorded
11 history to burn over the Sierra Crest and ultimately consume a footprint roughly
12 ten times the size of large wildfires that had ignited in the same area during
13 summer months in prior years.

14 A few weeks into the Dixie Fire, as firefighting operations continued, key
15 suppression strategies failed, due largely to external factors such as extreme
16 weather and resource shortages. In late July, firefighting agencies began
17 initiating large-scale firing operations (i.e., setting fires ahead of the advancing
18 wildfire) along the Dixie Fire's northern and eastern flanks to try to stop its
19 spread and protect nearby population centers. By early August, a decline in
20 suppression resources assigned to the fire and accompanying Red Flag
21 conditions allowed the fire to advance past the firing operations and destroy the
22 historic town of Greenville. Around this period, the fire burned so intensely that it
23 created its own local weather system, generating erratic winds that caused
24 embers to spot across long distances and propel the fire's growth. The intensity
25 of the Dixie Fire was enhanced by elevated fuel loads—unburned vegetation
26 that had accumulated over decades due to the area's lack of recent fire history—
27 combined with extreme weather conditions amplified by climate change, as
28 demonstrated by PG&E's expert's burn severity modeling.

29 As a measure for how these external factors exacerbated the costs resulting
30 from the Dixie Fire, PG&E's expert examined claims data for areas burned after
31 the firing operations failed in early August. These data show that approximately
32 \$1.117 billion in losses are attributable to external factors that caused the fire's

1 growth during this critical period, including \$611 million from the destruction of
2 Greenville alone.

3 **G. PG&E's Litigation Management Was Prudent**

4 As described in detail in Chapter 5, PG&E reasonably incurred costs to
5 defend and resolve third-party claims arising out of the Kincade and Dixie Fires.
6 PG&E faced hundreds of lawsuits filed by thousands of plaintiffs seeking
7 compensation for their losses related to the Kincade and Dixie Fires. PG&E
8 reasonably pursued settlement in light of the risk inherent in litigating hundreds
9 of cases through trial, as well as the significant exposure that it faced due to
10 California's inverse condemnation doctrine.

11 California courts have interpreted inverse condemnation to provide recovery
12 for property damage without requiring that plaintiffs establish fault on the part of
13 the public entity.¹¹⁵ Inverse condemnation is rooted in the Takings Clause of
14 the California Constitution, which provides that private parties are entitled to
15 compensation when their property is damaged for public use.¹¹⁶ Traditionally,
16 only governmental entities were liable for inverse condemnation. But courts
17 have extended liability to investor-owned utilities by treating them as public
18 entities, reasoning that the "cost-spreading rationale underlying inverse
19 condemnation" applies to utilities because they can recover any damages
20 liability through rate increases.¹¹⁷

21 PG&E believes that cases holding that inverse condemnation applies to
22 investor-owned utilities, and that the inverse condemnation standard is strict
23 liability, were incorrectly decided. PG&E and other investor-owned utilities have
24 challenged the application of inverse condemnation liability to them, including at
25 the appellate level, but have not prevailed.¹¹⁸ As the Commission recognized

¹¹⁵ See *Pacific Bell v. City of San Diego* (2000) 81 Cal.App.4th 596, 602 (explaining that "the presence or absence of fault by the public entity ordinarily is irrelevant" in assessing inverse condemnation).

¹¹⁶ See Cal. Const., Art. 1, § 19.

¹¹⁷ See *Simple Avo Paradise Ranch, LLC v. So. Cal. Ed. Co.* (2024) 102 Cal.App.5th 281, 304; see also *Pac. Bell Tel. Co. v. So. Cal. Ed. Co.* (2012) 208 Cal.App.4th 1400, 1407.

¹¹⁸ See *Simple Avo Paradise Ranch*, *supra*, 102 Cal.App.5th 281; *Pac. Bell Tel. Co.*, *supra*, 208 Cal. App. 4th 1400; e.g., *Harrison v. PG&E Corp.*, No. CGC17563108, 2018 WL 2447104, at *5 (Cal. Super. May 21, 2018); *Butte Fire Cases*, No. JCCP4853, 2018 WL 3371780, at *10 (Cal. Super. Apr. 26, 2018).

1 when authorizing PG&E to establish its WEMA, the viability of these claims in
2 the current legal landscape increases the financial risk and uncertainty
3 associated with wildfires.¹¹⁹

4 In light of the risks and expense associated with litigating plaintiffs' claims for
5 inverse condemnation, PG&E has reasonably pursued mediation and
6 settlements as the best method for resolving the thousands of claims that have
7 been asserted against the company, and has worked steadily to resolve those
8 claims over the last several years. PG&E prudently defended itself in the
9 litigation and incurred reasonable litigation costs, including for outside counsel,
10 experts, and related support necessary to defend mass litigations involving
11 nearly 12,000 individual plaintiffs. PG&E incurred approximately \$200 million in
12 litigation costs (recorded as of September 30, 2025) to defend and resolve
13 claims related to the 2019 Kincade Fire and the 2021 Dixie Fire. PG&E seeks
14 recovery of these litigation costs recorded in its WEMA.

15 PG&E has submitted eligible claims—i.e., claims exceeding the \$1 billion
16 threshold—for payment to the Wildfire Fund for both the Kincade and Dixie
17 Fires. PG&E has also submitted claims below the threshold for each fire so that
18 the Wildfire Fund Administrator could verify that those claims were paid
19 consistent with the statutory requirements. The Wildfire Fund Administrator has
20 reviewed the process PG&E used, and the amounts it paid, to resolve these
21 third-party claims to determine whether they were consistent with the exercise of
22 reasonable business judgment.¹²⁰ Because the Wildfire Fund Administrator
23 has already determined that PG&E's process for resolving these claims and the
24 amounts it paid were consistent with the exercise of reasonable business
25 judgment pursuant to Section 3292(f), the Commission does not further review
26 the settlement process or payments.

27 **H. PG&E's Facility Repair and Reconstruction Was Prudent**

28 As detailed in Chapter 6: Restoration Costs, this Application includes a
29 request for recovery of approximately \$242 million in expenses and \$71.6 million
30 in capital expenditures incurred for system restoration and repair across electric

¹¹⁹ See D.18-06-029, p. 5.

¹²⁰ See Pub. Util. Code § 3292(f)(1); California Earthquake Authority, Wildfire Fund Administrator, Claims Administration Procedures (as amended May 4, 2023), § II.A.

1 distribution, gas operations, power generation, and customer care in connection
2 with the Kincade and Dixie CEMA events. This request is limited to CEMA-
3 eligible, incremental capital, and expense costs that have not been included in
4 any prior cost recovery proceeding. Reconstructing the affected facilities was
5 not only prudent but necessary, given PG&E's obligation to maintain electric
6 service within its service area. Timely reconstruction of PG&E's damaged
7 facilities was essential to restore safe, reliable power to impacted communities.

8 In the process of rebuilding its infrastructure after the Kincade and Dixie
9 Fires, PG&E replaced damaged equipment with new assets that met or
10 exceeded the standards in place at the time. For example, as part of
11 reconstruction in response to the Dixie Fire, PG&E is undergrounding lines and
12 deploying other system-hardening wildfire mitigation measures. Although the
13 Kincade and Dixie Fires prompted the reconstruction, the infrastructure
14 improvements have strengthened the grid's resilience against future wildfires
15 and extreme weather. As the Commission allows cost recovery for prudent
16 investments in wildfire insurance to protect customers, it should likewise approve
17 recovery of costs associated with rebuilding facilities in a way that enhances
18 long-term wildfire mitigation and grid safety and resilience.

19 **I. PG&E's Cost Recovery Proposal Minimizes Rate Impacts for Customers**
20 **and Supports Affordability**

21 As described in Chapter 7: Cost Recovery and Revenue Requirements,
22 PG&E proposes to submit a securitization application, following a decision
23 resolving this Application. The securitization application will request
24 authorization for the issuance of recovery bonds, pursuant to Public Utilities
25 Code Sections 850 et seq., to finance the WEMA electric costs authorized for
26 rate recovery in this proceeding. If authorized, securitization of those costs
27 would protect low-income customers, who under existing law are exempt from
28 paying recovery charges. Recovery bonds also would promote efficient
29 financing and recovery of the WEMA electric costs by reducing the overall rate
30 burden for customers and obviating the need for standard cost recovery
31 ratemaking for the WEMA electric costs (which represent the vast majority of
32 PG&E's cost recovery request). Under the illustrative recovery bond proposal
33 described in Chapter 7, PG&E estimates that the average cost to customers of

1 the approximately \$1.52 billion in WEMA electric costs requested in this
2 Application would be about \$0.79 per month for 25 years.

3 **J. The Commission’s Consistent Application of the Presumption of Prudence**
4 **Will Promote Investor Confidence and Benefit Customers**

5 Granting PG&E’s request for recovery of its costs associated with the
6 Kincade and Dixie Fires is in the interest of PG&E, its customers, and the State.
7 A predictable, durable, and fair regulatory framework that supports utility cost
8 recovery serves the long-term interests of customers and the public. Such a
9 regulatory environment is viewed favorably by investors in the market, allowing
10 utilities to secure low-cost capital to support important investments in their
11 systems. Utility financial health is critical for supporting the State’s goals around
12 safe, reliable, clean, and affordable electricity service for customers.

13 Utilities operate in a capital-intensive industry and need ready access to low-
14 cost capital. As the Legislature recognized in enacting AB 1054, utilities “need
15 capital to fund ongoing operations and make new investments to promote safety,
16 reliability, and California’s clean energy mandates and ratepayers benefit from
17 low utility capital costs in the form of reduced rates.”¹²¹ Indeed, utilities face
18 unprecedented investment needs to address wildfire risk, upgrade aging
19 infrastructure, and support California’s climate and electrification goals. PG&E’s
20 capital investments in the near term will include major wildfire mitigation work
21 such as undergrounding powerlines, installing covered powerlines, installing
22 stronger and more fire resilient poles, and other system upgrades. PG&E
23 expects capital spending of \$41.2 billion over the 2026-2028 period (and a total
24 of approximately \$73 billion through 2030).¹²² More broadly, other California
25 utilities also are making significant investments in their systems: SCE expects

¹²¹ AB 1054 (2019-2020 Reg. Sess.), Sec. 1(a)(4); see also *id.*, Sec. 1(a)(2) (“With increased risk of catastrophic wildfires, the electrical corporations’ exposure to financial liability resulting from wildfires that were caused by utility equipment has created increased costs to ratepayers.”); 2019 Strike Force Report, p. 3 (“Utilities rely on credit to finance ongoing infrastructure investments, including fire mitigation. As utilities’ credit ratings deteriorate, their borrowing costs increase and those costs for capital necessary to make essential safety improvements are passed directly to customers. These downgrades . . . directly impact Californians’ access to safe, reliable and affordable electricity.”).

¹²² PG&E Form 8-K (Oct. 23, 2025), *2025 Third Quarter Earnings*, p. 9.

1 about \$21.9 billion over the same period,¹²³ while SDG&E and SoCalGas plan
2 another \$12.9 billion.¹²⁴ These figures reflect the scale of investment
3 necessary to keep the grid safe, resilient, and aligned with California’s ambitious
4 energy future.

5 The Commission has long recognized and endorsed the connection
6 between access to capital, customer affordability, and utility investments in
7 safety and reliability. In the wake of the 2000–2001 energy crisis, for example,
8 the Commission recognized that credit rating downgrades significantly increase
9 borrowing costs, which raise costs for customers.¹²⁵ The Commission has
10 more recently restated the premise, which underlies AB 1054’s cost recovery
11 approach, that strong utility finances are essential for providing reliable electric
12 service at reasonable rates.¹²⁶ Indeed, in a recent decision approving an
13 amended settlement agreement providing for recovery of costs associated with
14 the 2017 Thomas Fire, the Commission emphasized that “[a]ccess to low-cost
15 capital is essential for making the necessary investments to enhance safety and
16 to achieve the State’s ambitious clean energy goals, to the ultimate benefit of
17 customers, the public, and the State.”¹²⁷

18 A decision authorizing PG&E’s request will send a positive signal regarding
19 the fairness and predictability of California’s cost recovery framework and

¹²³ Edison International Form 8-K (Oct. 28, 2025), *Business Update*, p. 35.

¹²⁴ Sempra, *2024 Earnings Results + Capital Plan Update* (Feb. 25, 2025), p. 19.

¹²⁵ See *In Re S. California Edison Co.*, 207 P.U.R.4th 261 (2001); see also Order Instituting Rulemaking to Implement Pub. Utilities Code Section 451.2 Regarding Criteria and Methodology for Wildfire Cost Recovery Pursuant to Senate Bill 901, *supra*, at p. *1 (explaining that the Commission would consider the “increased cost of access to capital markets” in assessing the financial status of IOUs under SB 901); *In Re S. California Edison Co.*, 235 P.U.R.4th 1 (2004) (“We also recognize that an investor-owned utility’s credit rating and its access to capital are of critical importance to its ability to provide the infrastructure it needs to meet its customer service obligations.”); *In Re Pac. Gas & Elec. Co.* 230 P.U.R.4th 101 (2003) (“Continuous access to the capital markets and access to low cost capital facilitates the funding of power procurement activities as well as the capital expenditures necessary to sustain the safety and reliability of a utility’s operations.”) (internal quotation marks omitted).

¹²⁶ See Order Instituting Rulemaking to Implement Pub. Utilities Code Section 451.2 Regarding Criteria and Methodology for Wildfire Cost Recovery Pursuant to Senate Bill 901 (2018), 2019 WL 3240986, p. *3 (June 27, 2019).

¹²⁷ D.25-01-042, p. 21.

- 1 promote investor confidence in the AB 1054 framework. This will advance the
- 2 public interest and benefit the State and PG&E's customers.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

PRUDENCE OF OPERATIONS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
PRUDENCE OF OPERATIONS

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
PRUDENCE OF OPERATIONS

A. Introduction [Andrew Paul Abranches]

This chapter describes how Pacific Gas and Electric Company (PG&E) prudently designed and constructed, inspected and maintained, and operated its facilities to provide safe and reliable service to its customers at the time of the Kincade and Dixie Fires. PG&E's programs and policies, including for wildfire mitigation, met or exceeded regulatory requirements and were consistent with industry practices.

As the largest utility in California, PG&E manages an electrical transmission and distribution system across a vast, diverse service area that, in a relatively short period of time, has become increasingly susceptible to climate change and catastrophic wildfires. The interim fire-threat map adopted by the California Public Utilities Commission's (CPUC or Commission) in 2012 designated approximately 15 percent of PG&E's service area in the highest categories of wildfire risk. In January 2018, the final fire-threat map adopted by the Commission showed that more than 50 percent of PG&E's service area faced elevated or extreme risk of wildfires—representing a dramatic increase in areas identified as high-fire risk in PG&E's service area.

PG&E responded to the material increase in its risk profile by establishing policies, programs and procedures to reduce the risk of utility-caused ignitions in its service area. Beginning in 2019, PG&E submitted annually a Wildfire Mitigation Plan (WMP) or WMP update summarizing and describing its wildfire mitigation efforts. The Commission's review and ratification of PG&E's WMP, which followed review and approval of the WMP by the Office of Energy Infrastructure Safety (Energy Safety), was one of the prerequisites to PG&E's safety certification.¹ PG&E's safety certification establishes the presumption of reasonableness that governs this proceeding.

¹ As described in more detail in Chapter 1: Policy, the Wildfire Safety Division (WSD) had authority to review and approve WMPs prior to the establishment of Energy Safety in 2021. This testimony uses "Energy Safety" to refer to WSD and/or Energy Safety, depending on the relevant time frame.

1 The regulatory process through which PG&E obtained its safety certification
2 is supported by a strong foundation of reasonable policies and programs with
3 respect to PG&E's management of its electrical system, which PG&E describes
4 in this chapter under three broad categories. First, PG&E designed and
5 constructed its transmission and distribution electrical facilities based on
6 regulatory requirements, operational experience, local conditions, and
7 technological and industry developments. PG&E's design and construction
8 standards satisfy or exceed the requirements of Commission General Order
9 (GO) 95, which establishes requirements for overhead line design, construction,
10 and maintenance. PG&E implemented a program to harden its system by
11 upgrading and replacing distribution facilities in High Fire-Threat Districts
12 (HFTDs) with materials and designs that reduce the risks of utility-caused
13 ignition and are more resilient to wildfire exposure. PG&E also designed its
14 protection systems to quickly detect and respond to faults on the system and
15 isolate impacted portions of lines.

16 Second, PG&E inspected and maintained its facilities pursuant to robust
17 programs designed to meet or exceed regulatory requirements—including
18 through the Wildfire Safety Inspection Program (WSIP). Consistent with
19 Commission requirements and its own procedures, PG&E deployed a variety of
20 asset inspections, including detailed ground inspections, climbing inspections,
21 drone inspections, patrol inspections, and intrusive pole inspections. PG&E also
22 had a comprehensive vegetation management program to monitor the status of
23 vegetation in proximity to its lines and mitigate the potential for vegetation
24 contact with its facilities. PG&E's work included routine vegetation management
25 along distribution and transmission facilities, a pole-clearing program, and
26 programs targeting identification of dead or dying trees and focusing on circuit
27 segments with higher rates of vegetation-related outages. PG&E also reviewed
28 and audited its own performance as to inspection and maintenance programs.

29 Third, PG&E relied on a suite of operational policies, procedures, and
30 programs designed to address potential safety hazards and reduce the risk of
31 ignitions caused by PG&E's electrical equipment. PG&E used its transmission
32 grid control centers (GCC) and distribution control centers (DCC) to continuously
33 monitor and respond to events on PG&E's electrical system. In 2018, PG&E
34 implemented a Public Safety Power Shutoff (PSPS) program to proactively de-

energize portions of its system as a measure of last resort to reduce the risk of ignition during the most extreme conditions. PG&E rigorously planned and prepared for, and coordinated its response to, hazards, outages, and emergencies including wildfires.

B. PG&E's Diverse Service Area and Response to Increasing Fire Risk
[Andrew Paul Abranches]

1. PG&E's Service Area

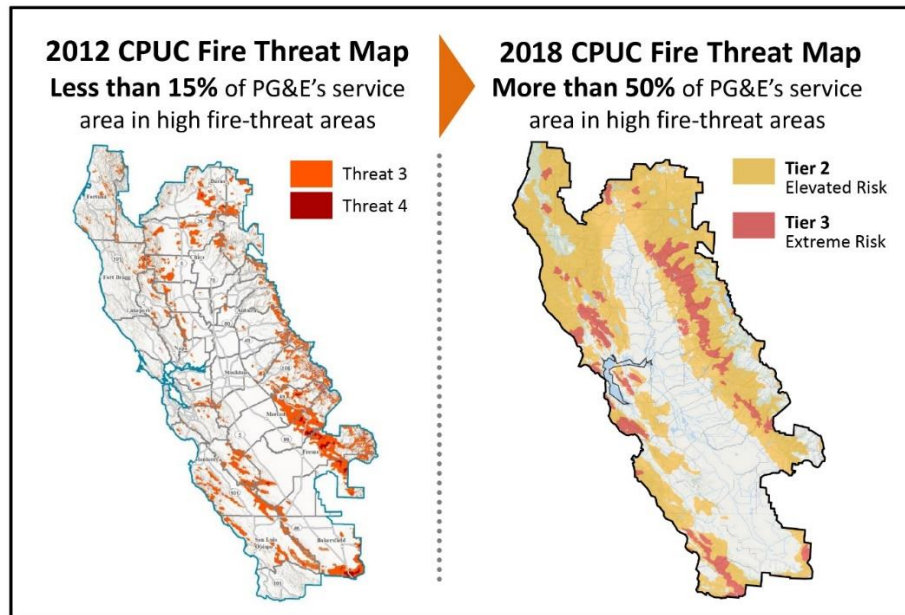
PG&E is the largest combined natural gas and electric utility in the United States and the largest utility in California. PG&E's service area covers more than 70,000 square miles across 47 of California's 58 counties. In total, PG&E operates approximately 81,000 circuit miles of overhead electric distribution lines (under 60 kilovolts (kV)) and 18,000 circuit miles of overhead electric transmission lines (60kV and above). PG&E's service area includes a diverse array of geography, from coastal areas to the Central Valley to the foothills and the Sierra Nevada. PG&E serves customers in dense urban cities, suburbs, and exurban communities, as well as towns and rural areas.

Wildfire risk is a significant issue for PG&E's service area. Wildfires have long been part of California's ecological environment. But in recent years, climate change and prolonged drought conditions have significantly increased the risk of catastrophic wildfires across the State.

Following the 2007 wildfires in Southern California, the Commission coordinated with the California Department of Forestry and Fire Protection (Cal Fire), utilities, communications infrastructure providers, and public safety agencies to develop a map that would support fire-safety regulations by designating areas at heightened risk of wildfires. An interim fire-threat map for Northern California was adopted in 2012 and designated less than 15 percent of PG&E's service territory in the highest categories of fire risk

(Threat Levels 3 and 4).² In January 2018, the Commission adopted its final Fire-Threat Map, under which more than half of PG&E's service area was classified as high fire risk.³ The 2012 and 2018 Fire-Threat Maps are shown in Figure 2-1.

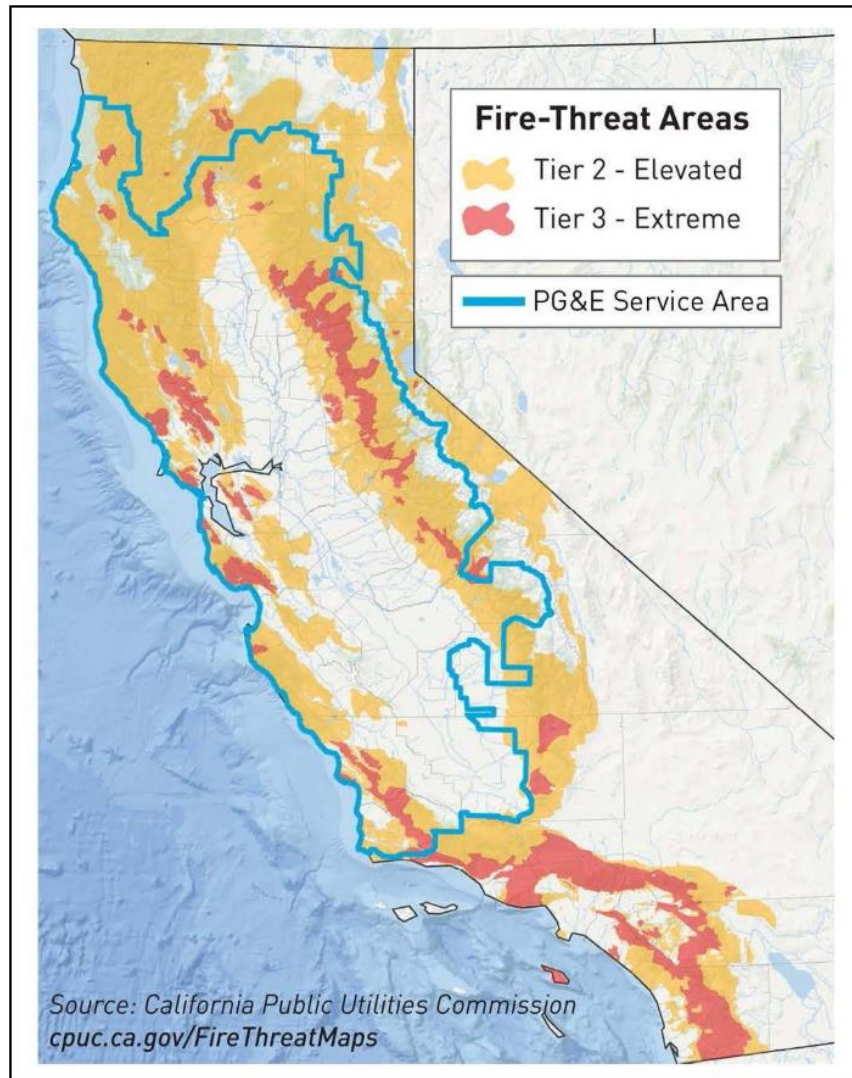
**FIGURE 2-1
FIRE-THREAT DESIGNATIONS, 2012 VS. 2018**



- ² That interim map (the “Reax Map”) was adopted by the Commission for use in Northern California pending adoption of a final fire-threat map. See D.12-01-032, *Decision Adopting Regulations to Reduce the Fire Hazards Associated with Overhead Electric Facilities and Aerial Communications Facilities*. The Reax Map classified fire-threat areas into four tiers based on relative likelihood and severity of power-line related fire ignition and spread. See Rulemaking 08-11-005, Phase 2 Workshop Report (Aug. 13, 2010), Appendix E, available at: <https://docs.cpuc.ca.gov/PublishedDocs/EFIELD/REPORT/122442.PDF> (accessed Oct. 28, 2025). Areas classified as Threat Levels 3 and 4 represented the highest wildfire-risk zones and were subject to additional fire-prevention measures adopted by the Commission.
- ³ The Final Fire-Threat Map designates three types of fire-threat areas: Tier 3 (extreme risk), Tier 2 (elevated risk), and a smaller Zone 1 (made up of areas on the Cal Fire and United States Forest Service High Hazard Zones map that are not subsumed within Tier 2 and Tier 3 HFTDs). See D.17-12-024, Appendix D; Disposition of Pacific Gas & Electric Co. Advice Letter (AL) No. 5211-E and San Diego Gas & Electric Company (SDG&E) AL No. 3172-E (Adoption of Final CPUC Fire-Threat Map) (Jan. 19, 2018), available at: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_5211-E.pdf (accessed Oct. 28, 2025). Approximately 65 percent of all HFTDs statewide were in PG&E's service area.

1 That change was significant and resulted in the highest fire-threat areas
2 encompassing nearly one third of PG&E's electrical system—over
3 25,000 miles of overhead distribution lines and 5,500 miles of overhead
4 transmission lines. Much of this system served low-density, non-urban
5 communities in the wildland-urban interface. The number of customers
6 living in these high-risk areas has continued to increase over time. Figure
7 2-2 below shows PG&E's service area overlayed on the final CPUC Fire-
8 Threat Map (which remains in effect statewide), reflecting the HFTDs in
9 PG&E's service area.

FIGURE 2-2
FIRE-THREAT DESIGNATIONS IN PG&E'S SERVICE AREA (2018)



2. PG&E's Management of Wildfire Risk

PG&E is committed to providing safe, reliable, and affordable electricity in the communities it serves. In response to the dramatic increase in wildfire risk in its service area, PG&E significantly expanded and strengthened its wildfire mitigation measures.

The destructive wildfire seasons of 2017 and 2018 altered the collective understanding of wildfire risk in California. These years evidenced the evolving wildfire risk landscape and highlighted the role of climate change in intensifying the threats to life and property arising from wildfires. This caused electric utilities, the State, local governments, and other policymakers to reevaluate policy solutions and investments that support wildfire prevention, suppression, and resilience. PG&E has actively contributed to these collective efforts and has made steady and sustainable progress in implementing wildfire mitigation practices across its operations.

Community Wildfire Safety Program (CWSP). In March 2018, PG&E established the CWSP, which is a key illustration of its increased wildfire-related efforts. Through the CWSP, PG&E redoubled its efforts to work with the Commission, peer utilities, customers, first responders, and other stakeholders to prevent and mitigate catastrophic wildfires caused by electric infrastructure. PG&E updated its standards for the design and construction, inspection and maintenance, and operations of its system to account for wildfire risk. PG&E worked diligently to develop a risk-based approach to identify the portions of its system at highest risk of causing ignitions so that it could focus on enhanced vegetation management and system hardening in those areas. It expanded its removal of trees identified as having a higher potential to fail and set a plan to perform enhanced vegetation management on approximately 2,500 circuit miles in HFTDs by the end of 2019. Through system hardening, PG&E increased its use of undergrounding where appropriate, replaced bare overhead conductor with covered conductor in certain circumstances, installed more resilient poles, and replaced existing equipment with equipment designated by Cal Fire as less likely to spark a wildfire.

Wildfire Safety Inspection Program (WSIP). In 2019, through the CWSP, PG&E implemented the WSIP to expand and accelerate inspections

1 of poles and associated equipment in HFTDs. The goal of the WSIP was to
2 identify and quickly remediate the most serious conditions in areas that were
3 the most likely to lead to catastrophic wildfires in the event of an ignition. In
4 2019, PG&E completed WSIP inspections on more than 700,000 structures
5 across its HFTDs, comprising roughly 30,500 miles of PG&E's electrical
6 system in areas identified by the Commission as having the greatest
7 potential risk of fire.

8 The inspections conducted pursuant to the WSIP were enhanced in a
9 number of respects, as compared to standard inspections. WSIP
10 inspections used ignition-related criteria to identify and mitigate conditions
11 most likely to cause wildfires. These inspections also integrated prescriptive
12 inspection checklists, photographic documentation, the routine use of
13 drones, and the engagement of a centralized inspection review team (CIRT).
14 Through WSIP inspections, PG&E also took prompt action to address issues
15 identified as an imminent risk to public or employee safety. The WSIP
16 framework represented a significant evolution in inspection of PG&E's
17 transmission and distribution systems and led to a significant increase in the
18 volume of notifications and repair work.

19 *Public Safety Power Shutoff (PSPS) Program.* As a further step aimed
20 at reducing wildfire risk associated with its system, PG&E implemented its
21 PSPS program in 2018 to proactively de-energize distribution and lower-
22 voltage (70 kV or below) transmission lines that traversed Tier 3 areas as a
23 measure of last resort during extreme fire risk conditions. In 2019, after the
24 Camp Fire, PG&E significantly expanded the scope of its PSPS program to
25 include all circuits (transmission and distribution) traversing Tier 2 and Tier 3
26 areas.

27 *Situational Awareness.* PG&E also improved its situational awareness
28 during this time by installing over 1,100 additional weather stations and
29 nearly 500 high-definition cameras between 2019 and 2021. PG&E
30 implemented advanced controls to support situational awareness, such as
31 increased capability for remote recloser blocking, strengthened work
32 procedures, and deployment of Safety and Infrastructure Protection Teams
33 (SIPT) with firefighting capabilities.

1 *Risk Models.* Beginning in 2018, PG&E developed distribution wildfire
2 risk models to support a risk-informed approach to wildfire mitigation
3 initiatives including system hardening and EVM. These models generally
4 considered the risk of equipment igniting a wildfire and its associated
5 consequences. In 2021, PG&E adopted further refined modeling for ranking
6 wildfire risk of distribution overhead circuits, which continued to generally
7 assess both the probability and predicted consequences of ignition. The
8 Equipment Risk Model ranked circuits based on the probability of ignition
9 associated with equipment failure and was used to prioritize system
10 hardening. The Vegetation Risk Model ranked circuits based on the
11 probability of ignition associated with contact from vegetation and was used
12 to inform enhanced vegetation management.

13 *Wildfire Mitigation Plans (WMP).* Since 2019, and consistent with Public
14 Utilities Code (Pub. Util. Code) Section 8386, PG&E prepared a WMP or
15 update to its WMP each year to describe its wildfire mitigation efforts and
16 targets.⁴ PG&E's WMPs were ratified through Commission resolutions.⁵
17 As described further in Chapter 1: Policy (Section E.1.a), PG&E's WMP is a
18 critical prerequisite for obtaining a safety certification from Energy Safety,
19 which certification gives rise to the presumption of prudence that is central to
20 this proceeding.

21 PG&E's WMP reflects the comprehensive scope and strategy of PG&E's
22 work to reduce ignition risks and strengthen the utility's overall response to
23 wildfire conditions. It describes efforts across a broad range of areas,
24 including risk identification and modeling, system hardening, inspection and
25 repair, vegetation management, expanded situational awareness, and

4 See Pub. Util. Code § 8386(b) ("Each electrical corporation shall annually prepare and submit a wildfire mitigation plan to the Wildfire Safety Division for review and approval. . . . In its discretion, the division may allow the annual submissions to be updates to the last approved comprehensive wildfire mitigation plan; provided, that each electrical corporation shall submit a comprehensive wildfire mitigation plan at least once every three years."). Beginning in 2023, PG&E transitioned to filing comprehensive three-year plans, with annual updates submitted in the intervening years. See *id.* ("In calendar year 2020, and thereafter, the plan shall cover at least a three-year period.").

5 In 2019, PG&E's WMP was approved by a Commission decision, but in subsequent years, PG&E's WMPs were approved by Energy Safety, and then ratified through Commission resolution. Prior to Energy Safety being established in 2021, WMPs were approved by the Wildfire Safety Division (WSD) at the Commission.

1 operations. PG&E's wildfire safety strategies were based on benchmarking
2 with other utilities, including San Diego Gas & Electric Company (SDG&E),
3 Southern California Edison, and several Australian utilities, and making
4 adaptations to reflect differences in service area and system design.⁶

5 As particularly relevant in this proceeding, PG&E's initial 2019 WMP and
6 2021 WMP update reflect its significant wildfire mitigation work in those
7 years.⁷ In February 2019, PG&E submitted its first WMP, which the
8 Commission reviewed and approved prior to the ignition of the Kincade
9 Fire.⁸ The plan encompassed over 100 initiatives and 147 sub-initiatives
10 with individual targets, including enhanced vegetation management
11 (targeting approximately 375,000 trees and 2,450 miles of high fire-threat
12 distribution line clearances), enhanced inspections of roughly 685,000
13 distribution poles and roughly 40,000 transmission structures, and system
14 hardening of about 150 miles of high-risk circuits. PG&E also committed to
15 increasing its situational awareness (targeting 400 new weather stations and
16 71 fire-watch cameras) and expanding its PSPS program to cover 25,200
17 distribution circuit miles and 5,500 miles of transmission lines traversing
18 HFTDs.

19 PG&E's 2021 WMP update was submitted in February 2021.⁹ It was
20 approved by Energy Safety in September 2021, and that action was ratified
21 by the Commission in October 2021.¹⁰ PG&E's 2021 WMP reflected
22 continued development of its wildfire risk mitigation efforts and included
23 numerous initiatives across system hardening, vegetation management, and
24 situational awareness. For example, the plan targeted installation of
25 approximately 250 sectionalizing devices and 70 sets of single-phase
26 reclosers to improve outage management, hardening of 180 circuit miles in

6 PG&E 2019 Wildfire Safety Plan (Feb. 6, 2019), pp. 2, 31, n.30.

7 Subsequent updates to PG&E's WMP were often referred to as the WMP for a particular year (e.g., the "2021 WMP").

8 See D.19-05-037, Decision on PG&E's 2019 WMP Pursuant to Senate Bill 901.

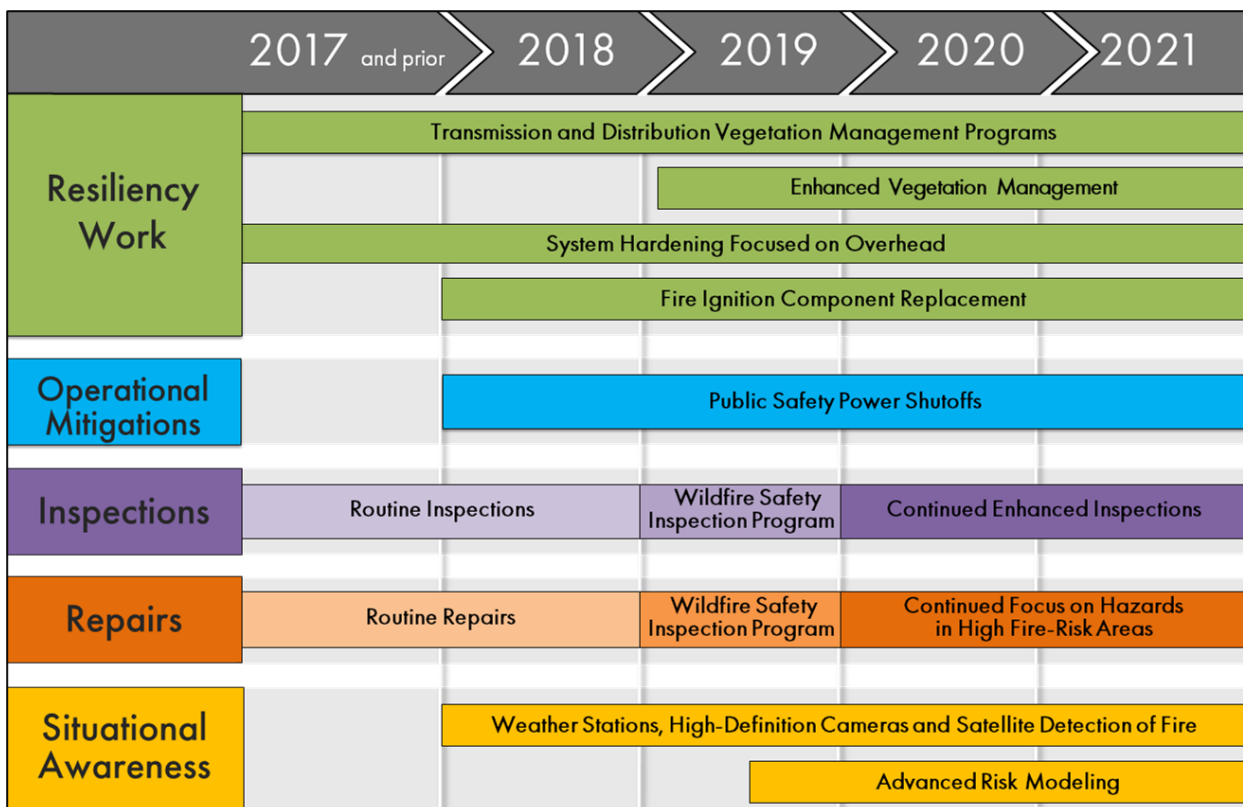
9 Res.WSD-021, Resolution Ratifying Action of the Energy Safety on PG&E's 2021 WMP Update Pursuant to Pub. Util. Code Section 8386.

10 *Id.*

HFTDs, and continuation of PG&E's Enhanced Vegetation Program (EVM) covering approximately 1,800 circuit miles annually.

Figure 2-3 below shows PG&E's wildfire mitigation initiatives from 2017 through 2021, and the progression and expansion of those efforts over time. Additionally, Appendix A to this Chapter 2 is a table summarizing PG&E's WMP milestones from 2019 through 2021 and reflecting that PG&E generally met or exceeded the targets it established for itself under the WMPs.

**FIGURE 2-3
LAYERS OF WILDFIRE PROTECTION**



In 2024, Energy Safety published its Annual Report on Compliance regarding PG&E's execution of its 2021 WMP (which was in place at the

1 time of ignition of the Dixie Fire).¹¹ Energy Safety “acknowledge[d] that
2 PG&E undertook significant efforts to reduce its wildfire risk.”¹² Indeed,
3 PG&E “completed the large majority of its 2021 WMP Update initiatives (132
4 of 147, or 90 percent), including seven of the 10 initiatives with the largest
5 allocated expenditure.”¹³ At the same time, Energy Safety recognized that
6 “ignitions attributable to PG&E infrastructure,” including the Dixie Fire,
7 “increased in 2021 relative to 2020.”¹⁴ Energy Safety urged PG&E to
8 continue to improve its performance.¹⁵

¹¹ In 2023, Energy Safety issued its Annual Report on Compliance (ARC) regarding PG&E’s execution of its 2020 WMP, finding that PG&E failed to substantially comply with its 2020 WMP. PG&E vigorously disputed that finding, submitting comments on Energy Safety’s report and subsequently seeking judicial review in the San Francisco Superior Court. The parties subsequently resolved this matter through settlement, pursuant to which Energy Safety agreed not to recommend that the CPUC pursue an enforcement action or impose penalties based on its Final 2020 WMP ARC.

There was no annual report on compliance for PG&E’s initial 2019 WMP because the requirement for Energy Safety to oversee WMP compliance was adopted in AB 1054 (itself enacted in July 2019). See Res.WSD-012, Attachment 1; Pub. Util. Code, § 8389(d)(3) (2019).

¹² Annual Report on Compliance for PG&E’s 2021 WMP Update (Sept. 2024), p. 1.

¹³ *Id.*

¹⁴ *Id.*

¹⁵ *Id.* at p. 35.

**TABLE 2-1
WILDFIRE MITIGATION PLAN MILESTONES COMPLETED (2019–2021)**

Category	2019	2020	2021
System Hardening (miles hardened)	171 line miles	342 line miles	210 line miles
Enhanced Vegetation Management	2,498 line miles	1,878 line miles	1,983 line miles
Trees Worked	1.52 million	1.81 million	1.83 million
Transmission Inspections	49,715 structures	26,282 structures	26,286 structures
Distribution Inspections	694,250 poles	349,692 poles	480,749 poles
Weather Stations Installed	426 weather stations	378 weather stations	308 weather stations
High-Definition Cameras Deployed	124 HD cameras	216 HD cameras	153 HD cameras
Distribution Sectionalization	241 devices	604 devices	269 devices
Transmission Line Switching		54 switches	41 switches

C. Design and Construction of PG&E’s Electrical Facilities [Carrell James Gill]

PG&E designed and constructed its transmission and distribution electrical facilities based on regulatory requirements, operational experience, local conditions, and technological and industry developments.

1. Electric Line Design and Construction

GO 95 sets forth “Rules for Overhead Electric Line Construction,” including requirements related to the design, construction, and maintenance of overhead powerlines. PG&E maintains a variety of internal standards to implement GO 95 requirements and support the safe and reliable design, construction, and operation of overhead transmission and distribution lines, including conductors and jumpers, insulators, poles, steel lattice towers, and other facilities.

1 PG&E's internal standards are managed and updated by a group of
2 experienced engineers and subject matter experts. That team develops
3 design and construction procedures, plus related procedures and bulletins,
4 and has processes to review and approve new standards. Any deviations
5 from the design standards must be approved by designated PG&E
6 engineers and qualified contractors and are subject to quality control (QC)
7 programs to verify adherence to PG&E's minimum standards. PG&E further
8 collaborates with peers and industry groups on design-related safety and
9 reliability issues.

10 At the time of the Kincade and Dixie Fires, PG&E's design and
11 construction standards met or exceeded the GO 95 requirements and were
12 updated as necessary to reflect Commission regulations, PG&E's
13 operational experience, and industry standards. For example, GO 95
14 requires that a minimum clearance be maintained between conductors and
15 the steel structure of a tower, and between the conductors themselves.
16 Rules 37 and 38 of GO 95 allow reductions of minimum conductor
17 clearances under certain environmental conditions, while PG&E's internal
18 minimum clearance standards generally do not allow such reductions.

19 PG&E also accounts for local conditions when designing and
20 constructing its electrical facilities. For instance, steel transmission towers
21 are built with durable materials to prevent corrosion, and PG&E selects
22 hardware that maintains strength over decades. As another example,
23 PG&E's construction standards for conductors on wood pole circuits are
24 designed to ensure that clearances are maintained despite differences in
25 temperature and loading conditions that can affect a conductor's "sag"
26 (meaning the downward curve in a conductor between two poles).

27 PG&E also had standards that address the management of idle electric
28 transmission and distribution line facilities.¹⁶ The standards implement Rule
29 31.6 of GO 95, which requires the removal of "permanently abandoned"
30 lines or portions of lines "that are determined by their owner to have no
31 foreseeable future use." At the time of the Kincade Fire, PG&E defined "idle

¹⁶ The standards were Utility Standard TD-1003S ("Management of Idle Electric Transmission Line Facilities") and TD-2459S ("Management of Idle Electric Distribution Lines").

transmission facilities” as “[f]acilities that are not currently being used to serve transmission load or generation facilities but may have a potential future use by the Company.” Idle transmission facilities that were determined to not have a foreseeable future use—i.e., permanently abandoned—were to be removed, consistent with Rule 31.6. Facilities that were idle and determined to have potential future use were to be designated as “temporarily out of service” and de-energized or kept energized at distribution voltages. With respect to idle transmission lines, PG&E’s transmission asset management team maintained a list of known idle transmission facilities and periodically reached out to personnel to verify the current condition of the known idle facilities and identify additional potentially idle facilities, which would then be investigated to determine whether they had potential future uses.

2. System Hardening to Reduce Risk

In 2018, PG&E launched a system hardening initiative to upgrade distribution facilities in HFTDs, and PG&E was executing that program at the time of the Kincade and Dixie Fires. The program is an ongoing, long-term capital investment program to rebuild facilities using materials and designs that reduce the risk of ignition and are more resilient to wildfire exposure.

The hardening methods include replacing bare overhead conductor with covered conductor, installing stronger poles, and undergrounding lines. Each system hardening project requires extensive field assessment and engineering analysis to determine the best method to reduce fire threat and consequence for that line.

PG&E prioritized system hardening projects using its wildfire risk models, which PG&E refined over time. The 2021 Wildfire Distribution Risk Model ranked identified circuit segments based on both the probability of ignitions and potential consequences of ignition. Probability was measured in two ways—by the likelihood of equipment failure and by the likelihood of vegetation contact with powerlines—while consequences captured the expected impacts if an ignition were to occur. System hardening work was re-prioritized following adoption of the 2021 Wildfire Distribution Risk Model, with the re-prioritization causing PG&E to consider new system hardening projects and put others on hold.

3. Protection Devices to Respond to Faults [Davis Erwin]

PG&E uses protective devices to detect and interrupt faults or other abnormal conditions on the system and to rapidly isolate and de-energize the affected portions of line. PG&E's protection systems provided the first line of defense against ignitions by de-energizing lines and equipment in response to specified conditions.

For the networked transmission system, system protection generally relies on protective relays, sensing devices, and circuit breakers. Protective relays monitor the flow of electricity and can initiate control action if they detect a fault or other abnormal condition. Voltage and current sensing devices provide inputs to protective relays, and communications systems are sometimes used to ensure correct operation of protective functions and to minimize fault duration. Circuit breakers are high-voltage switching devices that work with protective relays and sensing devices to de-energize transmission lines when faults are detected. PG&E's typical protection configuration includes overlapping zones of protection and redundant relays, allowing for full protection in the event of relay failure or maintenance.

For the radial overhead distribution system, system protection includes protective relays and circuit breakers, as well as line reclosers and fuses. Line reclosers are designed to quickly and safely de-energize lines when a fault is detected. Line reclosers support electric reliability and limit the number of customers exposed to outages by facilitating rapid fault isolation, sectionalizing, and restoring service following temporary faults. Fuses are mechanical devices that operate to de-energize the line downstream of the fuse. In general, for distribution grids, fuses act as a first line of defense to isolate distribution tap lines in the event of a disturbance. Fuses on powerlines are designed for single use and must be replaced after they operate.

For protective devices such as line reclosers and relays, the settings determine the duration and thresholds for the devices to pick up and de-energize the line or downstream line sections. PG&E's engineers make individualized determinations as to the appropriate configuration for each protection device, consistent with PG&E's standards and guided by

1 considerations including line topology, designed and expected load,
2 coordination with other protective devices, and risk mitigation.

3 In the years prior to the Kincade and Dixie Fires, PG&E made significant
4 investments and upgrades to system protection through equipment
5 replacements and device programming. For example, PG&E installed
6 additional line reclosers in HFTDs and also replaced and upgraded existing
7 line reclosers. PG&E also expanded deployment of Supervisory Control and
8 Data Acquisition (SCADA) technology, used to remotely communicate with,
9 monitor, and control devices on PG&E's electric circuits. Through SCADA,
10 PG&E could respond more quickly to changing system conditions.

11 PG&E's policies on the use of reclosing devices in HFTDs have evolved
12 over time. Consistent with standard practice across the industry, protective
13 devices on distribution lines were traditionally set to automatically reclose to
14 restore power to customers following temporary faults. In response to
15 increasing wildfire risk within PG&E's service area, PG&E began disabling
16 automatic reclosing in specified areas during periods of elevated wildfire
17 risk.

18 **D. Inspection and Maintenance of PG&E's Facilities [Carrell James Gill]**

19 PG&E inspected and maintained its transmission and distribution systems
20 pursuant to robust programs that met or exceeded regulatory requirements.

21 GO 165 requires utilities to inspect their electrical distribution and
22 transmission lines with sufficient frequency and detail. GO 165 defines several
23 types of inspections, including a "patrol" inspection, which is "a simple visual
24 inspection . . . designed to identify obvious structural problems and hazards"; a
25 "detailed" inspection, which is "one where individual pieces of equipment and
26 structures are carefully examined, visually and through use of routine diagnostic
27 test, as appropriate, and (if practical and if useful information can be so
28 gathered) opened, and the condition of each rated and recorded"; and an
29 "intrusive" inspection, which is "one involving movement of soil, taking samples
30 for analysis, and/or using more sophisticated diagnostic tools beyond visual
31 inspections or instrument reading."¹⁷

¹⁷ GO 165, pp. 1-2, Section III.A.

1 PG&E developed and implemented separate maintenance standards for its
2 transmission and distribution systems, called the Electric Transmission
3 Preventive Maintenance (ETPM) Manual and the Electric Distribution Preventive
4 Maintenance (EDPM) Manual, respectively. PG&E also performed annual
5 assessments of its asset inspection programs to identify and address areas for
6 improvement. PG&E created and filled specialized positions to conduct QC and
7 verify inspections, and it prepared and delivered specialized trainings targeted to
8 inspection roles and responsibilities.

9 Following the devastating wildfire seasons in 2017 and 2018, PG&E
10 developed the WSIP (under the umbrella of CWSP), which accelerated and
11 enhanced inspections of PG&E's electric distribution, transmission, and other
12 facilities in HFTDs using improved methods, including drone technology,
13 photographic documentation, and standardized checklists. It was
14 unprecedented in both the scope of inspections conducted and the methods
15 used. These enhanced inspections provided a more complete picture of system
16 conditions and allowed PG&E to identify and address risks more promptly.

17 In particular, the WSIP followed a risk-based approach grounded in a Failure
18 Modes and Effects Analysis (FMEA) that focused inspection efforts on asset
19 failure points most likely to lead to ignition. This framework identified how and
20 where PG&E's electric assets were most likely to fail, the potential effects of
21 such failures, and the relative likelihood that those failures could lead to ignition.
22 By focusing inspection procedures on the highest-risk components, the FMEA
23 allowed PG&E to develop more targeted and effective inspection methods. The
24 program advanced the WSIP's goal of identifying and remediating the most
25 serious conditions in the areas of highest wildfire risk and represented a
26 significant upgrade in both the safety and reliability of PG&E's transmission and
27 distribution systems.

28 PG&E invested considerable resources in implementing the WSIP. In 2019,
29 PG&E completed WSIP enhanced inspections on nearly all of its 49,715
30 transmission structures and 694,250 distribution poles in HFTDs.¹⁸ By the end

¹⁸ In May 2021, PG&E notified the Commission that 54,755 distribution poles had been inspected under the WSIP in 2019 but had not undergone a GO 165 routine inspection because of differences in the criteria for WSIP and routine inspections. PG&E took corrective actions to complete the inspections on an accelerated basis, and the Commission issued a \$2.5 million citation for not completing the inspections in 2019.

1 of 2019, PG&E's WSIP inspections had identified approximately 62,000 repairs
2 to be made on its transmission assets and over 225,000 repairs to be made on
3 its distribution assets, with PG&E spending over \$1.13 billion in 2019 on asset
4 maintenance and repairs. By the end of 2019, over 1,000 conditions requiring
5 immediate attention were identified and remediated, while over 10,000 additional
6 conditions requiring expedited attention were identified and remediated. Finding
7 and repairing these exigent conditions through enhanced inspections improved
8 the safety profile of PG&E's equipment.

9 Starting in 2020, PG&E incorporated the enhanced inspection processes
10 and tools developed for the WSIP into its routine compliance inspection and
11 maintenance program, adopting risk-informed maintenance cycles so that
12 facilities in Tier 3 HFTDs were subject to enhanced inspections annually, and
13 facilities in Tier 2 HFTDs were subject to enhanced inspections on a three-year
14 cycle.

15 Together with its robust vegetation management and quality assurance
16 efforts, these enhanced inspection programs were a key part of how PG&E
17 evolved its inspection programs to strengthen the safety and reliability of its
18 system.

19 **1. Transmission Facilities Inspections**

20 In the years before the Kincade Fire, PG&E implemented
21 comprehensive programs for the inspection and maintenance of its
22 transmission facilities that met or surpassed industry standards. PG&E's
23 program provided for detailed inspections, including climbing, drone, and
24 ground inspections; patrol inspections, both routine and emergency; and
25 infrared inspections. These inspections were performed by qualified
26 personnel in accordance with the standards set forth in the ETPM Manual,
27 which PG&E first published in 2011 and revised periodically as it enhanced
28 its inspection programs over time.

29 PG&E also conducted transmission inspections under the WSIP,
30 applying the enhanced methods in HFTDs introduced above. WSIP
31 inspections were carried out by linemen or troubleshooters trained and
32 experienced in power line maintenance and components who completed a
33 specialized WSIP orientation program. WSIP inspectors used mobile
34 technology and electronic checklists known as "Pronto Forms" to document

1 inspection findings electronically. All WSIP inspections were documented
2 with these electronic checklists and photographs regardless of whether any
3 corrective action was identified. This approach facilitated more efficient and
4 accurate recordkeeping and more immediate reporting of information
5 regarding the condition of PG&E's assets. For instance, preliminary
6 corrective notifications from WSIP climbing and drone inspections were then
7 sent to the CIRT for secondary review and prioritization, as discussed in
8 more detail below.

9 *Detailed inspections: ground, climbing, and drone.* Pursuant to the
10 ETPM Manual, detailed ground inspections focused on failure points
11 capable of visual inspection, typically conducted from the ground with
12 binoculars in accordance with the general inspection procedures laid out
13 above. Individual elements and components were examined carefully
14 through visual and/or routine diagnostic tests, and each abnormal condition
15 was graded and/or recorded. Detailed ground inspections were performed
16 by qualified personnel. PG&E added two important layers of enhanced
17 inspections after the Camp Fire and before the Kincade Fire as part of the
18 WSIP, both of which were subject to multiple levels of review through the
19 CIRT.

20 First, PG&E added a detailed climbing inspection for all transmission
21 assets. These detailed climbing inspections supported structure-based
22 observations of facilities to identify abnormal or hazardous conditions and
23 evaluate whether maintenance was warranted. WSIP climbing inspections
24 were performed by Qualified Electrical Workers (linemen or
25 troubleshooters), who completed electronic checklists to document findings
26 for all components identified in the FMEA on an inspected structure.
27 Inspectors also took photographs of specific components on each
28 transmission structure, regardless of whether an abnormal condition was
29 identified on the equipment.

30 Second, PG&E conducted drone inspections of all its transmission
31 assets, which were reviewed by a team of subject matter experts (SMEs) in
32 the newly created Drone Inspection Review Team (DIRT). During these
33 inspections, high-resolution photographs were taken of each asset. The
34 photographs were then sent to DIRT for review. A DIRT inspector reviewed

1 the photos to identify any potential conditions requiring repair. The DIRT
2 review included a safeguard called the “No Notification Review,” in which
3 another DIRT inspector re-examined drone photos from inspections that did
4 not generate any notifications to confirm there were no non-conformances.
5 The DIRT inspectors were qualified personnel with backgrounds in
6 transmission maintenance and engineering. They received comprehensive
7 training from PG&E, including how to identify and report non-conformances
8 with the ETPM Manual.

9 Any maintenance notifications created by DIRT in connection with
10 climbing or drone inspections were also sent to CIRT for review and
11 prioritization, and all photographs taken during those inspections were made
12 available to CIRT. CIRT was a cross-functional team of subject matter
13 experts with backgrounds in maintenance and engineering, including the
14 design, maintenance, operation, and components of electrical assets. CIRT
15 provided a uniform and centralized process to review all notifications
16 generated from field inspections for accuracy and prioritization.

17 CIRT processed work notifications through a standardized approach, by
18 reviewing photos, maps, and other field data. CIRT also followed a manual
19 that prescribed the composition of the review team and its procedures for
20 screening and prioritizing maintenance notifications. In particular, CIRT
21 determined final priority for conditions identified during WSIP climbing and
22 drone inspections, including by prioritizing conditions that might impact
23 overhead transmission equipment reliability or introduce a potential wildfire
24 ignition or public or personnel safety risk. Following review and approval by
25 CIRT, any notification became final and corrective actions were planned
26 based on the final priority level assigned. (If CIRT deemed the work
27 unnecessary, it canceled the notification.)

28 *Patrol inspections.* PG&E regularly conducted routine patrol inspections
29 to supplement the detailed ground inspections. All overhead transmission
30 line facilities were patrolled annually in years when detailed ground
31 inspections were not conducted. An overhead patrol could be performed by
32 walking, driving, or flying (via helicopter), although routine patrols were most
33 often done by flying. The inspector’s primary responsibilities during an
34 overhead patrol were to visually assess the electric facilities, looking for

1 obvious structural problems or hazards without using measuring devices,
2 tools, or diagnostic tests; to record that the facilities had been patrolled; and
3 to identify any abnormal conditions that, in the opinion of the inspector,
4 warranted maintenance before the next scheduled inspection. Any such
5 abnormal conditions were recorded and assigned a priority code for repair.
6 Issues identified included, for example, broken or chipped insulators, loose
7 or bent hardware, and wood pole deterioration. PG&E kept adequate and
8 auditable records of the patrols consistent with industry practices.

9 PG&E also performed non-routine patrols in response to specific
10 conditions that included, for example, situations where component defects
11 were visible from only certain vantage points, as well as third-party
12 observations and complaints. Between routine patrols, non-routine patrols,
13 and detailed inspections, transmission lines were often inspected multiple
14 times throughout the year.

15 *Infrared inspections.* PG&E used infrared (IR) imaging and
16 temperature-measuring systems as diagnostic tools for inspecting and
17 maintaining its transmission system (and, as discussed below, its
18 distribution system). IR inspections can identify “hot spots”—areas where
19 there is a temperature difference between two phases or two pieces of metal
20 on one phase—that are not visible to the naked eye. These areas of
21 abnormal heat can indicate degraded connections and equipment, such as
22 switch contacts, connectors, splices, and connections to equipment
23 terminals, before they fail.

24 IR inspections were carried out by inspectors who followed detailed
25 procedures in PG&E’s ETPM Manual. The ETPM Manual specified the
26 necessary equipment, camera setup, and scanning techniques, and stated
27 that IR inspections should generally be performed on lines loaded to at least
28 40 percent of the operating rating. Typically, IR inspections were performed
29 on overhead transmission circuits on a five-year cycle, with additional
30 inspections triggered by specific conditions such as component failure or
31 high fire hazard. This led to approximately 20% of PG&E’s transmission
32 lines being scheduled for an IR inspection each year. PG&E also conducted
33 IR patrols for lines that had exceeded their emergency ratings for 30
34 minutes or more to inspect for possible component damage.

2. Distribution Facilities Inspections

PG&E had longstanding and thorough inspection and maintenance programs for distribution equipment at the time of the Dixie Fire. PG&E's procedures for maintaining the reliability and safety of its electric distribution system were summarized in its EDPM Manual. In particular, the EDPM Manual described procedures and standards for routine inspections and patrols of PG&E's distribution lines and facilities pursuant to GO 165. The manual also covered other requirements applicable to PG&E personnel, including those relating to safety, compliance, assessment and notification processes, and record retention.

PG&E also conducted enhanced inspections of its distribution facilities under the WSIP, applying similar expanded methods in HFTDs. These inspections provided a more detailed assessment of distribution equipment and helped identify and address potential ignition risks more efficiently.

Detailed Inspections. Overhead distribution facilities were subject to a detailed inspection, at a minimum, every five years. Starting in 2020, PG&E increased that frequency to annual inspections in Tier 3 areas and every three years in Tier 2 areas. To perform these inspections, PG&E relied primarily on its own dedicated compliance inspectors—a specialized role created in 2003 to complete GO 165 patrols and inspections. Compliance inspectors were journeyman linemen who completed PG&E's New Inspector training and qualification process, which focused on identifying and assessing conditions that could affect safety or reliability. Prior to 2020, nearly all GO 165 distribution patrols and inspections were completed by these PG&E compliance inspectors, with only limited supplemental contractor support. Beginning in 2020, PG&E temporarily increased contractor use to meet the demands of higher inspection volumes and accelerated due dates associated with HFTD inspection cycles.

Routine Patrol Inspections. PG&E also performed patrols of its distribution system to help ensure system safety and reliability. These patrols, like detailed inspections, were conducted by PG&E compliance inspectors or company representatives trained and qualified to perform the duties of a compliance inspector. Patrolled overhead facilities included primary, secondary, service, and other associated electric distribution

1 facilities. Towers supporting only distribution facilities were also included in
2 the overhead patrol. As with transmission facilities, an overhead patrol
3 could be performed by walking, driving, or helicopter. Consistent with
4 regulatory requirements, these inspections were performed annually in
5 urban areas and every other year in rural areas, unless the areas had been
6 inspected earlier that year for a non-routine reason. Beginning in 2018, and
7 consistent with Commission rule changes, all HFTD poles were patrolled
8 annually (except in years they were subject to detailed inspections).

9 *IR Inspections.* As with the transmission system, PG&E used IR
10 inspection and imaging for its distribution system. PG&E instituted a project
11 to inspect each mile of its distribution lines with IR cameras for high splice
12 counts—that is, evidence of numerous prior repairs—and hotspots that
13 might indicate risk of equipment failures that could lead to wildfires. During
14 the inspection process, spans with three or more overhead splices were
15 inventoried and used to inform PG&E’s targeted replacement program for
16 overhead conductors. As with the transmission guidance described above,
17 PG&E policy for distribution IR inspections called for inspecting under load
18 and, where feasible, at least 40 percent of the line’s operating rating. The
19 rationale was substantially the same: adequate loading was important to
20 obtain meaningful temperature readings.

21 *Pole test and treat inspections.* For wood poles, intrusive inspections
22 were required by GO 165. Intrusive inspections are meant to identify
23 internal or below-ground decay that could be present but not externally
24 visible in wooden poles. GO 165 required such inspections for wood poles
25 that were over 15 years old, with follow-on inspections every 20 years for
26 wood poles that passed an intrusive inspection. PG&E designed its Pole
27 Test and Treat program to meet or exceed the GO 165 minimum
28 requirements in HFTDs: In those areas, it performed intrusive inspections
29 on wood poles on an approximate 10-year cycle. These inspections were
30 conducted by specialized contractors.

31 PG&E also worked to maintain its miscellaneous overhead distribution
32 equipment. It required and performed preventive maintenance for such
33 equipment in accordance with PG&E, manufacturer, and engineering
34 requirements. PG&E also refined its distribution maintenance standards

1 over time, including through a 2020 update that supplemented the EDPM
2 Manual with additional requirements for inspections, patrols, and
3 recordkeeping.

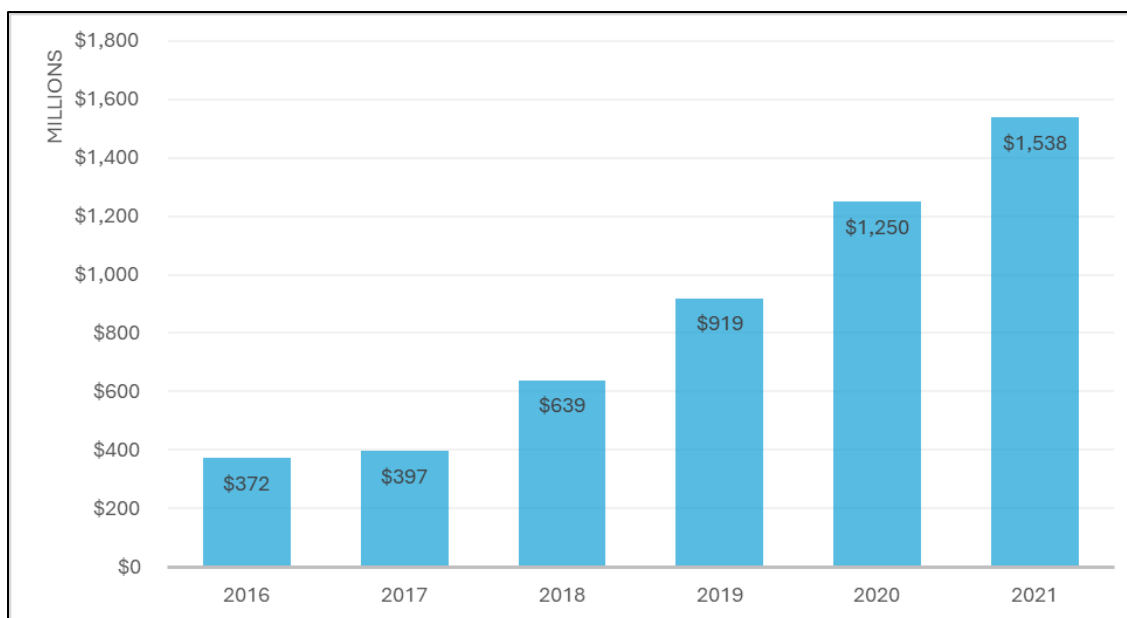
4 PG&E also performed regular testing of its distribution equipment.
5 PG&E annually tested its capacitor banks, line reclosers, voltage regulators,
6 and other equipment. PG&E tested its fault indicators every three years.
7 PG&E also annually performed visual assessments of its capacitor banks,
8 line reclosers, fault indicators, and sump pumps/manholes.

9 **3. Vegetation Management [Angela Sanford]**

10 PG&E had robust vegetation management programs in place at the time
11 of the Kincade and Dixie Fires. These programs mitigated risk and
12 supported compliance with laws and regulations through regular patrols and
13 pruning and removal of vegetation in proximity to electrical infrastructure
14 across PG&E's approximately 70,000-square-mile service area.

15 In the years preceding the Kincade and Dixie Fires, drought conditions
16 and rising temperatures increased the risk of a catastrophic wildfire in the
17 event of an ignition, prompting PG&E to make unprecedented investments
18 to mitigate the risk posed by vegetation near its powerlines. As shown in
19 Figure 2-4, PG&E's annual spending on vegetation management from 2017
20 to 2021 grew from approximately \$400 million a year to approximately \$1.5
21 billion, reflecting an increase of 275 percent.

**FIGURE 2-4
ANNUAL SPENDING ON VEGETATION MANAGEMENT (MILLIONS)**



The increase in investment reflected, in part, the expansion of PG&E's vegetation management workforce—from 4,446 in 2019 to 10,265 in 2021—
together with increased work, as the number of trees trimmed or removed
annually grew from approximately 1.36 million in 2016 to over 1.8 million in
2020 and remained elevated through 2021, as shown in Table 2-2.

**TABLE 2-2
ANNUAL TREES TRIMMED OR REMOVED (2016–2021)**

2016	2017	2018	2019	2020	2021
1.36 million	1.36 million	1.35 million	1.52 million	1.81 million	1.83 million

All vegetation management activities were overseen by PG&E
employees, including Regional Managers, Supervising Vegetation Program
Managers and Vegetation Program Managers for geographical divisions
throughout PG&E's service area. During the relevant time frame, PG&E
utilized qualified contractors to perform vegetation management inspections
and tree work, a standard practice across the industry. PG&E worked with a
select group of well-established contractors that engaged and trained
vegetation management inspectors with specified education and experience.
All such contractor inspectors were trained on PG&E's vegetation

1 management standards and procedures, and PG&E developed a
2 comprehensive inspector training program that was implemented in 2020.

3 PG&E's vegetation management program included routine vegetation
4 management, which encompassed: (1) the distribution vegetation
5 management program, (2) the transmission vegetation management
6 program, and (3) the pole clearing program. PG&E's vegetation
7 management program also implemented additional vegetation management
8 programs, as described below. PG&E conducted QC and quality assurance
9 (QA) audits for its vegetation management programs.

10 **a. Routine Vegetation Management Programs**

11 PG&E's routine programs serve as the baseline for PG&E's
12 vegetation management activities, which significantly reduce—but do
13 not eliminate—the risk of vegetation-related outages and ignitions.

14 *Distribution vegetation management program.* PG&E's Routine
15 Distribution Vegetation Management Program included inspections that
16 were followed by tree work, when necessary, in the period prior to the
17 Kincade and Dixie Fires. Inspectors known as “pre-inspectors” patrolled
18 PG&E's distribution lines to identify and prescribe tree work for trees
19 that might grow too close to powerlines, as well as trees that were dead,
20 dying, diseased, or otherwise hazardous.¹⁹ Any required tree work was
21 conducted in accordance with work prescriptions assigned by pre-
22 inspectors. Following the Camp Fire in 2018, PG&E prioritized
23 conducting routine inspections of high-fire-risk circuits before the onset
24 of fire season.

25 *Transmission vegetation management program.* PG&E also
26 performed annual vegetation management patrols along all of its
27 approximately 18,000 miles of overhead transmission lines.
28 Transmission line patrols included pruning, removing, or otherwise
29 controlling vegetation that posed a hazard or interfered with site use.
30 These patrols were conducted using Light Detection and Ranging

¹⁹ Pre-inspectors were required to have one year of arboricultural experience, be a certified arborist, utility specialist, or registered professional forester, or have a 2- or 4-year degree in a related field. In 2021, approximately 90 percent of PG&E's pre-inspectors were arborists certified by the International Society of Arboriculture.

(LiDAR) technology that could determine the distances and clearances of vegetation in relation to the electric conductors and easement boundaries. LiDAR was used to identify spans where trees had the potential to contact transmission lines. If a tree was identified, a subsequent ground inspection was conducted to assess the health of the identified tree and to determine if additional action, including removal, was necessary. PG&E's transmission-line vegetation management also featured a Right-of-Way Maintenance Program, which was designed to clear incompatible vegetation from the right-of-way. PG&E also implemented Integrated Vegetation Management techniques, such as chemical treatments and removals, to encourage the growth of preferred species—i.e., those less likely to come into contact with transmission lines.

Pole clearing program. PG&E's pole clearing program, also known as the Vegetation Control (VC) program, was principally designed to maintain specified clearance distances around certain poles in State Responsibility Areas (SRAs).²⁰ SRAs are areas where the state has assumed primary financial responsibility for wildfire prevention and suppression. The pole clearing program focused on poles with equipment that might generate electrical arcs, sparks or hot material during normal operation (referred to as nonexempt poles). Between one and four times each year, patrols inspected the poles for surrounding vegetation. Clearance work generally included removing vegetation and applying herbicide. Beyond that work in SRAs, PG&E conducted some vegetation control work in other areas identified as having high fire risk, in excess of its regulatory obligations.

Through its routine VC program, PG&E maintained required vegetation clearance, or "fire break," around electric poles, for the space around a pole extending vertically from the ground to the highest point of the conductor attachment and horizontally to ten feet from the pole in all directions. At ground level (0-8 feet), flammable materials such as

²⁰ Public Resources Code Section 4292 requires a minimum clearance distance of ten feet around specified poles or towers in SRAs.

1 trash, debris, grass, brush, and low tree limbs were cleared within ten
2 feet of the pole base. PG&E also aimed to trim dead or diseased
3 vegetation from eight feet above ground up to the top of the conductor
4 attachment.

5 **b. Additional Vegetation Management Efforts**

6 In addition to its routine vegetation management work, PG&E
7 implemented several targeted programs to address specific wildfire and
8 reliability risks on its distribution system. These efforts complemented
9 PG&E's ongoing patrol and clearance activities and further reduced
10 vegetation-related ignition and outage risks.

11 *Drought and Tree Mortality Response Program.* In 2014, PG&E
12 established its Drought and Tree Mortality Response Program, also
13 referred to as the CEMA program (now called second patrols).²¹
14 Second patrols applied to PG&E's distribution system and included
15 ground and aerial inspections and tree work in HFTDs. The program
16 was created in response to growing threats from drought and bark
17 beetle infestations that caused historic tree mortality rates.²² The
18 program focused on inspecting for dead, dying, or diseased trees, and
19 between 2014 and 2017, PG&E worked approximately 400,000 such
20 trees through this program.²³ In July 2019, the scope of CEMA (second
21 patrols) reinforced the need for inspectors to also look for routine
22 compliance issues. In addition to identifying dead, dying, and declining
23 trees, inspectors were also to identify green trees with the potential to
24 impact electric facilities or green trees observed within the minimum
25 distance requirements.

²¹ CEMA refers to the Catastrophic Emergency Memorandum Account, in which the costs of this effort were originally recorded given the program was initiated in response to then-Governor Brown's proclamation of a state of emergency in response to the drought and associated Commission directives for the utilities to take measures in response to the drought to reduce the likelihood of fires started by utility facilities.

²² CEMA patrol standards were governed by PG&E's Vegetation Management Second Patrol Practices Procedure and Second Patrol Scope of Work Requirements, among others.

²³ In 2015, PG&E worked 19,000 trees in its service territory; that number grew to 225,000 in 2016. And in 2017, PG&E worked 156,000 trees through its CEMA program.

1 Second patrols generally took place on a six month off-cycle
2 cadence from the routine patrols, resulting in distribution circuits being
3 inspected twice each year. Second patrols could be ground or aerial
4 patrols. Ground patrols involved an inspector walking along the
5 distribution line (similar to routine patrols). Aerial patrols involved an
6 inspector flying in a helicopter over the distribution lines.

7 *Accelerated Wildfire Risk Reduction.* PG&E also implemented the
8 Accelerated Wildfire Risk Reduction (AWRR) program—a short-term
9 initiative designed to address immediate wildfire risks following the
10 October 2017 North Bay wildfires. The AWRR program was carried out
11 between September and December 2018 in Tier 3 HFTDs and reflected
12 PG&E’s focus on prioritizing enhanced vegetation work in the
13 highest-risk areas. The program targeted conditions most likely to
14 cause ignitions, including overhanging branches with the potential to
15 contact primary voltage lines, hazardous trees capable of striking PG&E
16 facilities, and tree species most likely to interfere with primary lines. It
17 also reduced vegetation and fuel beneath and adjacent to high-voltage
18 lines in cooperation with property owners. To expedite implementation,
19 PG&E managed AWRR through a separate management structure
20 rather than through its standard vegetation management organization.
21 Through this effort, PG&E completed work on approximately 650 line
22 miles. Beginning in December 2018, AWRR activities were incorporated
23 into PG&E’s EVM program.

24 *Enhanced Vegetation Management (EVM).* Beginning in late 2018,
25 PG&E implemented its EVM program.²⁴ The EVM program aimed to
26 further reduce wildfire risk posed by vegetation near overhead
27 distribution lines in HFTDs by going above and beyond regulatory
28 requirements. EVM work consisted of two phases: In Phase 1,
29 pre-inspectors identified vegetation for removal or trimming if it
30 encroached on specified clearances for PG&E’s powerlines, was
31 overhanging a conductor, or was a dead, dying, or diseased tree posing

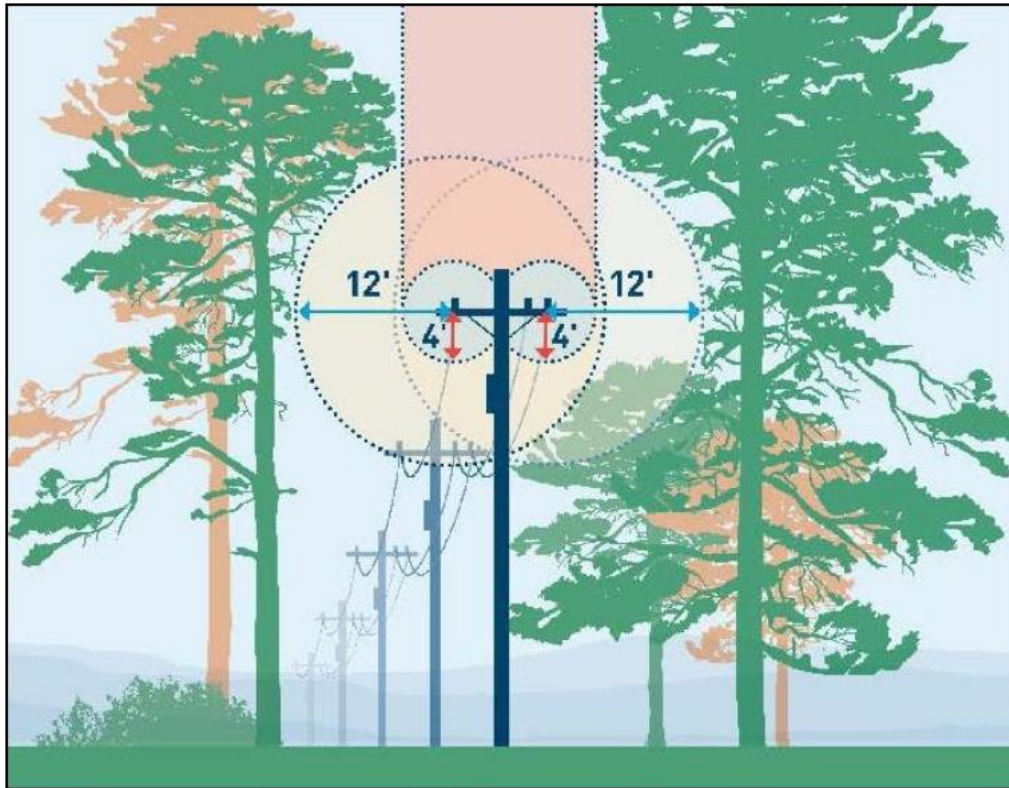
²⁴ PG&E discontinued the EVM program at the end of 2022 as part of a broader shift toward increased reliance on operational wildfire mitigation strategies like EPSS.

1 a risk to PG&E's facilities. Figure 2-5 below illustrates the EVM
2 clearance standards applied during Phase 1. The diagram reflects that
3 trees are maintained to provide at least 12 feet of clearance from
4 conductors. In addition, a 4-foot minimum clearance is maintained
5 immediately around each conductor to ensure a buffer against
6 vegetation contact.

7 Phase 2 involved inspecting and assessing all trees tall enough to
8 strike electrical assets. This entailed an additional inspection of every
9 tree with "strike potential" along overhead distribution powerlines in
10 HFTDs. Circuit segments within HFTDs were prioritized for EVM based
11 on their assessed wildfire risk.²⁵

²⁵ On April 15, 2021, PG&E was placed into Step 1 of the Commission's Enhanced Oversight and Enforcement Process (EOE Process) based on a finding that it had not properly prioritized the highest risk EVM work in 2020. On May 6, 2021, PG&E submitted a corrective action plan setting forth its work plan to prioritize the highest-risk circuit segments for work in 2021, and the company ultimately exceeded its goal by completing 98 percent of EVM work in the highest 20 percent of circuit protection zones. In 2022, the Commission determined that PG&E had sufficiently demonstrated its commitment to performing EVM on the highest risk lines and issued a resolution authorizing PG&E to exit Step 1 of the EOE Process.

FIGURE 2-5
VEGETATION TRIMMING AND OVERHANGING TREE LIMBS



Reliability Program. PG&E's Reliability Program was a further supplement to its other vegetation management work. The Reliability Program involved additional foot patrols and tree work, and it targeted circuit segments with higher rates of vegetation-caused outages and downed wires. The program—formerly known as the Public Safety and Reliability or Enhanced Electric Vegetation Management Program—had been in place for more than a decade by the time of the Dixie Fire and focused on PG&E's distribution system. Reliability patrols were planned using historical outage data, including information recorded in PG&E's Integrated Logging Information System (ILIS) and vegetation management outage databases, along with input from local vegetation management personnel. By prioritizing areas with the greatest history of vegetation-related reliability issues, the program reduced both service interruptions and potential wildfire risks.

4. Quality Control and Audit Programs [Carrell James Gill]

PG&E assessed, reviewed, and managed the quality of inspection work. Its QC and audit programs were managed by three internal organizations: System Inspections, Quality Management (QM), and Internal Audit (IA). Those programs identified anomalies in inspection results in order to identify gaps, determine their causes, and pursue improvement opportunities.

System Inspections. The System Inspections organization focused on work performed in the field and consisted of three groups: (1) Inspection Review Specialists; (2) QC; and (3) CIRT, described above. Inspection Review Specialists observed inspections to help ensure quality and offer real-time feedback to field inspection personnel.²⁶ The QC team conducted independent desktop reviews, shortly after initial inspections, of samples of inspections. These reviews focused on detailed overhead inspections of assets in HFTDs. As described above, CIRT administered a centralized process to review and prioritize notifications generated from field inspections.

Quality Management. The QM department, established in 2019, was responsible for the portfolio of audits conducted by both employees and contractors. The QM group created audit plans to verify compliance with inspection standards. It improved tools and reference materials to support field inspection plans, such as by introducing mobile electronic checklists. The QM department included the Quality Verification (QV) and Quality Assurance (QA) groups. The QV group performed field audits on internal and contract inspection records to determine the completeness and accuracy of inspections. Its audits were functionally similar to the QC audits described above but occurred over a longer timeframe and covered a smaller sample of inspections. The QA team evaluated inspection programs at the programmatic level. Its responsibilities included reviewing inspection procedures and standards, assessing inspection-related training, ensuring that standards complied with relevant rules and regulations, examining documentation practices, and identifying any gaps in inspection programs and processes.

²⁶ Inspection Review Specialists also reviewed and gave feedback to CIRT personnel.

1 *Audits.* The IA team conducted audits to sample completed work to
2 ensure it adhered to PG&E's established process requirements and
3 standards. IA employed a risk-based methodology to develop its annual
4 audit plan, taking into account both current and emerging risks, including
5 wildfire risks. The resulting plan included audits specifically focused on
6 high-risk activities. The primary focus of these audits was on the strength of
7 PG&E's internal processes and controls, with particular attention to
8 confirming that work met quality expectations and that proper review and
9 approval procedures were followed. As part of the audit process, IA
10 conducted field visits, interviewed PG&E subject matter experts, and
11 reviewed relevant documentation and records.

12 PG&E also conducted additional QC reviews for its vegetation
13 management work. PG&E contracted with California Forestry & Vegetation
14 Management Inc., a specialist in vegetation management auditing, for
15 specially trained workers to perform field work inspections to support audits
16 between 2016 and 2019.²⁷ PG&E employees have performed the audit
17 field work since 2020.

18 PG&E was also subject to external audits. The Commission's Electric
19 Safety and Reliability Branch (ESRB) performed audits of PG&E's
20 compliance with GO 165 and related inspection and maintenance programs.
21 These audits reviewed all parts of the inspection program, including
22 documentation, field validation of completed inspections and patrols, and
23 pending and completed maintenance work identified on electric corrective
24 action notifications. PG&E provided responses to ESRB audit reports as
25 appropriate, including to address corrective actions and their status.

26 **E. Operation of PG&E's Transmission and Distribution System [Roderick** 27 **Robinson]**

28 PG&E relied on a suite of operational policies and practices designed to
29 address potential safety hazards and reduce the risk of ignitions caused by
30 PG&E's electrical equipment. To promote reliable and safe operation of its
31 system, trained personnel at PG&E's transmission and distribution control
32 centers (GCCs and DCCs, respectively) continuously monitored PG&E's

27 Formal QA audits specific to PG&E's VC program began in 2018.

1 electrical systems and responded to events on the system, dispatching qualified
2 field personnel as necessary. PG&E's transmission and distribution operators
3 and supporting field personnel operated under a structured set of formal
4 procedures to guide their actions under normal and emergency conditions to
5 support safe and reliable operation of PG&E's electrical system.

6 In the years preceding the Kincade and Dixie Fires, PG&E implemented
7 specific operational practices to mitigate the risk of wildfires, including a PSPS
8 program to proactively de-energize PG&E's powerlines as a measure of last
9 resort during high fire-threat conditions and disabling of automatic reclosing in
10 specified high fire-risk areas during specified conditions. Further, through its
11 emergency planning and operational preparedness programs and strategies,
12 PG&E effectively responded to emergencies and fostered community
13 preparedness.

14 **1. Monitoring and Responding to Unplanned Outages and Hazards**

15 **[Roderick Robinson]**

16 In 2019 and 2021, PG&E operated two Electric Transmission GCCs and
17 three Electric DCCs. Those control centers played a critical role in
18 continuously monitoring and operating PG&E's electrical system and
19 responding to emergencies. In order to qualify for normal shift duty, system
20 operators in PG&E's control centers were required to complete operator
21 training programs, on-the-job training, and role-specific evaluations.

22 Grid operators within the GCCs monitored and operated PG&E's electric
23 transmission system under the direction of the California Independent
24 System Operator (CAISO). They responded to emergencies, tracked
25 information about unplanned outages, and assessed the condition of
26 damaged or inoperative equipment. When made aware of a safety hazard
27 involving PG&E's transmission equipment, grid operators were trained to
28 take immediate and appropriate actions to address the hazard based on the
29 facts and circumstances known to them at the time.

30 Similarly, distribution operators within the DCCs monitored PG&E's
31 electric distribution system for outages and SCADA alarms indicating trouble
32 on the system. Distribution operators are trained to operate the electric
33 distribution system to protect public safety and property, and are authorized
34 to de-energize lines if determined to be appropriate based on known facts

1 and circumstances. Distribution operators dispatched highly-qualified field
2 personnel called troubleshooters to investigate or remediate issues as
3 needed. Distribution operators could actively control PG&E's distribution
4 system by remotely operating SCADA-capable reclosers, circuit breakers,
5 and other field devices, and also took action in coordination with field
6 personnel. The primary tool used by distribution operators was the
7 Distribution Management System (DMS), which displayed various maps and
8 information regarding circuits, including the locations of fuses, switches,
9 transformers, and other devices.

10 The SCADA system generated alarms that were transmitted to the GCC
11 or DCC when specified events occurred on PG&E's electrical system. For
12 example, PG&E's Utility Procedure TD-2700P-09 ("Responding to
13 Emergencies and Alarms") set forth SCADA alarms for DCCs, with assigned
14 priority levels ranging from Priority 1 (lowest) to Priority 10 (most critical).
15 Higher priority level alarms (Priorities 6 to 10) required immediate action and
16 included events such as circuit breaker and line recloser operations,
17 transformer oil level and temperature alarms, and fires. Priorities 4 and 5,
18 which included events like security alarms and other less urgent field
19 alarms, required operators to analyze the situation and take action as
20 needed. Lower priority level alarms had various required actions depending
21 on alarm type, with Priority 1 alarms informational only.

22 When fuses rather than line reclosers and relays operated and de-
23 energized line sections in response to events on the system, the DCC
24 generally received notice of outages from PG&E's Outage Management
25 Tool or field personnel. The Outage Management Tool is a web-based
26 application populated by customer calls and smart meter notifications.
27 Unplanned outages are a common feature of operating a high-voltage
28 electric system. For example, based on records in PG&E's ILIS database,
29 PG&E experienced approximately 1,121 unplanned outages on distribution
30 lines in HFTDs in the two months preceding the Dixie Fire. Outages were
31 often caused by transitory events such as animal contacts, balloons, or tree
32 branches blowing across the powerlines. When outages occurred on the
33 distribution system, field personnel were dispatched to investigate the cause
34 of the outage, in coordination with distribution operators. Field personnel

1 were required to patrol the line and to coordinate with distribution operators
2 to take any necessary actions to make the line safe before it would be re-
3 energized.

4 **2. Fire Prevention Protocols [Shawn Holder]**

5 During the period covering the Kincade and Dixie Fires, PG&E used
6 wildfire mitigation programs and protocols to reduce the risk of electric
7 equipment-caused ignitions.

8 **a. Enhanced Situational Awareness Tools [Scott Strenfel]**

9 Following the 2017 and 2018 wildfire seasons, PG&E enhanced its
10 situational awareness capabilities to address increasing fire risk in its
11 service area. PG&E also created the Wildfire Safety Operations Center
12 (WSOC) in 2018 to monitor wildfire risks in real time.²⁸

13 PG&E focused on developing additional detailed and real-time
14 information about wildfire risk to guide its risk-reduction measures.
15 PG&E used data from weather stations in its service area to help
16 forecast and monitor for high fire-risk weather conditions, including
17 verifying conditions before de-energizing circuits in a PSPS event and
18 confirming that weather conditions were safe before lines were
19 re-energized. PG&E installed high-definition, pan-tilt-zoom cameras to
20 identify, confirm, and track wildfire ignition, spread, and fire behavior.

21 PG&E also developed modeling tools to better understand the
22 potential for fires to ignite and spread. For example, following
23 benchmarking sessions with SDG&E, PG&E Meteorology developed the
24 Fire Potential Index (FPI), which used hour-by-hour forecast and
25 tracking information to create daily updates based on weather data and
26 fuel conditions. In addition to FPI forecasts, PG&E also generated
27 short- and medium-term weather forecasts across the service area
28 using information from several public and proprietary sources.

²⁸ The WSOC began transitioning to an all-hazards center in 2021, and was renamed the Hazard Awareness & Warning Center (HAWC). From a wildfire perspective, the HAWC remains the operating unit that serves as PG&E's central information hub for all wildfire-related data.

1 **b. Public Safety Power Shutoff [Shawn Holder]**

2 In 2018, PG&E implemented a PSPS program to proactively de-
3 energize portions of its electric system as a measure of last resort to
4 mitigate the risk of catastrophic wildfires. In developing its PSPS
5 program, PG&E performed extensive benchmarking with SDG&E, which
6 had implemented a proactive de-energization program following the
7 2007 San Diego wildfires. PG&E also incorporated the proactive de-
8 energization guidelines and requirements developed by the
9 Commission.

10 PG&E's initial PSPS program in 2018 included distribution and
11 lower-voltage (70kV or below) transmission lines traversing Tier 3
12 HFTDs. PG&E significantly expanded the program in 2019 to include all
13 distribution and transmission lines traversing Tier 2 or Tier 3 HFTDs as
14 potentially in scope for PSPS. PG&E also was simultaneously working
15 to upgrade its system to promote sectionalizing and more targeted
16 execution. A mature systemwide PSPS program takes time to develop
17 and PG&E acknowledges the challenges for its customers and the
18 communities it serves associated with early execution of PSPS events,
19 including in connection with the October 23, 2019 wind event.

20 PG&E's PSPS preparations were driven by forecasts of fire danger
21 and high wind conditions by PG&E's Meteorology team. When those
22 forecasts indicated a need for PSPS readiness, PG&E activated its
23 Emergency Operations Center (EOC), with a designated Officer in
24 Charge, to monitor and analyze weather information and local conditions
25 leading up to and during the time period(s) of concern. PG&E
26 considered multiple factors to determine the scope of a potential PSPS
27 event and to identify the geographic areas of concern. This included
28 PG&E's FPI forecasts, designed to forecast when a potential ignition is
29 most likely to result in a catastrophic fire, and its Outage Producing
30 Winds (OPW) model, designed to forecast when unplanned outages
31 associated with wind events are most likely to occur.

32 All distribution lines within the identified area(s) were deemed in
33 scope for potential de-energization. Transmission lines were evaluated
34 on a line-by-line basis to determine which transmission lines within the

1 identified area(s) would be deemed in scope for potential de-
2 energization. PG&E used a risk-informed methodology to evaluate both
3 the wildfire risk and grid reliability risk of individual transmission lines to
4 support targeted scoping and de-energization of transmission lines.

5 Throughout the time period leading up to a potential PSPS event,
6 PG&E continually monitored forecasts for the identified geographic
7 areas and time periods. During the event, decisions regarding whether
8 to proactively de-energize were based on real-time conditions, assessed
9 through the latest weather models, available weather station data, and
10 real-time field observations from PG&E crews. In making the ultimate
11 decision of whether to de-energize, the Officer in Charge used
12 predetermined PSPS guidance thresholds to weigh the public safety
13 impacts of de-energization relative to the potential safety impacts of a
14 catastrophic wildfire.

15 PG&E further refined its PSPS program after 2019, including by
16 continuing to upgrade and install sectionalizing devices on distribution
17 circuits to limit the scope and duration of PSPS events, including the
18 number of customers impacted. PG&E also continued to expand its
19 network of weather stations to provide granular data regarding local
20 conditions to guide its PSPS decision-making. In 2020, PG&E
21 developed a map addressing areas of increased fire risk, intended to
22 further refine PG&E's understanding of catastrophic wildfire risk in its
23 service territory and inform the geographic scope of its PSPS
24 implementation. This was incorporated into PG&E's PSPS program in
25 2021 as PG&E continued to evaluate additional geographic areas for
26 inclusion in potential PSPS events based on the combined potential for
27 catastrophic fires and risk of ignition.

28 **c. Recloser Operations [Roderick Robinson]**

29 Reclosing devices are high-voltage switches that can restore power
30 to a line after a temporary fault. PG&E's use of reclosing devices on the
31 distribution system has evolved over time. Reclosing devices on the
32 distribution system were traditionally set to reclose quickly to clear
33 temporary faults and restore service to customers. In 2017, in order to
34 reduce the risk of ignitions caused by sustained faults, PG&E piloted a

1 program to block automatic reclosing for certain reclosers and circuit
2 breakers in specified high-risk wildfire areas when a fire index area had
3 a fire danger rating of very high or extreme. In 2019, PG&E adopted its
4 formal procedure regarding disabling of automatic reclosing (Utility
5 Procedure TD-1464P-01), which provided that reclosing devices
6 associated with distribution lines and transmission lines at 115kV and
7 below would be disabled in HFTDs during the determined fire risk
8 season. PG&E determined the seasonal timing for disabling and
9 enabling reclosing devices based on recommendations from the
10 Meteorology and HAWC teams. PG&E also focused on installing
11 additional protective devices to support sectionalizing and upgrading
12 reclosing devices in high-risk wildfire areas to support SCADA
13 capability, which enabled operators to control the devices remotely.

14 PG&E had a longstanding practice of disabling automatic reclosing
15 on devices associated with transmission lines that connect to power
16 generation facilities, in order to assure the safety and stability of
17 generation facilities.

18 **3. Emergency Planning and Operational Preparedness [Angelina M.** 19 **Gibson]**

20 During emergency events (including the Kincade and Dixie Fires),
21 PG&E followed Incident Command System (ICS), Standardize Emergency
22 Management System (SEMS), and National Incident Management System
23 (NIMS) protocols to ensure a standardized approach to coordination with
24 public safety partners. ICS provided interoperability with federal, state, and
25 county emergency response through a common organizational structure and
26 processes for integrating facilities, equipment, personnel, procedures, and
27 communications. Incident teams received specific training that included
28 courses on ICS Fundamentals and PG&E's Company Emergency Response
29 Plan.

30 At the local level, PG&E's Electric Operations Emergency Centers
31 (OECs) supported emergency response by directing resources to assess
32 damage, secure hazardous situations, restore service safely, and
33 communicate the status of recovery efforts internally. The OECs reported
34 up to PG&E's Regional Emergency Centers, which in turn reported up to a

1 centralized EOC that coordinated emergency response resources among
2 regions in PG&E's service territory.

3 PG&E also implemented strategies to ensure open communication
4 during major incidents with affected local communities, as well as the
5 CPUC, Cal Fire, and the California Office of Emergency Services. PG&E's
6 Public Safety Specialists—many of them retired senior officers from Cal Fire
7 or local fire departments—coordinated and communicated with Cal Fire
8 during these incidents, including the Kincade and Dixie Fires. During daily
9 "Cooperators Meetings" in connection with these fires, PG&E provided an
10 overview of its assessment, repair, and restoration processes, and
11 answered questions.

12 PG&E also established in-house fire protection services in 2018 known
13 as the SIPT program, which were comprised of two-person teams, certified
14 by the California Fire Marshal, with experience and training in fire prevention
15 and suppression. PG&E deployed SIPTs as field observers on high fire-risk
16 days to provide additional personnel and resources, inform PSPS decision
17 making, protect critical utility infrastructure, and assist with emergency
18 response in coordination with emergency response agencies. To support
19 SIPT's fire-protection capabilities, PG&E developed custom engines and fire
20 retardant pumps. At the time of the Dixie Fire, the SIPT program had grown
21 to 40 crews in 32 locations across PG&E's service territory.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3A

THE KINCADE FIRE

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3A
THE KINCADE FIRE

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3A
THE KINCADE FIRE

A. Introduction [Andrew Paul Abranches]

This chapter sets forth Pacific Gas and Electric Company's (PG&E) testimony regarding the 2019 Kincade Fire and PG&E's prudent operation of its system in relation to that event. The Kincade Fire ignited on October 23, 2019, in Sonoma County, in a geothermal field known as the Geysers. The Geysers is a complex of geothermal power plants, where Calpine Corporation (Calpine) owned and operated 13 plants that were connected to PG&E-owned transmission lines.

The California Department of Forestry and Fire Protection (Cal Fire) issued a report concluding that the fire was attributable to PG&E's electrical equipment.¹ Specifically, the Kincade fire agency report stated that the ignition resulted from a broken jumper conductor on a transmission tower (Tower 001/006) that carried the Geysers #9-Lakeville 230kV transmission line (referred to in this and other chapters of testimony as the Geysers #9 Line), which connected to the Geysers Units 9/10 facility owned by Calpine. While PG&E takes issue with many of the assertions in Cal Fire's report, PG&E does not dispute this cause determination.

The available evidence shows that PG&E was a prudent manager of its system in relation to the ignition of the Kincade Fire. PG&E retained two independent experts to evaluate the cause of the fire: Dr. Erik Christiansen, a fire origin-and-cause expert; and Dr. Larry Eiselstein, a metallurgical engineer with more than thirty years of experience in materials-failure analysis. Dr. Christiansen confirmed that the ignition resulted from the separation of a jumper conductor on PG&E's Geysers #9 Line. Dr. Eiselstein concluded that the jumper conductor separated at a point that was within a solid metal "shoe" covering the conductor. PG&E had no prior indication before the Kincade Fire that the jumper conductor would fail in this manner.

¹ The report is referred to herein as the Kincade fire agency report and is attached as Attachment 1 to this chapter of testimony.

1 PG&E prudently designed and constructed the PG&E facilities associated
2 with the ignition. Historically, the Geysers #9 Line, carried by Tower 001/006,
3 delivered power generated at the Geysers Units 9/10 plant to PG&E's system.
4 In May 2006, PG&E removed the generation tie line connecting Tower 001/006
5 to the Geysers Units 9/10 switchyard in response to a request from Calpine
6 which advised that the plant was "mothballed" or out of service. In light of the
7 communications from Calpine and the status of the Geysers power plant, PG&E
8 appropriately maintained the Geysers #9 Line for future use serving Calpine.

9 PG&E also regularly inspected Tower 001/006 and the Geysers #9 Line
10 using various methods. A drone inspection in May 2019 yielded high-resolution
11 photographs of the facilities from a high elevation and from multiple angles.
12 Neither the drone inspection nor the other inspections completed by PG&E
13 identified any indication that the jumper was at risk of failing. At the time of
14 ignition, the only outstanding maintenance item related to Tower 001/006 was a
15 low-priority notification for repainting.

16 PG&E prudently operated its system in relation to the ignition of and
17 response to the fire. PG&E appropriately deployed and utilized its Public Safety
18 Power Shutoff (PSPS) and emergency response protocols on October 23, 2019.
19 Review of electrical event records confirms that PG&E's protection system
20 operated as expected in response to the electrical events associated with the
21 ignition.

22 This chapter also addresses the alleged violations identified by the
23 Commission's Safety and Enforcement Division (SED) in connection with its
24 investigation into the Kincade Fire. For the reasons described below, SED's
25 alleged violations do not create "serious doubt" regarding PG&E's prudence.

26 **B. The Kincade Fire [Carrell James Gill]**

27 The Kincade Fire ignited on the evening of October 23, 2019, in the Geysers
28 geothermal field next to a geothermal power plant known as Geysers Units 9/10
29 operated by the power company Calpine.² The location of the ignition was near
30 John Kincade Road, approximately 13 miles east of Cloverdale in Sonoma
31 County. This area was classified as a Tier 3 High Fire-Threat District (HFTD)

2 A geothermal field is an area where water rises to the Earth's surface as hot springs, geysers, or steam.

1 under the Commission’s final Fire Threat Map in 2018, although it had not
2 previously been identified as an area of high fire risk under the Commission’s
3 interim fire threat map prior to 2018. The Kincade Fire was active for 14 days
4 and burned 77,758 acres before being fully contained on November 6, 2019.

5 **1. PG&E’s Facilities Related to the Kincade Fire [Carrell James Gill]**

6 The Kincade Fire was caused by a separated jumper conductor at
7 PG&E transmission Tower 001/006 next to Geysers Units 9/10.³ Tower
8 001/006 is shown in the image below. It had three cross arms that traversed
9 the tower horizontally carrying two 230kV transmission circuits, the Geysers
10 #9 Line and the Geysers #12-Fulton 230kV transmission line (the Geysers
11 #12 Line). The Geysers #9 Line ran north from PG&E’s Lakeville Substation
12 and ended at Tower 001/006. It was connected to the eastern arms of
13 Tower 001/006, on the side of Tower 001/006 closest to Geysers Units
14 9/10. The jumper at issue on the Geysers #9 Line was connected to the top
15 eastern arm on Tower 001/006. The Geysers #12 line—also supported by
16 Tower 001/006—ran parallel to the Geysers #9 Line and continued
17 northward past Geysers Units 9/10 to an active Calpine-owned geothermal
18 plant, Geysers Unit 12.

3 The numbering for Tower 001/006 is based on its position as the sixth tower in the first mile of the Geysers #12 Line.

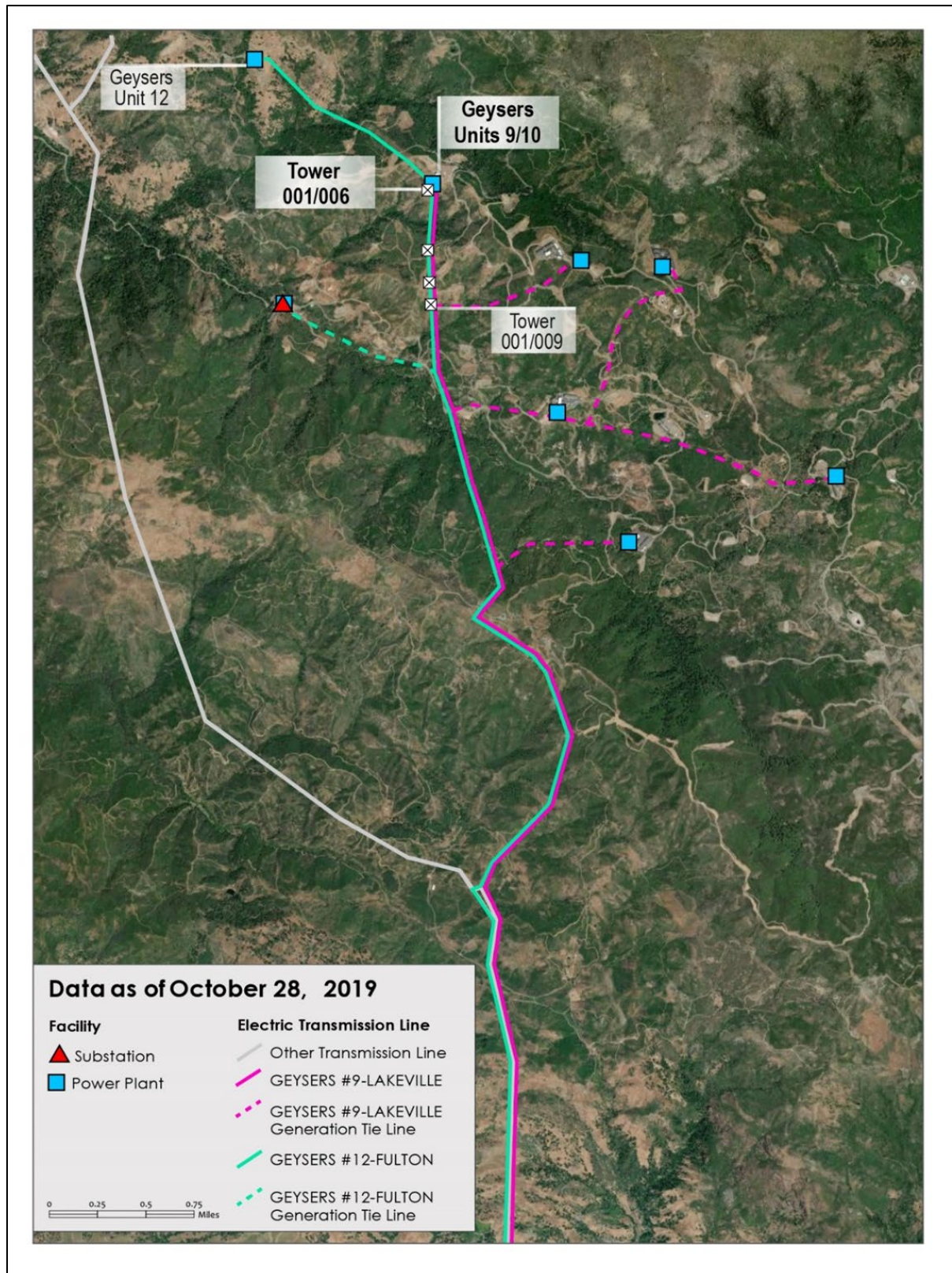
**FIGURE 3A-1
TOWER 001/006**



1 The circuit map below shows, as of October 2019, the Calpine-owned
2 geothermal power plants in the Geysers area and the PG&E facilities in and
3 around the area where the Kincade Fire ignited. In particular, it shows the
4 three spans of the Geysers #9 Line between Tower 001/009 and Tower
5 001/006 that remained in place and no longer carried load after PG&E
6 disconnected the Geysers #9 Line from the Geysers Units 9/10 power plant
7 in May 2006. After disconnection and at the time of the Kincade Fire, the
8 three spans remained part of the continuous 43 miles of the Geysers #9
9 Line, which continued to serve other customers, including other Calpine
10 facilities. Tower 001/006 also continued to support the active Geysers #12
11 Line, which continued north from Tower 001/006 to an active power plant.⁴

⁴ The diagram is based on a PG&E-generated GIS map reflecting a data snapshot taken at the time of the fire, which included data only on those facilities and lines PG&E considered significant to the conditions present at the time of the fire. The diagram therefore may not reflect all existing circuits or equipment in the area as of October 28, 2019.

**FIGURE 3A-2
THE GEYSERS #9 LINE**



1 **2. The Kincade Fire Resulted from a Broken Jumper Conductor**
2 **[Erik Christiansen]**

3 I am a licensed professional engineer specializing in fire
4 origin-and-cause analysis. I was engaged by PG&E to conduct an
5 independent origin-and-cause investigation of the Kincade Fire, which
6 included reviewing Cal Fire's findings and photographic evidence, and
7 visiting the ignition site.

8 An investigation into the origin and cause of the Kincade Fire was
9 conducted by Cal Fire, and Cal Fire's findings are set forth in the Kincade
10 fire agency report.⁵ As described in that report, on October 23, 2019 (the
11 date of ignition), a Calpine employee driving in the area observed a fire in
12 front of PG&E Tower 001/006 at Geysers Units 9/10. The employee
13 reported the fire at approximately 9:20 p.m. When Cal Fire investigators
14 arrived at the origin area later that night, they encountered high-speed and
15 erratic winds. Investigators observed what appeared to be a disconnected
16 or separated conductor wire hanging from one of the insulators on Tower
17 001/006.

18 On November 1, 2019, evidence was collected from Tower 001/006.
19 Under Cal Fire's supervision and direction, PG&E removed the incident
20 jumper and sections of the lattice steel frame of the tower that showed
21 potential electrical contact.

22 As described in the Kincade fire agency report, Cal Fire investigators
23 identified the area adjacent to Tower 001/006 as the general origin area of
24 the Kincade Fire and concluded that the ignition resulted from a mechanical
25 failure on PG&E's Geysers #9 Line. Specifically, the Cal Fire investigation
26 team concluded that the separation of a jumper conductor resulted in one
27 end of the jumper conductor hanging down and coming into contact with (or
28 close proximity to) the transmission tower box frame, creating a
29 phase-to-ground fault. The resulting fault caused arcing between the jumper
30 conductor and steel tower, generating intense heat that produced molten

5 Kincade fire agency report (Oct. 23, 2019), Attachment 1 to this chapter of testimony.

1 metal droplets, which fell into a receptive fuel bed and ignited the fire. I
2 agree with that ultimate conclusion.⁶

3 **3. Post-Incident Examination Indicates Mechanical Separation of the** 4 **Jumper Conductor [Larry Eiselstein]**

5 I am a metallurgical engineer with extensive experience analyzing the
6 performance and failure of metallic components. This section describes my
7 conclusions regarding how the jumper conductor failed based on
8 metallurgical analysis of the materials collected from the vicinity of Tower
9 001/006 of the Geysers #9 Line. As part of my work, I physically examined
10 the evidence collected by Cal Fire after the Kincade Fire, including the failed
11 jumper conductor and tower arm. The broken ends of the failed jumper
12 conductor were recovered and analyzed using optical microscopy, scanning
13 electron microscopy and CT scan (computed tomography scan, which is a
14 common form of medical imaging).

15 As shown in Figure 3A-3, the jumper conductors were previously located
16 on the top eastern arm of the transmission tower, Tower 001/006. Each
17 jumper conductor was supported at the metal shoe on one end, and then
18 tied together with the other jumper conductor on the other end. The jumpers
19 previously connected to the generation tie line for the Geysers Units 9/10
20 power plant, but that connection was removed in 2006. The jumper
21 conductors were each twisted multi-strand all-aluminum conductors.
22 Two dead-end insulators and a support insulator string hung from the tower
23 arm, supporting each of the two jumper conductors at two points. The
24 insulators prevented electricity from passing between the conductors and
25 the metal tower. One of the two jumper conductors—the incident jumper—
26 broke within its metal shoe, causing the jumper conductor to fall and arc
27 against the tower structure below it.

6 I agree with the origin and cause conclusion in the Kincade fire agency report. I do not otherwise adopt or affirm statements set forth in the Kincade fire agency report.

**FIGURE 3A-3
TOWER 001/006 JUMPER CONFIGURATION**



1 Based on my examination of the evidence, associated reports and
2 documents, and my training and experience, I reached the following
3 conclusions. I determined that the jumper conductor separated due to
4 fatigue, i.e., the gradual weakening of the conductor, induced by gusting
5 winds over time. I also determined that there was no visible indication of
6 fatigue prior to the separation, and that the separation point was located
7 within the solid metal shoe, which obscured the failure location prior to
8 separation.

**FIGURE 3A-4
PHOTOGRAPHS OF THE SHOE AND THE CONDUCTOR FRACTURE**

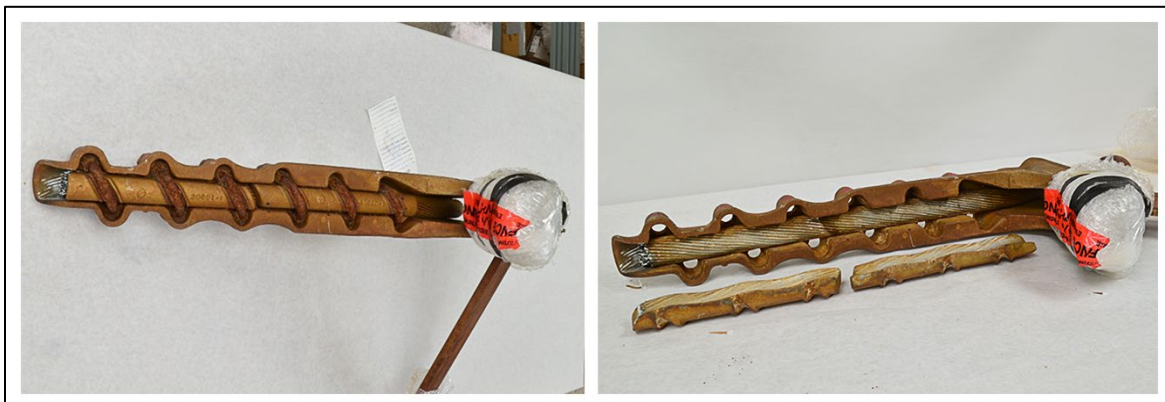
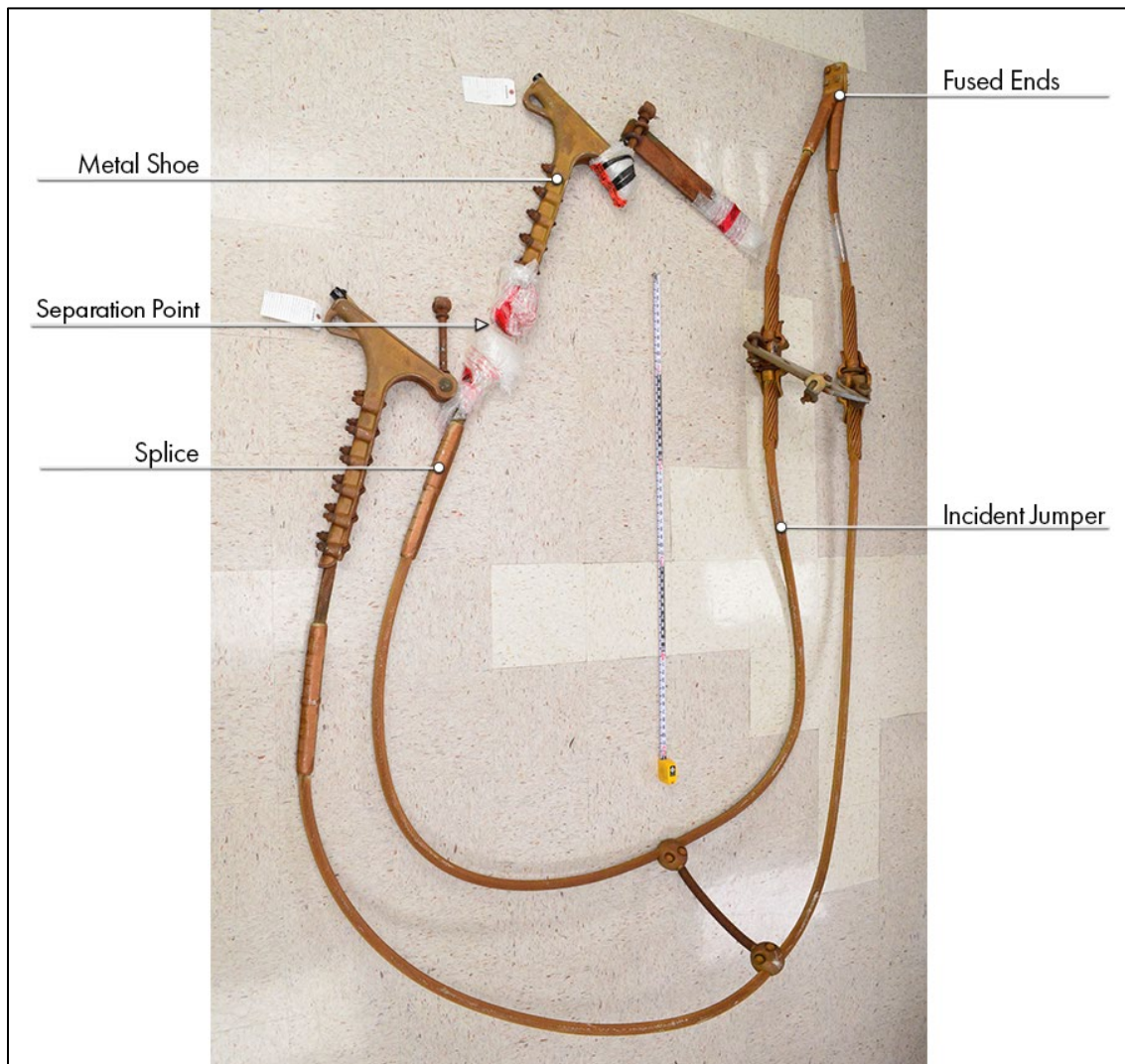


FIGURE 3A-5
INCIDENT JUMPER CONDUCTOR AFTER THE KINCADE FIRE



- 1 *Fatigue affecting the jumper conductor.* Fatigue occurs when a
- 2 component is subjected to repeated stresses. In this case, movement of the
- 3 jumper induced stresses that, although individually below the ultimate
- 4 strength of the metal, collectively over time initiated and propagated cracks
- 5 until fracture occurred. The incident jumper conductor separated due to the

combined effects of high-cycle fatigue,⁷ low-cycle fatigue,⁸ and fretting fatigue.⁹ When stresses vary in magnitude, fatigue damage may accumulate from both high- and low-cycle fatigue.

Authoritative reference manuals make clear that the leading causes of wind-induced fatigue typically apply to long, heavy transmission spans (which are under high tension), rather than to jumper conductors (which are under low tension).¹⁰ The specific type of wind loading that most commonly induces damage from high-cycle fatigue (and fretting fatigue, in the case of a multistranded cable) is called aeolian vibration.¹¹ Aeolian vibration is low-amplitude, high-frequency vibration caused by steady, moderate winds.

On long spans, the significant weight of the conductor makes the conductor more vulnerable to aeolian vibration. By contrast, shorter jumper conductors experience little to no aeolian vibration because of their relatively short lengths and very low tension. The separation of the incident jumper was not caused by aeolian vibration and instead can be primarily attributed to repeated exposure to gusting winds, which induced stresses from loading cycles and frictional movement between the conductor wires. Over time, this initiated and propagated fatigue cracks, eventually leading to complete separation of the conductor.

No visible sign of fatigue before separation. From my review of the evidence, I also determined that there was no visible indication of fatigue on

-
- ⁷ High-cycle fatigue develops under relatively low stresses and a relatively high number of loading cycles (generally more than 10,000). When wind blows across a transmission line, the conductor moves back and forth in what is called a loading cycle. Even though each individual stress is not enough to bend or deform the component, the repeated motion over time weakens the material and may result in fatigue.
- ⁸ Low-cycle fatigue arises from higher stresses that result in permanent deformation with each loading cycle. Low-cycle fatigue typically involves fewer than 10,000 cycles. A simple example is repeatedly bending a coat hanger wire until it breaks.
- ⁹ Fretting fatigue is caused by small, repetitive frictional movements between the wires in a conductor. It accelerates damage by reducing the material's fatigue strength and service life from what would be expected for a single-wire strand.
- ¹⁰ The literature also indicates that long-span fatigue failures are generally mitigated using vibration dampers. Such vibration dampers were present on the facilities here.
- ¹¹ Aeolian vibrations are the "fundamental cause of conductor fatigue failures." U. Cosmai, P. Van Dyke, Laura Mazola, and Jean-Louis Lillien, "Chapter 10: Conductor Motions" in *Overhead Lines*, CIGRE Green Book, Springer Reference, International Council on Large Electric Systems, 2017 at p. 588.

1 the conductor prior to the separation. It is difficult to analyze and to attempt
2 to predict failures due to wind-induced loading, particularly where fretting
3 fatigue is also involved. Often, there are few or no visible indications of
4 fatigue until separation, even for equipment in plain view. Indeed, in the
5 years preceding the Kincade Fire, Tower 001/006 and the associated lines
6 were inspected on multiple occasions, and these inspections showed no
7 signs that the jumper was at risk of failing.¹² Drone inspection photographs
8 taken several months prior to the jumper conductor separation confirm that
9 no indication of damage was observed prior to the incident.

10 Moreover, the separation point was located within a metal shoe, which
11 obscured the area experiencing fatigue. Inspection photographs do not
12 show any visible physical indications of fatigue in that area (e.g., evidence of
13 fraying wires outside the shoe), and infrared inspections did not detect any
14 abnormal heat conditions.¹³ Thus, my examination indicates that no signs
15 of damage near the failure location would have been visible prior to the
16 mechanical separation. This is consistent with the SED's written
17 investigation report (SED Report), which states that it was "unlikely that the
18 signs of fatigue stress weakening the incident jumper cable would have
19 been visible via a visual inspection, since it occurred within the shoe and
20 splice."¹⁴

21 The SED Report goes on to note that the "incident jumper cable showed
22 slight signs of bowing or bird-caging at the points near the exit of the shoe"
23 and that this was seen "on the other phases' jumper cables for the Incident
24 Line" too, positing that this slight "bowing or bird-caging" could be "indicative
25 of fatigue stress."¹⁵ Bird-caging occurs when the strands of a conductor are

¹² Consistent with the discussion above, PG&E records indicate that fatigue failure of a jumper conductor is uncommon for PG&E equipment. When fatigue failures have occurred on PG&E transmission equipment before the Kincade Fire, they have typically occurred on main spans, which are under high tension.

¹³ As discussed in Chapter 2: Prudence of Operations, infrared inspections use a thermal imaging camera to detect abnormal heat conditions on a line, which can indicate degraded equipment, such as broken wires in a conductor. The Geysers #9 Line at Tower 001/006 no longer carried generation or customer load, so equipment issues were unlikely to appear as an abnormal heat condition during an infrared inspection.

¹⁴ CPUC, SED Incident Investigation Report (Oct. 27, 2021) (SED Report), p. 27.

¹⁵ SED Report, p. 17.

1 no longer lying together as manufactured. Bird-caging may present in
2 different visual variations depending on the nature and severity, and in its
3 most extreme form the strands flare outward radially forming shapes similar
4 to baskets or birdcages.¹⁶ Bird-caging is often considered an installation or
5 handling defect and not a sign of fatigue or imminent failure unless
6 accompanied by other indications such as broken strands. Based on my
7 review of pre-incident photographs of the jumper conductor, there is no
8 reason to think that bird-caging had occurred before the incident as a sign of
9 fatigue, and any bird-caging observed *after* the jumper had been removed
10 following the fire could be due to other factors, e.g., slight twisting or
11 bending during removal.

12 **C. PG&E Prudently Operated Its System in Relation to Ignition of the Kincade**
13 **Fire [Davis Erwin; Angelina M. Gibson; Shawn Holder]**

14 PG&E prudently operated its system on October 23, 2019, in relation to the
15 ignition of the Kincade Fire. PG&E's protection system operated as expected in
16 response to the electrical events associated with the ignition, as confirmed by
17 records from that time. PG&E also appropriately deployed and utilized its
18 emergency response and PSPS protocols on the date of ignition.

19 **1. PG&E's Protection Systems Operated as Expected in Response to the**
20 **Electrical Faults Caused by the Separated Jumper Conductor**
21 **[Davis Erwin]**

22 On October 23, 2019, PG&E's protection systems operated as expected
23 in response to the jumper conductor separation and contact at Tower
24 001/006.

25 The Geysers #9 Line was protected by two protective relays and a
26 circuit breaker, the Lakeville Circuit Breaker (CB) 222, located at the
27 Lakeville substation. Based on analysis of electrical event records
28 downloaded after the fire, the protective relays monitoring the Geysers #9
29 Line detected a ground fault at approximately 9:19 p.m. on October 23,
30 2019. The fault event caused the relays to send commands to the circuit
31 breaker to open and de-energize the Geysers #9 Line. As a result, the fault

¹⁶ The strands of the conductor may be either broken and sticking out from the strand bundle or at least one wire diameter above the conductor diameter.

1 lasted for less than one-quarter of a second.¹⁷ The automatic reclosing
2 functionality on the Geysers #9 Line was disabled at that time and therefore
3 the relays did not test the line after the circuit breaker opened. That was
4 consistent with PG&E's longstanding practice of disabling automatic
5 reclosing for transmission lines connected to power generation facilities, in
6 order to best assure the safety and stability of the generation facilities.

7 **2. PG&E Followed Its Emergency Response and PSPS Protocols in** 8 **Connection with the Kincade Fire [Angelina M. Gibson; Shawn Holder]**

9 On October 20, 2019, PG&E activated its companywide Emergency
10 Operations Center (EOC) to prepare for a potential PSPS event in response
11 to forecasts of an extreme wind event that would create a heightened risk of
12 wildfires. In the EOC, representatives from Cal Fire, California Governor's
13 Office of Emergency Services (Cal OES), and the CPUC joined PG&E and
14 provided real-time input on its decision-making. PG&E also notified over 95
15 city, county, and tribal government agencies about the potential PSPS event
16 and discussed preparations.

17 By October 22, 2019, the National Weather Service had placed over
18 one million PG&E customers under a Fire Weather Watch or Red Flag
19 Warning in anticipation of the wind event. PG&E's in-house meteorology
20 team and risk assessment models similarly predicted a high risk for outages
21 and significant fires as a result of the weather event.

22 PG&E proceeded to determine the scope of potential de-energization for
23 a PSPS event based on meteorological forecasts and indicators of wildfire
24 risk, including PG&E's Fire Potential Index (FPI) forecasts and its Outage
25 Producing Winds (OPW) model. With respect to transmission lines such as
26 the Geysers #9 Line, PG&E used a risk-informed methodology and its
27 operational judgment to determine on a line-by-line basis which transmission
28 lines within the identified area(s) would be deemed in scope for potential
29 de-energization.¹⁸

¹⁷ The duration of the fault was 14.2 cycles, meaning that given the standard frequency of 60 cycles per second, it lasted 0.237 seconds. (14.2Cycles/60Hz = 0.237 seconds).

¹⁸ See Chapter 2: Prudence of Operations, Section E.2.b.

1 At the time PG&E determined the scope of the October 23, 2019 PSPS
2 event, the meteorological forecasts for the area around the Geysers #9 Line
3 were steady, with wind gusts of up to 45 miles-per-hour and FPI of 0.35
4 forecasted. PG&E considered those inputs as well as information about the
5 Geysers #9 Line, such as the latest asset health information and the
6 historical outage performance.¹⁹ Based on that assessment, and consistent
7 with its process of evaluating transmission lines on a line-by-line basis,
8 PG&E did not identify the Geysers #9 line as in scope for potential
9 de-energization on October 23, 2019.²⁰

10 When the electrical events associated with the Kincade Fire occurred,
11 PG&E's Grid Control Center (GCC) took immediate action. As noted, a
12 relay on the Geysers #9 Line was recorded at 9:19 p.m. on October 23,
13 2019. Approximately eight minutes later, the GCC operator notified PG&E's
14 Transmission, Substation, Maintenance & Construction (TSM&C)
15 department that the line had relayed, and that a fire near the Geysers Units
16 9/10 plant had been reported by a passing Calpine employee.²¹

17 PG&E troubleshooters were dispatched at approximately 9:30 p.m. to
18 investigate the Geysers #9 Line. They reached the area at approximately
19 11:00 p.m., but they were unable to complete their patrol because the area,
20 which is mountainous with limited access points, was experiencing heavy
21 winds and fire. A PG&E troubleshooter reached Tower 001/006 at
22 approximately 7:00 a.m. the next morning, by which time the area had been
23 secured by Cal Fire.

24 Because PG&E had already activated its Emergency Operations Center
25 and the local Electric Operations Emergency Center (OEC) in connection

¹⁹ There were no unplanned outages on the Geysers #9 Line in the 12 months preceding the Kincade Fire.

²⁰ As part of its investigation of the Kincade Fire, SED "review[ed] the PSPS event to the extent that the PSPS event is related to" the Kincade Fire. SED Report, p. 20. SED's report indicated that SED found no violation of Commission regulations regarding PG&E's determination to exclude the Geysers #9 Line from the initial scope of the October 23, 2019 PSPS event. *Id.* at 22.

²¹ Within minutes of the relay, a Calpine employee reported to the GCC that a fire was observed near the Geysers Units 9/10 generating facility adjacent to Tower 001/006 on the Geysers #9 Line. At approximately 9:25 p.m., or about six minutes after the Geysers #9 Line relayed, 911 emergency response crews were dispatched to respond to a fire near John Kincade Road and Burned Mountain Road.

1 with the October 23, 2019 PSPS event, PG&E was able to quickly pivot to
2 include the Kincade Fire response in its existing emergency response
3 activities once it became aware of the incident.

4 PG&E ultimately activated all 19 local OECs in its service territory, as
5 well as three Regional Emergency Centers, to provide emergency response
6 at the local level and coordinate the allocation of resources. PG&E also
7 activated an Incident Command System team in response to the fire. That
8 enabled it to manage resources, accountability, and interagency
9 coordination in the days and weeks after the fire began.²²

10 During the fire's progression, PG&E kept emergency response protocols
11 active, facilitating integration of its internal command staff with the broader
12 emergency management community. PG&E coordinated in real time with
13 the Cal Fire Incident Management Team assigned to the incident and local
14 and state officials. For example, both PG&E and Cal Fire developed daily
15 incident action plans regarding fire suppression activity, and the
16 assessment, repair and restoration of infrastructure damaged by the
17 Kincade Fire. PG&E also focused on public safety messaging and
18 operational support to protect infrastructure and prevent further ignition
19 risks.

20 **D. PG&E Prudently Designed and Maintained the Geysers #9 Line**
21 **[Carrell James Gill]**

22 As described below, PG&E prudently designed and constructed Tower
23 001/006 and maintained the facilities on Tower 001/006 and the Geysers #9
24 Line for future use serving Calpine. PG&E regularly inspected and maintained
25 Tower 001/006 and the Geysers #9 Line. The only open notification related to
26 Tower 001/006 in PG&E's system at the time of the Kincade Fire addressed
27 repainting of the structure and was not overdue.

28 **1. PG&E Appropriately Designed and Constructed Tower 001/006**

29 As discussed in Chapter 2: Prudence of Operations, PG&E designed
30 and constructed its transmission system to provide safe and reliable service
31 to its customers. PG&E's design and construction standards met or

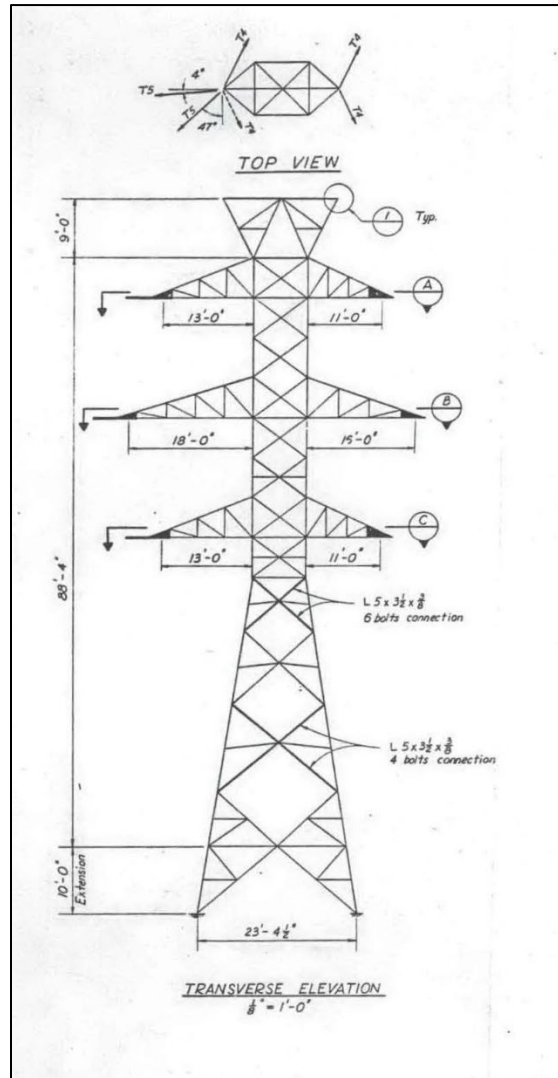
²² See Chapter 2: Prudence of Operations, Section E.3, describing PG&E's emergency response and coordination.

1 exceeded the Commission's regulatory requirements set forth in General
2 Order (GO) 95 and were updated as needed to account for PG&E's
3 operational experience, evolving industry standards, and local conditions.
4 Consistent with these standards, PG&E appropriately designed and
5 constructed Tower 001/006 on the Geysers #9 Line.

6 Tower 001/006 was placed into service in 1973 and built with lattice
7 steel consistent with PG&E's standards and the known local conditions of
8 the Geysers area. PG&E's internal design standards for steel transmission
9 towers required the use of robust materials and corrosion-resistant hardware
10 to ensure long-term strength. The design of the Geysers #9 Line used
11 1113 kcmil all-aluminum bundled conductors (AAC), with two conductors per
12 phase. These were large, heavy-duty conductors, chosen to provide
13 strength and reliability for high-voltage transmission appropriate to the
14 conditions of the Geysers area.

15 Tower 001/006 conformed with PG&E's clearance requirements for
16 towers in heavy loading districts like the Geysers, which met or exceeded
17 regulatory requirements. Like other towers on the Geysers #9 Line, Tower
18 001/006 was designed with horizontal offsets of the conductors, which
19 helped maintain required clearances and reduce the potential for
20 conductor-to-conductor contact. The design drawing for Tower 001/006 in
21 Figure 3A-6 below reflects that the middle arms are between four and five
22 feet longer than the upper and lower arms.

FIGURE 3A-6
DESIGN DRAWING APPLICABLE TO TOWER 001/006



- 1 In designing and constructing transmission structures, PG&E integrated
- 2 specific features to mitigate the effects of wind on jumpers and related
- 3 components. As of October 2019, industry literature recognized the impact
- 4 of wind on conductor spans and jumpers, and addressed appropriate

1 mitigations.²³ PG&E's internal design standards noted the risks created by
2 wind and incorporated industry-standard mitigations. PG&E's standards
3 required the use of dampers, which were recognized as the most effective
4 method of controlling aeolian vibration; spacers to maintain distance
5 between conductors and mitigate oscillation; and offset arms on towers to
6 increase clearance between phases and minimize the potential for
7 conductor contact. These measures were intended to mitigate wind-induced
8 forces, reducing the risk of mechanical fatigue and supporting reliable
9 performance under varying conditions.

10 At the time of the Kincade Fire, industry-standard mitigations for wind
11 movement of conductors and jumpers were present on the Geysers #9 Line
12 and Tower 001/006, as shown in Figure 3A-7 and discussed in more detail
13 below. PG&E's design standards incorporated both targeted wind-mitigation
14 measures and other design practices that provided additional wind
15 resilience.

23 The Electric Power Research Institute (EPRI) and International Council on Large Electric Systems (CIGRE) manuals published in 2017 also described the principal causes of wind-induced fatigue and explained that they apply primarily to main spans rather than jumpers. The manuals identified three primary types of overhead conductor motion caused by wind: aeolian vibrations, wake-induced oscillations, and conductor galloping. Aeolian vibration and wake-induced oscillation require conductor cables to be under substantial tension and therefore are not an issue for jumper cables, which are not highly tensioned. Conductor galloping occurs mostly in flat terrain under sustained icy conditions, which are not present in the area of the Kincade Fire.

FIGURE 3A-7
WIND MITIGATIONS ON TOWER 001/006 AS OF MAY 2019



Dampers to Control Aeolian Vibration. PG&E’s design standard for overhead electrical transmission lines, entitled “Overhead Transmission Line Design Criteria” and effective August 15, 2017, required the installation of dampers to control vibration from wind. Specifically, PG&E’s standards required Stockbridge-type dampers, which were recognized as the most effective type for controlling aeolian vibration on spans above certain lengths. Figure 3A-7, a photograph taken during a May 2019 drone inspection, shows four Stockbridge-type dampers on the bundled conductors connecting to the incident jumper at Tower 001/006 (two per conductor in the bundle). The use of four dampers provided an even greater margin of safety than the industry-standard guidance, which would have required only two dampers (one per conductor in the bundle).

Spacers to Maintain Distance and Control Oscillation. PG&E’s design standard also required the installation of staggered helical-type spacers on long spans of bundled conductors. These spacers were designed to mitigate oscillations from wind. By fixing the bundled conductors together, the spacers keep the bundle moving as a single unit and prevent the relative motion that causes oscillations of the individual conductors in the bundle. PG&E’s standards required positioning the spacers at unequal intervals no

1 greater than approximately 60 meters apart, closer together than was
2 posited by industry-leading literature for high-wind conditions. Figure 3A-7
3 above shows a fixed, or “spring,” spacer installed on the jumper on Tower
4 001/006 at the time of the Kincade Fire ignition;²⁴ flexible helical spacers
5 were installed along the conductor spans themselves.

6 *Heavy Insulators and Support Insulator Strings.* PG&E’s design
7 standard also required the use of heavy insulators (e.g., made of ceramic,
8 rather than composite material) in high-wind areas and support insulator
9 strings on dead-end jumpers. Although these insulators were not added
10 solely for wind mitigation purposes, they helped to restrain conductors and
11 reduce movement during high-wind conditions. This went beyond industry
12 literature, which recommended, but did not require, support insulator strings
13 on jumper cables. Ceramic insulators, including a ceramic support insulator
14 string on the incident jumper, were present on Tower 001/006 at the time of
15 the Kincade Fire.²⁵

16 Following the Kincade Fire, PG&E studied the incident and updated its
17 internal design standards, including with respect to jumper construction.
18 PG&E issued new guidance stating that “[o]pen dead-end jumpers on
19 bundled conductor are not to be tied together” and also specifying
20 that “[d]ead-end jumpers are to be cut as short as practical for reconnecting
21 on both sides of the dead-end.” PG&E also conducted testing that indicated
22 the location of the splice on the incident jumper in close proximity to the
23 metal shoe may have contributed to the fatigue; PG&E subsequently issued

24 Rigid spacers were not installed on conductor spans because they could adversely affect aeolian vibrations, but were permitted on jumpers, which do not experience aeolian vibrations.

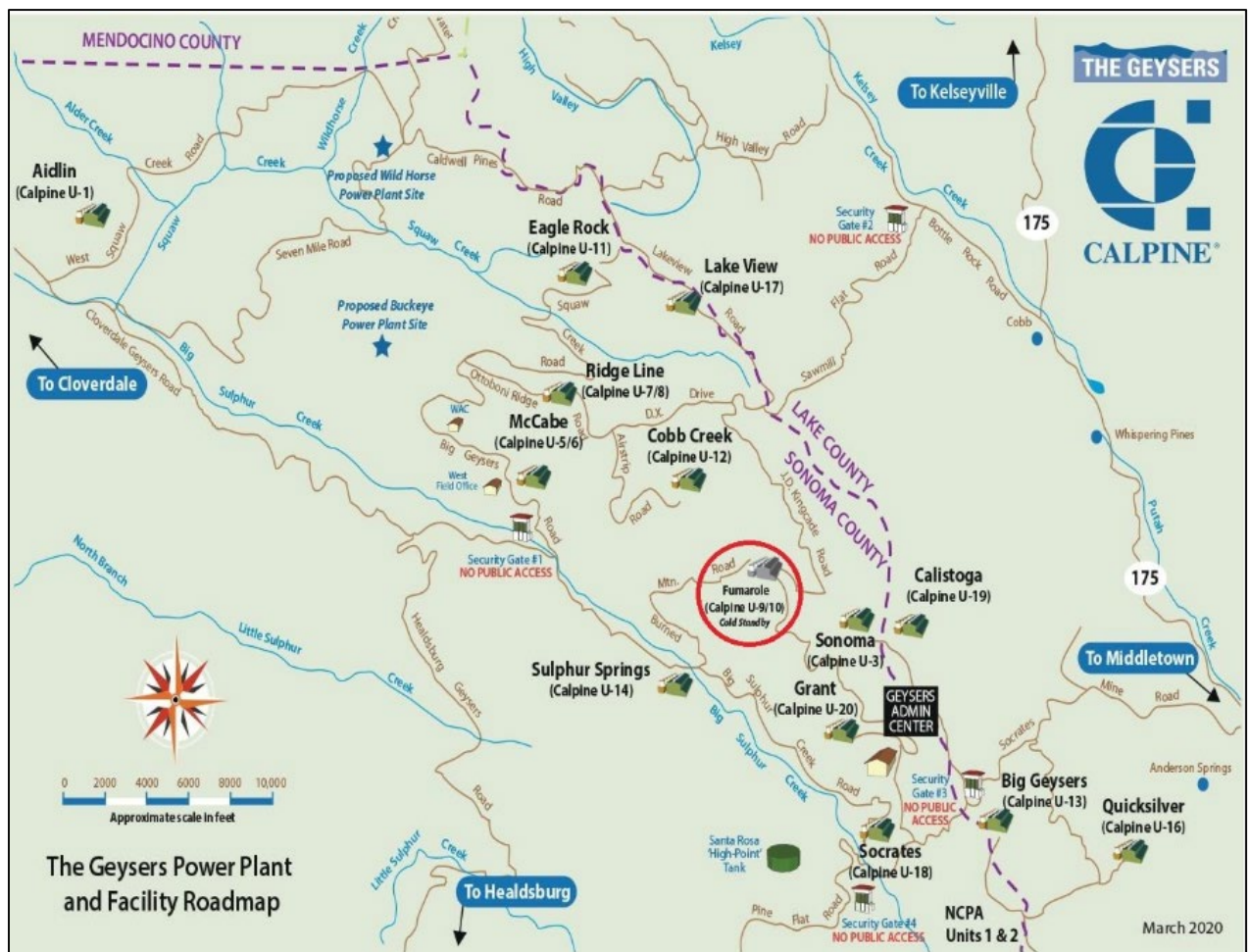
25 A 1985 structure data sheet showed a weight on the insulator support string for the jumper on the Geysers #9 Line at Tower 001/006 before the generation tie line for Geysers Units 9/10 was disconnected in 2006 and the incident jumper was reconfigured into an open position. At the time of the Kincade Fire, the incident jumper was supported by a heavy ceramic support insulator string and did not have a weight. PG&E is not aware of a structure data sheet showing the incident jumper’s open configuration or any internal standard requiring a weight in these circumstances. Although structure data sheets may be updated in connection with engineering work, there was no written requirement to prepare one at the time the work was performed in 2006.

guidance providing that jumper splices or connections should be installed as close as possible to the midpoint between jumper terminations or other hardware.

2. PG&E Maintained the Geysers #9 Line for Future Use Serving Calpine

The PG&E facilities related to the Kincade Fire were in the area of the Geysers geothermal power plants. Calpine owned and operated 13 active plants in the Geysers, and each was connected to PG&E-owned transmission lines. As relevant here, PG&E's transmission Tower 001/006 carried the Geysers #9 Line, which previously connected to the Geysers Units 9/10 plant (also called Fumarole as shown in Figure 3A-8).

FIGURE 3A-8
MAP OF CALPINE-OWNED GEOTHERMAL POWER PLANTS IN THE GEYSERS (MARCH 2020)



1 Figure 3A-8 above is a Calpine map showing the Geysers area in March
2 2020.²⁶ It includes over a dozen active power plants: Aidlin (Calpine U-1);
3 Sonoma (Calpine U-3); McCabe (Calpine U-5/6); Ridgeline (Calpine U-7/8);
4 Eagle Rock (Calpine U-11); Cobb Creek (Calpine U-12); Big Geysers
5 (Calpine U-13); Sulphur Springs (Calpine U-14); Quick Silver (Calpine
6 U-16); Lake View (Calpine U-17); Socrates (Calpine U-18); Calistoga
7 (Calpine U-19); Grant (Calpine U-20); and NCPA #1 and NCPA #2 (owned
8 by the Northern California Power Agency, a public joint powers agency).
9 Geysers Units 9/10, circled in red for emphasis herein, was the only Calpine
10 plant identified as in “Cold Standby.”

11 Historically, the Geysers #9 Line delivered power generated at the
12 Geysers Units 9/10 plant to PG&E’s Lakeville Substation. Geysers
13 Units 9/10 were connected to the Geysers #9 Line by a generation tie line
14 between the Geysers Units 9/10 switchyard and Tower 001/006.²⁷ In
15 October 2005, Calpine emailed PG&E requesting that PG&E clean the
16 insulators on Tower 001/006 and remove the generation tie line between the
17 Calpine-owned switchyard at Geysers Units 9/10 and the tower. The
18 Geysers Units 9/10 plant was not generating power at the time.²⁸ Calpine
19 advised PG&E in its October 2005 email that Geysers Units 9/10 had been
20 “mothballed for several years.”²⁹ In the electric utility industry, “mothballed”
21 is another term for “cold standby” and means that the facility is temporarily

²⁶ This map was captured from Calpine’s website, <https://geysers.com/The-Geysers/Map-Of-The-Geysers-Field>, on June 23, 2022.

²⁷ A generation tie line is a type of transmission line that connects a power plant to the main transmission grid, creating a bridge between the generation facility and the broader transmission system.

²⁸ PG&E understands that Calpine took Geysers Units 9/10 offline in 2001.

²⁹ At the time of the Kincade Fire, Calpine’s website indicated that Geysers Units 9/10 were in “cold standby.”

1 out of service and may be brought back online by the operator.³⁰ That
2 indicated that Calpine was preserving Geysers Units 9/10 for possible future
3 use and had not abandoned the facilities following Calpine's decision to take
4 them offline. Indeed, Calpine continued to pay PG&E a monthly charge for
5 PG&E transmission service to Geysers Units 9/10 pursuant to a Generator
6 Special Facilities Agreement (GSFA) between the parties.³¹

7 In response to Calpine's request, PG&E removed the generation tie line
8 connecting Tower 001/006 to the Geysers Units 9/10 switchyard in May
9 2006. PG&E also installed new insulators on the tower.

³⁰ See FERC, Division of Energy Market Assessments, Glossary, defining "Mothballed capacity" as "[a] power plant that is out-of-service, but is being maintained in such a condition that an operator can bring it back into service", available at: <https://www.ferc.gov/industries-data/market-assessments/overview/glossary> (accessed Sept. 4, 2025); California Energy Commission, Energy Glossary, "Lay up is another term for cold storage and describes the status of equipment (such as a power plant) that has been placed in storage ('mothballed') for latter use.", available at: <https://www.energy.ca.gov/resources/energy-glossary> (accessed Sept. 4, 2025).

³¹ PG&E and Calpine executed the GSFA in 2004 and it required Calpine to provide written notice if it intended to "cease operation" at Geysers Units 9/10 and to pay a "facility termination charge" for removal of PG&E facilities connecting to the plant, i.e., the last three spans of the Geysers #9 Line between Tower 001/006 and Tower 001/009. Calpine never provided such notice or paid a facility termination charge.

FIGURE 3A-9
PHOTOGRAPH OF TOWER 001/006 AND GEYSERS UNITS 9/10 SWITCHYARD



1 Consistent with the status of Geysers Units 9/10, when disconnecting
2 the generation tie line from Tower 001/006 in 2006, PG&E performed the
3 work in a manner that made it feasible to reconnect the plant in the future.
4 In particular, the crew that performed the disconnection work left in place the
5 jumpers on Tower 001/006 in an “open” configuration to allow the plant to be
6 more easily and safely reconnected to the Geysers #9 Line when Calpine
7 was ready to do so. This configuration facilitated reconnection by
8 maintaining the jumper conductor, including the structural connection to the
9 support insulator, and avoiding further modification to the equipment. After
10 the disconnection work, for each of the three phases of the Geysers #9 Line,
11 the ends of the two jumper conductors—previously connected to the

1 generation tie line—were fused together and the support insulator string
2 helped maintain tension and secure the conductors.³²

3 As discussed in Chapter 2: Prudence of Operations, Section C.1, PG&E
4 had its own standard to address the management of idle electric
5 transmission line facilities, which implemented the regulatory requirements
6 in General Order 95, Rule 31.6, for the removal of “abandoned” facilities
7 (i.e., facilities that are “determined by their owner to have no foreseeable
8 future use”).³³ PG&E’s standard included a definition of idle transmission
9 facilities and laid out a process to review potentially idle facilities.³⁴

10 In the years preceding the Kincade Fire, there was not a consistent
11 approach in the industry regarding the management of idle facilities,
12 including with respect to facilities that had a foreseeable future use but were
13 not currently serving load. PG&E implemented its idle facilities standard
14 reasonably and in good faith. At the time of the Kincade Fire, the list of
15 potentially idle transmission facilities included 72 facilities,³⁵ approximately
16 16 of which involved spans of active transmission lines. The Geysers #9
17 Line (including the last three spans of that line) and Tower 001/006 were not
18 identified as potentially “idle” under PG&E’s idle transmission facilities
19 standard prior to the Kincade Fire.

³² PG&E has not identified any engineering standards, drawings, or guidance documents in the transmission industry from prior to the Kincade Fire that referenced the specific jumper configuration at Tower 001/006 or that recommended or discouraged that specific configuration. No other industry standards on or before October 23, 2019 prohibited open jumpers, nor were there any industry standards that regulated the length of such jumpers, with the exception of PG&E’s clearance requirements, which are applicable to all conductors (and with which the conductors on Tower 001/006 complied).

³³ GO 95, Rule 31.6 provides that “[l]ines or portions of lines permanently abandoned shall be removed by their owners... . [L]ines that are permanently abandoned [are] those lines that are determined by their owner to have no foreseeable future use.”

³⁴ PG&E’s standard defined “idle transmission facilities” as: “Facilities that are not currently being used to serve transmission load or generation facilities but may have a potential future use by the Company. Idle facilities can be either transmission line facilities that are de-energized or facilities that are energized at distribution voltages.” Utility Standard: TD-1003S, Management of Electric Transmission Facilities, Rev. 0 at 6; see also Chapter 2: Prudence of Operations, Section C.1.

³⁵ A subsequent review reduced this number to 64, all of which have since been removed.

1 PG&E has continued to evolve and mature its implementation of the idle
2 facilities standard in the years since the Kincade Fire, consistent with
3 PG&E's culture of continuous improvement. Following the fire, PG&E
4 updated its idle facilities policy to state that idle transmission facilities that
5 may need to be de-energized include energized lines or spans of lines not
6 currently being used to serve transmission load or generation facilities.
7 PG&E also revised its inspection forms so that inspectors are required to
8 report facilities not serving customer load.

9 **3. PG&E Regularly Inspected and Maintained Tower 001/006 and the** 10 **Geysers #9 Line**

11 As described in Chapter 2: Prudence of Operations, Section D.1, in the
12 years before the Kincade Fire PG&E had a comprehensive program for
13 inspecting and maintaining its transmission facilities and enhanced its
14 inspection methods following the 2017 North Bay wildfires and 2018 Camp
15 Fire. The program incorporated a range of inspection methods, including
16 climbing, drone, infrared, and ground inspections, as well as various patrols.

17 Tower 001/006 and the associated lines were inspected multiple times
18 in the months preceding the Kincade Fire. Each inspection was conducted
19 by well-trained and qualified inspectors and involved a comprehensive
20 review, including looking at the condition of the conductors and jumpers and
21 checking for broken strands or other signs of mechanical damage. None of
22 these inspections identified any issues with the incident jumper conductor.³⁶

23 At the time of the Kincade Fire, Tower 001/006 had only one open
24 maintenance notification. This notification was assigned a low-priority code
25 and called for repainting of the structure to address rust by February 2020.

26 *Climbing Inspection.* On February 6, 2019, PG&E performed a climbing
27 inspection of Tower 001/006 as part of the Wildfire Safety Inspection
28 Program (WSIP). There were eight non-conformances identified, prompting

36 The Safety and Enforcement Division's report stated that the incident jumper conductor "showed slight signs of bowing or bird-caging at the points near the exit of the shoe" that and stated that this "may have weakened the structural integrity of the jumper cable[.]" SED Report, p. 17. PG&E's inspection procedures expressly identified bird-caging as an issue to observe during inspections and provided explicit guidance about whether and when repairs were needed to address bird-caging. No such condition was identified on the incident jumper.

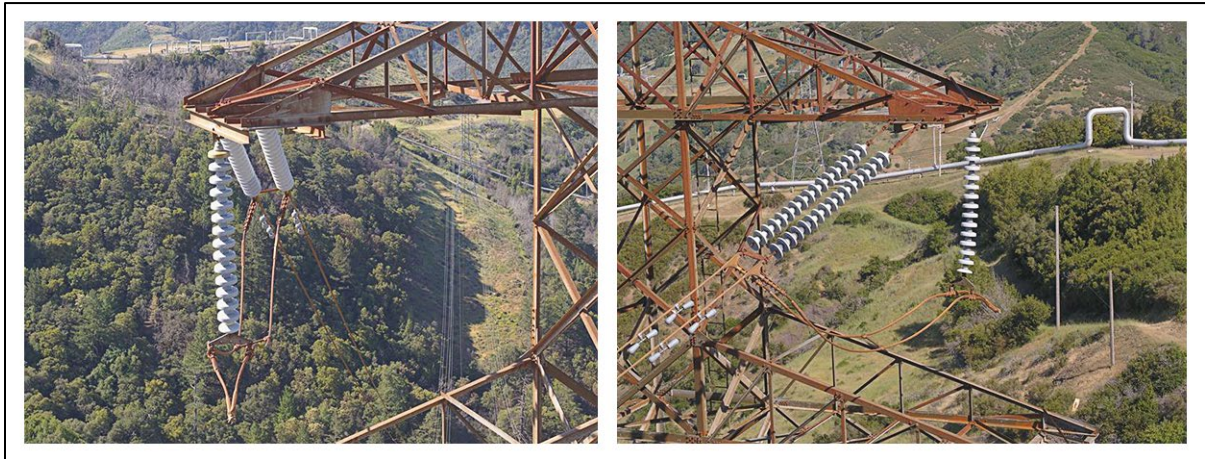
1 five work orders. The WSIP inspection form documented these
2 non-conformances, including issues with the amount of rust on the tower
3 structure and a small crack in one of the concrete footings. None of the
4 non-conformances related to the jumper conductors. Under the prompt
5 “Jumper in poor condition,” the inspectors answered “no.” As shown in
6 Figure 3A-10, the climbing inspectors were in close proximity to the insulator
7 and jumper assemblies, meaning they could observe a visible problem.

FIGURE 3A-10
ILLUSTRATIVE PHOTOGRAPHS FROM FEBRUARY 6, 2019 CLIMBING INSPECTION



8 *Drone Inspection.* On May 11, 2019, PG&E conducted a drone
9 inspection of Tower 001/006 as part of the WSIP. Through that inspection,
10 PG&E took high-resolution photographs of the facilities from a high elevation
11 and from multiple angles. Those photographs were then sent to the Drone
12 Inspection Review Team (DIRT) for review and made available to the
13 Centralized Inspection Review Team (CIRT). A few illustrative photographs
14 from the drone inspection are shown in Figure 3A-11 below. That inspection
15 identified no issues related to the jumper.

FIGURE 3A-11
ILLUSTRATIVE PHOTOGRAPHS FROM MAY 11, 2019 DRONE INSPECTION



On June 18, 2019, DIRT re-reviewed the May 2019 drone photographs as part of a routine review of inspection forms where no conditions were reported. Again, no issues related to the jumper were identified.³⁷ PG&E's DIRT conducted an additional re-review of the drone photographs in August 2019, which also identified no issues related to the jumper. This re-review focused on identifying wear on certain equipment, specifically towers located in HFTDs with C-hooks and hanger plates. In this assessment, between 10% and 30% wear was noted for the hanger plates for Tower 001/006, which did not warrant a maintenance tag under PG&E's inspection guidance.

Ground Inspections. PG&E also performed several detailed ground inspections of Tower 001/006 in the years preceding the Kincade Fire. The Geysers #9 Line was subject to detailed ground inspections in 2009, 2014, and 2019. Detailed ground inspections were performed by transmission troubleshooters, who are qualified electrical workers. No issue related to the jumper conductors at Tower 001/006 was identified during these inspections.

Air Patrols. In the years prior to the Kincade Fire, the Geysers #9 and #12 Lines were inspected annually through routine air patrols except in

³⁷ The only condition identified as a result of the re-review was a missing danger sign on the structure.

years when ground inspections were conducted. No issue related to the jumper conductors was identified.

Infrared Patrols. PG&E performed infrared inspections of the Geysers #9 and #12 Lines at Tower 001/006 in the years preceding the Kincade Fire, specifically on May 20, 2015, and June 18, 2018. These inspections did not identify any hot spots or other issues related to the incident jumper.

Table 3A-1 below summarizes the inspection history of Tower 001/006 in the five years preceding the Kincade Fire.

**TABLE 3A-1
EQUIPMENT INSPECTION HISTORY FOR TOWER 001/006**

WSIP Climbing Inspection <i>(Performed as part of WSIP)</i>	
2019 Climbing Inspection (Geysers #12 Line)	February 6, 2019
WSIP Drone Inspection <i>(Performed as part of WSIP)</i>	
2019 Drone Inspection (Geysers #12 Line)	May 23, 2019
2019 Re-Review Drone Photos (Geysers #12 Line)	June 18, 2019
Routine Detailed Inspection <i>(Performed every 5 years)^(a)</i>	
2019 Ground Inspection (Geysers #9 Line)	July 18, 2019
2019 Ground Inspection (Geysers #12 Line)	July 11, 2019
2014 Ground Inspection (Geysers #9 Line)	June 2, 2014
2014 Ground Inspection (Geysers #12 Line)	May 1, 2014
Routine Patrol Inspection <i>(Performed annually except in years with a routine detailed inspection)</i>	
2018 Air Patrol (Geysers #9 Line)	April 23, 2018
2018 Air Patrol (Geysers #12 Line)	April 20, 2018
2017 Air Patrol (Geysers #9 & #12 Lines)	May 16, 2017
2016 Air Patrol (Geysers #9 & #12 Lines)	April 20, 2016
2015 Air Patrol (Geysers #9 & #12 Lines)	May 6, 2015
Infrared Inspection <i>(Performed every 5 years and as triggered)</i>	
2018 Infrared Patrol (Geysers #9 & #12 Lines)	June 18, 2018
2015 Infrared Patrol (Geysers #12 Line)	May 20, 2015
2014 Infrared Patrol (Geysers #12 Line)	June 10, 2014
2014 Infrared Patrol (Geysers #9 Line)	June 17, 2014

(a) Inspection cycles for 230kV lines are established in PG&E's Electric Transmission Preventive Maintenance Manual.

1 **E. SED's Alleged Violations Do Not Raise Serious Doubt as to PG&E's**
2 **Prudence Under Section 451.1(c) [William Manheim]**

3 Following the Kincade Fire, SED investigated the event for compliance with
4 the Commission's rules and regulations. SED set forth alleged violations related
5 to the Kincade Fire in a written investigation report (SED Report). The SED
6 Report identified three alleged violations related to the Kincade Fire: (1) an
7 alleged failure to remove the Geysers #9 Line in violation of GO 95, Rule 31.6
8 (which is titled "Abandoned Lines"), (2) an alleged failure to configure the jumper
9 cables on Tower 001/006 in accordance with PG&E's policies in violation of GO
10 95, Rule 31.1, and (3) an alleged violation of Public Utilities Code Section 451
11 that is largely derivative of the other alleged violations.

12 PG&E and SED resolved the investigation through an Administrative
13 Consent Order (ACO), a negotiated settlement pursuant to Commission
14 Resolution M-4846 (Resolution Adopting Commission Enforcement Policy).³⁸
15 The Commission issued a resolution approving the ACO on December 2,
16 2021.³⁹ SED's alleged violations were not litigated, and PG&E did not admit
17 any imprudence, nor did the Commission make any findings on those issues.⁴⁰
18 For the reasons described below, PG&E strongly disputed SED's alleged
19 violations, and these allegations do not show imprudence by PG&E or create
20 "serious doubt" about PG&E's prudence, as would be required to disrupt the
21 statutory presumption of reasonableness under Section 451.1.

22 **1. Alleged Violation Related to Abandonment of Facilities**

23 The SED Report alleged that PG&E violated GO 95, Rule 31.6, by
24 abandoning and failing to remove the Geysers #9 Line spans at issue.
25 Under GO 95, Rule 31.6, "[l]ines or portions of lines permanently abandoned
26 shall be removed by their owners. . . . [L]ines that are permanently
27 abandoned [are] those lines that are determined by their owner to have no

38 As set forth in the Commission's Enforcement Policy, "[a] negotiated proposed settlement shall be memorialized in a proposed Administrative Consent Order [which] shall become final upon review and approval by the Commission." Res. M-4846, Attachment, CPUC, Enforcement Policy (Nov. 5, 2020), p. 10.

39 See Resolution SED-6, as modified by Resolution SED-6A (modified to include discussion of the Penalty Assessment Methodology).

40 *Id.*

1 foreseeable future use.” When PG&E disconnected the Geysers #9 Line
2 from Geysers Units 9/10, it left in place the section of the line running from
3 Tower 001/006 to nearby Tower 001/009. SED found PG&E in violation of
4 GO 95, Rule 31.6 because it alleged that PG&E “failed to remove an
5 abandoned line.”⁴¹

6 That alleged violation is inconsistent with the evidence. As noted,
7 Rule 31.6 defines permanently abandoned lines “as those lines that are
8 *determined by their owner* to have no foreseeable future use.”⁴² Contrary
9 to the premise of SED’s alleged violation, the Geysers #9 Line was not
10 permanently abandoned because PG&E (the owner) never determined that
11 the line had no foreseeable future use. To the contrary, and as set forth
12 above, the information available from Calpine regarding Geysers Units 9/10
13 indicated there *was* a foreseeable future use for these facilities, and PG&E
14 continued to operate and actively inspect and maintain these facilities for
15 use serving Calpine.

16 On these facts, SED’s alleged violation is not supported by the
17 evidence. PG&E did not act imprudently by continuing to inspect and
18 maintain the Geysers #9 Line facilities for the potential future reconnection
19 of Geysers Units 9/10.

20 **2. Alleged Violation Related to the Jumper Configuration at** 21 **Tower 001/006**

22 The SED Report alleged that PG&E violated GO 95, Rule 31.1, by
23 failing to “configure the jumper cables and insulator strings at the Incident
24 Tower in a manner that is permitted by its own procedures and policies.”⁴³
25 Rule 31.1 generally provides that the design, construction, and maintenance
26 of utility facilities should provide safe, proper, and adequate service, and be

⁴¹ SED Report, p. 32.

⁴² General Order 95, Rule 31.6 (emphasis added).

⁴³ SED Report, p. 32.

1 done in accordance with local conditions.⁴⁴ SED's allegation did not point
2 to or quote any specific provision of Rule 31.1 that was violated. SED's
3 allegation also did not cite any specific PG&E standard that was violated.⁴⁵
4 Nor did it identify any industry standard inconsistent with the jumper
5 configuration.

6 The evidence shows that it was prudent to leave the jumper cable
7 configured as it was because, as discussed above, it was foreseeable that
8 the Geysers #9 Line at Tower 001/006 would need to be reconnected to
9 Geysers Units 9/10 in the future. Leaving the jumper cables in place would
10 make reconnecting PG&E's transmission line to Calpine's equipment easier
11 and safer. These facilities complied with PG&E's design and construction
12 standards, including wind-mitigation measures that exceeded industry
13 requirements at the time.

14 SED alleged that the jumper on Tower 001/006 failed because the
15 jumper configuration was more susceptible to "a greater range of movement
16 than other configurations on [PG&E's] system, thereby making it vulnerable
17 to...low-cycle fatigue."⁴⁶ That allegation relies on hindsight. All jumpers are
18 subject to movement due to wind, and SED presented no evidence
19 supporting its allegation that the post-disconnection configuration was more
20 susceptible to wind sway. Nor is there any evidence that PG&E believed or

⁴⁴ General Order 95, Rule 31.1, states: "Electrical supply and communication systems shall be designed, constructed, and maintained for their intended use, regard being given to the conditions under which they are to be operated, to enable the furnishing of safe, proper, and adequate service. ¶ For all particulars not specified in these rules, design, construction, and maintenance should be done in accordance with accepted good practice for the given local conditions known at the time by those responsible for the design, construction, or maintenance of communication or supply lines and equipment."

⁴⁵ See *supra* note 25.

⁴⁶ SED Report, pp. 30-31.

1 was aware before the fire that the jumper configuration might be more
2 susceptible to wind sway or fatigue failure.⁴⁷

3 **3. Alleged Violation of Section 451**

4 The SED Report alleged a violation of Public Utilities Code Section 451
5 based on the same conduct described above. Section 451 states: "Every
6 public utility shall furnish and maintain such adequate, efficient, just, and
7 reasonable service, instrumentalities, equipment, and facilities, including
8 telephone facilities, as defined in Section 54.1 of the Civil Code, as are
9 necessary to promote the safety, health, comfort, and convenience of its
10 patrons, employees, and the public."⁴⁸ SED alleges that PG&E violated
11 Section 451 because it "left abandoned energized equipment and failed to
12 remediate an imprudent configuration of the Incident Tower's jumper
13 cables."⁴⁹

14 For the reasons and based on the evidence described above, PG&E's
15 maintenance and configuration of the Geysers #9 Line was prudent and was
16 not inconsistent with Section 451. PG&E safely inspected and operated the
17 facilities consistent with its robust standards at the time for managing
18 transmission lines.

⁴⁷ SED pointed to the Sawmill Fire, a 2016 wildfire near the Geysers, as indicating that PG&E was "aware" that its "equipment in the area was susceptible to fatigue failure induced by high wind events." SED Report, p. 31. It also pointed to the Camp Fire as indicating that the configuration on Tower 001/006 could pose "a potential hazard." SED Report, p. 30. But the facilities and points of failure involved in those incidents were materially different. The Sawmill Fire involved the failure of a thin, single-stranded, de-energized bond wire after the staples securing it to a wooden pole came loose. The Camp Fire was caused by wear on a C-hook attachment. Neither of those failure mechanisms is relevant to the Kincade Fire, which involved a 61-strand jumper conductor installed on a steel transmission tower, as described herein.

⁴⁸ Pub. Util. Code, § 451.

⁴⁹ SED Report, p. 32.

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3A
ATTACHMENT 1
KINCADE FIRE AGENCY REPORT

CAL FIRE



CALIFORNIA DEPARTMENT OF FORESTRY AND FIRE PROTECTION

Sonoma-Lake-Napa Unit
1199 Big Tree Road
St. Helena, CA 94574

INVESTIGATION REPORT

CASE NUMBER: 19CALNU019376

CASE NAME: Kincade

DATE: October 23, 2019

INCIDENT TYPE: Wildland Fire

INCIDENT INVESTIGATORS: Gary Uboldi, Fire Captain, LNU
William Laird, Fire Captain, LNU
Kyle Steis, Fire Captain, LNU
Ryan Smith, Battalion Chief, MEU

1 **1 - VIOLATION(S):**

2 **1 Count: California Public Utility Code Section 2110.**

3 Every public utility and every officer, agent, or employee of any public utility, who
4 violates or fails to comply with, or who procures, aids, or abets any violation by any
5 public utility of any provision of the California Constitution or of this part, or who fails to
6 comply with any part of any order, decision, rule, direction, demand, or requirement of
7 the commission, or who procures, aids, or abets any public utility in the violation or
8 noncompliance in a case in which a penalty has not otherwise been provided, is guilty of
9 a misdemeanor and is punishable by a fine not exceeding five thousand dollars
10 (\$5,000), or by imprisonment in a county jail not exceeding one year, or by both fine and
11 imprisonment.

12 (Amended by Stats. 2012, Ch. 464, Sec. 2. (AB 861) Effective January 1, 2013.)
13

14 **4 Counts: California Penal Code Section 452.1(a)(2):**

15 (a) Notwithstanding any other law, any person who is convicted of a felony violation of
16 Section 452 shall be punished by a one-, two-, or three-year enhancement for each of
17 the following circumstances that is found to be true:

18 (2) A firefighter, peace officer, or other emergency personnel suffered great bodily injury
19 as a result of the offense. The additional term provided by this subdivision shall be
20 imposed whenever applicable, including any instance in which there is a violation of
21 subdivision (a) of Section 452.

22 (Added by Stats. 1994, Ch. 421, Sec. 4. Effective September 7, 1994.)
23
24
25
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1 Counts: California Penal Code Section 452 (b)

A person is guilty of unlawfully causing a fire when he recklessly sets fire to or burns or causes to be burned, any structure, forest land or property.

(b) Unlawfully causing a fire that causes an inhabited structure or inhabited property to burn is a felony punishable by imprisonment in the state prison for two, three or four years, or by imprisonment in the county jail for not more than one year, or by a fine, or by both such imprisonment and fine.

(Amended by Stats. 1982, Ch. 1133, Sec. 2. Effective September 17, 1982.)

1 Counts: California Penal Code Section 452 (c)

A person is guilty of unlawfully causing a fire when he recklessly sets fire to or burns or causes to be burned, any structure, forest land or property.

(c) Unlawfully causing a fire of a structure or forest land is a felony punishable by imprisonment in the state prison for 16 months, two or three years, or by imprisonment in the county jail for not more than six months, or by a fine, or by both such imprisonment and fine.

(Amended by Stats. 1982, Ch. 1133, Sec. 2. Effective September 17, 1982.)

1 Count: California Penal Code Section 452.1(a)(4)

(a) Notwithstanding any other law, any person who is convicted of a felony violation of Section 452 shall be punished by a one-, two-, or three-year enhancement for each of the following circumstances that is found to be true:

(4) The defendant proximately caused multiple structures to burn in any single violation of Section 452.

(Added by Stats. 1994, Ch. 421, Sec. 4. Effective September 7, 1994.)

1 **1 Count: California Penal Code Section 452.1(a)(1)**

2 (a) Notwithstanding any other law, any person who is convicted of a felony violation of
3 Section 452 shall be punished by a one-, two-, or three-year enhancement for each of
4 the following circumstances that is found to be true:

5 (1) The defendant has been previously convicted of a felony violation of Section 451 or
6 452.

7 (Added by Stats. 1994, Ch. 421, Sec. 4. Effective September 7, 1994.)
8

9 **1 Count: California Public Resource Code Section 4421.**

10 A person shall not set fire or cause fire to be set to any forest, brush, or other flammable
11 material which is on any land that is not his own, or under his legal control, without the
12 permission of the owner, lessee, or agent of the owner or lessee of the land.

13 (Repealed and added by Stats. 1965, Ch. 1144.)
14

15 **1 Count: California Health and Safety Code Section 13001.**

16 Every person is guilty of a misdemeanor who, through careless or negligent action,
17 throws or places any lighted cigarette, cigar, ashes, or other flaming or glowing
18 substance, or any substance or thing which may cause a fire, in any place where it may
19 directly or indirectly start a fire, or who uses or operates a welding torch, tar pot or any
20 other device which may cause a fire, who does not clear the inflammable material
21 surrounding the operation or take such other reasonable precautions necessary to
22 insure against the starting and spreading of fire.

23 (Amended by Stats. 1965, Ch. 732.)
24
25
26
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29
30
31

2 - SUMMARY:

On October 23, 2019 at approximately 9:24 PM a fire occurred in the area of the de-commissioned 9-10 Fumarole Geothermal Power Plant located east of the community of Geyserville, Sonoma County, California. At the time Sonoma County was experiencing a Red Flag weather event, issued by the National Weather Service, and a Pacific Gas & Electric Company (PG&E), public safety power shutoff (PSPS) due to an increased fire hazard threat for the area.

The resulting fire spread and became to be known as the Kincade fire. The Kincade fire burned a total of 77,758 acres of land, damaged a total of 60 buildings, destroyed a total of 374 structures, and injured 4 firefighters which required hospitalization. The Kincade fire also caused the largest mandatory evacuation in history for Sonoma County effecting an estimated total of 494,336 residents. The Kincade fire burned for 15 days until it was fully contained November 6, 2019.

The subsequent fire investigation identified the cause of the fire as a mechanical failure of a Pacific Gas & Electric Company (PG&E) electrical transmission line and tower located near the de-commissioned 9-10 Fumarole Geothermal Power Plant on John Kincade Road.

During the investigation, it was determined the PG&E electrical transmission line which had supplied the de-commissioned 9-10 Fumarole Geothermal Power Plant was abandoned for the last thirteen years yet remained energized up until the Kincade fire. It was identified that the PG&E electrical transmission line was in violation of the California Public Utilities Commission (CPUC) General Orders #95 (GO95), Section III, Part 31.6 regarding the disposition of abandoned electrical transmission lines.

Due to exposure to adverse weather for several years, the high fire hazard weather conditions on October 23, 2019 and the conditions which violated the CPUC GO95 requirements a resulting fire occurred due to a mechanical failure of the PG&E electrical transmission line.

3 - SUBJECT:

S-1 Pacific Gas and Electric Company (PG&E)

77 Beale Street

24th floor

San Francisco, CA 94105

4 – VICTIMS:

In total, the Kincade Fire consumed 77,758 acres within Lake and Sonoma Counties. The fire damaged 60 structures and destroyed 374 structures (See Damage Inspection Summary Report for a full list of victims).

WITNESSES:

W-1 Name: Greg Sullivan

Can testify to: Providing information to STEIS of the fire on October 23, 2019

W-2 Name: John Woods

Can testify to: Reporting a fire to the Calpine Geysers Administration Center the Night of October 23, 2019

W-3 Name: Scott Paradise

Can testify to: Seeing a flash(did they have a location of where the flash was located?) from Sawmill Road the night of October 23, 2019

W-4 Name: Trevor Foster

Can testify to: Calpine had deenergized their 21 kv powerlines October 23, 2019

1 W-5 Name: Kurt Seel

2 [REDACTED]
3 [REDACTED]
4 Can testify to: Providing Calpine's J5 log confirming Calpine had deenergized
5 their 21kv powerlines on October 23, 2019.
6

7 W-6 Name: Joe McNeil

8 [REDACTED]
9 [REDACTED]
10 Can testify to: Retained as an arborist at Kincade Fire.
11

12 W-7 Name: Jim Nolt

13 [REDACTED]
14 [REDACTED]
15 Can testify to: Retained as an electrical engineer at Kincade Fire
16

17 W-8 Name: Tom McNeil

18 [REDACTED]
19 [REDACTED]
20 Can testify to: Using metal detecting equipment at Kincade Fire
21

22 W-9 Name: Gary Lawson

23 [REDACTED]
24 [REDACTED]
25 Can testify to: Using metal detecting equipment at Kincade Fire
26

27 W-10 Name: Matthew Yunge

28 [REDACTED]
29 [REDACTED]
30 Can testify to: Representing California Public Utilities Commission
31

1 W-11 Name: Andie Biggs

2 [REDACTED]
3 [REDACTED]

4 Can testify to: Representing California Public Utilities Commission

6 W-12 Name: Nathan Sarina

7 [REDACTED]
8 [REDACTED]

9 Can testify to: Representing California Public Utilities Commission

11 W-13 Name: Oscar Miguel

12 [REDACTED]
13 [REDACTED]

14 Can testify to: Flying drone at 9/10 Fumoral, hired by PG&E

16 W-14 W-14

17 [REDACTED]
18 [REDACTED]

19 Can testify to: Being present while drone was being flown at 9/10 Fumoral

21 W-15 W-15

22 [REDACTED]
23 [REDACTED]

24 Can testify to: Being present while drone was being flown at 9/10 Fumoral

26 W-16 W-16

27 [REDACTED]
28 [REDACTED]

29 Can testify to: Evaluating PG&E needs for evidence removal at the direction of
30 CAL FIRE.

1 W-17 W-17

2
3
4 Can testify to: Coordinated evidence removal for PG&E at the direction of
5 CAL FIRE.
6

7 W-18 W-18

8
9
10 Can testify to: Removing transmission tower equipment
11

12 W-19 W-19

13
14
15 Can testify to: Removing transmission tower equipment
16

17 W-20 W-20

18
19
20 Can testify to: Removing transmission tower equipment
21

22 W-21 W-21

23
24
25 Can testify to: Removing transmission tower equipment
26

27 W-22 W-22

28
29
30 Can testify to: Removing transmission tower equipment
31

1 W-23 W-23

2
3
4 Can testify to: Removing transmission tower equipment
5

6 W-24 Name: Scott Middleton

7
8
9 Can testify to: Assisting with crane operation for removing transmission tower
10 equipment
11

12 W-25 Name: Jim Passantino

13
14
15 Can testify to: Assisting with crane operation for removing transmission tower
16 equipment
17

18 W-26 Name: Nick Arend

19
20
21 Can testify to: Assisting with crane operation for removing transmission tower
22 equipment
23

24 W-27 Name: Jane Luckhardt

25
26
27 Can testify to: Providing documents from Northern California Power Agency
28
29
30
31

1 W-28 Name: Alexander Frampton

2 [REDACTED]
3 [REDACTED]

4 Can testify to: Providing scene security at Kincade Fire

5
6 W-29 Name: Robert Torres

7 [REDACTED]
8 [REDACTED]

9 Can testify to: Providing scene security at Kincade Fire

10
11 W-30 Name: Matt Wilson

12 [REDACTED]
13 [REDACTED]

14 Can testify to: Providing scene security at Kincade Fire

15
16 W-31 Name: Matt Woods

17 [REDACTED]
18 [REDACTED]

19 Can testify to: Photographic documentation at Kincade Fire

20
21 W-32 Name: Chris Kirk

22 [REDACTED]
23 [REDACTED]

24 Can testify to: Assisting with transportation of evidence items

25
26 W-33 Name: Wesley Daniels

27 [REDACTED]
28 [REDACTED]

29 Can testify to: Assisting with transportation of evidence items

1 W-34 Name: Shawn Zimmermaker



4 Can testify to: logistical support to the investigation of Kincade Fire

6 W-35 Name: Nicholas Labedski



9 Can testify to: Providing assistance with evidence documentation.

11 W-36 Name: David Karoly



14 Can testify to: Providing assistance with evidence documentation.

16 W-37 Name: Garrett Jackson



19 Can testify to: Providing assistance with evidence documentation.

21 W-38 Name: Jay Fazio



24 Can testify to: Providing assistance with evidence documentation.

26 W-39 Name: Dorus Van Goidsenhoven



29 Can testify to: Providing assistance with evidence documentation.

5 - EVIDENCE:

- E-1 One, Thumb drive containing UAV images taken by Matt WOODS.
- E-2 Section of box arm
- E-3 Insulator
- E-4.1 Dead end shoe
- E-4.2 Top jumper
- E-5 Middle jumper
- E-6 Bottom jumper
- E-7 LiDAR files
- E-8 External hard drive containing UAV images

6 – CONDITIONS:**Fuel:**

Grass and brush. Fuel continuity in and around the area of Tower 1-6 41129171 was sparse and separated receptive fuel bed. The vegetation around Tower 1-6 41129171 appeared to have been recently cut and trimmed. I did not see any brush over six feet in height within the immediate area of Tower 1-6 41129171. (May consider explaining the condition of the brush located just past the immediate tower location. This can help show how the fire moved from the sparse grass to the field of manzanita.) The fuel moisture readings were recorded to be 4.9 percent at 9 pm on October 23, 2019, from the Hawkeye Remote Automated Weather Station (RAWS) which is 5.6 miles southwest of Tower 1-6 41129171.

Weather:

The National Weather Service (NWS) had issued a red flag warning for the North Bay Mountains on October 23, 2019. The National Weather Service issues a Red Flag Warning when they are forecasting warm temperatures, very low humidity, and stronger winds are expected to combine to produce an increased risk of fire danger for a designated area. The weather for the Geysers area was forecasted to produce 15-25 mile per hour winds with gust 30-40 miles per hour and low relative humidity. (See attachment 3.1 & 3.2 for weather readings).

At approximately 12:30 AM on October 24, 2019 when I left my vehicle to do a visual inspection of Tower 1-6 41129171. I experienced a notable increase in wind speed between where my vehicle was parked near the entry gate of 9-10 Fumarole site and base of Tower 1-6 41129171. While the wind speed at both locations were strong, it appeared Tower 1-6 41129171 was exposed to far stronger winds than we were experiencing near the entry gate. The approximate distance between Tower 1-6 41129171 and the front entry gate was 200 yards.

- 1 Weather taken by STEIS on 10/24/2019 at 12:20 AM
2 Weather Device: Kestrel 3000
3 Location: 9-10 Fumarole front entry gate
4 Temperature: 68 degrees Fahrenheit
5 Relative humidity: 6%
6 Wind: 35 miles per hour
7 Wind direction: North
8
9 Remote Automated Weather Station (RAWS)
10 Weather Station Name: Hawkeye
11 Location: Approximately one mile west of the intersection of Geysers Road and
12 Hawkeye Ridge Road, Geyserville, CA.
13 (Approximately 5.6 miles southwest from Tower 1-6 41129171.)
14 GPS Location: 38° 46' 54" -122° 55' 01"
15 Elevation: 2000 FT.
16 National Weather Service ID#: 042010
17 Date & Time: October 23, 2019 at 9:00 pm.
18 Temperature: 75 degrees Fahrenheit
19 Relative humidity: 7%
20 Wind: 7 miles per hour with gust to 28 miles per hour.
21 Wind direction: North
22 (See Attachment 3.2 for additional RAWS data)
23
24 **Topography:**
25 The general origin area of the fire is located on a mid-slope spur ridge on a southwest
26 facing slope southeast of Burned Mountain (elev. 2969 FT.)
27

7 – EQUIPMENT:

One, Pacific Gas & Electric Company (PG&E) owned electrical transmission tower (Tower 1-6 41129171), located southwest of the adjacent property of the decommissioned 9-10 Fumarole power plant site. The electrical transmission tower is further described by the following identifiable markings and signage which is located on one of the tower supports legs.

The first identifiable marking is a sign with a yellow in color background and the numbers "1-6 41129171" written black in color. This sign is attached to the tower support leg by three, silver metal straps.

The second identifiable set of markings on the tower are stenciled numbers and letters black in color, painted directly to the tower support leg. The numbers and letters read "0-1 GEYSERS 0-GEYSERS". Reading the stenciled numbers and letters was difficult due to weathering and fading on the tower support leg, there is a possibility the second "0" on stenciled markings may be an "8".

Global Positioning Coordinates of (Tower 1-6 41129171):
N 38 47.746, W -122 46.030

*Note, Tower 1-6 41129171 is also referenced in PG&E documents as
"Tower Structure 001-006".

The involved PG&E electrical transmission lines connected to
Tower 1-6 41129171 are referenced in PG&E documentation as
"Geysers #9 – Lakeville 230KV"

8 - PROPERTY:

The origin of the Kincade Fire was located at Global Positioning Coordinates (WGS 84)
N 38 47.746, W 122 46.030

The origin property is located adjacent to the CAL PINE Corporation decommissioned
9-10 Fumarole Geothermal Power Plant located in Cloverdale, CA. PG&E
documentation provided to me refers to the "9-10 Fumarole Power Plant" which is
located adjacent to the origin property also as "Geysers #9 & #10 PP".

Property Owner: EST of Don Emerson

[REDACTED]

[REDACTED]

Property size: 1,448.2 acres

9 - NARRATIVE:

On Wednesday October 23, 2019 at approximately 9:27 PM, the CAL FIRE, St. Helena Emergency Command Center (ECC) dispatched a vegetation fire in the northeastern corner of Sonoma County. ECC reported the fire location to be in the Geysers Geothermal field, (Geysers) near the Calpine 9-10 Fumarole power plant site. This area is further described as Kincade Road east of the community of Geyserville, CA. The 9-10 Fumarole power plant located in the Geysers area is known to me as being decommissioned and no longer in use for power generation.

At approximately 9:27 PM on October 23, 2019 I received a text message alert from ECC on my state issued cellular phone reporting a vegetation fire at the Geysers 9-10 – Fumarole Power plant. I responded to the fire in uniform in my department marked and assigned vehicle from southern Sonoma County. During my response to the fire on Kincade Road I diverted to assist with suppression activities for approximately six to seven separate newly reported fires which were along my route to the Kincade incident. All the newly reported fires I responded to were un-founded or it was discovered the reporting parties were mistakenly reporting the glow of the Kincade Fire as a new fire.

After becoming available from the above reported fires I continued to the Kincade Fire. I drove north on State Highway 101 just south of the Highway 12 interchange in the city of Santa Rosa and could see a glow and smoke from the location of the Geysers. I contacted LAIRD on his cellular phone and asked LAIRD what his status was and if he needed anything from me before I left the Santa Rosa area. LAIRD told me he was attempting to make access to up to the area of John Kincade Road. LAIRD told me he had spoken briefly to STEIS over the phone before losing cellular signal. LAIRD told me he believed STEIS was ahead of him. LAIRD requested I continue responding to the incident.

Per LAIRD and my conversation, I continued to the incident as requested. I was continuing to assist and support in the investigation of the fire.

1 I arrived at the incident at approximately 10:00 PM on October 23, 2019 and attempted
2 to make access via Geysers Road and Red Winery Road. I was able to drive northeast
3 on Geysers Road until my access was blocked by dangerous fire conditions. While
4 waiting for the fire conditions to subside so I could pass, I assist with evacuations for
5 residents on Geysers Road.

6
7 When the fire conditions improved on Geysers Road I continued up Geysers Road into
8 the area of Kincade Road. While in route to the 9-10 Fumarole site I saw, the fire was
9 advancing in a southwestern direction roughly towards the town of Windsor. The
10 predominate direction of fire spread and conditions supported the initial reports of the
11 fire originating from the area of John Kincade Road in the Geysers. My route to Kincade
12 Road was as follows, Geysers Road to Big Sulphur Creek Road, to Burned Mountain
13 Road to John Kincade Road. I located CAL FIRE Peace Officers Kyle STEIS and
14 William LAIRD at the 9-10 Fumarole site located behind an open gate on the west side
15 of Kincade Road. The fire conditions and macro fire indicators I saw during my drive
16 supported STEIS and LAIRD's initial theory that the fire originated from the area near
17 the 9-10 Fumarole site.

18
19 When I arrived at the 9-10 Fumarole site I saw the area was experiencing high speed
20 winds predominately out of the north. The winds appeared to be erratic and shifting
21 rapidly. LAIRD, STEIS and I were initially parked in the area southeast of the 9-10
22 Fumarole building. STEIS told me he had received information from Calpine employee
23 John Woods regarding the report of the fire in the area near 9-10 Fumarole.

24
25 STEIS told me the conversation between John WOOD and him in summary. John
26 WOOD said he was driving on Burned Mountain Road. John WOOD said out of the
27 corner of his eye he saw a fire on the hillside above Burned Mountain Road. John
28 WOOD said the fire appeared to be one to two acres in size. John WOOD said the fire
29 was located on the downhill side, in front of the tower located at the 9-10 Fumarole site.
30 John WOOD reported the fire to the Geysers Administration Center (GAC) and drove to
31 the 9-10 Fumarole site to open the gate at the 9-10 Fumarole site.

1 STEIS told me after speaking with John WOOD he obtained the log book from the GAC
2 showing the time, date, and location when John WOOD reported the fire to the GAC.
3 STEIS told me the log book showed that at 21:20 (9:20 PM) the Lakeville 230KV was
4 tripped.

5
6 After speaking with LAIRD and STEIS I drove my vehicle west of our parked location
7 towards the electrical transmission tower located on the west side of the site to
8 investigate the area for life safety hazards and possible origin of the fire.

9
10 I parked my vehicle pointed west towards the electrical transmission tower (Tower 1-6
11 41129171) on the south side of the main building and could see a wire hanging down
12 which appeared to be out of place on the top portion of the electrical transmission tower.
13 I drove my vehicle back to STEIS and LAIRD's location, parked, exited my vehicle and
14 walked around the site of 9-10 Fumarole with the assistance of my department assigned
15 night-vision goggles (NVG).

16
17 I started walking south of the main building visually inspecting the electrical lines and
18 transmission tower 1-6 41129171 from a safe distance. I could see the vertically
19 mounted electrical insulators on the east side of the transmission tower closest to me
20 were swinging violently back and forth. I also saw the corresponding electrical wires
21 which were connected to the tower to the south were swinging in unison with the wind. I
22 saw an electrical wire on the east side of the tower on the top set of wires, this wire
23 appeared to be disconnected and dangling from the insulator on the tower.

24 I continued inspecting the area around the site and Tower 1-6 41129171. I saw six sets
25 of paired wires each were connected to the south side span box frame of the tower. I
26 saw only three electrical wires were connected to the north side span box frame of the
27 tower. Both the north and south electrical wire spans appeared to be attached to the
28 adjacent and respective electrical transmission Tower 1-6 41129171. I continued my
29 visual inspection around the north side of the main building back to my vehicle.

1 I waited in my vehicle for the remainder of the night until sunrise when I had enough
2 light to see without the assistance of my night vision. After sunrise, I used a spotting
3 scope to visually inspect the electrical transmission Tower 1-6 41129171 and adjacent
4 vegetation in the area. I started my visual inspection of the canyon south of the
5 electrical transmission tower at the 9-10 Fumarole site. I saw advancing and lateral
6 macro fire spread fire indicators in the form of protection directing me back towards the
7 location of Tower 1-6 41129171 at the 9-10 Fumarole site.

8
9 I walked to the north side of the main building at the 9-10 Fumarole site and saw
10 backing, lateral, and advancing macro fire spread fire indicators in the form of sooting
11 and staining directing me back towards the location of the base of the electrical
12 transmission tower 1-6 41129171 at the 9-10 Fumarole site.

13
14 After inspecting the macro fire spread fire indicators surrounding area of the 9-10
15 Fumarole site I determined the approximate location of the general origin area was
16 around Tower 1-6 41129171. I continued to inspect the electrical transmission Tower 1-
17 6 41129171 at the 9-10 Fumarole site. The wind at the site had decreased slightly and
18 allowed me to get a better view of the wire dangling from the electrical transmission
19 tower. When I visually inspected the wire with my spotting scope I could see the end of
20 the conductor wire from the Geysers #9 – Lakeville 230KV circuit appeared to be shiny
21 in areas and had approximately three to four wires protruding from the manufactured
22 braid of the wire. The wire in question appeared to have been one of two wires which
23 were originally attached to the top of the transmission wire coming from the south wire
24 span of the electrical transmission Tower 1-6 41129171.



Figure 1, (IMG_1493.JPG) Photo of the highlighted conductor wire on tower 1-6 41129171.

I visually inspected the box frame area of the electrical transmission tower adjacent to the location of the severed wire. The wire was hanging down near the center or middle box frame arm on the east side of the tower. The end of the wire was still swinging in the wind and when the wind would subside the wire would come to rest hanging approximately two to three feet from the middle box frame arm.

I continued to visually inspect the middle box frame arm on the east side of the tower. I saw what appeared to be a black soot or burn mark on the vertical / south face of the outer most metal structural member of the middle box frame arm. From my experience and training the black soot and burn marks appeared to have been the result of an electrical arc.

The soot mark appeared on the lower edge of the metal structural member of the middle box frame arm. The soot mark was oblong in shape and was orientated in a vertical fashion. Due to poor lighting and shadow conditions I could not sufficiently visually inspect the underside of the metal structural member of the middle box frame arm.

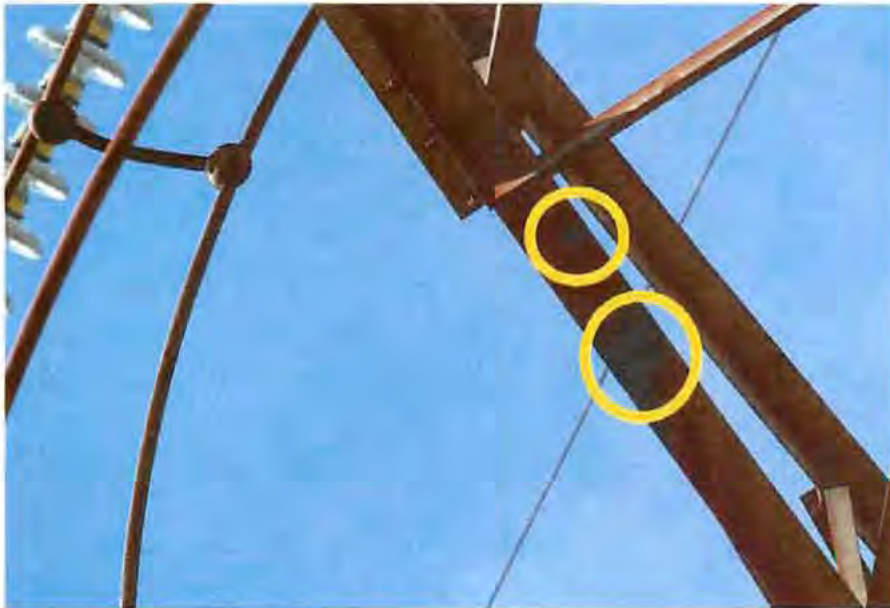


Figure 2 (IMG_1497.JPG) Photo of the highlighted electrical arc marks on the box frame of Tower 1-6 41129171.

I temporality suspended my visual inspection of the electrical transmission tower until the lighting conditions improved. I met with CAL FIRE Battalion Chief Ryan SMITH who arrived at scene to assist with the investigation. SMITH and I began to conduct a visual inspection of macro fire pattern indicators of the area adjacent to the 9-10 Fumarole site. SMITH and I agreed the macro fire pattern indicators directed us back to a general origin area bellow the location of the electrical transmission Tower 1-6 41129171.

After identifying Tower 1-6 41129171 location as a possible location of the general origin area of the fire I identified and marked the vehicle access points with three inch, yellow "CRIME SCENE DO NOT CROSS" barricade tape. Do to the size of the scene I feasibly could not fully cordon off the whole security perimeter around the origin. I identified and marked the following perimeter lines.

- The main access gate at the 9-10 Fumarole site and the two-adjacent access road which crosses under the overhead pipe line crossings to the northeast of the 9-10 Fumarole site main gate.
- Southwest from the main access gate at the 9-10 Fumarole site to the edge of the hillside along the chain link fence.
- West of the 9-10 Fumarole site, down the ridge to a third access point.

1 Prior to SMITH and I conducting a visual inspection for micro fire pattern indicators I
2 photographed the location with my department issued digital camera. I photographed
3 the tower area and adjacent areas around Tower 1-6 41129171.



4
5 *Figure 3(IAR) 1460(JPG) Looking west at east side of Tower 1-6 41129171. The highlighted area is the location on the tower*
6 *where the failure occurred on October 23, 2019.*

7 SMITH and I worked separately identifying fire spread indicators on our own. We started
8 our visual inspection on the south facing slope of the canyon south of the 9-10
9 Fumarole site. The location of our starting point was near an unburned area bellow the
10 tower. SMITH and I worked from advancing fire pattern indicators we located bellow the
11 tower. We worked our way between two lateral and advancing fire pattern indicator
12 transitional zones from east to west along the slope at different elevations SMITH and I
13 utilized a parallel lane search technique while moving up slope towards the tower.
14 SMITH and I marked fire pattern indicators with colored flagging.

1 SMITH and I identified and marked the fire pattern indicators we located with the
2 corresponding colors that have been identified by the National Wildfire Coordinating
3 Group, curriculum.

- 4 • Red colored flags represent advancing fire pattern indicators.
- 5 • Yellow colored flags represent lateral fire pattern indicators.
- 6 • Blue colored flags represent backing fire pattern indicators.
- 7 • Green colored flags represent areas of interest.
- 8 • White colored flags represent potential evidence.

9
10 I located several lateral and advancing fire spread indicators east and south of the tower
11 indicating the fire spread from the location down slope from the tower and in line with
12 the previous weather condition I had experienced on October 23, 2019. We continued
13 our visual inspection west, along the slope below the tower and around the peak of the
14 ridge line and to the north in to the canyon on the north side of the electrical
15 transmission Tower 1-6 41129171. After we made the first pass I began my search
16 pattern in the opposite direction south back to our starting point at a different elevation
17 on the slope.

18
19 During my visual inspection, I saw the surface of the slope was steep and consisted of
20 loose dirt. The composition and orientation of the vegetation on the slope consisted of
21 isolated patches of dried grass and vegetation. The slope had limited continuity
22 between vegetation around the electrical transmission tower. The area was also littered
23 with metal hardware, electrical wires and chunks of tar paper like material. The majority
24 of this littered material showed physical evidence of corrosion and weathering,
25 indicating to me these items had been lost or discarded on the ground for a significant
26 time prior to the fire.

I located a specific origin area (SOA), down slope / south of the electrical transmission tower at the 9-10 Fumarole site. This SOA consisted of both advancing and backing fire spread indicators within a proximity of each other. This area of interest indicated to me that there was a high probability a heat source initially ignited vegetation from this location which spread to surrounding vegetation.



Figure 4.(IMG 1551.JPG) The general origin area (GOA) on south side of Tower 1-6 4/1/29/17

After identifying several SOA's around the down slope side of the electrical transmission tower at the 9-10 Fumarole site with SMITH, I started my visual inspection of the SOA's by visually inspecting the undisturbed area for evidence items. After I was completed with a preliminary visual inspection I deployed the hand-held magnet on the areas of the SOA's by passing the magnet approximately one to two inches over the surface of the ground.

While passing the magnet over the surface of the SOA areas, I listened for an audible sound from the magnet of a ferrous metal evidence item contacting the magnet surface. After each sweep over an SOA I would visually inspect the surface / face of the magnet for ferrous metal evidence items. I performed between ten to twelve sweeps over each SOA, inspecting the surface / face of the magnet between each sweep.

1 After performing a magnetic sweep of each I again did another visual inspection looking
2 for additional evidence items. I performed the visual search and magnet sweep of both
3 SMITH's and my SOA's areas which we had identified. I did not locate any evidence
4 items from SMITH and my areas of interest.

5 STEIS informed me he had ordered a private security company to provide twenty-four-
6 hour scene security for the scene. For additional information regarding the details of the
7 scene security refer to attachment 6.5 (CAL FIRE LE71 Supplementary Report STEIS).

8
9 **October 25, 2019**

10 I arrived at the electrical transmission tower at the 9-10 Fumarole site at approximately
11 10:00 AM. I began taking additional photographs with my department issued digital
12 camera and global positioning system (GPS) camera attachment.

13
14 After taking photographs I assisted CAL FIRE, Multimedia Officer Matt WOODS with
15 collecting photo and video evidence with his department assigned unmanned aerial
16 vehicle (UAV). I briefed WOODS on what items and locations of interest we would need
17 him to capture video and photographs of at the site. I saw WOODS operate and collect
18 videos and photos with his UAV around the upper portion of the electrical transmission
19 tower at the 9-10 Fumarole site. After WOODS completed documenting the electrical
20 transmission tower he directed his attention towards documenting the surrounding area
21 around the electrical transmission tower.

22
23 While at the 9-10 Fumarole site STEIS showed me an image he had received from
24 ZIMMERMAKER. The image was a screen shot from the Situation Awareness and
25 Collaboration Tool (SCOUT) website. The image was a satellite overhead view of the 9-
26 10 Fumarole site and the surrounding area. The file name was 20191023-1.1-2135. The
27 image showed a red shaded area covering the area surrounding the 9-10 Fumarole site
28 and PG&E electrical transmission Tower 1-6 41129171. STEIS told me the red shaded
29 area represented a heat signature which was identified on October 23, 2019 at 21:35
30 (9:35 PM). The identified heat signature / red shaded area covered our GOA and
31 supported the fire spread pattern indicators I had located at the 9-10 Fumarole site.

1 The identified heat signature / red shaded area also supported John WOOD's statement
2 of where he first discovered the fire when he reported it to the GAC.

3
4 On my way home from leaving the 9-10 Fumarole site I was involved in the rescue of a
5 fire shelter deployment of three individuals near the 10000 address block of Pine Flat
6 Road in Geyserville, CA. After I located the three individuals and passed them off to
7 assisting rescue personnel for medical treatment and transport, I secured the fire shelter
8 deployment site. Prior to taking photographs at the fire shelter deployment site with my
9 department issued camera I removed the secure digital (SD) memory card from my
10 camera which had the digital photographs taken between October 23, 2019 through
11 October 25, 2019 from the 9-10 Fumarole site.

12
13 I secured the SD memory card from October 23, 2019 through October 25, 2019 from
14 the 9-10 Fumarole site in my vehicle. I used a separate SD memory card to document
15 the fire shelter deployment site on October 25, 2019.

16
17 **October 26, 2019**

18 I arrived at the electrical transmission tower at the 9-10 Fumarole site at approximately
19 10:00 AM.

20
21 I began supervising and monitoring the activities of our three CAL FIRE, survey crew
22 members and electrical engineer Jim NOLT. After my arrival two representatives from
23 the California Public Utilities Commission (CPUC) arrived at the 9-10 Fumarole site
24 escorted by LAIRD.

25
26 I monitored the activities of the three parties and insured that the three parties remained
27 separated and did not discuss or share any comments or questions regarding the
28 ongoing investigation.

1 While NOLT was visually inspecting Tower 1-6 41129171 he showed me he discovered
2 a location of interest on the box frame of Tower 1-6 41129171. This location of interest
3 appeared to be an additional electrical arc mark on the box frame different from the
4 original arc marks which I had previously located.

5
6 I met with STEIS and he informed me Pacific Gas and Electric (PG&E) employees
7 deployed a UAV around the 9-10 Fumarole site earlier that day which is a crime scene
8 of an ongoing investigation. STEIS told me he confiscated two SD memory cards from
9 the UAV which was operated by PG&E employees. STEIS transferred custody of the
10 two confiscated SD memory cards to me before I left the scene.

11
12 I secured the two SD memory cards in my vehicle and drove directly to the CAL FIRE,
13 Santa Rosa Prevention Office. Once I arrived at CAL FIRE, Santa Rosa Prevention
14 Office I secured a total of five SD memory cards in to our evidence locker, they are as
15 listed below:

- 16 - One SD card (*9-10 Fumarole site photos, taken by me between the dates of*
17 *October 23, 2019 to October 26, 2019*).
- 18 - One micro SD card (*from my vehicle dash camera from the fire shelter*
19 *deployment on the date of October 25, 2019*)
- 20 - One SD card (*from my camera from documenting the fire shelter deployment on*
21 *the date of October 25, 2019*)
- 22 - Two SD memory cards (*SD memory cards from the UAV which was operated by*
23 *PG&E employees / representatives on October 26, 2019*).

October 28, 2019

On October 28, 2019, I contacted Sonoma County Sheriff's Sergeant Gary LARSON of crime scene investigations by phone. I requested LARSON's assistance with locating ferrous and non-ferrous metallic evidence items at the 9-10 Fumarole site. I requested LARSON's assistance because I did not have the appropriate equipment available to me to search and identify both ferrous and non-ferrous metallic items. On October 24, 2019, I used a hand-held magnet to attempt to locate ferrous metallic items within our SOA's. I was not able to locate any magnetic ferrous metallic items of interest on October 24, 2019.

October 29, 2019

On October 29, 2019 at approximately 9:30 AM I met with Sonoma County Sheriff's Sergeant Gary LARSON and Detective Tom MCNEIL. I escorted LARSON and MCNEIL from the intersection of Highway 128 and Geysers Road to the 9-10 Fumarole site in the geysers. I requested assistance from LARSON on October 28, 2019 for use of their metal detector.

When we arrived at the 9-10 Fumarole site I saw many of our fire pattern indicator flags had been blown away surrounding our GOA at the 9-10 Fumarole site due to strong winds. I did note the flags within the SOA's areas which were to be searched by LARSON and MCNEIL remained in place allowing us to continue with our evidence search. I briefed LARSON and MCNEIL on how we planned on utilizing them and their metal detection equipment. I explained to LARSON and MCNEIL that we would like them to attempt to locate ferrous and non-ferrous metal evidence items within our general origin area (GOA or SOA or Both?) under the electrical transmission tower at the 9-10 Fumarole site. I explained to LARSON and MCNEIL the ferrous and non-ferrous metallic items we were looking for could be as small or if not smaller than a "BB" or pellet.

1 Prior to deploying LARSON and MCNEIL, I marked the outer edge of the search area
2 with survey string. The approximate dimensions of this area were twenty feet wide,
3 vertical / cross slope and sixty feet long, horizontal. The top of the search area started
4 from the base southwest support leg of the electrical transmission tower and extended
5 down the slope. On the east side of the search area we used a prominent manzanita
6 bush as our search boundary line. We sectioned off the area in to a single grid which
7 was approximately three feet vertical and twenty feet horizontal. We moved the grid
8 lane up the slope after it was searched completely.

9
10 LARSON and MCNEIL started their search at the bottom of the search grid and worked
11 their way up the slope to the base of the southwest support leg of the electrical
12 transmission tower. MCNEIL was operating the metal detector in the grid lane.
13 As MCNEIL worked his way up the slope searching for ferrous and non-ferrous metal
14 items. LAIRD and I searched the areas of interest which were identified by MCNEIL and
15 his metal detector for possible evidence items. I searched each area of interest with
16 surgical forceps.

17
18 I started my visual inspection of the SOA's by visually inspecting the undisturbed area
19 for ferrous and non-ferrous metal evidence items. After I was completed with a
20 preliminary visual inspection I began to remove loose rocks, vegetation and soil from
21 the area and discarding these items out of the search area. After I removed the loose
22 rocks vegetation and soil I again did another visual inspection looking for ferrous and
23 non-ferrous metal evidence items. I continued this process until I reached native
24 undisturbed soil or material. I felt it was necessary to remove the loose material and
25 rocks within the SOA to insure we did not miss any small evidence items which could
26 have been buried under the material.

1 I conducted this search method six times within the search area after an area of interest
2 was identified. I did not locate any ferrous or non-ferrous metal evidence items within
3 this search area. I cannot rule out that these evidence items still do not exist within the
4 search area. Due to environmental factors with the slope, vegetation, and soil
5 composition the task of searching for the ferrous and non-ferrous metal evidence items
6 was extremely difficult. LARSON, MCNEIL, LAIRD and I, terminated our search upon
7 reaching the top of the search area and not finding any evidence related items.

8
9 **November 1, 2019**

10 I arrived at the 9-10 Fumarole site at approximately 8:00 AM. I attended a briefing
11 presented by CAL FIRE Region Deputy Chief Shawn ZIMMERMAKER.
12 ZIMMERMAKER was giving the briefing to CAL FIRE and PG&E employees and
13 contractors. ZIMMERMAKER informed the group several times that this was an ongoing
14 investigation and reiterated the requirement of confidentiality and non-disclosure for all
15 parties in attendance that day. After ZIMMERMAKER's briefing PG&E continued the
16 discussion with an operational and safety briefing for the day.

17
18 After the briefing, I parked my vehicle on the northwest corner of the main building at
19 the 9-10 Fumarole site. I was tasked with evidence collection and processing for the
20 day. With the assistance of the PG&E employees we identified an area northeast of the
21 tower to receive possible evidence items.

22
23 Once the removal operation started, the crane operator lowered all items which were
24 removed to this identified receiving area. Not all items which were removed were
25 collected as evidence. I did however mark each item which I received at this area with a
26 piece of blue tape. On each piece of tape, I marked the sequence in which the item was
27 removed, starting from first to last in numerical order. I also marked the original location
28 and orientation on the tower from which it came from.

1 When the suspect box frame was removed from the tower the crane operator lowered it
2 to the designated receiving area. Prior to setting the box frame on to the ground the
3 crane operator hung the steel structure / box frame arm five to six feet off the ground to
4 allow me to video the overall condition of the box frame. I took a video with my state
5 issued cellular phone, I could capture all sides and the underside of the box frame
6 before the crane operator set the box frame on to wooden blocks which were on the
7 ground.

8
9 After the crane personnel disconnected the box frame from the crane rigging I
10 photographed the box frame in place on the ground prior to disturbing the item.
11 I located several more electrical arc marks on the box frame near where I originally
12 discovered the first electrical arc mark on October 23 & 24, 2019. The electrical arc
13 marks appeared to be made recently. The arc marks on the surface of the box frame
14 were dark black in color, distinctively different than the overall surface condition with
15 small shiny bare spots and irregularities in the surface of the metal.



16
17 *Figure 5.(IMG_1829.JPG) One of several newly discovered electrical arc marks located on the box frame located after the*
18 *removal of the box frame from tower [~6-4][2917].*

1 We determined our best course of action to properly collect and preserve the evidence
2 located on the box frame was to cut the affected area out of the structure. I took
3 additional photographs to document the additional possible electrical arc marks prior to
4 marking the area on the structure to cut. I selected and identified the areas to be cut or
5 un-bolted a significant distance away from the possible areas of evidentiary value on the
6 box frame. I marked and labeled each specific section or area on the structure to be
7 either cut or to be un-bolted with blue tape. On the blue tape, I wrote either "cut" or "un-
8 bolt", with an arrow delineating the exact location to perform the task. Prior to allowing
9 the PG&E personnel to perform the task of cutting and removing the section of box
10 frame I briefed them on how I wanted the task performed.

11
12 After I was done briefing the PG&E crew I allowed them to conduct the cutting and un-
13 bolting while under my direct supervision. The PG&E crew used electric cordless impact
14 wrenches with crescent wrenches to remove the identified nuts and bolts. After
15 removing all nuts and bolts the PG&E crew attempted to cut the identified areas of the
16 box frame with an electric cordless band saw. The electric cordless band saw was
17 inefficient at cutting the material of the box frame, so the PG&E personnel changed
18 tools and used an electric cordless reciprocating saw with a metal blade.

19
20 While the PG&E personnel performed the cutting of the box frame I stood directly over
21 the area of electrical arc marks on the structure to protect them from being accidentally
22 disturbed. I also placed a canvas drop cloth on the ground under this area for further
23 surface protection from the ground. I watched as each cut which was made by the
24 PG&E personnel. The PG&E personnel made slow methodical cuts to insure no further
25 damage was done to the box frame. I did not see PG&E personnel make any accidental
26 contacts with the saw blade against the box frame while making the cuts.

1 After all the cuts were made on the box frame we lowered the selected section to the
2 ground on to the canvas cloth. We then lifted the section free and out of the main
3 remaining steel structure. We placed the selected section against a fence without
4 striking or dragging the section against the ground or any other hard objects. After this
5 section was removed I photographed it in place and attached an evidence tag to it.

6
7 I packaged the items with the following method. I wrapped the electrical arc mark areas
8 on the selected piece of box frame with several layers of plastic bubble wrap. After the
9 bubble wrap I wrapped the entire section of bubble wrap with clear cling packing wrap.
10 After the clear cling packing wrap, I wrapped the clear cling packing wrap with black
11 electrical tape. I finished the packaging with a single strip of red evidence tape placing it
12 length wise along the beam, signed and wrote the time dated the evidence tape. I
13 performed this packaging method on each of the evidence items collected which had
14 sensitive surface areas of interest on them.

15
16 After the box frame was removed I received several more sections of insulators,
17 conductors and hardware. I located several pieces of hardware and conductors which
18 had what appeared to have electrical arc marks on them. I took photographs of these
19 items and locations pre-and post-packaging.



20
21 *Figure 6.(IMG_1866.JPG) Six bolt wire clamp with electrical arc marks near the bolt holes from Tower 1-6 41129171.*

1 After all identified evidence items, had been removed from the tower I loaded or
2 supervised the loading of the evidence items in to a department flatbed truck. We
3 packaged each item so it would have minimum surface contact with each other. We
4 placed plywood sheets between each evidence item for protection during transport.

5
6 After all the evidence items, were loaded in to the truck I instructed the driver CAL FIRE,
7 Forestry Logistics Officer Chris KIRK to drive to CAL FIRE, Santa Rosa Station located
8 at 2210 West College Ave. Santa Rosa, CA. I instructed the KIRK I was going to follow
9 him to the destination and to remain in eye sight of my truck for the duration of the trip
10 and not to make any stops.

11
12 As we were departing the 9-10 Fumarole site, KIRK informed me he was unfamiliar with
13 the road system in this portion of the Geysers and didn't know how to get back to the
14 city of Santa Rosa. I instructed KIRK to follow me instead. I drove in front of the truck
15 hauling the evidence and guided him out of the Geysers area.

16 While driving in front of the evidence truck and in transit I kept the evidence truck in my
17 view and closely monitored the truck whenever we slowed down to allow oncoming
18 vehicles to pass. I did not see the evidence truck tampered with or stop the entire trip.

19
20 When we reached the intersection of Geysers Road and Highway 128 I instructed KIRK
21 to pass me and continue to our destination. For the remaining duration of the trip I
22 remained behind the evidence truck until we reached CAL FIRE, Santa Rosa Station.

23
24 When we arrived at CAL FIRE, Santa Rosa Station we carefully removed and placed all
25 the evidence items in to a secured steel shipping container designated for large
26 evidence item storage. After I secured all the evidence items I locked the access doors
27 and placed plastic shipping container seals on all the access doors of the container. I
28 photographed the serial numbers on the door seals and sent the photos of the seals to
29 STEIS via text message to document the secure delivery.

1 I transferred all three hundred and fifty-three digital photographs taken with my state
2 issued digital camera from the fire investigation on the Kincade incident directly from my
3 two, 32 gigabyte secure digital cards (SD cards) to two digital video recorders compact
4 disc (DVR CD discs). I made two unaltered copies of these photographs. I placed one
5 copy in to our evidence storage and packaged the second. I kept a third digital copy on
6 my state issued laptop computer for case review and construction of a photo catalog.

7
8 I transfer all five digital photographs and one video taken with my state issued cellular
9 phone from the fire investigation on the Kincade incident directly from my state issued
10 cellular phone to two digital video recorders compact disc (DVR CD disc). I made two
11 unaltered copies of these photographs.

12
13 I placed one copy in to our evidence storage and packaged the second. I kept a third
14 digital copy on my state issued laptop computer for case review and construction of a
15 photo catalog.

16
17 I captured a total of three hundred fifty-eight digital photographs and one digital video.
18 The digital video was approximately one minute and forty seconds in duration.
19 I erased all digital copies of the photographs and videos from my state issued laptop
20 computer after completing my case review and construction of a photo catalog for the
21 final report.

Investigation conclusion

Based on my training and experience I believe an electrical/mechanical failure occurred on the night of October 23, 2019 at the PG&E owned electrical transmission Tower 1-6 41129171 at the 9-10 Fumarole site. I believe a low cycle fatigue (work hardening) type failure occurred to the energized wire conductor on the 230KV, electrical transmission line, Geysers #9 – Lakeville at the location of the six-bolt connector which secures the energized wire conductor to the insulator on the box frame of Tower 1-6 41129171.

Low cycle fatigue has two fundamental characteristics: plastic deformation in each cycle and low cycle phenomenon. The materials have a finite endurance for this type of load. The term cycle refers to repeated applications of stress that lead to eventual fatigue and failure. Low cycle pertains to a long period between applications. In the application of Tower 1-6 41129171 the "material" we refer to is the affected electrical transmission line. The "cycle" represents the range and amount of repetitive movement to the affected electrical transmission line by the wind.

The original design of Tower 1-6 41129171 included having three anchor points on the energized conductor wire connecting the electrical transmission line to the 9-10 Fumarole power plant. The first securing the electrical transmission line between the two towers at the six-bolt saddle camp. The second anchor point on the section of the electrical transmission line was between the tower and electrical transmission line. The third anchor point was the electrical transmission line itself between the tower and the power plant.

This original design secured the electrical transmission line in place from excessive repetitive movement from the wind. The third anchor point was removed by PG&E during the decommissioning of Fumarole 9-10 in 2001. The removal of the third anchor point allowed the affected loose section of electrical transmission line to increase its cycle and range of movement.

1 The increased cycle and range of movement from the wind accelerated the low cycle
2 fatigue phenomenon at the location of the six-bolt saddle clamp resulting in an eventual
3 fatigue and failure at the location of the six-bolt saddle clamp on electrical transmission
4 line on October 23, 2019. I witnessed this event on the night of October 23, 2019 when I
5 saw the dramatic difference in the movement between the two sets of wires on either
6 side of Tower 1-6 41129171.

7
8 The low cycle fatigue failure resulted in the energized conductor wire swinging down
9 and contacting the grounded box frame portion of Tower 1-6 41129171, allowing the
10 upper phase of electrical transmission line Geysers #9 – Lakeville to ground to Tower 1-
11 6 41129171.

12
13 When the upper phase of electrical transmission line Geysers #9 – Lakeville ground to
14 the box frame of Tower 1-6 41129171 the contact resulted in an electrical failure which
15 produced multiple sparks which fell from the box frame portion of Tower 1-6 41129171.
16 Based on the number of electrical arc marks on the box frame of Tower 1-6 41129171 I
17 believe the electrical conductor contacted the box frame a minimum of twelve times if
18 not more.

19
20 Each time the electrical conductor contacted (went to ground) on the box frame it would
21 had produced a significant number of sparks and molten material. This production of
22 sparks and molten material fell from the tower landed in the sparse but, receptive initial
23 flammable fuel bed bellow the tower. As a result, multiple origins were created under
24 Tower 1-6 41129171. The overall petite size of molten material which fell from Tower 1-
25 6 41129171 were lost in the numerous rocks and loose soil on the hillside under Tower
26 1-6 41129171.

27 Based on multiple fire spread indicators, SMITH and I could identify these areas as
28 general origin areas under Tower 1-6 41129171. I saw macro and micro advancing type
29 fire spread indicators spreading from the general origin area locations outward in to
30 what is now the Kincade fire burn.

1 The pin flags representing the various types of advancing, lateral, and backing fire
2 spread indicators formed a upside down "V" shaped pattern below the electrical
3 transmission Tower 1-6 41129171. The narrow end of the "V" was directed up slope
4 originating from the base of the electrical transmission Tower 1-6 41129171. While the
5 wide end of the "V" was directed down slope away from the tower. This pattern created
6 by the fire spread indicators is consistent with the appropriate identification and location
7 of the general origin area of the fire. During the investigation, I did not locate any at
8 other evidence which contradicted my hypothesis on the location and origin of the fire.

9
10 I can rule out the remaining ten fire cause types except for electrical for the Kincade fire.
11 Based on location, fire spread indicators, available fuels, weather, time of day, and the
12 evidence and facts presented to me I have determined the Kincade was ignited by an
13 electrical failure on the PG&E owned electrical transmission Tower 1-6 41129171 at the
14 9-10 Fumarole site.

15
16 A consideration of the past fire history of the Geysers geothermal area does also come
17 in to question with regards to whether reasonable precautions necessary were taken to
18 insure against the starting and spread of a fire occurred. I observed several factors at
19 the Kincade Fire which were common to past large electrical caused fires which
20 occurred in the Geysers area. Weather and topography are two of the predominate
21 contributing factors for large scale fires in the Geysers area. The Geysers area
22 experiences stronger weather conditions compared to the surrounding areas in Sonoma
23 and Lake counties.

24
25 As a reference, I was the lead fire investigator for the 2018 Sawmill fire involving PG&E
26 owned electrical equipment. I identified PG&E owned electrical equipment as the cause
27 of the fire. In the instance of similarity between the Kincade and Sawmill fire, slope
28 aspect, topographical location, and the type of mechanical failure (low cycle fatigue).
29 Both origins were located on southwestern facing slopes. Both origins were located on
30 mid slope, predominate spur ridges from the main ridgeline.

1 Both mechanical failures were the result of low cycle fatigue. I believe these factors
2 contribute to the PG&E equipment being exposed to above average wind conditions
3 which contributed to an elevated risk of mechanical failure due to low cycle fatigue.
4

5 During the Sawmill fire investigation, I noted high winds were a factor in the mechanical
6 failure of the PG&E owned electrical equipment which caused the fire. The findings for
7 the cause of Sawmill fire were communicated to PG&E, I would expect PG&E to make
8 note of the findings and make the appropriate changes or institute preventive measures
9 to eliminate future failures with equipment exposed to similar conditions.
10

11 Another factor which is a concern, is the involved PG&E electrical equipment on PG&E
12 electrical transmission line, Geysers #9 – Lakeville which caused the Kincade fire. It
13 appears to be operationally nonessential or functional for power generation or
14 distribution of electricity beyond PG&E tower #001-009 on the Geysers #9 – Lakeville
15 electrical transmission line.
16

17 Per a 2010 report published by the Geothermal Resources Council titled "the Geysers
18 Geothermal Field Special Report NO. 20 Update 1990-2010, list the closure of
19 Fumarole #10 geothermal power plant in 2000 and Fumarole #9 geothermal power
20 plant in 2001.
21

22 Per documentation provided to me by PG&E I have also located information in dated
23 back to August of 2006, regarding performing the job of the removal of Geysers 9 from
24 the transmission grid by removing the conductor tapping Geysers 9 to Tower 0/1 (Tower
25 1-6 41129171).

26 Given the above documentation I could determine that at a minimum, portions of the
27 Fumarole 9 -10 power plant were still connected to the Geysers #9 – Lakeville electrical
28 transmission line. Additionally, the final disconnects of the Fumarole 9 power plant
29 occurred in 2006. I have not been able to ascertain the operational or functional use for
30 the energized electrical equipment located on Tower 1-6 41129171 for a minimum of
31 the last thirteen years.

1 Per the California Public Utilities Commission General Orders 95 regulations (GO95),
2 section III, part 31.6 Abandoned Lines. "Lines or portions of lines permanently
3 abandoned shall be removed by their owners so that such lines shall not become a
4 public nuisance or a hazard to life or property. For the purposes of this rule, lines that
5 are permanently abandoned shall be defined as those lines that are determined by their
6 owner to have no foreseeable future use."

7
8 Given that PG&E has not utilized the involved section of electrical transmission line on
9 Geysers #9 – Lakeville for thirteen years. I consider the section of electrical
10 transmission line on Geysers #9 – Lakeville between PG&E tower #001-009 and tower
11 #001/006 (tower 1-6 41129171) to be abandoned.

12
13 By the removal or the de-energization of the equipment on tower 1-6 41129171, PG&E
14 could have minimized or eliminated the fire hazard risk, public nuisance, hazard to life
15 and property, effectively preventing the Kincade fire all together on the night of October
16 23, 2019.

17
18 On May 5, 2020, I drove to the location tower 1-6 41129171 (PG&E tower 001/006) on
19 the electrical transmission line of Geysers #9 – Lakeville. When I arrived to tower 1-6
20 41129171 (PG&E tower 001/006) I saw PG&E had removed the three jumper conductor
21 wires and corresponding insulators from all three phases of the Geysers #9 – Lakeville
22 electrical transmission lines on tower 1-6 41129171 (PG&E tower 001/006). PG&E had
23 cut the conductor wire on the tower after the six-bolt connector and left approximately a
24 twelve-inch-long section of conductor wire.

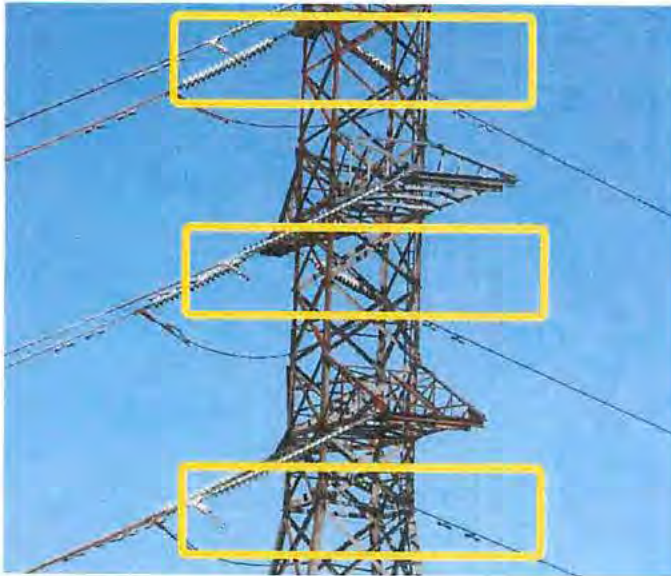


Figure 7 (IMG1891.JPG) Photo taken May 3, 2020 by U BOH DL G. Highlighted sections are where the conductors were removed from tower 1-6 41129171 (PG&E tower 001/006) by PG&E after the Kincade Fire.

I left tower 1-6 41129171 (PG&E tower 001/006) and drove south on John Kincade Road along the Geysers #9 – Lakeville electrical transmission line to tower 001/008. At tower 001/008 I saw PG&E had removed the conductor wire on the tower between the two spans on all three phases.

I continued to tower 001/009 on the Geysers #9 – Lakeville electrical transmission line. Prior to the Kincade fire, tower 001/009 on the Geysers #9 – Lakeville electrical transmission line was where the electrical transmission line split and connected the Sonoma Calpine power plant (which is currently in use) and the decommissioned 9/10 Fumarole (Geysers #9 / #10) power plant. When I arrived, I saw PG&E had removed the conductor wire which would have energized the section of the Geysers #9 – Lakeville electrical transmission line connecting the 9/10 Fumarole (Geysers #9 / #10) power plant.



Figure 8(IMG1902.JPG.) Photo taken on May 5, 2020 by UBOLDI, G. The highlighted sections are where PG&E removed the conductor wires from tower 001/009 on the Geysers #9 – Lakeville electrical transmission line after the Kincade Fire.

If the above proper corrective measures were originally taken by PG&E when the 9/10 Fumarole (Geysers #9 / #10) power plant was decommissioned in 2001 the Kincade fire would have not occurred on October 23, 2019 due to a failure on tower 1-6 41129171.

PG&E identified the weather event on October 23, 2019 as a high fire danger threat and issued a Public Safety Power Shutoff (PSPS) for communities of Sonoma County. Per PG&E the high fire danger weather risk condition thresholds were not met for the Geysers area to initiate a PSPS to the electrical distribution system in the Geysers Area. Prior to the night of October 23, 2019, the Cal pine corporation had made the decision to deenergize their own electrical infrastructure in the Geysers area because of the Red Flag Weather watch and the PSPS.

After considering all the facts presented to me I do not believe PG&E took reasonable precautions necessary to insure against the starting and spreading of fire particularly for the following reasons.

- 1 • PG&E was aware of the current elevated fire hazard with the suspected electrical
2 transmission lines and past major fire history in the Geysers area. PG&E should
3 be aware the hostile weather conditions commonly found in the Geysers area as
4 a major contributing factor towards premature equipment failure.
5
- 6 • PG&E allowed abandoned lines to remain in place and energized creating a
7 public nuisance and producing a hazard to life and property.
8
- 9 • I believe after the Kincade fire, PG&E is now aware the energized the section of
10 the Geysers #9 – Lakeville electrical transmission line connecting the 9/10
11 Fumarole (Geysers #9 / #10) power plant was operationally useless and
12 abandoned, which is a violation of the CPUC GO95 requirements regarding the
13 final disposition of abandoned electrical lines.
14

15 Due to the above listed factors I have confidence in that PG&E violated the following
16 California Penal, Public Utility, Public Resource, and Health and Safety codes.
17

- 18 • California Penal Code Section 452.1(a)(2)
19 (a) Notwithstanding any other law, any person who is convicted of a felony violation of
20 Section 452 shall be punished by a one-, two-, or three-year enhancement for each of
21 the following circumstances that is found to be true:
22 (2) A firefighter, peace officer, or other emergency personnel suffered great bodily injury
23 as a result of the offense. The additional term provided by this subdivision shall be
24 imposed whenever applicable, including any instance in which there is a violation of
25 subdivision (a) of Section 452.
26 The Kincade fire injured four firefighters to the extent of hospitalization for treatment and
27 evaluation. Multiple other injuries were also sustained by firefighters but did not require
28 hospitalization.
29
30

- California Public Utility Code Section 2110.

Every public utility and every officer, agent, or employee of any public utility, who violates or fails to comply with, or who procures, aids, or abets any violation by any public utility of any provision of the California Constitution or of this part, or who fails to comply with any part of any order, decision, rule, direction, demand, or requirement of the commission, or who procures, aids, or abets any public utility in the violation or noncompliance in a case in which a penalty has not otherwise been provided, is guilty of a misdemeanor and is punishable by a fine not exceeding five thousand dollars (\$5,000), or by imprisonment in a county jail not exceeding one year, or by both fine and imprisonment.

PG&E failed to follow the CPUC General Orders 95 (GO95) regarding the removal of abandoned powerlines from the Geysers #9 – Lakeville electrical transmission line between tower 001/009 to tower 1-6 41129171 (PG&E tower 001/006) at the 9/10 Fumarole (Geysers #9 / #10) power plant.

- California Penal Code Section 452.1(a)(4)

(a) Notwithstanding any other law, any person who is convicted of a felony violation of Section 452 shall be punished by a one-, two-, or three-year enhancement for each of the following circumstances that is found to be true:

(4) The defendant proximately caused multiple structures to burn in any single violation of Section 452.

A total of 374 inhabited residential and commercial structures were destroyed due to the Kincade fire. With an additional 60 inhabited residential and commercial structures damaged.

- California Health & Safety Code Section 13001,

Every person is guilty of a misdemeanor who, through careless or negligent action, throws or places any lighted cigarette, cigar, ashes, or other flaming or glowing substance, or any substance or thing which may cause a fire, in any place where it may directly or indirectly start a fire, or who uses or operates a welding torch, tar pot or any other device which may cause a fire, who does not clear the inflammable material surrounding the operation or take such other reasonable precautions necessary to insure against the starting and spreading of fire.

PG&E showed careless or negligent action by not taking the prior history and risks associated with their electrical equipment in the Geysers and by not taking reasonable precautions to remove or prevent an equipment failure which caused the Kincade Fire which burned 77,758 acres and burned three hundred seventy-four inhabited structures.

- California Public Resources Code Section 4421

A person shall not set fire or cause fire to be set to any forest, brush, or other flammable material which is on any land that is not his own, or under his legal control, without the permission of the owner, lessee, or agent of the owner or lessee of the land.

A catastrophic failure occurred on October 23, 2019 to PG&E Electrical Transmission Line identified as Geysers #9 – Lakeville at Tower 1-6 41129171 (001-006) The failure caused the ignition of the Kincade Fire which burned the properties of land owners other than PG&E.

I reserve the right to re-examine my hypothesis and conclusion to the cause of this fire pending the discovery of additional information, evidence, and statements which were not available to me at the time of writing this report. The discovery of additional information, evidence, and statements could amend or reinforce my opinions and cause conclusions of this report.

End of report.

 7/16/2020

Fire Captain Specialist Gary Uboldi

CAL FIRE

Sonoma-Lake-Napa Unit

10 - ATTACHMENTS:

- 1 CAL FIRE FC34 Dispatch Action Report
- 2 Fire Perimeter Maps
- 3.1 Weather
- 3.2 Hawkeye RAWS Info & Data
- 4.1 Photo catalog Disc 1 UBOLDI
- 4.2 Photo Catalog Disc 2 UBOLDI
- 4.3 Photo Catalog Cell Phone UBOLDI
- 5.1 LIDAR 2019-11-07_draft Ledger_01
- 5.2 LIDAR 2019-11-07_draft Ledger_02
- 6.1 CAL FIRE LE71 Supplementary Report LAIRD
- 6.2A CAL FIRE LE71 Supplementary Report ZIMMERMAKER
- 6.2B Photo Catalog ZIMMERMAKER
- 6.3 CAL FIRE LE71 Supplementary Report WOODS #1
- 6.4 CAL FIRE LE71 Supplementary Report WOODS #2
- 6.5 CAL FIRE LE71 Supplementary Report STEIS
- 7 CAL FIRE LE75e Evidence Log
- 8 CAL FIRE LE77a Confidentiality Agreements
- 9 CALPINE Log Book
- 10 CALPINE PSPS Sequential Shutdown Plan
- 11 Air Operations Summary ICS-220
- 12.1 PG&E Drone Inspection Form
- 12.2 PG&E Transmission Re-Review Inspection
- 12.3 PG&E Steel Structure Detailed Inspection Form
- 12.4 PG&E Inspection Photos
- 13 PG&E 09-04-2019 Progress Report on Implementation of De-Energization Guidelines
- 14.1 PG&E Transmission Line Map A
- 14.2 PG&E Geysers Area Map B
- 14.3 PG&E Subject Area Map C

- 15 Arborist Report – MCNEIL
- 16 Electrical Engineer Report – JHNOLT
- 17 Geysers Geothermal Field Special Report NO.20
- 18 PG&E Document Routing Request 2006-09938
- 19 Photo catalog Disc 3 UBOLDI
- 20 ANAMET Laboratory Report

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3B

THE DIXIE FIRE

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3B
THE DIXIE FIRE

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3B
THE DIXIE FIRE

A. Introduction [Andrew Paul Abranches]

This chapter sets forth Pacific Gas and Electric Company's (PG&E) testimony regarding the 2021 Dixie Fire and PG&E's prudent operation of its system in relation to that event. The Dixie Fire ignited in the afternoon of July 13, 2021, in a remote area near PG&E's Cresta Dam in the Feather River Canyon.

The California Department of Forestry and Fire Protection (Cal Fire) issued a report concluding that the fire was attributable to PG&E's electrical equipment.¹ Specifically, the report stated that the ignition resulted from a Douglas fir tree (the Subject Tree) falling onto a PG&E 12kV distribution line called the Bucks Creek 1101 (Bucks Creek 1101 Circuit) and remaining in contact with energized conductors over a period of time. While PG&E takes issue with many of the assertions in the Dixie fire agency report, PG&E does not dispute this cause determination.

The available evidence shows that PG&E was a prudent manager of its system in relation to the ignition of the Dixie Fire. Trees along the Bucks Creek 1101 Circuit were inspected numerous times in the years prior to the Dixie Fire and the Subject Tree was not identified as a potential hazard. While post-fire examination and dissection of the tree showed an old wound at its base that likely contributed to its failure, the tree stood for years without incident, and pre-fire patrols and photographs show that the tree appeared healthy and did not have an obvious defect or significant lean.

PG&E also regularly inspected equipment on the Bucks Creek 1101 Circuit, and there were no outstanding work requests related to the subject span at the time of the fire. Cal Fire did not identify any equipment-related issues or failures associated with the Dixie Fire ignition. In early 2021, PG&E approved the Bucks Creek 1101 Circuit for system hardening—primarily undergrounding—as part of

¹ The report is referred to herein as the Dixie fire agency report and is included as Attachment 1 to this chapter of testimony.

1 a risk-informed approach to mitigate wildfire risk, and that project was in
2 progress at the time of the fire.

3 PG&E prudently operated its system in relation to the ignition of and
4 response to the fire. On the morning of July 13, 2021, PG&E learned of an
5 outage at its Cresta Dam facility, which was served by the Bucks Creek 1101
6 Circuit. Around the same time that morning, PG&E's distribution control center
7 received indication of a fault on the Bucks Creek 1101 Circuit, followed
8 immediately by confirmation that the circuit had returned to normal. PG&E
9 personnel responded to these events diligently and consistent with PG&E's
10 procedures.

11 The distribution operator monitoring electrical activity on the circuit that
12 morning dispatched a distribution troubleshooter to investigate the outage. The
13 distribution operator evaluated available electrical information and found no
14 anomaly indicative of an ongoing ground fault or other safety hazard. The
15 troubleshooter traveled to Cresta Dam to investigate the outage and inspected
16 the Bucks Creek 1101 Circuit from the dam, observing that at least one of the
17 upstream fuses had operated, which explained the outage. He saw no
18 indication of a wire down, a tree on the line, or a fire. Overcoming significant
19 access challenges, the PG&E troubleshooter was able to reach the fuses late in
20 the afternoon, at which point he observed the Subject Tree on the line and the
21 fire. The troubleshooter took immediate action to de-energize the line by
22 opening the third fuse, and he fought the fire on his own before firefighters
23 arrived at the scene.

24 PG&E's system protection operated as expected in response to events on
25 the day of the ignition. When the Subject Tree first fell on the line, it created a
26 phase-to-phase fault involving two of the three conductors, and fuses just
27 upstream of the origin area operated quickly to interrupt the fault and de-
28 energize those two conductors. Because the third phase was not involved in the
29 fault, its fuse did not operate, and this conductor remained energized and in
30 contact with the tree. This contact resulted in a high-impedance (low current)
31 ground fault that appeared consistent with normal load and was therefore not
32 detected.

33 This chapter also addresses the alleged violations identified by the
34 Commission's Safety and Enforcement Division (SED) in connection with its

1 investigation of the Dixie Fire. For the reasons described below, SED's alleged
2 violations do not create "serious doubt" regarding PG&E's prudence.

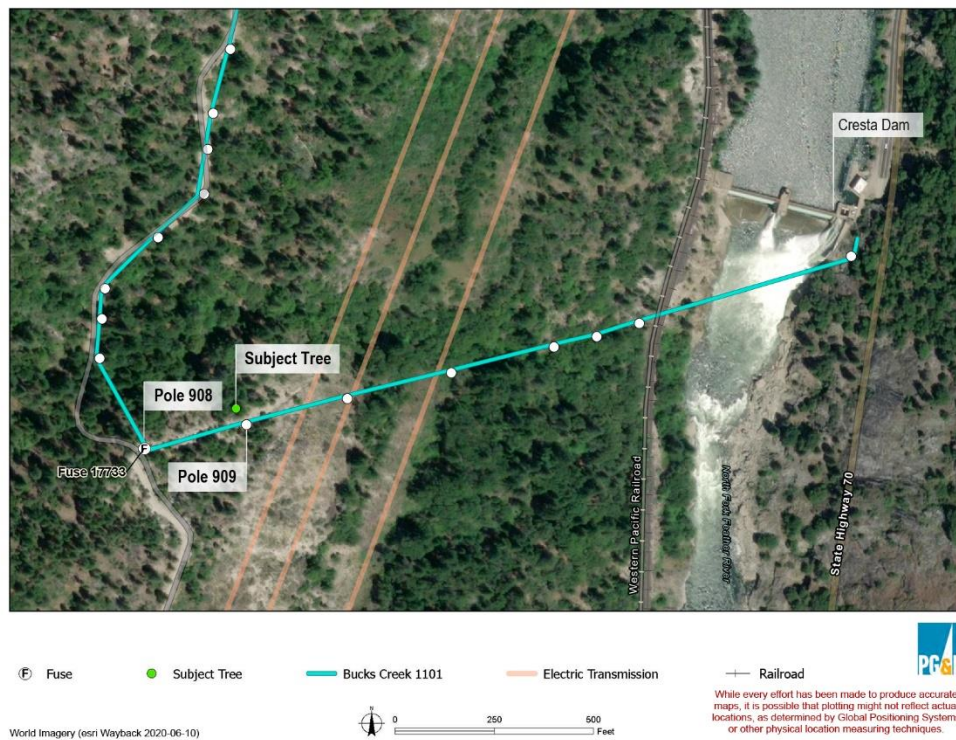
3 **B. The Dixie Fire [Carrell James Gill; Erik Christiansen]**

4 The Dixie Fire ignited in the afternoon of July 13, 2021, in a remote area
5 above the Cresta Dam in Plumas County. The ignition occurred as a result of
6 the Subject Tree falling onto the Bucks Creek 1101 Circuit. The Dixie Fire
7 ultimately became the largest single-origin wildfire in California history, burning
8 approximately 963,309 acres. The Dixie Fire was active for over three months
9 before it was fully contained on October 25, 2021.

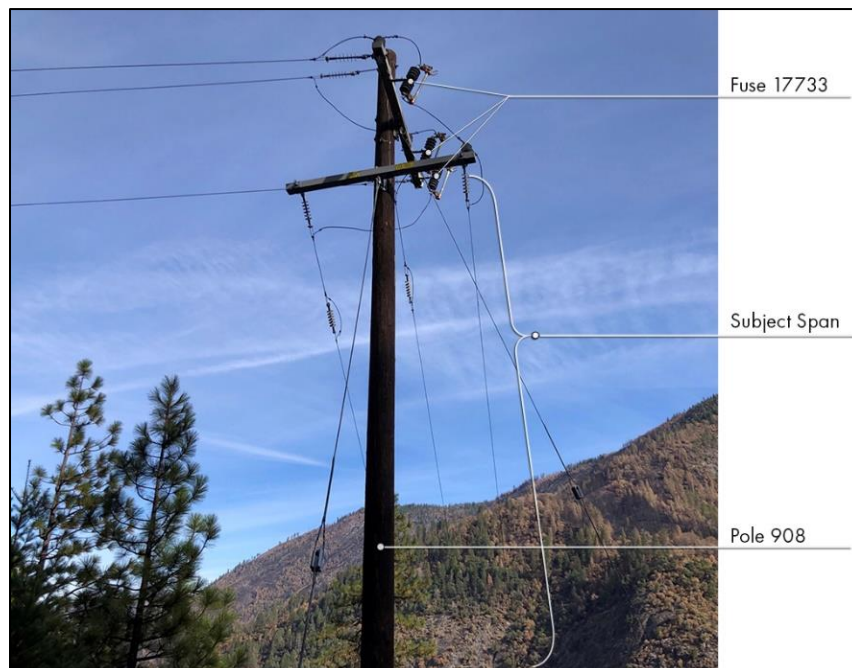
10 **1. PG&E's Facilities Related to the Dixie Fire [Carrell James Gill]**

11 The PG&E facilities at issue are part of the Bucks Creek 1101 Circuit, at
12 the span between pole numbers 100403908 (Pole 908) and 100403909
13 (Pole 909). This span (the Subject Span) is near the end of the circuit and
14 located on a steep slope that runs down from a single-lane dirt road to the
15 Cresta Dam in the Feather River Canyon. This area was designated as a
16 Tier 2 High Fire Threat District (HFTD) in the Commission's final 2018 Fire
17 Threat Map, though the area had not previously been designated as high
18 fire risk under the earlier interim fire threat map. The figures below show the
19 specific facilities at Poles 908 and 909 as of July 13, 2021, as well as an
20 aerial view of the Subject Span.

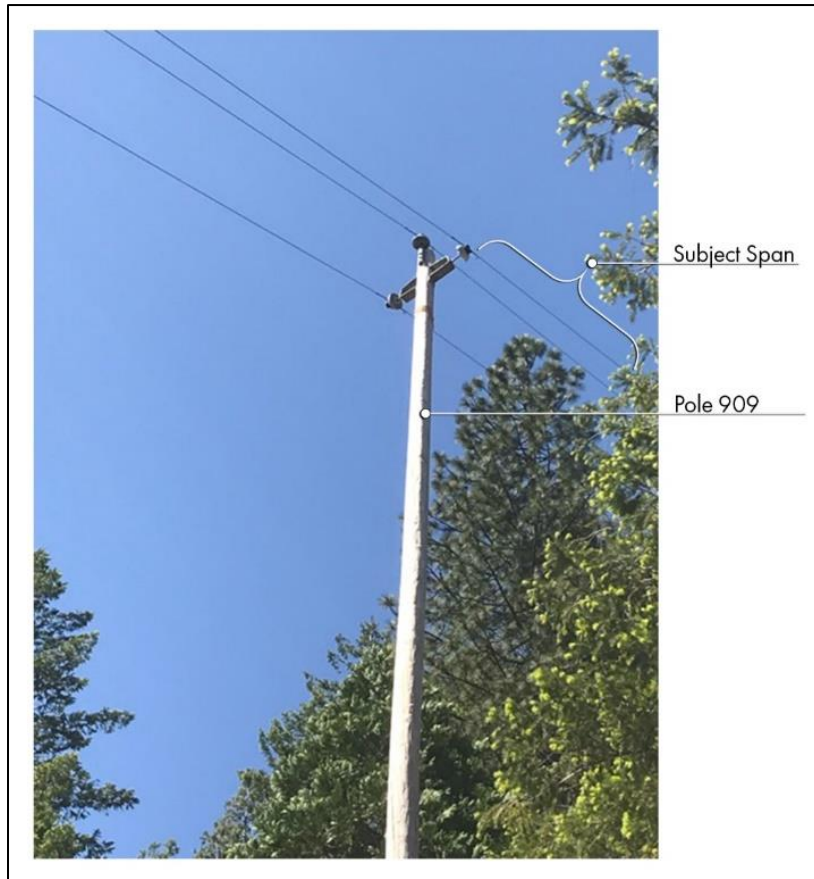
**FIGURE 3B-1
SUBJECT SPAN ON BUCKS CREEK 1101 CIRCUIT**



**FIGURE 3B-2
POLE 908**



**FIGURE 3B-3
POLE 909**



2. The Dixie Fire Resulted from the Subject Tree Falling on the Bucks Creek 1101 Circuit [Erik Christiansen]

I was engaged by PG&E after the Dixie Fire to perform an independent evaluation of the origin and cause of the fire. The Dixie Fire ignited on July 13, 2021, in Plumas County, in a remote area of the Feather River Canyon near Cresta Dam, a PG&E hydroelectric generation facility. I understand that the fire was first observed by approximately 4:50 p.m. by a PG&E troubleshooter, who arrived at the area of origin to investigate the source of an outage at Cresta Dam that had occurred earlier in the day. Following ignition, the fire ultimately burned for more than 100 days and

1 affected Plumas, Butte, Tehama, Lassen, and Shasta Counties before it was
2 fully contained on October 25, 2021.²

3 Cal Fire conducted an investigation into the origin and cause of the Dixie
4 Fire. Cal Fire concluded that the fire was caused by the Subject Tree falling
5 onto the Bucks Creek 1101 Circuit early in the morning of July 13, 2021.

6 Cal Fire's expert examined the electrical equipment and did not identify any
7 equipment-related issues or failures associated with the ignition. Based on
8 my review of the physical evidence, electrical data, and observations from
9 my site visits in July 2021, I agree that the probable cause of the Dixie Fire
10 was a sustained high-impedance fault condition resulting from tree contact
11 with the Bucks Creek 1101 Circuit.³

12 The Subject Tree was located north of the circuit, which runs nominally
13 east-west between Pole 908 (uphill) and Pole 909 (downhill) at that location.
14 The Subject Tree fell to the south, and the physical evidence indicates that it
15 initially landed on the circuit approximately thirty to thirty-five feet west
16 (uphill) of Pole 909. As shown in Figure 3B-4, a close-up photograph taken
17 after the incident, the center and south conductors in this span (associated
18 with the B and C phases in electrical records) were both caught underneath
19 the same branch of the Subject Tree, which pushed these two conductors
20 into close enough proximity to create a phase-to-phase fault of sufficient
21 magnitude to operate the B and C phase fuses mounted on Pole 908. The
22 north (A phase) conductor was not involved in the phase-to-phase fault
23 because it was caught underneath a lower branch on the tree, which
24 separated it from the two other conductors. Therefore, the A phase did not
25 experience elevated fault current, and its fuse did not operate.

2 The Dixie Fire later merged with the Fly Fire, which ignited on July 22, 2021, near Quincy in Plumas County, California. I visited the origin area of the Fly Fire on August 5, 2021, and understand the Fly Fire resulted from a white fir tree uprooting and falling onto a PG&E distribution line referred to as the Gansner 1101 circuit.

3 While I agree with Cal Fire's ultimate origin-and-cause conclusion, I do not otherwise adopt or affirm statements or allegations set forth in the Dixie fire agency report.

FIGURE 3B-4
SUBJECT TREE ON CONDUCTORS AT POLE 909⁴



1 After its initial impact, the Subject Tree slid downhill along the top of the
2 conductors in the Subject Span. The Subject Tree stopped when it reached
3 Pole 909, with the weight of the tree primarily supported by the north
4 (A phase) conductor. The A phase remained energized and in contact with
5 the Subject Tree, resulting in a high-impedance fault, i.e., a fault in which a
6 small amount of electricity flowed through the tree to the ground. Over the
7 course of several hours, this low and undetected flow of electricity caused
8 localized heating that resulted in charring, smoldering, and burning on the
9 surface of the Subject Tree where it was in contact with the north conductor.
10 Examination of the tree trunk after the incident showed significant localized
11 charring at this location. Burning material from this area likely fell to the
12 ground and landed in a receptive fuel bed, resulting in the fire's ignition.

⁴ This photograph has been enhanced to improve visibility of the Subject Tree and conductors.

1 **C. PG&E Regularly Performed Vegetation Management [Angela Sanford]**

2 As described in detail in Chapter 2: Prudence of Operations, PG&E had
3 comprehensive vegetation management programs that it implemented
4 throughout its approximately 70,000 square mile service area to reduce the risk
5 of outages and ignitions from vegetation in proximity to electrical infrastructure.

6 **1. Vegetation Management Inspections Did Not Identify the Subject Tree**
7 **as a Potential Hazard**

8 The Bucks Creek 1101 Circuit was subject to numerous vegetation
9 management inspections in the years preceding the Dixie Fire, as shown in
10 Table 3B-1 below. Specifically, between 2016 and 2021, PG&E's vegetation
11 management contractors performed at least nine patrols along the Bucks
12 Creek 1101 Circuit and identified hundreds of trees that were subsequently
13 pruned, removed, or otherwise worked.⁵ The Subject Tree was not identified for
14 work during any of PG&E's vegetation management patrols.

15 The Bucks Creek 1101 Circuit was prioritized for work pursuant to PG&E's
16 Enhanced Vegetation Management (EVM) program; at the time of the fire, the
17 line had not yet been planned for EVM work in a specific year based on its EVM
18 prioritization list ranking under PG&E's 2021 Wildfire Distribution Risk Model.⁶
19 Based on the circuit's ranking and the targeted pace of EVM work during this
20 period (approximately 1,800 miles per year), PG&E anticipated scheduling the
21 Bucks Creek 1101 Circuit for EVM work in the 2024 to 2026 time frame.

5 The Bucks Creek 1101 Circuit was significantly shortened after it was damaged in the 2018 Camp Fire. As a result, certain trees identified for work during the 2018 Routine Patrol ultimately did not need to be worked because they were no longer in proximity to electrical facilities following the circuit reconfiguration.

6 The Bucks Creek 1101 Circuit was ranked 568 out of 3,074 circuit sections in the version of the Vegetation Tree Weighted Prioritization Ranking described in PG&E's Enhanced Oversight and Enforcement Process Corrective Action Plan, filed May 6, 2021.

**TABLE 3B-1
VEGETATION MANAGEMENT INSPECTIONS ON BUCKS CREEK 1101 CIRCUIT**

Inspection	Date Completed
CEMA Aerial Patrol	2016
Routine Patrol	2016
Routine Patrol	2017 ^(a)
Routine Patrol	2018
AWRR Patrol	2018 ^(b)
Routine Patrol	2019
CEMA Aerial Patrol	2020
Routine Patrol	2020
CEMA Aerial Patrol	2021

-
- (a) The 2017 Routine Patrol was partially completed due to access issues, which prevented the Subject Span from being patrolled. Because the Routine Patrol was not completed, there was no CEMA patrol that year.
- (b) The 2018 AWRR patrol, which replaced the CEMA patrol that year, may have focused on Tier 3 areas, in which case it would not have included the Subject Span.

2. Prior to the Dixie Fire, the Subject Tree Looked Like a Healthy, Typical Tree [Galen Wright]

I was engaged by PG&E after the Dixie Fire to perform an independent evaluation of the Subject Tree. The Subject Tree was a Douglas fir that was over 65 feet tall and its base was located roughly 40 feet from the powerlines.

Post-failure examination of the Subject Tree showed an old wound at its base from prior damage that likely contributed to its failure. But the proximate cause of the Subject Tree's failure may have been a *different* tree that failed and contacted the Subject Tree. This second tree—a ponderosa pine—was located uphill from the Subject Tree and even farther from the powerline right-of-way. As acknowledged by Cal Fire's retained arborist,⁷ the second tree failed at around the same time as the Subject Tree and likely contacted the Subject Tree when it did, which in turn may have caused the Subject Tree to fail and contact the line. The second tree did not pose a

⁷ Cal Fire's retained arborist prepared Attachment W to the Dixie fire agency report, which is included as Attachment 2 to this chapter of testimony.

1 strike risk for PG&E's facilities given its distance from the Bucks Creek 1101
2 Circuit, and PG&E was under no obligation to inspect it.

3 Based on my training and experience and my review and examination of
4 the available evidence,⁸ I conclude that the wound at the base of the
5 Subject Tree was likely not visible during the vegetation management
6 patrols performed in the years preceding the Dixie Fire. And even if the
7 wound had been visible during prior inspections, it likely would not have
8 appeared to be a hazard that required removing the Subject Tree. Cal Fire's
9 arborist acknowledged that the Subject Tree was standing vertical without a
10 lean and appeared alive and vital at the time of failure.

11 Utility vegetation management inspectors generally assess trees from
12 the utility's right-of-way based on conditions that are visible from that
13 vantage point, referred to in the industry as a "Level 1" inspection. If, from
14 the right-of-way, they see indicators of a potential problem requiring closer
15 inspection, they would conduct a "Level 2" inspection, which requires a 360-
16 degree inspection of the tree. Pre-fire photographs show that the Subject
17 Tree appeared to be a healthy tree typical of other trees in this stand, with
18 no obvious indicators of significant defects—such as insect infestation,
19 disease, or decay—that would trigger a Level 2 inspection. The tree's
20 shape and foliage color were normal and typical for Douglas firs in this area,
21 and the live crown ratio (a key health indicator) was approximately 95%—
22 i.e., there were live branches along nearly the entire length of the tree's
23 height—a positive sign.⁹ These indicators of a healthy tree are visible in
24 Figure 3B-5 and Figure 3B-6, which are photographs of the Subject Tree
25 taken during PG&E patrols and inspections before the Dixie Fire.

⁸ For my analysis, I reviewed photographs of the Subject Tree from before and after the fire, examined the stump of the Subject Tree and portions of the tree remaining in the Cal Fire warehouse after the destructive testing done at the request of Cal Fire's retained arborist, reviewed the Dixie fire agency report and relevant attachments (including the attachment prepared by Cal Fire's retained arborist), and reviewed statements of the trained inspectors who performed patrols in the area of origin.

⁹ The Live Crown Ratio is the measure of the length of the live foliage compared to the overall height of the tree. Trees with a live crown ratio of less than 30 percent are not expected to be long-term trees.

FIGURE 3B-5
AUGUST 2019 PHOTOGRAPH SHOWING THE SUBJECT TREE

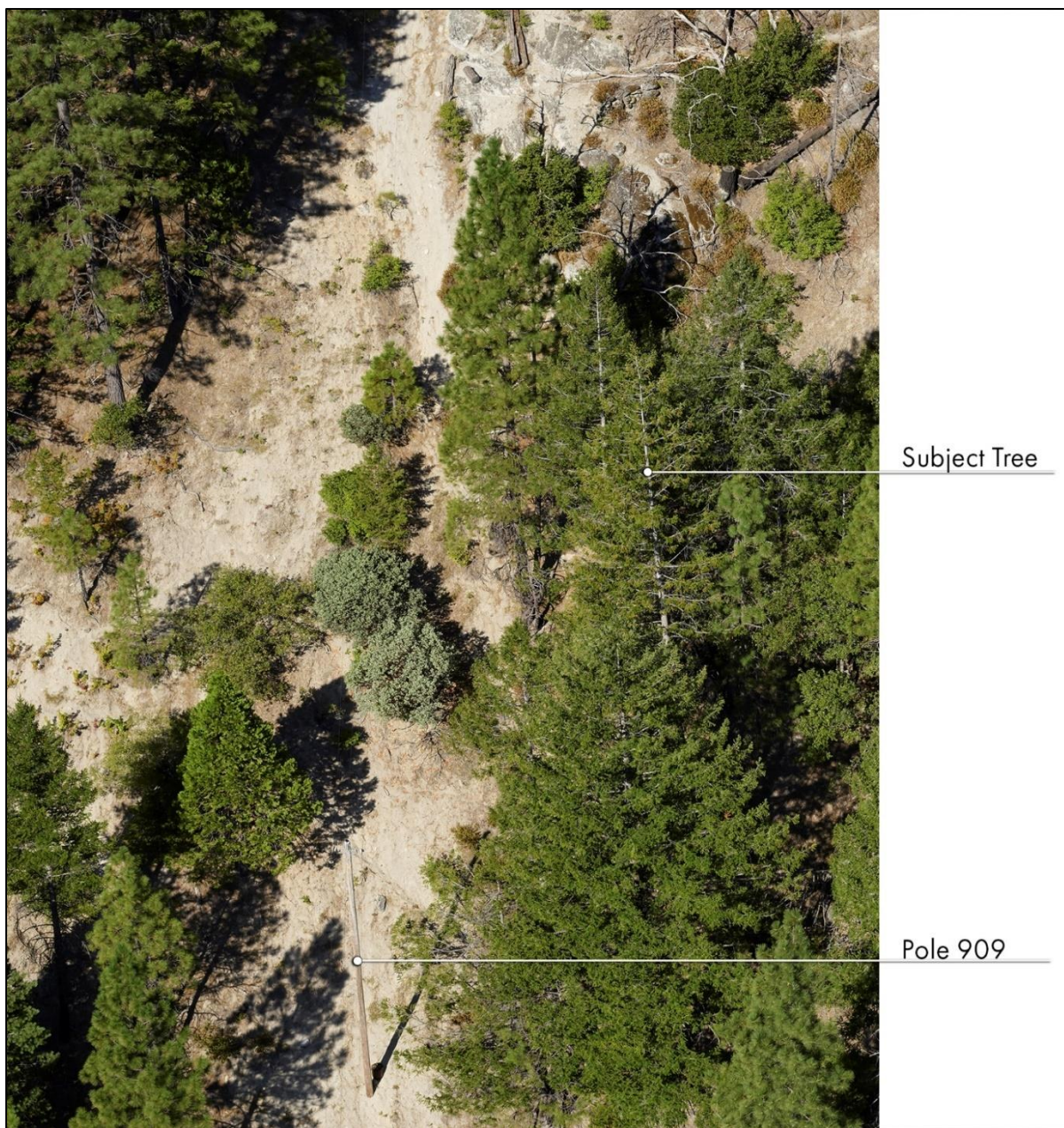
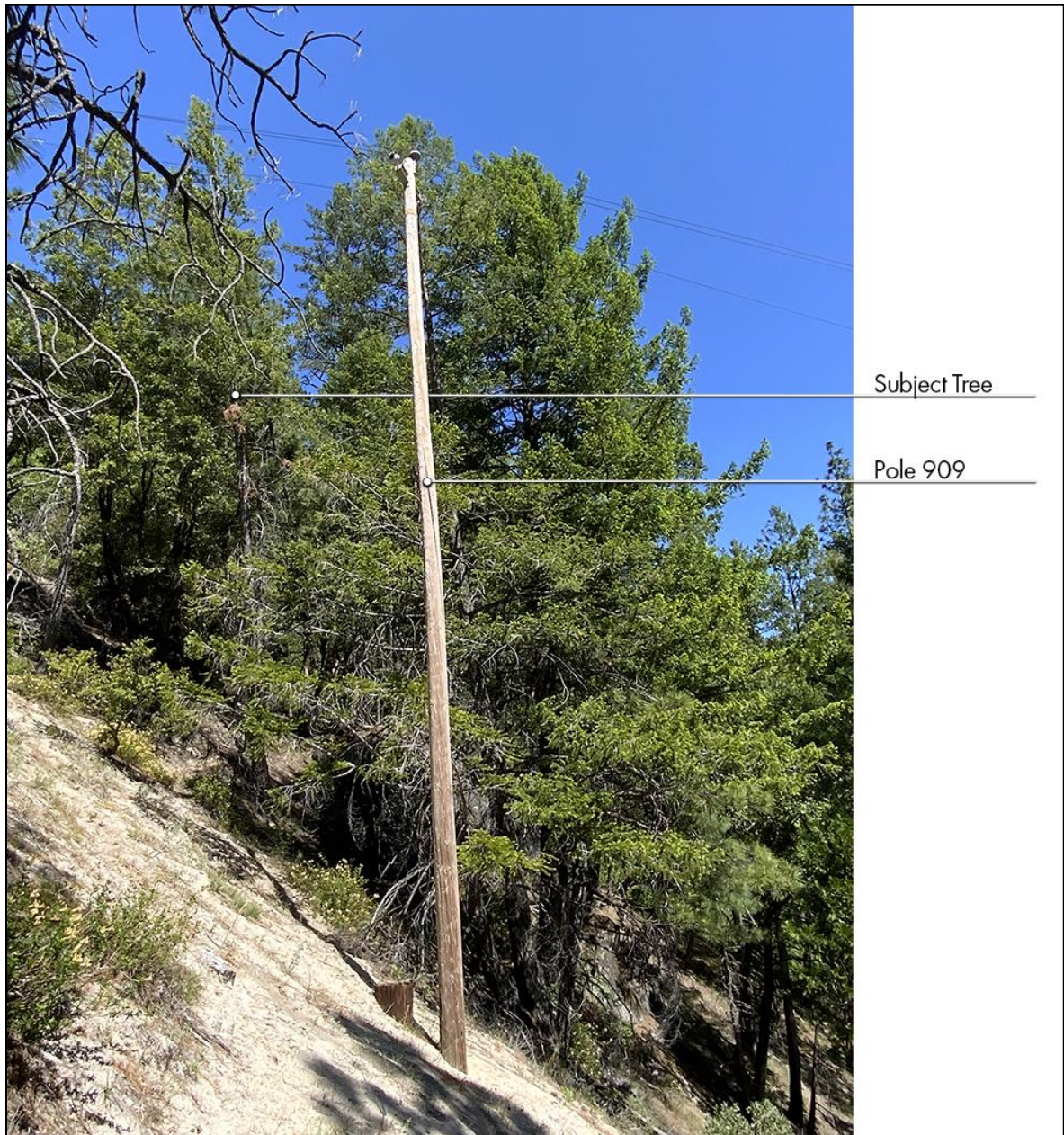


FIGURE 3B-6
MAY 2021 PHOTOGRAPH FROM EQUIPMENT INSPECTION SHOWING THE SUBJECT TREE IN
THE BACKGROUND



- 1 When the Subject Tree failed on the day of the fire, the lower portion of
- 2 the tree's stem (i.e., trunk) separated from the tree's base, as shown in
- 3 Figure 3B-7 below; it did not uproot. Both the stump and lower portion of the
- 4 trunk were heavily burned by the fire.

1 In light of the fire damage to the Subject Tree and the surrounding area,
2 it is not possible to reach a definitive conclusion based on post-failure
3 examination and dissection of the Subject Tree that any pre-failure damage
4 to the tree would have been visible from a Level 1 inspection. However, the
5 available pre-fire evidence indicates that the wound was *not visible* during a
6 Level 1 inspection.

7 Based on my review of a photograph taken less than two months before
8 the fire (see Figure 3B-6), it appears that several factors obscured the
9 Subject Tree's base, including roots from an uprooted tree, lower foliage on
10 the Subject Tree and adjacent trees, and nearby lower vegetation.

11 The photograph shows that the base of the Subject Tree was also
12 obscured by shadows depending on the time of day and year. I believe
13 those shadows likely would have been longer, and thus further obscured the
14 view of the Subject Tree's base, during the most recent routine patrol in
15 December 2020 given the time of year of that inspection. Based on my
16 examination of the evidence and my training and experience, I also believe
17 the wound was partially covered in bark, which would have made it appear
18 smaller and closer in color to the healthy bark on the tree.

19 While Cal Fire's retained arborist opined that the old wound on the
20 Subject Tree would have been visible because it was on the side of the tree
21 facing toward the line, it does not appear he conducted any meaningful
22 investigation into the pre-fire conditions that would have obscured the view
23 of the base of the tree.¹⁰ The arborist inspected the area only *after* the
24 Subject Tree failed and broke above the stump, and after the Subject Tree
25 and the surrounding area, including vegetation that may have obscured the
26 wound, were significantly damaged or even destroyed by the fire, as shown
27 by Figure 3B-7.

¹⁰ It is my understanding that Cal Fire's arborist did not review pre-fire photographs of the Subject Tree and he did not cite such materials in his attachment to the Dixie fire agency report, which would affect the accuracy of his opinions and conclusions reflected therein. For instance, while Cal Fire's retained arborist stated he saw no evidence of low vegetation that may have impeded visibility of the base of the tree, that is inconsistent with pre-fire photographs showing shrubs and other low vegetation in the area. See Figure 3B-6.

FIGURE 3B-7
PHOTOGRAPH SHOWING POST-FIRE CONDITION OF
SUBJECT TREE STUMP AND LOWER TRUNK



1 The remnants of the Subject Tree were also significantly altered after
2 the fire. Before PG&E was permitted to examine the Subject Tree after its
3 failure, Cal Fire’s arborist asked Cal Fire to remove the material portions of
4 the tree from the origin area and cut the tree into numerous small pieces.¹¹
5 The arborist’s destructive testing made it impossible to evaluate the
6 condition of the Subject Tree as it would have been seen by an inspector in
7 the field. Dissection also exposed interior sections of the Subject Tree that
8 would not have been visible to a utility inspector. Cal Fire’s arborist
9 nonetheless relied on this compromised evidence to opine that the wound at
10 the base of the tree would have been visible to an inspector.

11 This speculative opinion of Cal Fire’s retained arborist that the wound
12 would have been visible to a utility inspector before the fire is inconsistent

11 This destructive testing was done without notice to PG&E and resulted in key portions of the Subject Tree being cut into nearly three dozen smaller pieces. The remaining portions of the tree were stored in a warehouse that was not climate controlled and allowed mold to grow on the tree, which was visible during an evidence examination that took place in October 2021.

1 with the factual record of the Subject Tree's pre-fire condition. Numerous
2 trained vegetation management inspectors inspected this area in the years
3 before the fire, and not one of them identified the tree as a hazard. The
4 speculation of one arborist not certified in utility inspections—and who never
5 saw the Subject Tree before the fire and did not meaningfully investigate
6 pre-fire conditions—does not outweigh the consistent findings of the
7 qualified personnel who did.

8 The Subject Span was inspected by PG&E's qualified contractors on
9 two occasions in the 12 months preceding the Dixie Fire. The Subject Tree
10 is located on a steep slope where the Bucks Creek 1101 Circuit runs from a
11 single-lane unpaved road downhill toward Cresta Dam at the bottom.¹² The
12 trained inspector who performed the routine patrol in early December 2020
13 confirmed that he hiked down the slope along the right-of-way for at least
14 one span—reaching the area where the Subject Tree was located to do a
15 visual examination—before encountering terrain that was too steep and
16 unstable to continue further.¹³ He also observed thick undergrowth in the
17 general area. This inspector did not identify the Subject Tree or other trees
18 located along the Subject Span for work. The Subject Span was also
19 inspected as part of an aerial patrol of the Bucks Creek 1101 Circuit in
20 January 2021.

21 I understand that, after the fire, the vegetation management inspectors
22 who performed these inspections in late 2020 and early 2021 reviewed pre-
23 fire photographs of the Subject Tree including those shown in Figure 3B-5
24 and Figure 3B-6 above and stated that, while they did not recall this specific
25 tree, they would not have marked the Subject Tree for work given its healthy
26 appearance, green canopy, and lack of any concerning lean. From the
27 available evidence, I have not seen anything that would cause me to
28 question or otherwise second-guess the conclusions of PG&E's trained
29 inspectors that were based on the actual, pre-fire conditions in the field.

¹² I measured a 62 percent grade for this slope.

¹³ I understand that, due to the safety risks posed by the terrain, the inspector conducted a visual inspection of the remainder of the trees downslope of the Subject Span using a Rangefinder, which is acceptable industry practice.

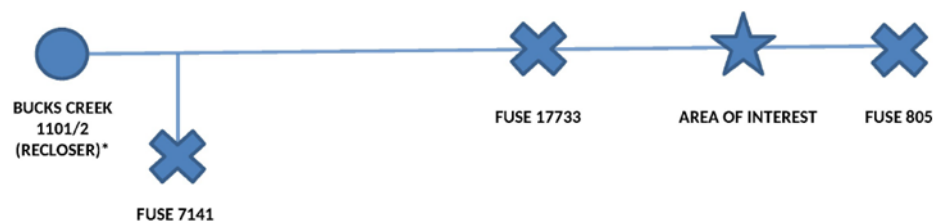
D. PG&E Prudently Operated Its System in Connection with the Dixie Fire [Davis Erwin; Roderick Robinson]

On the day of the fire, PG&E's protection devices operated as expected to detect and respond to faults on the Bucks Creek 1101 Circuit, and PG&E appropriately responded to events on its system consistent with its operational protocols.

1. PG&E's System Protection Operated as Expected in Response to the Electrical Faults Caused by the Subject Tree [Davis Erwin]

PG&E's system protection on the Bucks Creek 1101 Circuit operated as expected on July 13, 2021. Figure 3B-8 shows a simple single-line diagram of system protection on the Bucks Creek 1101 Circuit, with the "Area of Interest" showing the relative location of the Subject Span.

**FIGURE 3B-8
SINGLE-LINE DIAGRAM OF SYSTEM PROTECTION ON THE BUCKS CREEK 1101 CIRCUIT**



The line recloser for the Bucks Creek 1101 Circuit located at the Bucks Creek substation served as a protective device for the entire circuit in conjunction with the installed fuse protection. Under the settings in place on July 13, 2021, the line recloser was set to operate and de-energize the line if it detected any one of three preset fault conditions, none of which occurred on the day of the ignition. The line recloser would operate: (1) if it detected phase current of 100 amps or more sufficient to meet the applicable Time-Current Characteristic Curve (TCC);¹⁴ (2) if it detected ground current of 50 amps or more sufficient to meet the applicable TCC; or (3) under the "Sensitive Earth Fault" setting, if it detected ground current that remained at

¹⁴ Under a TCC, the greater the fault current in excess of the minimum trip setting, the quicker the recloser would operate to de-energize the line.

1 20 amps or more continuously for a period of 20 seconds. On May 6, 2021,
2 PG&E had disabled the automatic reclosing functionality of the Bucks Creek
3 1101 Circuit recloser as a wildfire risk mitigation measure, and it remained
4 disabled on the day the Dixie Fire ignited. Fuse 17733 was the closest
5 upstream protection to the Subject Span; it was located at Pole 908, the
6 uphill pole of the Subject Span. Fuse 17733 had a 10-amp rating, which
7 was consistent with proper and conventional coordination of protective
8 devices, where downstream protective devices typically operate first to
9 quickly respond to and isolate fault conditions while limiting the customer
10 impact of outages. This protection system was reasonable, appropriate, and
11 consistent with industry standards.

12 Based on analysis of electrical event records downloaded after the fire,
13 the line recloser for the Bucks Creek 1101 Circuit recorded a transient
14 phase-to-phase fault involving the B and C phase conductors at
15 approximately 6:48 a.m. on July 13, 2021.¹⁵ Because the phase-to-phase
16 fault resulted in fault current well in excess of 10 amps on the B and C
17 phases, the fuses on those two phases of Fuse 17733 responded to the
18 fault by operating to de-energize those phases. Because the A-phase
19 conductor was not involved in the phase-to-phase fault and did not
20 experience current in excess of 10 amps, the fuse on that phase did not
21 operate, and the A phase remained energized and in contact with the
22 Subject Tree.¹⁶

23 When the Subject Tree remained in contact with the A phase of the
24 Bucks Creek 1101 Circuit, it created a high-impedance fault. While most
25 faults generate excessive current that is high in amplitude and therefore
26 easily detectable by protective devices, high-impedance faults are difficult

15 The line recloser was programmed to record oscillography when it detected phase or ground current in excess of its “minimum to trip” thresholds, whether or not the current lasted long enough to cause the recloser to operate. After the fire, PG&E downloaded electrical event records from the line recloser, including the event associated with this B-phase-to-C-phase fault.

16 The transient phase-to-phase fault that occurred at approximately 6:48 a.m. did not cause the line recloser to operate because the downstream fuses operated as intended to interrupt the fault current. Post-incident analysis of the recorded oscillography showed that the phase-to-phase fault lasted less than 4/100ths of a second (.0395 seconds). The line recloser did not record any other instances of current in excess of minimum-to-trip thresholds on any of the three phases on July 13, 2021.

for protection systems to detect. They occur when an energized primary conductor comes into contact with a quasi-insulating object such as a tree and the resulting line-to-ground fault does not draw significant fault current. High-impedance faults present unique system protection challenges because they are difficult to differentiate from operating load. (In other words, high-impedance fault current is not detectably higher than normal load current.) This was the case with the minimal current generated by the high-impedance fault caused by the Subject Tree remaining in contact with the Subject Span on July 13, 2021.¹⁷ Since the Dixie Fire, PG&E has undertaken several initiatives to address high-impedance faults, including installing new recloser controllers that enhance detection of low-current, line-to-ground faults and developing its Enhanced Powerline Safety Settings (EPSS).

2. PG&E Followed Its Response and PSPS Protocols in Connection with the Dixie Fire [Roderick Robinson; Shawn Holder]

The Dixie Fire ignited on a blue-sky day. PG&E received notice of an outage at its Cresta Dam facility at approximately 6:48 a.m. on July 13, 2021, and took reasonable and appropriate steps to respond to that outage, consistent with its procedures. As described in detail below, the PG&E troubleshooter who was dispatched overcame significant access challenges that impeded and delayed the investigation of the outage during the course of the day. There was no indication of an emergency or a continuing hazard on the line until the PG&E troubleshooter was able to access the site late that afternoon, after the fire had started. At that time, the troubleshooter took immediate steps to ensure the line was de-energized, radioed to report the fire, and even attempted to fight the fire by himself before fire suppression resources arrived on scene.

The conditions on July 13, 2021, did not meet, or even approach, PG&E's criteria for implementation of a Public Safety Power Shutoff (PSPS)

¹⁷ PG&E's load data for the Bucks Creek 1101 Circuit shows a maximum recorded current on July 13, 2021, of 2.5 amps on any phase after the B-phase-to-C-phase fault at approximately 6:48 a.m. And the calculated potential ground current values during this same period were between 0 and 1.6 amps. These currents were well below the phase and ground current thresholds for event pickup or recloser operation for the line recloser.

1 event. A PSPS event was not considered given there was not a significant
2 wind event forecast, there were no Red Flag Warnings in effect, and no
3 areas in PG&E's service area were forecast to meet PSPS criteria.

4 With respect to the outage on the Bucks Creek 1101 Circuit that day,
5 multiple PG&E employees from different units within the company
6 responded and coordinated their actions to investigate and monitor the
7 potential source of trouble. At approximately 6:48 a.m., the SCADA system
8 transmitted an alarm that the current on the Bucks Creek 1101 Circuit had
9 momentarily exceeded the minimum trip threshold for the line recloser. The
10 alarm did not advise the distribution operators what type of fault (ground or
11 phase) triggered the alarm, and it was immediately followed by a notification
12 that the current had returned to normal. The alarm was assigned a P04
13 (Priority 4) priority level, requiring that a distribution operator analyze the
14 alarm based on the known circumstances (which was performed) without
15 any other specific action required in response.

16 At about the same time, PG&E's Hydroelectric Rock Creek Switching
17 Center received an automatic notification that the Cresta Dam, a PG&E-
18 operated hydroelectric generation facility, had lost power. The notification
19 indicated that a standby generator was supplying power to the Cresta Dam.
20 In response to the notification, the hydro operator monitoring the facility
21 dispatched a roving operator to investigate the alarm and check the Cresta
22 Dam. PG&E's Cresta Dam facility is unmanned and did not have an
23 operator onsite. At approximately 7:21 a.m., the hydro operator called a
24 distribution operator at PG&E's Northern Distribution Control Center (NDCC)
25 to report that Cresta Dam had lost power and that a roving operator was en
26 route.¹⁸ In response to the outage report, the distribution operator carefully
27 analyzed the conditions on the line. This involved a thorough review of
28 SCADA data and PG&E's Outage Management Tool, which confirmed that
29 the circuit breaker was closed, the electrical load was stable and balanced

¹⁸ PG&E's hydroelectric operations and distribution control center are housed in separate lines of business within the company.

1 across all three phases, and there was no excessive ground current.¹⁹ The
2 distribution operator did not see a reason to de-energize the entire circuit
3 based on this review, and he was not otherwise aware of a safety hazard
4 that would have caused him to de-energize the circuit. System operators
5 also continued to monitor the phase load and ground current for the Bucks
6 Creek 1101 Circuit during the outage response for any indication or a
7 problem.

8 At 8:52 a.m., the roving operator reported back to the hydro operator
9 that the lights were out in a tunnel near the Cresta Dam, and the Cresta
10 Dam station service was out. The roving operator subsequently reported
11 that the Bucks Creek 1101 Circuit was still supplying station service to the
12 Bucks Creek Powerhouse, which is approximately 3.7 miles northeast of
13 Cresta Dam. He did not report any safety hazard or any indication of a fire.

14 At 9:07 a.m., the hydro operator shared the roving operator's report with
15 the distribution operator, who promptly called dispatch to assign a
16 troubleshooter. The dispatcher created a Priority 1 field order or "tag," which
17 calls for a same-day response. Priority 1 was the appropriate response for a
18 non-emergency electric outage pursuant to PG&E's dispatch procedures.²⁰

19 After receiving the tag, the troubleshooter called the distribution operator
20 for further information about the outage before heading to Cresta Dam.²¹
21 The operator explained that the outage was likely due to a fuse that
22 operated, potentially at Cresta Dam (Fuse 805), or up the hill from Cresta
23 Dam (Fuse 17733). The troubleshooter and distribution operator discussed

¹⁹ If a fault is not sufficient in amplitude or duration to trigger operation of a protection device, a distribution operator can assess the potential for a ground fault by comparing the ground current and the loads on each phase in real time with historical experience. The SED also reviewed the load data and did not identify any issues with the load. See SED Incident Investigation Report (SED Report) (Oct. 9, 2023), p. 40.

²⁰ As described in Chapter 2: Prudence of Operations, Priority 0 tags are for immediate safety issues like fire, gas leaks, downed wires, and other situations requiring an immediate response. Following the Dixie Fire, PG&E revised its procedures to target responding to all outages in HFTDs within 60 minutes when it is safe to do so.

²¹ The tag was initially assigned to a Quincy-based troubleshooter, who requested that the tag be reassigned to a Chico-based troubleshooter. The tag was subsequently reassigned to the Chico-based troubleshooter who responded to the tag. On the way to Cresta Dam, the troubleshooter addressed another Priority 1 tag that he had received prior to the Cresta Dam tag.

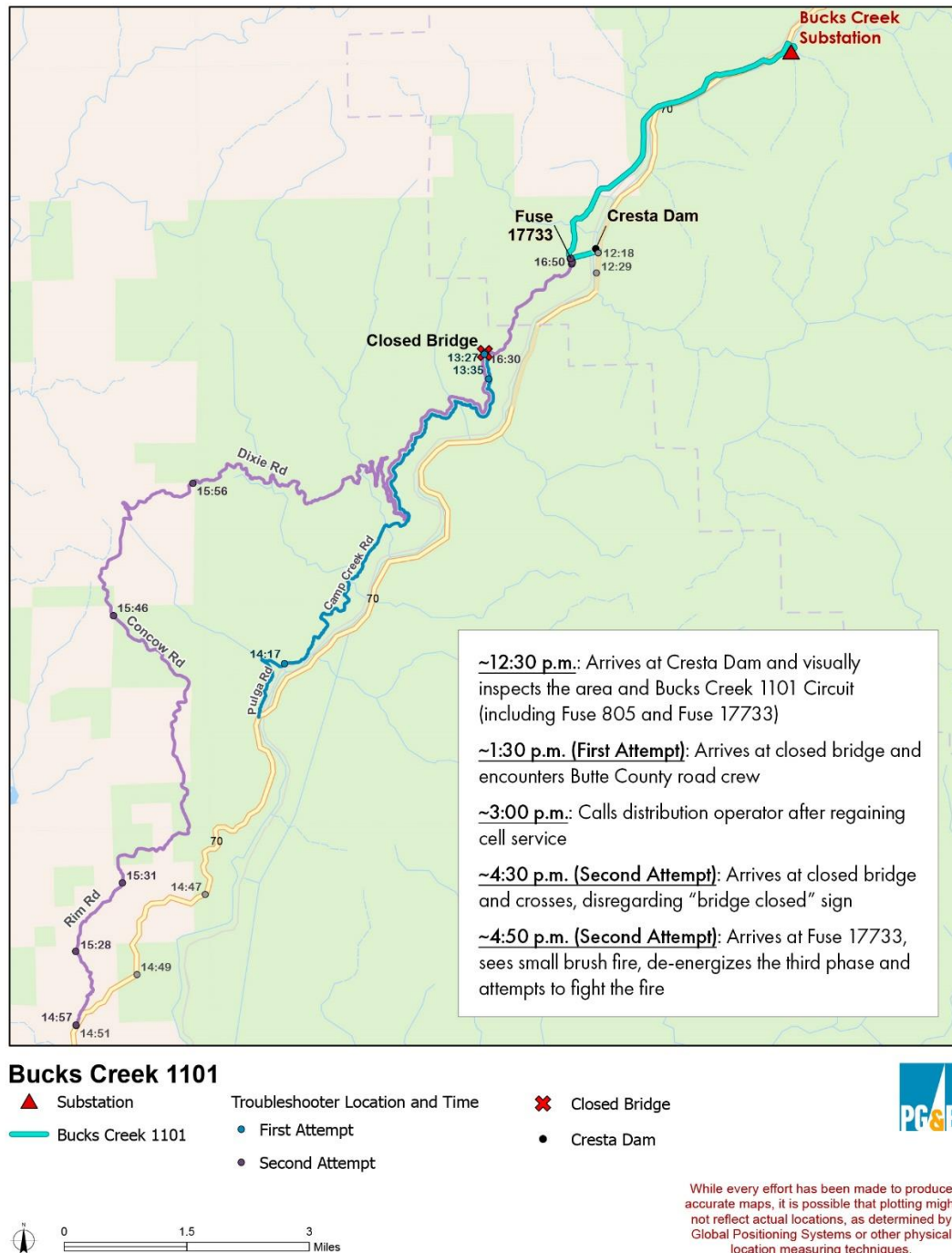
1 the difficulty of accessing Fuse 17733.²² The troubleshooter began his
2 investigation at Fuse 805 at Cresta Dam, adjacent to Highway 70.

3 The troubleshooter arrived at Cresta Dam at approximately 12:30 p.m.
4 He determined that Fuse 805 had not operated and inspected the area to
5 determine the source of the power outage. He also visually inspected the
6 circuit between Cresta Dam toward Fuse 17733 and observed that all of the
7 poles and wires appeared to be in their normal position. Looking up the line
8 with his binoculars, he saw what appeared to be at least one open fuse at
9 Fuse 17733 hanging down from Pole 908, indicating that a fuse had
10 operated.²³ The troubleshooter did not see any indications of a line down,
11 vegetation on the line, or a fire. Although the troubleshooter could look
12 across the Feather River Canyon from the Cresta Dam and use binoculars
13 to visually inspect the Bucks Creek 1101 Circuit, he had to travel a circuitous
14 route to reach Fuse 17733—driving down Highway 70 and then turning onto
15 a long, unpaved access road heading north toward the fuses. Figure 3B-9
16 shows the troubleshooter's route and progress as he investigated the
17 outage, including his initial inspection at the Cresta Dam and his attempts to
18 access Fuse 17733.
19

22 Fuse 17733 had a permanent tag in the Distribution Management System (DMS) indicating "no access."

23 When a fuse operates to shut off power, it hangs down from the "cutout" where it is installed on the pole top. The fuses at Fuse 17733 are shown in Figure 3B-2 above. From the troubleshooter's perspective at the dam, the fuses were in a line behind one another on the upper crossarm of the pole, making it difficult for him to discern whether one, two, or all three of the fuses had operated.

FIGURE 3B-9
TROUBLESHOOTER'S ROUTE TO ACCESS FUSE 17733²⁴



²⁴ The time stamps in Figure 3B-9 are based on GPS tracking data from the troubleshooter's vehicle.

1 The troubleshooter's first attempt to reach Fuse 17733 was blocked by a
2 bridge closure and slowed by an access road in poor condition. When the
3 troubleshooter reached the bridge, he was stopped by a Butte County road
4 crew performing maintenance work on the bridge. He observed that
5 portions of the bridge decking were missing, and the crew told him it would
6 be at least two hours before he could pass. He then drove back down the
7 access road to a location with cell service.

8 At approximately 3:00 p.m., the troubleshooter reached an area with cell
9 service and saw that he had received two Priority 0 emergency tags that
10 required an immediate response and were unrelated to the Cresta Dam tag.
11 He called the distribution operator working the afternoon shift and asked
12 whether he should leave the area to attend to the Priority 0 tags or stay to
13 address the Cresta Dam tag. The distribution operator explained that other
14 troubleshooters were closer to the Priority 0 tags, and they determined he
15 would stay in the area and wait for the bridge to reopen.²⁵ The
16 troubleshooter made a second attempt to reach Fuse 17733, using an
17 alternative route that he believed might be quicker than his initial route. He
18 arrived at the bridge at approximately 4:30 p.m. and encountered a "Bridge
19 Closed" sign. The troubleshooter got out of his truck to check if the bridge
20 was passable and decided to cross the bridge despite the sign because the
21 repairs appeared sufficient for him to cross. He arrived at Pole 908, where
22 Fuse 17733 was mounted, by approximately 4:50 p.m. At that time, he
23 observed that fuses on two of the phases had operated and the third fuse
24 remained closed, indicating that phase remained energized.

25 While using the bucket of his truck to access the fuses, he observed a
26 fire downhill from his position and a tree on the span between Pole 908 and
27 the next pole, Pole 909. He quickly opened the third fuse to de-energize the
28 remaining phase and attempted to radio the dispatch operators in Rocklin

25 After the phone call, the NDCC supervisor reviewed the real-time phase load and ground current data for the Bucks Creek 1101 Circuit and did not see a reason to de-energize the circuit. If the NDCC supervisor or distribution operator had known of an emergency or safety hazard that required de-energizing the circuit before the troubleshooter arrived at Fuse 17733, the operator could have de-energized the circuit remotely at the Bucks Creek Substation or instructed the troubleshooter to de-energize the Bucks Creek 1101 Circuit at Switch 941.

1 and Chico for help.²⁶ Around the same time, a PG&E employee at the Rock
2 Creek Powerhouse heard a radio call by a PG&E employee driving south on
3 Highway 70 who had observed a small plume of smoke, and Cal Fire was
4 notified shortly thereafter.

5 The troubleshooter fought the fire himself, sliding about 60 to 80 yards
6 downhill with a fire extinguisher from his truck. He emptied the fire
7 extinguisher but was unable to put out the fire. He then climbed back uphill
8 and connected via radio with his supervisor, who called 911. The
9 troubleshooter next took a pressurized water canister and a McLeod tool
10 from his truck, descended the hill again, and continued to fight the fire. After
11 emptying the pressurized water canister, he attempted to dig a fire break
12 near the access road. The troubleshooter remained in the area to offer
13 assistance after fire suppression resources began to respond. This included
14 offering to help bring a Cal Fire ground crew and their equipment to the fire
15 when they would not bring their truck across the closed bridge impeding
16 access to the site. He left the area at approximately 8:00 p.m. after he was
17 told his help was no longer needed.

18 As with the Kincade Fire, PG&E activated an Incident Command System
19 in response to the Dixie Fire and coordinated with Cal Fire and the California
20 Interagency Management Team. Through the Incident Command System,
21 PG&E provided real-time coordination with fire suppression teams,
22 communication with local and state officials, public safety messaging, and
23 operational support to protect infrastructure and mitigate further ignition
24 risks.

25 **E. PG&E Appropriately Designed and Constructed the Dixie Facilities and**
26 **Was Implementing System Hardening Mitigations [Carrell James Gill]**

27 The distribution facilities at the Subject Span were constructed consistent
28 with PG&E's standards and General Order (GO) 95 requirements. As shown in
29 Figure 3B-2, the conductors at Pole 908 were in a horizontal configuration, with

26 Troubleshooters are authorized to de-energize power lines without first contacting a distribution operator to protect life or property during emergencies or if single phasing is present. If single phasing is present, for example, where a single fuse has operated on a three-phase circuit (which can damage customer equipment), troubleshooters are directed to open the remaining fuses or take other steps to mitigate the condition before performing a patrol.

1 the outside phases attached to a lower crossarm on the pole and the center
2 phase attached to the pole itself. The line turned at Pole 908, and jumper
3 conductors connected the lower conductors on the Subject Span to Fuse 17733
4 and the conductors attached to the upper crossarm. As shown in Figure 3B-3,
5 the conductors at Pole 909 were in a triangular configuration, with the outside
6 phases attached to brackets and the center phase elevated and attached to an
7 insulator mounted on top of the pole. The conductors were #4 copper primary
8 conductor. Cal Fire did not identify any equipment-related issues or failures
9 associated with ignition of the Dixie Fire.

10 As described in Chapter 2: Prudence of Operations and in more detail in
11 PG&E's Wildfire Mitigation Plans during the relevant time frame, PG&E was
12 implementing and prioritizing system hardening projects based on risk. At the
13 time of the Dixie Fire, PG&E was in the middle of implementing a system
14 hardening project on the Bucks Creek 1101 Circuit based on a recent change in
15 the assessment of equipment risk on the line. In particular, as PG&E developed
16 and refined its circuit risk models, there were significant adjustments to the risk
17 rankings of distribution circuits. Under the 2020 version of PG&E's wildfire risk
18 model, the Bucks Creek 1101 Circuit was ranked 1,605 out of 3,205 circuit
19 sections for system hardening. PG&E's 2021 Wildfire Distribution Risk Model
20 (2021 Risk Model) yielded revised risk rankings and identified the circuit as 11
21 out of 3,365 circuit sections for risk of equipment failure.²⁷ The 2021 Risk
22 Model rankings became the new framework for prioritizing system hardening
23 projects.

24 PG&E moved very quickly after this increased risk ranking for equipment
25 risk to approve the Bucks Creek 1101 Circuit for system hardening and begin
26 executing the approved hardening. The plan for hardening the Circuit, which
27 was reviewed and approved in approximately January 2021 by PG&E's Wildfire

²⁷ The Bucks Creek 1101 Circuit's elevated risk ranking for equipment failure under the 2021 Risk Model was based on the presence of older and smaller gauge conductor, the presence of splices from prior conductor repairs, and estimates of acres burned and fire intensity generated from fire-consequence modeling. The circuit had a significantly lower risk ranking for vegetation contact, used for prioritizing EVM work, as described above.

1 Risk Governance Steering Committee (WRGSC),²⁸ involved rerouting and
2 undergrounding the Circuit along a state highway, which required PG&E to
3 obtain regulatory agency approvals from multiple different agencies. In April
4 2021, representatives of PG&E, the Commission, Cal Fire, the California
5 Department of Transportation, the U.S. Forest Service, and others participated
6 in a site visit to the Bucks Creek 1101 Circuit to discuss planning, engineering,
7 permitting, and construction for this and other hardening projects.

8 The system hardening project was in the planning stages at the time of the
9 Dixie Fire, and it was ultimately completed in 2024.

10 **F. PG&E Regularly Inspected and Maintained the Facilities [Carrell James** 11 **Gill]**

12 At the time of the Dixie Fire, PG&E inspected and maintained its distribution
13 system pursuant to a robust program that met or exceeded regulatory
14 requirements, including General Order (GO) 165. These inspections were in
15 addition to the vegetation management inspections detailed above.

- 16 • Detailed Ground Inspections: PG&E performed detailed inspections of
17 Bucks Creek 1101 Circuit in December 2016 and May 2021. The
18 inspectors did not identify any required work on the Subject Span.
- 19 • Wildfire Safety Inspection Program (WSIP) Inspections: PG&E
20 performed a WSIP inspection (similar to a detailed inspection) of the
21 Bucks Creek 1101 Circuit in May 2019.²⁹ Pole 908 (the uphill pole) was
22 identified as damaged and subsequently replaced on July 21, 2019. The
23 inspectors did not identify any abnormal conditions or corrective work on
24 Pole 909.
- 25 • Routine Patrol Inspections: PG&E most recently performed routine air
26 patrol inspections of the Bucks Creek 1101 Circuit in accordance with
27 GO 165 criteria in June 2019 and May 2020. PG&E did not identify any
28 items for work related to the Subject Span.
- 29 • Intrusive Pole Inspections: Pursuant to GO 165, intrusive pole
30 inspections were required for all wood poles over 15 years old, with a

²⁸ PG&E established the WRGSC to review and approve plans for critical wildfire risk mitigation programs in late 2020. Chaired by PG&E's Chief Risk Officer, the WRGSC included leaders from Electric Operations, Risk and Internal Audit, and other teams.

²⁹ WSIP is described in more detail in Chapter 2: Prudence of Operations, section D.3.

1 follow-on interval of 20 years for further inspections. PG&E last
 2 performed intrusive pole inspections on Pole 909 and Pole 908 in
 3 December 2008 (as noted above, Pole 908 was replaced in 2019).
 4 PG&E did not identify any required work on either pole at that time.
 5 Table 3B-2 below summarizes the inspection history of Poles 908 and 909
 6 in the 5 years leading up to the Dixie Fire, as well as the 2008 intrusive pole
 7 inspections. As noted, none of these inspections resulted in work orders, other
 8 than the replacement of Pole 908 in 2019.

TABLE 3B-2
EQUIPMENT INSPECTION HISTORY FOR POLES 908 AND 909

WSIP Inspection		
<i>(No regulatory requirement)</i>		
WSIP Inspection		May 4, 2019
Routine Detailed Inspection		
<i>(Required every 5 years)</i>		
Ground Inspection		May 13, 2021
Ground Inspection		December 4, 2016
Routine Patrol Inspection		
<i>(Required annually as of 2018,^(a) except in years with a routine detailed inspection)</i>		
Air Patrol		May 29, 2020
Air Patrol		June 4, 2019
Air Patrol		April 17, 2018
Air Patrol		December 4, 2016
Intrusive Pole Inspection		
<i>(Required 20 years after initial inspection)</i>		
Intrusive Pole Inspection (Pole 908)		December 23, 2008
Intrusive Pole Inspection (Pole 909)		December 22, 2008

(a) Prior to 2018, GO 165 generally required patrol inspections in rural areas every two years, except in high fire risk areas in certain Southern California counties. D.17-12-024 amended GO 165 to increase the frequency of patrol inspections in rural areas to once per year in Tier 2 and Tier 3 HFTDs.

**G. SED's Alleged Violations Do Not Raise Serious Doubt under
 Section 451.1(c) [William Manheim]**

Following the Dixie Fire, SED investigated the incident for compliance with the Commission's rules and regulations and issued a written investigation report setting forth seven alleged violations (SED Report). The SED Report identified

1 three alleged violations related to the cause of the Dixie Fire: (1) failure to
2 identify the Subject Tree as a hazard prior to the fire, in violation of GO 95,
3 Rule 31.1; (2) failure to identify the Subject Tree contacting the circuit during the
4 troubleshooter's visual inspection from the Cresta Dam on the day of ignition in
5 violation of GO 95, Rule 31.1; and (3) failure to assign a higher priority to the
6 initial outage response in violation of Public Utilities Code Section 451. The
7 SED Report identified four additional violations unrelated to the cause of the
8 Dixie Fire that involved late completion of a corrective work tag and records
9 issues.

10 PG&E and SED resolved this investigation through an Administrative
11 Consent Order (ACO), a negotiated settlement pursuant to Commission
12 Resolution M-4846 (Resolution Adopting Commission Enforcement Policy).³⁰
13 The Commission issued Resolution SED-8 approving the ACO on February 2,
14 2024. SED's alleged violations were not litigated, and PG&E did not admit any
15 imprudence, nor did the Commission make any findings on those issues. For
16 the reasons described below, PG&E strongly disputed SED's alleged violations
17 related to the cause of the Dixie Fire, which, in any event, do not create "serious
18 doubt" about the reasonableness of PG&E's conduct or show any imprudence
19 by PG&E under Section 451.1(c). (With respect to the remaining alleged
20 violations, each unrelated to the cause of the fire, PG&E disputed one violation
21 related to completion of a tag and, only for purposes of the ACO, did not contest
22 the three remaining violations.)

³⁰ As set forth in the Commission's Enforcement Policy, "(a) negotiated proposed settlement shall be memorialized in a proposed Administrative Consent Order (which) shall become final upon review and approval by the Commission." Res. M-4846, Attachment, Enforcement Policy (Nov. 5, 2020), p. 10.

1 **1. Alleged Violation Related to the Subject Tree**

2 The SED Report alleged a violation of GO 95, Rule 31.1, because
3 PG&E did not identify the Subject Tree as a hazard prior to the fire.³¹
4 PG&E disputed this alleged violation.

5 First, the fact that the Subject Tree failed is not evidence of a violation of
6 Commission rules or regulations, much less imprudence. No rule requires
7 that a utility vegetation management program prevent all tree failures, and
8 that would not be feasible. Rather, a prudent utility vegetation management
9 program must take reasonable steps to identify and address visible hazards,
10 which PG&E's program did. GO 95, Rule 35 specifically addresses the
11 requirements related to hazard trees:

12 When a (utility) has **actual knowledge**, obtained either through normal
13 operating practices or notification to the Company, that dead, rotten or
14 diseased trees or dead, rotten or diseased portions of otherwise healthy
15 trees overhang or lean toward and may fall into a span of supply or
16 communication lines, said trees or portions thereof should be
17 removed.³²

18 Because PG&E had no knowledge that the Subject Tree posed a fall risk or
19 other hazard, this Rule was not violated and the SED Report acknowledged
20 as much.³³

21 Second, SED acknowledged the evidence that the Subject Tree
22 appeared healthy with a green canopy and that PG&E's trained inspectors
23 reported based on their review of pre-fire photographs that the tree would
24 not have merited closer review or work.³⁴ Yet SED cited the opinion of

31 Specifically, SED alleged that PG&E violated GO 95, Rule 31.1 by "failing to identify a hazardous tree condition and not taking appropriate steps to prevent the Subject Tree from striking the overhead conductors." SED Report, p. 2; see *also* GO 95, Rule 31.1 ("For all particulars not specified in these rules, design, construction, and maintenance should be done in accordance with accepted good practice for the given local conditions known at the time by those responsible for the design, construction, or maintenance of communication or supply lines and equipment.").

32 GO 95, Rule 35 (emphasis added).

33 SED Report, p. 33 ("Since PG&E did not have knowledge of the tree, SED did not identify a violation of GO 95, Rule 35.").

34 See, e.g., SED Report, p. 28 and n.68 (citing 2019 photographs showing the green canopy and noting that "color of the canopy is a key factor in vegetation management inspectors' determination of tree health"), p. 31 (describing inspector statements that the Subject Tree appeared healthy and that he did not see any indications that a Level 2 assessment would have been performed).

1 Cal Fire's retained arborist that the wound at the base of the Subject Tree
2 *should* have been identified during a Level 1 visual inspection to support an
3 alleged violation of Rule 31.1. Cal Fire's retained arborist opines that the
4 base of the Subject Tree was injured in 2008.

5 As described above, however, PG&E performed numerous vegetation
6 management patrols in and near the origin area in the years preceding the
7 Dixie Fire. It is wholly implausible to suppose that a visible wound on the
8 Subject Tree would have been missed by trained inspectors in multiple
9 patrols. As set forth in detail in the above testimony of PG&E's independent
10 expert (Section C.2), there is no basis to conclude the wound at the base of
11 the Subject Tree was visible. The available evidence indicates the tree
12 appeared healthy and the wound likely was not visible. Moreover, the
13 patrols were part of a robust vegetation management program that met, and
14 in certain areas exceeded, industry standards, as described in detail in
15 Chapter 2: Prudence of Operations (Section D.3). The SED Report
16 acknowledged that the scope of PG&E's program included the identification
17 of hazard trees showing signs of distress,³⁵ and did not find that PG&E's
18 programmatic approach fell short. The hindsight opinion of Cal Fire's
19 retained arborist does not support a violation of Rule 31.1, and certainly
20 does not create serious doubt regarding PG&E's prudence.

21 **2. Alleged Violations Related to PG&E's Response to the Outage**

22 The SED Report alleged two violations related to PG&E's response to
23 the outage on the Bucks Creek 1101 Circuit. PG&E disputed both alleged
24 violations.

25 First, the SED Report alleged a GO 95, Rule 31.1 violation based on a
26 finding that the troubleshooter erred in not seeing the Subject Tree on the
27 line when he performed a visual inspection of the Bucks Creek 1101 Circuit
28 from a distance at Cresta Dam. Based on site visits after the Dixie Fire had
29 burned through this area, SED and Cal Fire concluded that the Subject Tree
30 on the line would have been visible from that location. These post-incident
31 observations had the benefit of hindsight because the investigators had

35 SED Report, p. 33 and n.93 (citing PG&E's Distribution Vegetation Management Standard and providing PG&E's definition of "Hazard Trees").

1 already been to the Subject Span and knew exactly what they were looking
2 for and where along the circuit. In any event, the SED Report
3 acknowledged that the troubleshooter took the initiative to examine the line
4 from Cresta Dam, visually examined the line between the dam and the
5 location of the fuses to look for signs of trouble, and used binoculars to
6 magnify his view. The SED Report did not identify any different or additional
7 action the troubleshooter could or should have taken; it simply criticizes that
8 he did not see the tree on the line. That is not a supportable basis for a
9 Rule 31.1 violation, and does not show any imprudence.

10 Second, the SED Report alleged that PG&E violated Public Utilities
11 Code Section 451 by failing to adequately consider the risk of the
12 Bucks Creek 1101 Circuit when responding to the outage.³⁶ As described
13 in Section D.2 above, PG&E's response to the Cresta Dam outage was
14 consistent with its procedures and reasonable and appropriate based on the
15 information available to PG&E personnel in real time. The distribution
16 operators addressing the outage followed PG&E's procedures when they
17 dispatched a troubleshooter with a Priority 1, same-day tag, and they
18 checked available electrical data at various times during the course of the
19 day and did not see any indication of a continuing safety hazard. PG&E was
20 not aware of any emergency until the troubleshooter arrived at the site in the
21 afternoon after the fire had started, when he immediately took steps to open
22 the third fuse to ensure the line was de-energized, and then attempted to
23 fight the fire himself. The SED Report cited no support for its claim that
24 PG&E should have incorporated the equipment failure risk model used to
25 prioritize long-term system hardening projects into its operational decision-
26 making in response to an outage, and did not identify any utility that did so.

27 **3. Alleged Violations Unrelated to the Cause of the Dixie Fire**

28 The SED Report included four additional alleged violations that are
29 unrelated to ignition of the Dixie Fire. The alleged violations do not involve
30 conduct relevant here and, even if they did, are not evidence of imprudence.

³⁶ Specifically, SED alleged that "PG&E failed to adequately consider the hazard of Bucks Creek 1101 circuit in its response to the outage at Cresta Dam." SED Report, p. 2.

1 One of the alleged violations was that PG&E did not timely complete a
2 work order to replace a pole located outside the origin area, in violation of
3 GO 95, Rule 18.B. In disputing this alleged violation, PG&E explained that
4 the work at issue required a permit and Rule 18.B allows extensions under
5 such circumstances. The required work also was completed in November
6 2016—nearly five years before the Dixie Fire. In any event, an alleged
7 delay in the execution of a work order is not evidence of imprudence. As
8 described in detail in Chapter 2: Prudence of Operations, PG&E had robust
9 programs for executing and prioritizing corrective work identified through
10 inspections.

11 The remainder of the alleged violations, which PG&E agreed not to
12 contest for purposes of the ACO, were records-related issues³⁷ not causally
13 related to the ignition of the Dixie Fire:

- 14 • An alleged recordkeeping violation concerning the date that the 2020
15 routine vegetation management patrol was completed. There was no
16 dispute that the inspection occurred.
- 17 • An alleged recordkeeping violation concerning a missing page in the
18 documentation for the 2019 vegetation management routine patrol.
19 There was no dispute that the routine patrol was completed, including
20 the section of the route along the Subject Span.
- 21 • An alleged violation concerning PG&E's delay in formally revising its
22 vegetation management procedure to incorporate updated minimum
23 clearance requirements. There is no dispute that PG&E implemented
24 the minimum distance clearance requirements on a timely basis.

³⁷ PG&E now uses electronic systems to record vegetation management patrol information.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3B

ATTACHMENT 1

DIXIE FIRE AGENCY REPORT

CAL FIRE



CALIFORNIA DEPARTMENT OF FORESTRY AND FIRE PROTECTION

INVESTIGATION REPORT

CASE NUMBER:	21CABTU009205-58
CASE NAME:	DIXIE
DATE:	July 13, 2021
INCIDENT TYPE:	Vegetation Fire
INCIDENT INVESTIGATORS:	Matthew Palade (Fire Captain Specialist) Butte Unit Lance Berry (Battalion Chief) Northern Region

1 **VIOLATIONS**

3 **Public Resource Code 4293**

4 Except as otherwise provided in Sections 4294 to 4296, inclusive, any person that
5 owns, controls, operates, or maintains any electrical transmission or distribution line
6 upon any mountainous land, or in forest-covered land, brush-covered land, or grass-
7 covered land shall, during such times and in such areas as are determined to be
8 necessary by the director or the agency which has primary responsibility for the fire
9 protection of such areas, maintain a clearance of the respective distances which are
10 specified in this section in all directions between all vegetation and all conductors which
11 are carrying electric current:

12 (a) For any line which is operating at 2,400 or more volts, but less than 72,000
13 volts, four feet.

14 (b) For any line which is operating at 72,000 or more volts, but less than 110,000
15 volts, six feet.

16 (c) For any line which is operating at 110,000 or more volts, 10 feet.

17 In every case, such distance shall be sufficiently great to furnish the required clearance
18 at any position of the wire, or conductor when the adjacent air temperature is 120
19 degrees Fahrenheit, or less. **Dead trees, old decadent or rotten trees, trees**
20 **weakened by decay or disease and trees or portions thereof that are leaning**
21 **toward the line which may contact the line from the side or may fall on the line**
22 **shall be felled, cut, or trimmed so as to remove such hazard.** The director or the
23 agency which has primary responsibility for the fire protection of such areas may permit
24 exceptions from the requirements of this section which are based upon the specific
25 circumstances involved.

27 **Public Resource Code 4421**

28 A person shall not set fire or cause fire to be set to a forest, brush, or other flammable
29 material that is on land that is not the person's own land, or under the person's legal
30 control, without the permission of the owner, lessee, or owner's agent or lessee of the
31 land.

Penal Code 452

A person is guilty of unlawfully causing a fire when he recklessly sets fire to or burns or causes to be burned, any **structure, forest land or property**.

(b) Unlawfully causing a fire that causes an inhabited structure or inhabited property to burn is a felony punishable by imprisonment in the state prison for two, three or four years, or by imprisonment in the county jail for not more than one year, or by a fine, or by both such imprisonment and fine.

(c) Unlawfully causing a fire of a structure or forest land is a felony punishable by imprisonment in the state prison for 16 months, two or three years, or by imprisonment in the county jail for not more than six months, or by a fine, or by both such imprisonment and fine.

Penal Code 452.1

(a) Notwithstanding any other law, any person who is convicted of a felony violation of Section 452 shall be punished by a one-, two-, or three-year enhancement for each of the following circumstances that is found to be true:

(1) The defendant has been previously convicted of a felony violation of Section 451 or 452.

(2) A firefighter, peace officer, or other emergency personnel suffered great bodily injury as a result of the offense. The additional term provided by this subdivision shall be imposed whenever applicable, including any instance in which there is a violation of subdivision (a) of Section 452.

(4) The defendant proximately caused multiple structures to burn in any single violation of Section 452.

(b) The additional term specified in subdivision (a) of Section 452.1 shall not be imposed unless the existence of any fact required under this section shall be alleged in the accusatory pleading and either admitted by the defendant in open court or found to be true by the trier of fact.

Penal Code 454

(a) Every person who violates Section 451 or 452 during and within an area of any of the following, when proclaimed by the Governor, shall be punished by imprisonment in the state prison, as specified in subdivision (b):

(2) A state of emergency pursuant to Section 8625 of the Government Code.

(b) Any person who is described in subdivision (a) and who violates subdivision

(a), (b), or (c) of Section 451 shall be punished by imprisonment in the state

prison for five, seven, or nine years. All other persons who are described in

subdivision (a) shall be punished by imprisonment in the state prison for three,

five, or seven years.



SUMMARY

On Tuesday July 13, 2021 at approximately 5:07 PM, the Dixie Fire was reported in a remote area above the Cresta Dam in Plumas County, CA, near the community of Pulga. The fire ignited below the Pacific Gas and Electric (PG&E) Bucks 1101 12KV distribution circuit, between pole number 120772797 and an unmarked pole approximately 300 feet east. The fire ignited as a result of a 65' tall, damaged and decayed Douglas-Fir tree when it fell and contacted conductors at approximately 6:48 AM. Two of the three fuses blew (opened) upon initial contact with the conductors, but the third fuse remained closed and kept a line energized. The tree being in contact with energized conductors and the ground created a high impedance fault. The high impedance fault energized the tree, which caused heat and arcing to ignite a dry and receptive fuel bed over the course of 10 hours. Because PG&E had an excessively delayed response to the fault, the fire was not discovered until a PG&E troubleman W-1 arrived at scene at approximately 4:55 PM. Upon W-1's discovery, the fire was too large for him to contain and a 911 response was requested. Simultaneously the fire was visible from Highway 70 and multiple parties reported the fire via 911.

The Dixie Fire burned in a remote location which made access by fire personnel extremely difficult. In the initial attack phase of the fire a drone incursion caused critical air resources to be grounded. The Dixie fire was influenced by steep terrain, dry receptive fuel beds and drought conditions. The Dixie fire burned 963,309 acres of federal, state, and private lands in Butte, Plumas, Lassen, Tehama, and Shasta counties before it was contained on October 26, 2021. The Dixie fire destroyed 1311 structures and damaged 94. Of those 1311 destroyed were 763 residential homes, 12 multi family homes, 8 commercial residential homes, 148 nonresidential commercial structures and 466 detached structures. The Dixie fire destroyed the communities of Greenville and Canyon Dam and caused major damage to the communities of Chester and Janesville. One CAL FIRE Captain sustained major injuries and three CAL FIRE firefighters sustained minor injuries when they were struck by a tree while engaged in suppression efforts.

1 The Dixie fire was the largest non-complex wildfire in California history and the second
2 largest in US history. Smoke from the Dixie fire caused unhealthy air quality over much
3 of the western united states including states as far east as Colorado and Utah. The
4 suppression cost to date is over 650 million dollars.

5
6 During the investigation CAL FIRE retained the expertise of Joe McNeil. MCNEIL is a
7 certified arborist and consultant. MCNEIL concluded the tree that fell across the
8 conductors was previously damaged and had visible outward signs of that damage and
9 decay which would have been noticeable at the ground level by inspectors pre fire,
10 without extraordinary effort.

11
12 California Public Resource Code 4293 states that **dead trees, old decadent or rotten**
13 **trees, trees weakened by decay or disease and trees or portions thereof that are**
14 **leaning toward the line** which may contact the line from the side or may fall on the line
15 shall be felled, cut, or trimmed so as to remove such hazard.

SUBJECT

Pacific Gas and Electric (PG&E) Corporation
77 Beale Street
PO Box 770000
San Francisco, CA 94177
(415) 973-1000

WITNESSES**W-1** (PG&E Troubleman)**W-2** (PG&E Rock Creek Powerhouse)**W-3** (PG&E Acting Supervisor)

A handwritten signature in blue ink, appearing to be 'J. [unclear]', written over a horizontal line.

1 **W-4** (911 Caller)

2 Rich EPPERSON

3 [REDACTED]
4 [REDACTED]
5 [REDACTED]

6

7 **W-5** (911 Caller)

8 Karla & Michael ALBERT

9 [REDACTED]
10 [REDACTED]
11 [REDACTED]

12

13 **W-6** (911 Caller)

14 Ronnie NULPH

15 [REDACTED]
16 [REDACTED]
17 [REDACTED]

18

19 **W-7** (Butte County Public Works)

20 Miguel FLORES

21 [REDACTED]
22 [REDACTED]
23 [REDACTED]

24

25 **W-8** (Butte County Public Works)

26 Kevin THOMAS

27 [REDACTED]
28 [REDACTED]
29 [REDACTED]

30

31



1 **W-9** (Butte County Public Works)

2 Sean HASSEL



7 **VICTIMS**

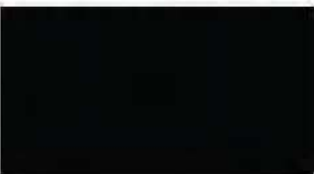
8 See attached Damage Inspection Summary (DINS)
9 (Attachment V)

11 **INVESTIGATORS**

13 **I-1** Matthew PALADE

14 Fire Captain / Peace Officer

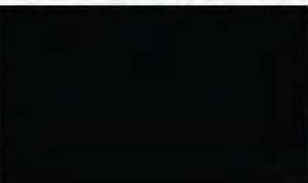
15 CAL FIRE Butte Unit



20 **I-2** Lance BERRY

21 Battalion Chief / Peace Officer

22 CAL FIRE Northern Region



Handwritten initials in blue ink, appearing to be 'sf' or similar, written over a horizontal line.

1 **I-3 Mike THOMPSON**

2 Assistant Chief / Peace Officer

3 CAL FIRE Northern Region

4 [REDACTED]
5 [REDACTED]
6 [REDACTED]

7

8 **I-4 Shane LARSEN**

9 Forester 1 / Peace Officer

10 CAL FIRE Sacramento

11 [REDACTED]
12 [REDACTED]
13 [REDACTED]

14

15 **I-5 Jeremy MONROE**

16 Deputy Chief / Peace Officer

17 CAL FIRE Sacramento Headquarters

18 [REDACTED]
19 [REDACTED]
20 [REDACTED]

21

22 **I-6 Chip FOWLER**

23 Battalion Chief / Investigator

24 CAL FIRE Butte Unit

25 [REDACTED]
26 [REDACTED]
27 [REDACTED]

28

29

30

31

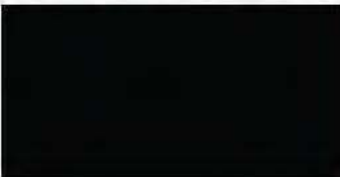


SPECIALISTS**SP-1 Joe MCNEIL**

McNeil Arboriculture

**SP-2 Scott HYLTON**

TSH Consulting

**SP-3 B&B High Voltage Line Contractors****SP-4 Element Security**

EVIDENCE

- 1
- 2
- 3 **E-1** Fuse from conductor #1
- 4 **E-2** Fuse from conductor #2
- 5 **E-3** Fuse from conductor #3
- 6 **E-4** Tree trunk in contact with conductor #1
- 7 **E-5** Tree limb in contact with conductor #1
- 8 **E-6** Piece of conductor#1
- 9 **E-7** Piece of conductor #1 showing arcing.
- 10 **E-8** Piece of conductor #2 showing tree material embedded.
- 11 **E-9** Piece of conductor #3 showing burn where tree rested.
- 12 **E-10** Piece of conductor #2 showing arcing.
- 13 **E-11-1** Subject tree trunk (bottom)
- 14 **E-11-1.1** Sub section of E-11 for McNeil Arboriculture
- 15 **E-11-1.2** Sub section of E-11 for McNeil Arboriculture
- 16 **E-11-2** Subject tree trunk (middle)
- 17 **E-11-3** Subject tree trunk (top)
- 18 **E-11-1.2** Sub section of E-11 for McNeil Arboriculture
- 19 **E-12** Subject tree stump (root)
- 20 **E-13** Subject tree stump
- 21 **E-13-1** Sub section of E-13 for McNeil Arboriculture
- 22 **E-13-2** Sub section of E-13 for McNeil Arboriculture
- 23 **E-13-3** Sub section of E-13 for McNeil Arboriculture
- 24 **E-13-4** Sub section of E-13 for McNeil Arboriculture
- 25 **E-13-5** Sub section of E-13 for McNeil Arboriculture
- 26 **E-13-6** Sub section of E-13 for McNeil Arboriculture
- 27 **E-13-7** Sub section of E-13 for McNeil Arboriculture
- 28 **E-13-8** Sub section of E-13 for McNeil Arboriculture
- 29 **E-13-9** Sub section of E-13 for McNeil Arboriculture
- 30 **E-14** Origin photos (SD card) 152 Images
- 31 **E-15** Evidence collection photos (SD card) 152 Images

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12

Officer Initials



E-16 Evidence collection photos (SD card) 48 Images

See attached evidence log sheet (Attachment H)

CONDITIONS

Weather conditions on July 13, 2021, at approximately 6:48 AM (time of the initial subject tree failure) as recorded at the Jarbo Gap weather station located at 11972 CA-70, Oroville, CA 95965, were as follows.

Temperature: 76-80 degrees Fahrenheit

Wind: 20-22 MPH from the North East

Relative Humidity: 16 percent

Weather conditions on July 13, 2021, at approximately 5:00 PM (time of the Dixie fire dispatch) as recorded at the Jarbo Gap weather station were as follows.

Temperature: 91-94 degrees Fahrenheit

Wind: 12-14 MPH from the southwest

Relative Humidity: 25 percent

CAL FIRE Lightning data base indicated that there was no lightning activity in or around the Dixie Fire origin between at least June 30, 2021 and July 13, 2021.

Typically, high, and gusty winds exist in the Feather River canyon. Great Basin morning heating results in air expansion that is funneled through the Feather River Canyon in the early mornings during normal weather patterns. Several perpendicular creek drainages converge with the Feather River Canyon creating turbulent wind patterns throughout the mornings and afternoons.

California Governor, Gavin Newsom issued a State of Emergency Proclamation on April 21, 2021, due to ongoing drought conditions. That proclamation remained in affect throughout the duration of the Dixie Fire.

See proclamation (Attachment U)

ORIGIN AREA

Elevation: Approximately 2358 feet above sea level.

Latitude & Longitude: 39 52'29.14" N X 121 22'42.47" W

Fuels: Mixed brush and annual grasses with a mix of conifer and oak trees.

Terrain: Mid slope on an approximate 50% grade west of the Feather River with an east aspect.

Access: Access to the Dixie Fire's origin is Highway 70 to Pulga Road, to Camp Creek Road. Camp Creek Road is a narrow, two track dirt/rock road with several narrow bridge crossings. Camp Creek Road could be accessed via Rock Creek Road, however that section of road is washed out and impassable. It is approximately 11 miles from Highway 70 to the Dixie Fire's origin and takes approximately 1 hour to drive.

EQUIPMENT

The Pacific Gas & Electric Bucks 1101 12KV distribution circuit. Pole # 120772797, an unmarked pole approximately 300 feet east, all 3 conductors and equipment associated with both poles.

No other equipment was identified as being a contributing factor to the ignition of the Dixie Fire.

PROPERTY

Plumas County Assessor's parcel number 002-290-007 located at the origin is a 2,578-acre block of federal land, protected under CAL FIRE direct protection area (DPA). The property is further described in Book 2, Page 29 of the Plumas County Assessors map. (See attachment Y)

See attached CAL FIRE Damage Inspection Summary (DINS) for the list of damaged properties. (See attachment V)

NARRATIVE

On Tuesday July 13, 2021 at approximately 5:07 PM, the California Department of Forestry and Fire Protection (CAL FIRE) Oroville Emergency Command Center (ECC) received multiple reports and 911 calls of a vegetation fire in the Highway 70 canyon on the west side of the Feather River above Cresta Dam.

The first 911 caller identified himself as [REDACTED] W-2 (PG&E employee) and was calling from 3371 Highway 70 (Rock Creek Powerhouse). [REDACTED] W-2 stated he was relaying the information second hand and could only report the fire was located on the hillside above Cresta Dam in the Highway 70 canyon.

The second report of the fire came from Rich EPPERSON via radio to CAL-FIRE Butte ECC, at approximately 5:12 PM. EPPERSON was the engine strike team leader of a group of engines (ST-3225C) returning home from the Beckworth Fire. EPPERSON reported the fire to be in the Highway 70 canyon approximately 3 miles from the Butte County line and approximately three quarters of the way uphill. EPPERSON stated the fire was well established and approximately forty feet by forty feet in size, burning under powerlines. EPPERSON was reporting the fire from Highway 70.

At approximately 5:15 PM, Oroville ECC dispatched a full (high level) wildland fire response consisting of 6 engines, 2 dozers, 2 hand crews, 2 water tenders, 1 air attack, 2 tankers, 1 copter, 1 battalion chief, 1 training officer and 1 prevention officer. I had prevention coverage and was on the initial dispatch. I responded from my office at 220 Grand Avenue, Oroville, CA.

At approximately 5:42 PM, air attack 120 arrived over the fire, assumed "DIXIE" air attack, and reported the fire to be approximately 2 acres with a slow rate of spread. DIXIE air attack coordinated air resources attempting to surround the fire with retardant and keep it in check until ground resources could arrive. At approximately 6:31 PM, DIXIE air attack reported the fire was holding at approximately 2 acres with retardant LE80 (Rev. 7/2011)

1 around the perimeter, and copter 903 was continuing with water drops. At approximately
2 6:49 PM, Battalion 2113, Byron VANCE arrived at the Incident Command Post located
3 at 11975 Highway 70, Oroville, CA 95965 (Scooters Café) and assumed DIXIE Incident
4 Command. At approximately 7:49 PM, VANCE contacted Oroville ECC and requested
5 a law enforcement response due to a drone operating in the fire area. At approximately
6 8:01 PM, DIXIE air attack contacted Oroville ECC and advised he was ceasing all air
7 operations due to drone activity over the fire.

8
9 At approximately 9:00 PM, while attempting to access the fire via Camp Creek Road, I
10 came across a PG&E troubleman who I identified by name as W-1
11 W-1 was located at a bridge approximately 2 miles south of the fire. The bridge
12 had several signs posted around it stating the bridge was out of service for repair.
13 W-1's PG&E bucket truck was located on the fire side (north) side of the bridge.
14 CAL FIRE Engine 2183 was parked on the south side of the bridge blocking
15 W-1's egress. It was later determined Engine 2183 had parked at the bridge,
16 and walked into the fire on foot, not feeling it was safe to drive across the bridge. After
17 coordinating the movement of Engine 2183 and getting W-1's bucket truck
18 across the bridge, I conducted a brief interview with W-1 who told me the
19 following in summary:

20
21 W-1 stated that earlier in the day Cresta Dam had experienced a power
22 outage, (later determined thru Supervisory Control and Data Acquisition data to
23 have occurred at 6:48 AM) and he drove up Camp Creek Road at approximately
24 1:30 PM to inspect the power lines and determine the problem. When he got to
25 the bridge, he encountered Butte County Public Works employees who told him
26 the bridge was closed for repairs and would be impassable for at least a couple
27 of hours. W-1 stated he waited for the workers to complete the work,
28 which took approximately two hours, after which he continued up Camp Creek
29 Road until he found a pole that had two blown fuses and what he described as a
30 green tree across all three phases of conductors. W-1 stated he
31 positioned his bucket truck and started to raise his bucket to pull the third fuse

1 which was in the closed position. As he raised his bucket, he smelled smoke,
2 looked down hill and noticed a fire on the downhill side below the conductors.

3 W-1 stated he quickly pulled the remaining fuse, lowered his bucket, and
4 attempted to extinguish the fire with his water can (extinguisher). W-1

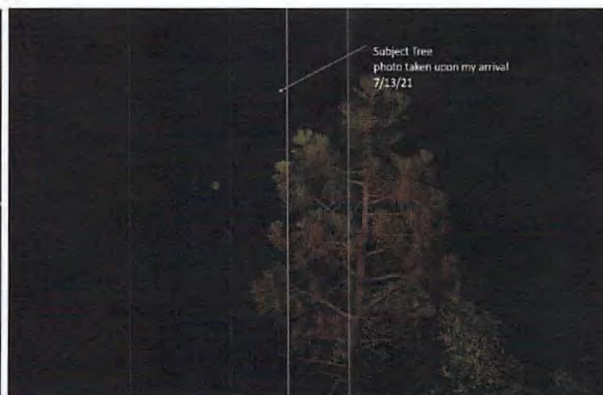
5 stated the fire was burning in pine needles and wasn't very large, but it quickly
6 got into a manzanita bush and he realized he could not contain the fire with the
7 water he had. W-1 stated he then attempted to contact anyone he could

8 via two-way radio to report the fire. Initially he did not get a response, but a short
9 time later someone responded to his calls and called 911. W-1 told me
10 that if I continued up Camp Creek Road, I would see the power pole and fire on
11 my right-hand side.

12
13 I collected a contact number for W-1 and continued up Camp Creek Road to the
14 fire. I arrived at approximately 9:45 PM and observed a vegetation fire on the steep
15 downhill (east) side of Camp Creek Road burning in brush and timber. The fire was
16 backing slowly downhill with approximately one foot flame lengths and appeared to be
17 contained on the edges by fire retardant dropped from air tankers. Engine 2183's crew
18 had started cutting hand line downhill on the south flank (edge) of the fire. The south
19 flank of the fire was located off a power line easement running east down hill toward
20 Cresta Dam.

21
22 I started to conduct my origin and cause investigation by walking the edge of Camp
23 Creek Road and then down the fires south flank looking for macro fire pattern indicators,
24 such as needle freeze and angle of char. While walking Camp Creek Road, I observed
25 a power pole on the downhill (east) side of Camp Creek road on the edge of the fire.
26 The conductors attached to this pole ran downhill toward Cresta Dam and north along
27 Camp Creek Road. I photographed the number on the pole (120772797), examined the
28 equipment on the top of the pole and noticed all three fuses were in the open position. I
29 photographed the equipment on the pole. Due to the time of night, the steep terrain
30 and suppression efforts, I found it very difficult to continue the investigation and decided
31 it was best to remain on the south flank hand line and not enter the burned area to

1 preserve the scene for the next day. At approximately 9:53 PM, I noticed increased fire
2 activity located in a steep draw. Within a few minutes the fire increased and made an
3 uphill run as it consumed an area of unburned brush and small trees. I observed a
4 moderate amount of ember cast over Camp Creek Road which threatened the
5 unburned (west) slope. As Magalia Crew 5 (Mag 5) arrived at the fire's edge I
6 expressed my concerns of a possible spot fire to the captain. Mag 5 Captain positioned
7 his crew members along Camp Creek Road to patrol for spot fires. I continued downhill
8 approximately 150 feet along the handline. With my flashlight I observed a pine tree
9 laying across all three conductors. Mag 5 Captain transmitted over the radio that the fire
10 had spotted across Camp Creek Road and was making a run uphill with a moderate
11 rate of spread. I photographed the tree across all three conductors and retreated up the
12 hill to Camp Creek Road.



13
14 On July 14, 2021, at approximately 12:30 AM, based upon my conversation with
15 W-1 and the evidence at scene, I sent a text message to CAL FIRE Prevention
16 Bureau Chief Mike WATERS and told him the cause of the fire looked to be PG&E as
17 the result of a tree down on power lines. WATERS advised me he would arrange for a
18 CAL FIRE contracted arborist to examine the tree. I remained on scene and became a
19 Division Group Supervisor (DIV B).

20
21 At approximately 12:30 PM, I was relieved by the incoming Division Group Supervisor
22 who told me resources would not be accessing the fire via Camp Creek Road due to the
23 road being too narrow for large engines and crew buses. Instead, all fire resources
24 would access the area via Highway 70 across the river or above from the U- Line and

1 would not be working in or nearby the origin area.

2
3 At approximately 2:00 PM, I met with WATERS and members of the Butte County
4 District Attorney's Office at the CAL FIRE Butte County Fire Prevention Bureau office
5 located at 220 Grand Avenue, Oroville, CA. I advised them that due to the time of night
6 and fire conditions, I had not conducted a complete origin and cause investigation of the
7 fire. I advised them that based upon my observations at scene, such as the tree across
8 all three phases of conductor and witness statements taken from W-1 I could
9 not rule out powerlines as a cause for the Dixie Fire. I advised them I needed to
10 examine the scene more thoroughly and complete my origin and cause investigation
11 prior to making a determination. WATERS advised me in addition to the arborist he
12 would contact additional CAL FIRE contracted specialists and CAL FIRE Investigators
13 to help examine the scene. We agreed to have a briefing the next morning at 9:00 AM,
14 to discuss the details and develop a plan before returning to the scene.

15
16 On July 15, 2021 at approximately 9:00 AM, I met with Element Security, TSH Electrical
17 Consulting (Scott HYLTON), Arboriculture Consultants (Todd and Joe MCNEIL) CAL
18 FIRE investigators (Mike WATERS, Lance BERRY and Mike THOMPSON) and Butte
19 County District Attorney's office (Marc Noel, Chris Oakley, John Duffy, Nick Moore and
20 Jennifer Dupre-Tokos). The meeting took place at the CAL FIRE Butte County Fire
21 Prevention Bureau office. During the meeting, I summarized my interview with
22 W-1 and the limited photos I had taken. We developed a plan to place
23 ELEMENT security at the intersection of Camp Creek Road and Dixie Road to restrict
24 access and complete a log of everyone entering or leaving the area. BERRY,
25 THOMPSON, and I would conduct an origin and cause investigation prior to allowing
26 CAL FIRE contractors such as HYLTON and MCNEIL to enter the scene if needed.
27 Butte County DA Investigators would remain out of the area as well while the origin and
28 cause investigation was conducted but would be allowed to observe and photograph as
29 needed.

30
31 At approximately 11:00 AM, I placed ELEMENT security at the intersection of Camp
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1 Creek and Dixie Road. At approximately 11:45 AM, we arrived at the origin and found it
2 to be undisturbed. At approximately 12:30 PM, BERRY, THOMPSON and I started
3 conducting the origin and cause investigation by first walking the edge of Camp Creek
4 Road and identifying the flanks of the fire that I had witnessed the evening of July 13,
5 2021. Next, we walked around the fire in a clock wise and counterclockwise direction
6 starting with the south flank where power pole 120772797 intersects with Camp Creek
7 Road and Engine 2183's hand line began. We observed macro fire pattern indicators
8 such as angle of char, foliage freeze, and protection that indicated the general origin
9 area (GOA) to be between power pole 120772797 and an unmarked pole approximately
10 300 feet east and downhill toward Cresta Dam. Between these two poles and nearest
11 the unmarked pole was a tree (subject tree) approximately 65 feet in length laying
12 across all three conductors. This section of line was later determined to be identified by
13 PG&E as the Bucks 1101 circuit.

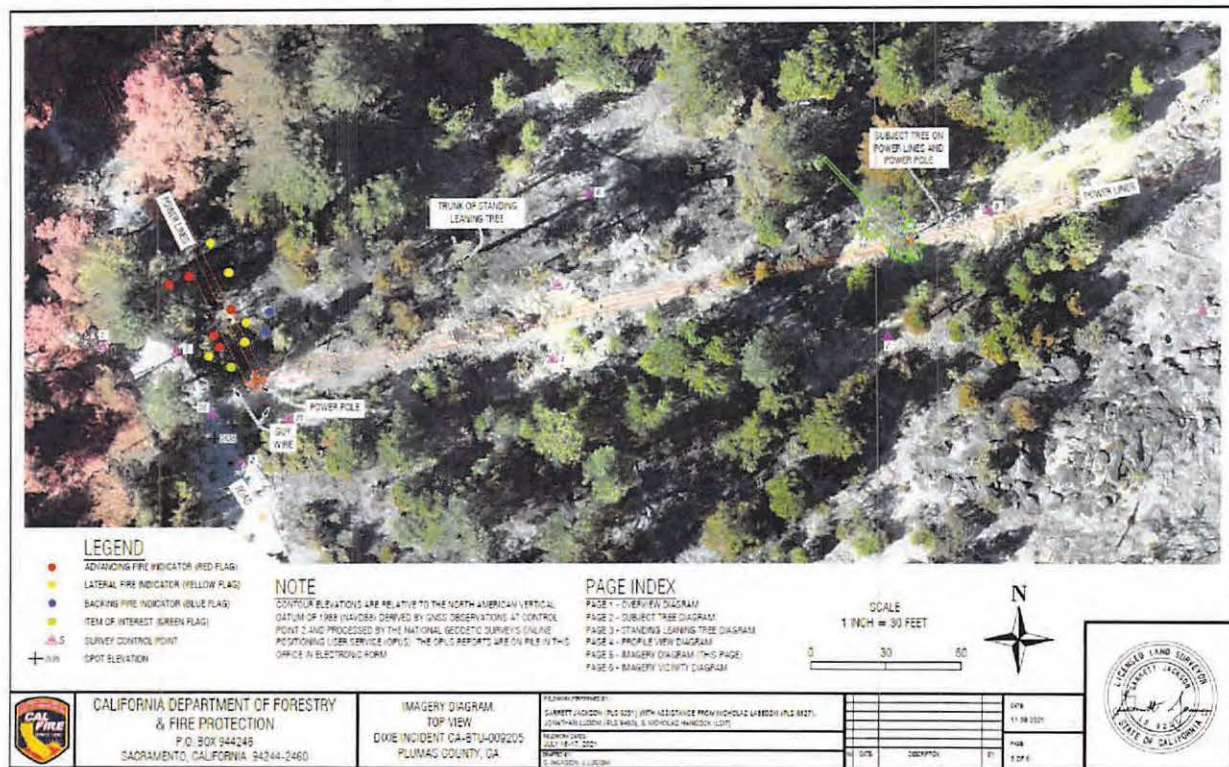
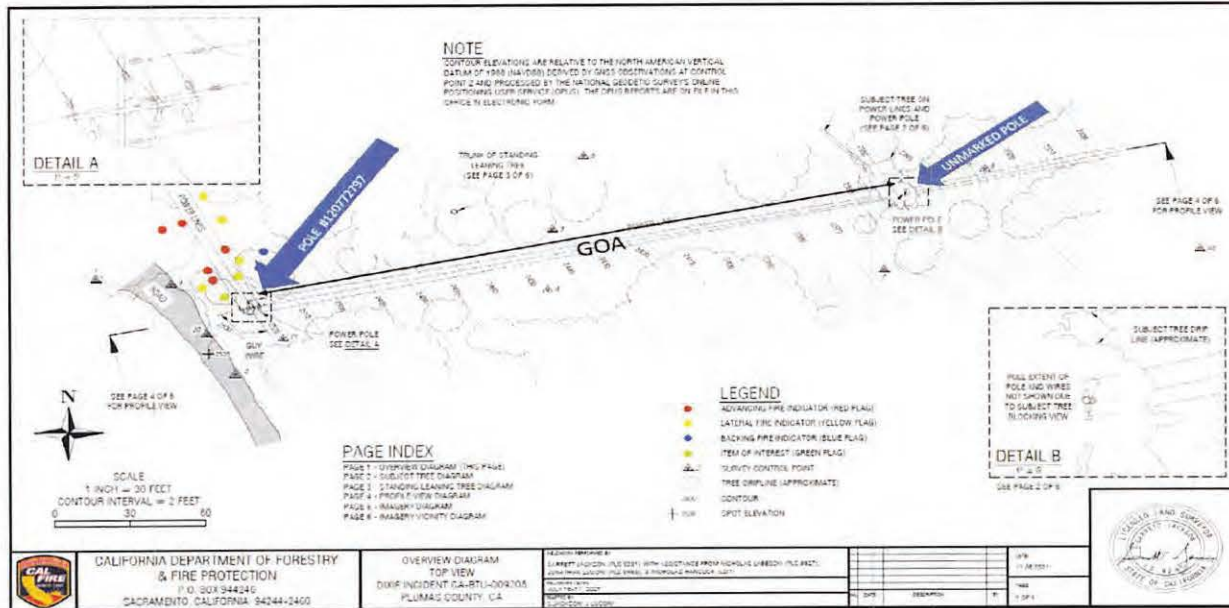


14
15 Fire suppression efforts within the GOA such as retardant drops, helicopter water drops
16 and handline construction in the light sandy soil made determining and locating a
17 specific origin area (SOA) very difficult. Nevertheless, we were able to determine
18 several areas of interest within the GOA. Those areas had fire pattern indicators such
19 as angle of char, lower intensity burning, sooting and staining. These fire pattern
20 indicators would be consistent with those found in the SOA.

21
22 Based upon these fire pattern indicators and witness statements from [REDACTED] W-1 we
23 determined the SOA was located between pole 120772797 and the unmarked pole. The
24 ignition area, or areas, was located within this SOA. No other sources of ignition



- 1 besides the powerlines and its associated equipment were located within the GOA.



At approximately 2:30 PM, we allowed HYLTON (TSH Electrical) and MCNEIL (arboricultural) to enter the scene to examine the subject tree and powerline

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24

Officer Initials

[Handwritten signature]

1 components. After their initial assessment of the components, I met with each
2 separately and asked how they would like to proceed and what we needed to examine
3 further.

4
5 HYLTON informed me he believed the fuses attached to pole 120772797 were
6 classified as "exempt" based upon his examination with binoculars. HYLTON stated two
7 of the three fuses were missing a red cap on the expulsion end (end facing ground
8 when fuse is in the closed position). HYLTON stated that he would need to examine the
9 fuses more closely to determine if they had operated as designed. HYLTON also
10 informed me he would like to examine all the equipment on the pole and all three
11 conductors more closely. I advised HYLTON I would arrange for a CAL FIRE contractor
12 to remove the equipment for his examination.

13
14 MCNEIL informed me after his preliminary evaluations of the subject tree he felt the tree
15 was compromised and not healthy before the fire. MCNEIL stated he would need to
16 examine the tree further to determine its pre – existing condition. MCNEIL advised me
17 he would need approximately 6 feet of the trunk removed and hauled out for
18 examination. He advised me it was ok to remove the trunk in sections if I marked the
19 orientation of the tree beforehand. MCNEIL advised me he would also like to have the
20 stump removed for evaluation and would send me picture schematics of how he would
21 like it to be cut. I told MCNEIL I would arrange for the tree and stump to be removed.
22 We then departed the scene for the day.



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25

Officer Initials

10

1 On July 16, 2021, at approximately 8:00 AM, I met with members from CAL FIRE
2 Technical Services at 220 Grand Avenue, Oroville, CA for a briefing. At briefing we
3 discussed the plan and objectives to conduct a drone flight and Light Intensity Distance
4 and Ranging (LIDAR) scan of the GOA and surrounding area. At approximately 9:30
5 AM, we concluded our briefing and drove to the origin area. Due to road conditions
6 (rocks and debris) in the travel route, we had a skid steer tractor clear the path. We
7 arrived at the origin area at approximately 1:30 PM. CAL FIRE Technical Service's
8 members conducted a drone flight of the GOA, overhead powerlines, and surrounding
9 vegetation.

10
11 After the drone flight was completed, BERRY and I used a handheld metal detector to
12 look for any type of metallic material that could have been expelled from the blown
13 fuses below the pole labeled 120772797. We conducted our search approximately 20
14 feet out from the base of the pole to the north, south, east, and west. Other than metal
15 debris from years of utility line work, we did not find anything that would have possibly
16 expelled from the fuses. We did collect one small piece of wire as an item of interest,
17 but later determined it was most likely waste discarded from previous utility work. The
18 wire did not resemble anything that could have been expelled from the fuse or overhead
19 equipment.

20
21 After completing our search with the metal detector, CAL FIRE Technical Services
22 members set up their equipment for LIDAR scanning. At approximately 6:00 PM, we
23 departed the origin area with a plan to return and finish LIDAR scanning the next
24 morning.

25
26 On July 17, 2021, at approximately 8:00 AM, I met with members from CAL FIRE
27 Technical Services, HYLTON and B&B High Voltage (utility line contractors) at 220
28 Grand Avenue, Oroville, CA for briefing. At briefing we discussed a plan for HYLTON
29 and B&B High Voltage to examine the Bucks 1101 circuit from the nearest switch to the
30 origin area and determine a plan to safely remove all necessary equipment in the
31 coming days. After briefing was concluded BERRY took CAL FIRE Technical Services
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1 members to the origin to complete their LIDAR scan. I took HILTON and B&B to the
2 Cresta Dam to examine the Bucks 1101 circuit from that vantage point. From the area
3 of Cresta dam I was able to see the subject tree laying across the conductors with the
4 naked eye and even more clearly with the use of binoculars. We observed the
5 conductors ran downhill from Camp Creek Road, across the Feather River to the Cresta
6 Dam and a secondary pole which most likely fed the lighting system for the Elephant
7 Butte tunnel. We drove up the Highway 70 canyon for several miles following the
8 conductors looking for the termination point or switch. We traced the conductors to a
9 pole with a switch located off Highway 70 and labeled 941. The switch was locked with
10 a PG&E lock and posted with a "MAN on LINE" tag. The tag read "RC For Fire"
11 attached to 941 and dated 7-13-21. The tag did not have a time referenced. I
12 photographed the tag and we proceeded to the origin.



13
14
15 We arrived at the origin at approximately 11:30 PM, and staged until approximately 1:00
16 PM, waiting for the completion of LIDAR. Once LIDAR was complete, we determined it
17 was safe to remove the fuses from pole 120772797. B&B employees used climbing
18 equipment to access the fuses. They photographed and removed the fuses and left all
19 other equipment intact. HYLTON examined all three fuses and tested them for
20 continuity. In electronics, a continuity test is the checking of an electric circuit to see if
21 current flows (that it is in fact a complete circuit). A continuity test is performed by
22 placing a small voltage (wired in series with an LED or noise-producing component such
23 as a piezoelectric speaker) across the chosen path. If electron flow is inhibited by
24 broken conductors, damaged components, or excessive resistance, the circuit is "open"
25 HYLTON concluded the two fuses from conductors 1 and 2 were in fact blown (open)

- 1 and did not have any continuity. Conductor 3 was not blown and did have continuity.
2 After HILTON examined the fuses, BERRY photographed while I packaged and labeled
3 them as evidence.
4
5 Fuse from conductor #1 (southern conductor) or far right conductor looking downhill
6 from Camp Creek Road was labeled E-1.



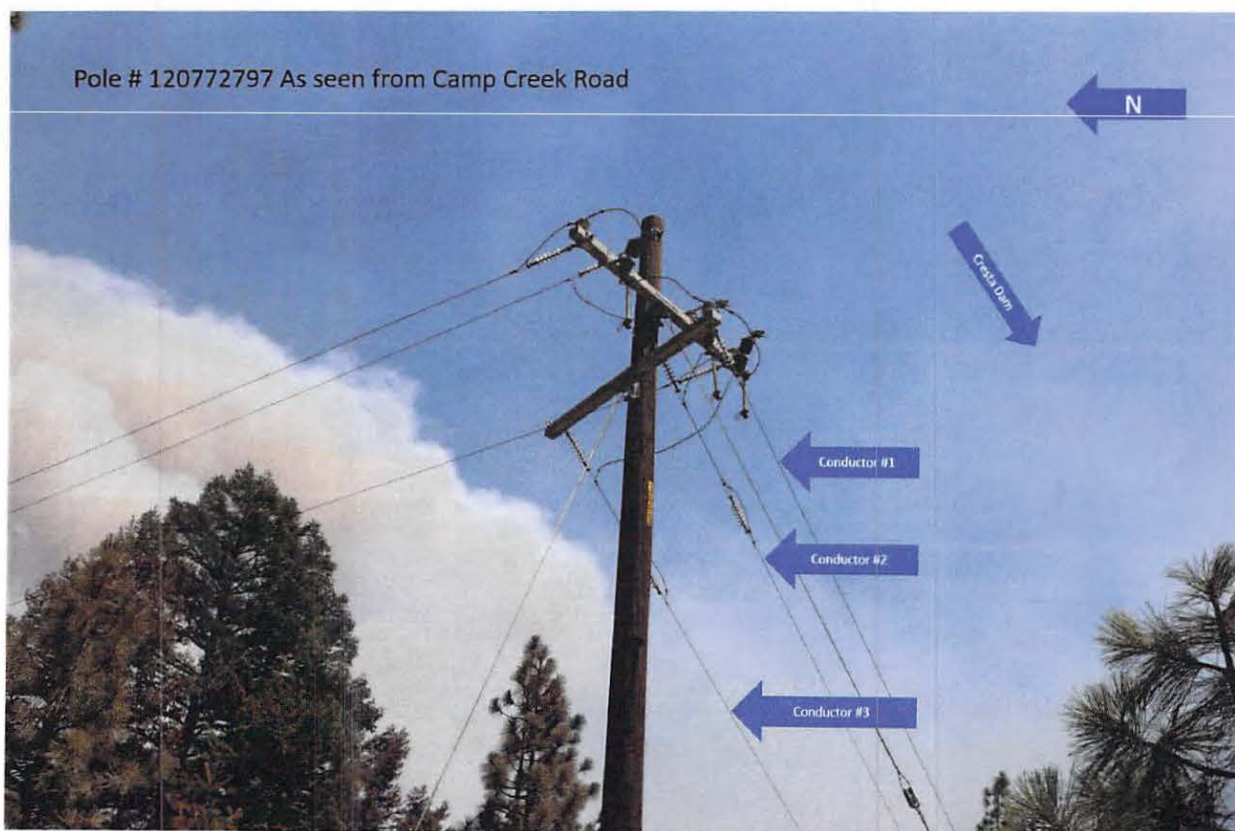
- 7
8 Fuse from conductor #2 (middle conductor) was labeled E-2.



- 1 Fuse from conductor #3 (northern conductor) or far left conductor looking downhill from
- 2 Camp Creek Road was labeled E-3.



3



4

Handwritten signature in blue ink.

1 After removal and packaging of the fuses we departed the origin.

2
3 On July 18, 2021, at approximately 9:00 AM, I met with CAL FIRE Investigators, CAL
4 FIRE private contractors, Butte County District attorney's representatives, Office of
5 Energy and Infrastructure Safety (OEIS), PG&E troubleman, PG&E attorneys and
6 PG&E private contractors at Scooters Café located at the intersection of Highway 70
7 and Deadwood Road. The plan was to examine, photograph and collect PG&E owned
8 equipment and the subject tree from the GOA. Before the operation took place all
9 representatives who were going to enter the scene were asked to sign a roster for
10 accountability and take part in a safety briefing. The following personnel from the
11 various entities were in attendance.

12
13 Jennifer DUPRE-TOKOS (BCDA)

14 Rick DUPRE-TOKOS (BCDA)

15 Marc NOEL (BCDA)

16 Jon DUFFY (BCDA)

17 Chris OAKLEY (BCDA)

18 Elizabeth MCALPINE (OEIS)

19 Caroline Thomas JACOBS (OEIS)

20 Scott HYLTON (TSH Electrical)

21 Greg BAIRD (B&B Line)

22 Alixa TAGGART (B&B Line)

23 Justin RAMIREZ (B&B Line)

24 Martin CASTRO (B&B Line)

25 [REDACTED] (PG&E)

26 [REDACTED] (PG&E EXPONENT)

27 [REDACTED] (PG&E EXPONENT)

28 [REDACTED] (PG&E)

29 [REDACTED] (PG&E)

30 Shawn ZIMMERMAKER (CAL FIRE)

31 Lance BERRY (CAL FIRE)

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1 Peter SMITH (CAL FIRE)
2 Randy SHAULIS (CAL FIRE contract tree faller)
3 Robert VAUGHN (CAL FIRE contract tree faller)
4

5 At approximately 10:00 AM we departed Scooters and arrived at the origin at
6 approximately 10:45 AM. Upon our arrival CAL FIRE contactors with B&B High Voltage
7 and a PG&E troubleman worked to ground the electrical equipment and make it safe for
8 tree removal and evidence collection. The line was grounded and deemed safe at
9 approximately 12:00 PM.

10
11 Due to fire activity, span of control and scene safety it was asked that all non-CAL FIRE
12 employees/contractors except for [REDACTED] (PG&E Troubleman) stay out of the
13 working area while line work or tree work was taking place. Once the equipment was
14 safely on the ground, respective entities such as PG&E contractors, OEIS and District
15 Attorney officials could observe and photograph. Several times during these operations
16 PG&E contractors and employees had to be reminded to keep their distance.

17
18 At approximately 12:30 PM, BERRY accompanied CAL FIRE contract faller Randy
19 SHAULIS down to the subject tree and photographed him while he cut the subject tree
20 free from the conductors. Before the tree was cut, BERRY used orange marking paint to
21 mark the tree's orientation on the trunk. Once the tree was free of the conductors
22 BERRY examined the tree and advised SHAULIS how he wanted it cut for evidence
23 purposes. SHAULIS cut two sections from the top of the tree that had come into contact
24 and rested on the conductors. BERRY photographed and packaged those sections of
25 the trunk as evidence, labeled E-4 and E-5.



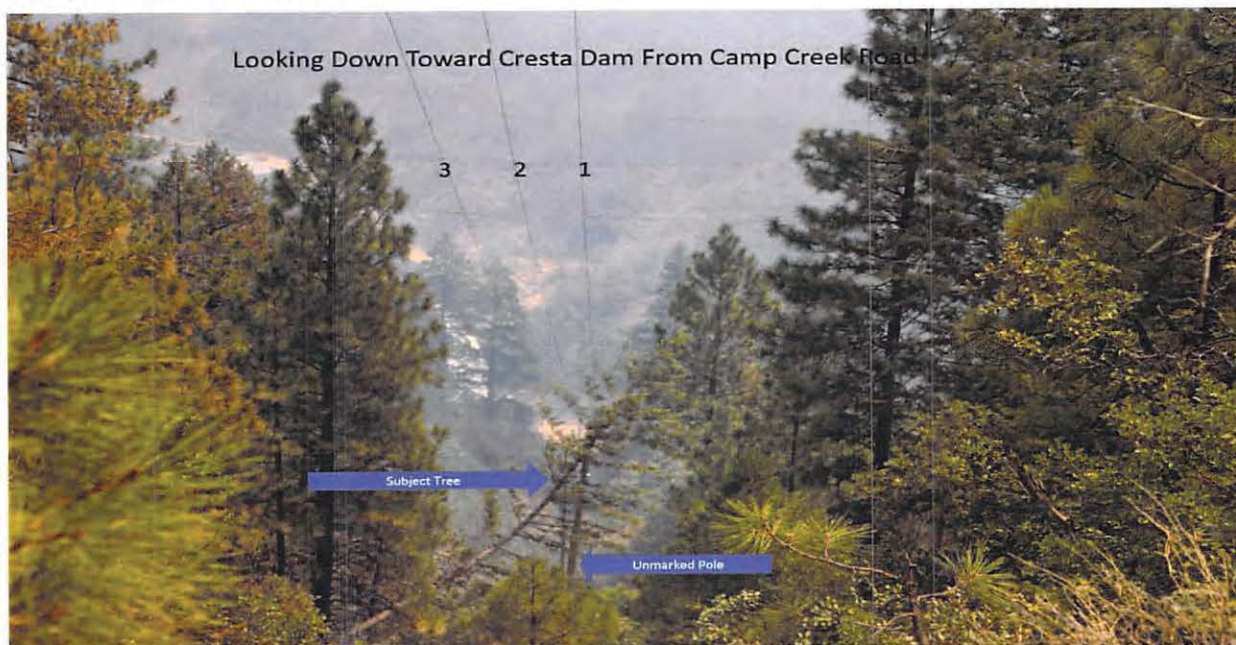
Once the tree was free from the conductors, members from B&B High Voltage removed the following equipment from the pole nearest Camp Creek Road labeled 120772797.

1. South phase cutout
2. Middle phase cutout
3. North phase cutout
4. North phase (top arm) high side jumper
5. Middle phase (top arm) high side jumper
6. South phase (top arm) high side jumper
7. West phase (low side) jumper off buck arm
8. Middle phase (low side) jumper off buck arm
9. East phase (low side) jumper off buck arm

The equipment was laid out on Camp Creek Road in the same orientation as it was removed. The equipment was examined and photographed by CAL FIRE electrical consultant Scott HYLTON. After his initial evaluation HYLTON advised me, he did not see anything that stood out to him that indicated a problem or failure of these items. The equipment was then evaluated and photographed by PG&E contractors who, despite being directed not to handle it continued to do so. At the direction of Butte County District Attorney's Office personnel, the equipment was packaged, inventoried, and labeled. The equipment was not assigned evidence numbers but were considered items of interest.

Once the equipment was taken from the pole, each conductor spanning from pole 120772797 downhill to the unmarked pole was lowered and examined by HYLTON for damage or signs of failure. PG&E contractors were allowed to examine, measure and photograph. Once again despite being told not to handle potential evidence PG&E employees and contractors continued to do so. Once examined and photographed each piece of damaged conductor was removed in a section and packaged as evidence. The conductor was then spliced with a new section and raised back into position. The following pieces of conductor showed signs of damage or failure. They were removed

1 and packaged as evidence.



2
3
4 **Conductor #1** (southern conductor) Approximately 5 feet of conductor was removed
5 and packaged as evidence labeled E-6. This conductor showed remnants of tree bark
6 and materials transfer approximately 4-5 feet uphill (west) from the insulator on the
7 unmarked pole and within 16 inches from the insulator where the tree came to rest. This
8 section of conductor also showed signs of deformation, arcing, and flattening where the
9 tree contacted the conductor.



- 1 **Conductor #1** (southern Conductor) Approximately 34 feet uphill (west) from the
2 insulator on the unmarked pole. Approximately 12 inches of conductor was removed
3 and packaged as E-7. This section of conductor showed signs of fresh arcing and
4 beading in multiple spots over the approximate 12-inch section.



- 5
6
7 **Conductor #2** (middle conductor) Approximately 5 feet of conductor was removed and
8 packaged as E-8. This conductor showed remnants of tree bark and materials transfer
9 from approximately 6 feet uphill (west) and up to 16 inches from the insulator on the
10 unmarked pole.



11

1
2 **Conductor #2** (middle conductor) Approximately 12 inches of conductor was removed
3 and packaged as E-10. This section of conductor was located approximately 32 feet
4 uphill from the insulator on the unmarked pole. This section of conductor showed signs
5 of fresh arcing and beading in multiple spots over the approximate 12-inch section.



6
7
8 **Conductor #3** (north conductor) Approximately 4 feet of conductor was removed and
9 packaged as E-9. This section of conductor showed signs of tree bark and material
10 transfer from approximately 34 feet uphill of the unmarked pole to within approximately
11 12 inches of the insulator on the unmarked pole. It also showed black remnants where
12 the tree trunk made constant contact after coming to rest. This area was located
13 approximately 33 inches uphill from the insulator.



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35

Officer Initials

1
2 Once we completed the on-site evaluation and collection of the electrical equipment, we
3 used a rope system to winch the base of the subject tree to the roadway. The tree was
4 then marked with orange paint to represent the bottom, middle and top sections. The
5 subject tree was then cut into 3 separate pieces for ease of transportation and
6 evaluation with MCNEIL's consultation. PG&E contractors were asked not to touch the
7 items but were allowed to examine, measure and photograph. Once again, despite
8 being asked not to touch, they did so anyway. The following evidence numbers were
9 assigned to each section.

10
11 "Bottom" was marked as E-11-1

12 "Middle" was marked as E-11-2

13 "Top" was marked as E-11-3



14
15
16 At approximately 6:30 PM, all personnel were accounted for and vacated the origin
17 area. All evidence was transported and secured in a CAL FIRE owned storage
18 container.

19
20 On July 21, 2021, at approximately 10:00 AM, BERRY and I arrived at the origin area
21 with CAL FIRE Peace Officer Jeremy MONROE and CAL FIRE Battalion Chief Chip

1 FOWLER both qualified fire investigator's (INVF). MONROE and FOWLER were
2 brought to the origin area to evaluate and if possible, narrow the SOA that had been
3 previously determined. MONROE and FOWLER had no knowledge of the fire, other
4 than what the public knew at that time and had not been involved in any of the previous
5 investigation roles. MONROE and FOWLER were given a brief layout of the area and
6 what I observed upon my arrival at scene on July 13, 2021. MONROE and FOWLER
7 were not given any direction or input as to what was being considered the GOA.
8 BERRY and I stayed on the road while MONROE and FOWLER observed the scene
9 and made their determination. (See attachment K. LE71 supplemental report from
10 MONROE and FOWLER)

11
12 On July 21, 2021, CAL FIRE Officer Shane LARSEN conducted interviews with Butte
13 County Public Works employees Sean HASSEL, Miguel FLORES and Kevin THOMAS.
14 HASSEL, FLORES and THOMAS were working on the bridge on Camp Creek Road on
15 July 13, 2021. They told LARSEN the following in summary.

16
17 They identified the bridge on Camp Creek as bridge 12C-0432 and stated that
18 they had started work on July 13, 2021 at approximately 9:00 or 9:30 AM. The
19 bridge had been flagged for repair due to some missing and rotten deck boards.
20 At approximately 1:30 PM, a PG&E employee, described as a 6-foot tall, clean
21 cut white male approximately 40 years old arrived at the bridge. The PG&E
22 employee stated, "I guess the bridge really is closed. I will tell the boss we need
23 a helicopter or something". The PG&E employee did not express any need or
24 urgency to get across the bridge and left. No other PG&E personnel attempted to
25 access the bridge while they were there, and they saw no helicopters or drones
26 flying in the area. They stated that they concluded work on the bridge at
27 approximately 3:20 PM and did not see or smell any smoke or fire during their
28 work. (See attachment's R&Q. Supplemental LE-71 reports from LARSEN)

29
30 On July 22, 2021, at approximately 11:00 AM, BERRY and I returned to the origin area
31 with a CAL FIRE contracted tree faller to remove the subject tree stump for evidence
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1 and further examination by CAL FIRE contracted arborist MCNEIL. With a digging tool
2 we exposed the soil around the base of the stump to cut the root system below the soil
3 line. This was done to ensure we had all the pertinent pieces of the stump that had been
4 exposed pre and post fire for forensic analysis.
5



6
7 After exposing the root system below the soil level, the stump and a large portion of the
8 root were photographed and cut loose. The stump and root were then packaged in
9 protective bubble wrap and loaded into a cargo net and flown by long line below the
10 Butte County Sheriff's Department helicopter to the Shady Rest Area along Highway 70.
11 The stump and root were then loaded into a CAL FIRE flatbed vehicle and driven to a
12 secure CAL FIRE evidence storage facility. The flatbed was followed by BERRY during
13 transport. The tap root was labeled as E-12 and the stump was labeled as E-13.



14
15
16 On July 23, 2021, at 9:00 PM, Element Security was relieved, and the scene was
17 released by CAL FIRE Officers.



On July 23, 2021, CAL FIRE Officer Shane LARSEN conducted an interview with PG&E employee [REDACTED] W-3, who told LARSEN the following in summary.

[REDACTED] W-3 stated he is a troubleman with PG&E, but is also filling in as a supervisor, overseeing 15 troublemen, including [REDACTED] W-1 [REDACTED] W-3 stated that [REDACTED] W-1 had been dispatched late in the morning to check out a fuse at Cresta Dam. [REDACTED] W-3 stated that he was unaware of any outages. [REDACTED] W-3 stated that [REDACTED] W-1 had not contacted him over the course of the day regarding the tag. [REDACTED] W-3 stated that [REDACTED] W-1 had later told him that while trying to make access up Camp Creek Road, he had encountered Butte County Public Works and could not cross the bridge and had to wait a couple hours before getting across. [REDACTED] W-3 stated at approximately 4:45 PM on July 13, 2021 he heard [REDACTED] W-1 who sounded frantic, calling out via two-way radio to Rocklin PG&E station. Rocklin was not answering back. [REDACTED] W-3 attempted to contact [REDACTED] W-1 via two-way radio. When [REDACTED] W-1 responded several minutes later he told [REDACTED] W-3 that there was a fire and he needed someone to come and help fight it. He stated that the fire was up on the hill above Cresta Dam, it was on the ground, and it hadn't gotten into the trees yet, and they were going to need a helicopter. [REDACTED] W-1 told [REDACTED] W-3 that the fire was located "approximately 1 span, load side of fuse cut-outs 17733, on the Bucks Creek 1101."

(See attachment T. Supplemental LE-71 report from LARSEN)

On Monday, August 2, 2021, at approximately 11:00 AM, I met with Joe MCNEIL at 220 Grand Avenue, Oroville CA. The purpose of the meeting was for MCNEIL to examine and test portions of the subject tree and stump.

After MCNEIL's examination, he advised me the tree most likely had visible damage he described as "cat facing" that may have been recognizable before the fire occurred.

MCNEIL explained that "cat facing" is a term used to describe damage to the tree trunk

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39

Officer Initials JS

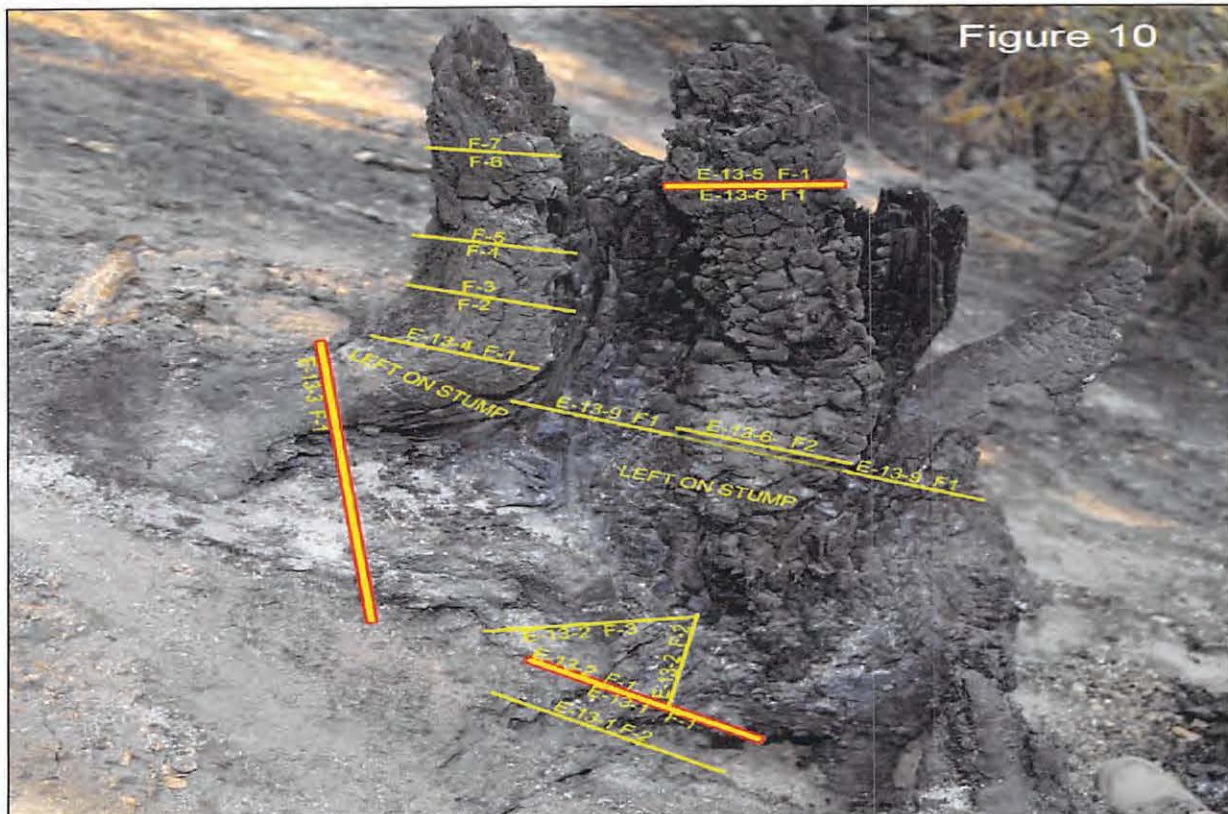
1 that generally occurs from a previous injury to the tree, such as fire damage or a
2 mechanical equipment strike. MCNEIL advised me he would like to cut several portions
3 from the stump and trunk for further testing and analysis. Due to the amount of damage
4 the base of the tree and stump sustained from the fire, MCNEIL felt this was the only
5 way to thoroughly examine the tree for age, degree of injury, decay, and stability. These
6 were all factors in determining whether the injury or stability of the tree was
7 recognizable pre fire.

8
9 Approximately five pieces were cut from the subject tree stump and labeled as evidence
10 numbers E-13-1, E-13-2, E-13-3, E-13-4, and E-13-5. All five pieces of evidence were
11 turned over to MCNEIL for testing and analysis. A chain of custody form was completed
12 and signed by MCNEIL and I. (See attachment M. LE-71 Stump evidence collection)

13
14 After MCNEIL's first visit he contacted me by phone and advised me he believed the
15 subject tree was damaged by some sort of event (most likely fire) in 2008 and again in
16 2015 or 2016. MCNEIL asked if I would be able to determine if there had been a fire or
17 other significant event in the area that could have damaged the subject tree. With the
18 use of CAL FIRE archived data and fire history maps, I determined that the 2008 Butte
19 lightning complex fire had burned through the footprint of the Dixie GOA. I was unable
20 to determine what the 2015/2016 event would have been. Based upon that information
21 MCNEIL advised me he would like to return for more samples of the subject tree stump.

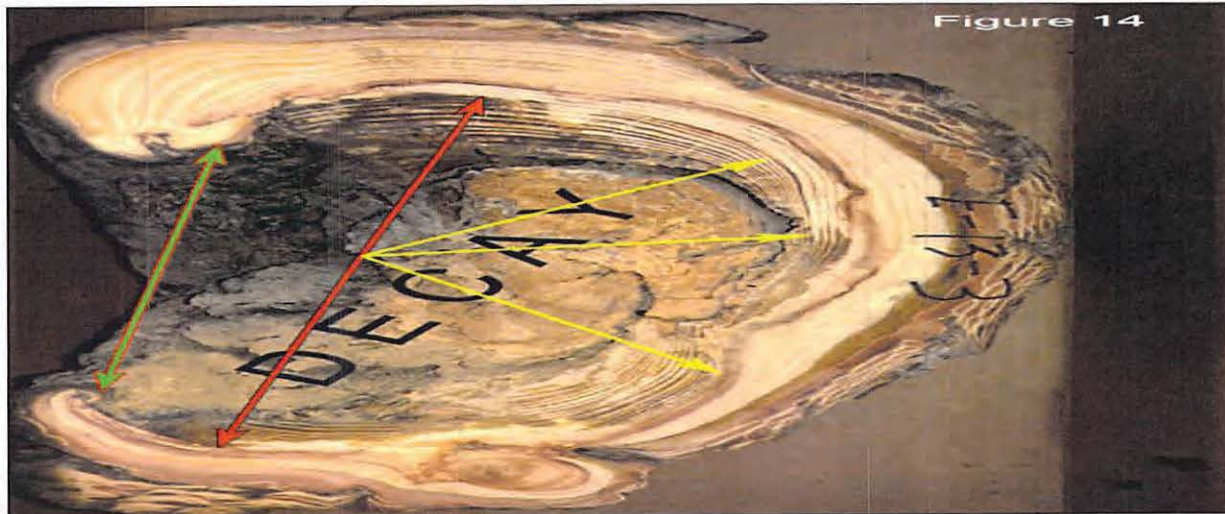


On September 11, 2021, at approximately 11:00 AM, MCNEILL returned and met with CAL FIRE Officer Mark HILLSKOTTER. MCNEIL removed four more pieces of the subject stump for further analysis and testing. Those pieces were labeled as evidence numbers E-13-6, E-13-7, E-13-8, and E-13-9. A chain of custody form was completed and signed by HILLSKOTTER and MCNEIL.



On October 10, 2021, I received MCNEIL's final report. In that report MCNEIL concluded that the subject tree was approximately ninety years old, approximately 15.8 inches in diameter and approximately 65 feet tall. "The tree was growing vertically without a lean" and was "alive and vital at the time of failure".

Based upon MCNEIL's evaluation the tree was likely significantly injured by the Butte Lightning Complex Fire in 2008 and by an unidentified event between 2015 and 2016. These injuries caused the live cambium (growing part of trunk) to be severely damaged

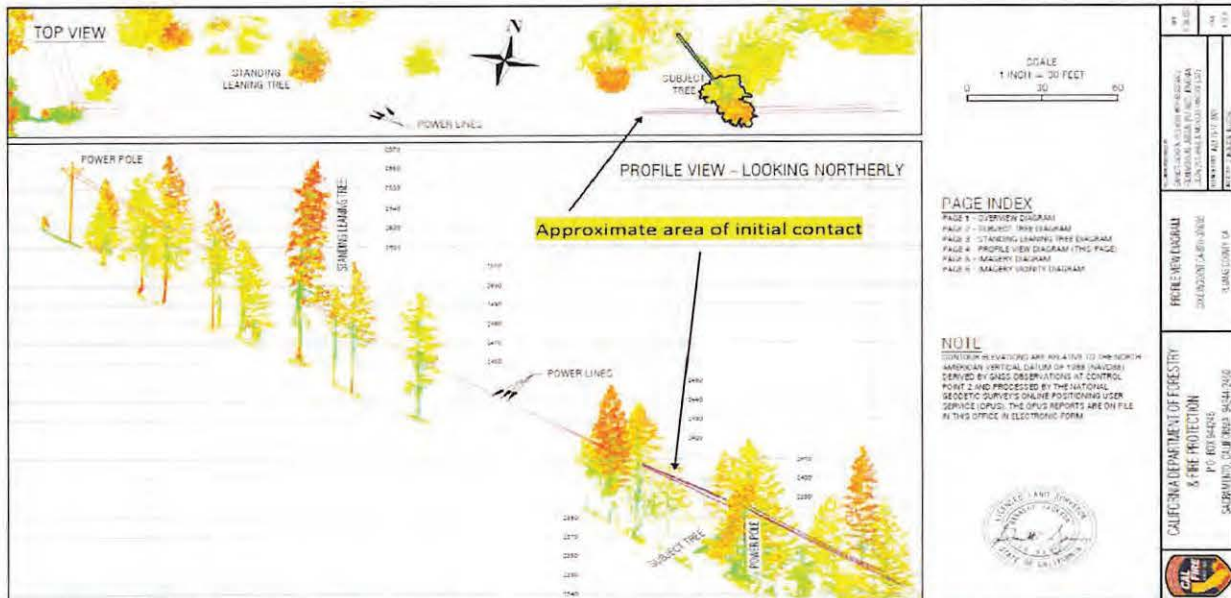


1
2
3 MCNEIL stated in the conclusion of his report that the International Society of
4 Arboriculture has adopted a Tree Risk Assessment Protocol within their Tree Risk
5 Assessment Qualification program. It is MCNEIL'S opinion that such an assessment,
6 following the protocol would have resulted in a risk rating of High for this Douglas fir
7 tree. (See MCNEIL'S full report attachment W)

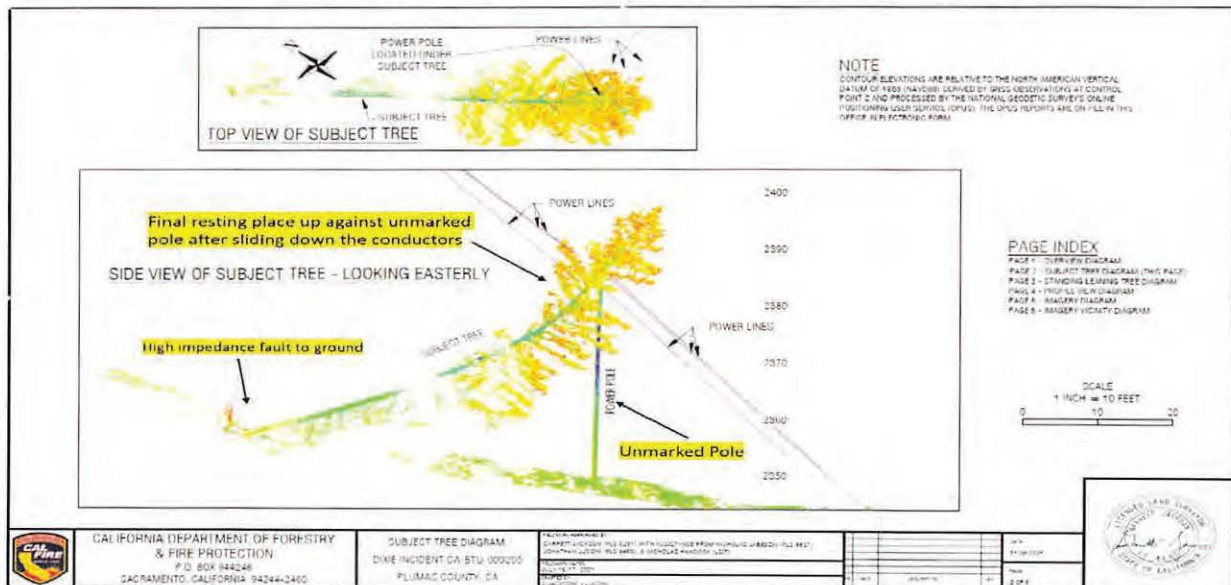
8
9 On October 12, 2021, at approximately 11:45 AM, MCNEIL returned all items of
10 evidence to me at 220 Grand Avenue, Oroville, CA. A chain of custody form was
11 completed and signed by MCNEIL and I. All evidence was returned to a secure CAL
12 FIRE storage facility.

13
14 On November 29, 2021, I received a copy of HYLTON's report. HYLTON concluded the
15 most probable scenario, based upon pole location, subject tree location, fuse status,
16 SCADA data and markings found on conductors is the subject tree fell across the line
17 approximately 32 feet west (uphill) of its final resting place (up against the unmarked
18 pole) at approximately 6:48 AM on July 13, 2021. The subject tree contacted all three
19 conductors (12kV) and, because the line is built on a steep slope, it slid down the
20 conductors and came to rest next to the pole. Two of the three fuses blew upon the
21 initial contact (fuses 1&2). The third fuse (fuse 3) remained intact and kept the line
22 energized. All three conductors were energized through back feed by the transformers

- 1 at Cresta Dam. This caused the tree to remain energized until the line was de –
 2 energized by PG&E.



- 3
 4 HYLTON concluded the tree being in contact with energized conductors (prior to PG&E
 5 de-energizing) and the ground created a high impedance fault. The tree may have
 6 initially stayed connected to the stump; or it may have broken loose and came to rest on
 7 the ground. In either case, the connection to the earth would create a poor (high
 8 impedance) path to ground. Poor electrical connections, especially at high voltage,
 9 create heat and cause arcing. (See HYLTON'S full report attachment X)



10

CONCLUSION

Based upon my training and experience, my personal observations, witness statements, and final reports generated by CAL FIRE consultants and contractors it is my determination the Dixie Fire was caused when a previously damaged and decaying Douglas-fir pine tree (subject tree) fell, contacted, and remained in all three phases of the Bucks 1101 circuit for approximately 10 hours, causing a high impedance fault and a path to ground. The high impedance fault and path to ground caused heating and arcing and eventually over the span of approximately 10 hours ignited a dry and receptive fuel bed.

It is my determination the prolonged response to the initial outage and fault that occurred at 6:48 AM, was a direct and negligent factor in the ignition of the fire. Had PG&E arrived on scene earlier, they could have detected the fault (subject tree in conductors) and opened the third fuse before it had time to ignite a receptive fuel bed. Per the SCADA data the fault and subsequent outage occurred at approximately 6:48 AM. Per witness statements from Butte County Public Works employees the bridge work did not commence until 9:00-9:30 AM. This provided several hours for PG&E to respond to the location of the fault prior to bridge work.

It is my determination that when PG&E could not access the fault because of the bridge work, they could have opened the 941 switch and de energized that portion of the Bucks 1101 circuit. It is common and historic knowledge that the Highway 70 corridor is known for extreme fire danger and poor access. Several large and devastating fires including the Camp Fire, (a PG&E caused fire) have ignited over the last several years in that geographical area. It is also common knowledge that the month of July in Butte County and surrounding areas is peak fire season, yet no sense of urgency was demonstrated by PG&E to determine the cause of the fault in a fire prone area during a severe time of year.

It is also my determination that through vegetative inspections required of PG&E the
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1 subject tree (approximately 65 feet tall and located approximately 50 feet from the
2 conductors) should have been discovered and removed between 2008 and 2021. Had
3 the subject tree have been removed per Public Resource Code 4293 the Dixie Fire
4 would not have ignited on July 13, 2021.

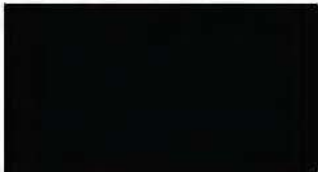
ATTACHMENTS

- A. 911 Calls
- B. FC-34 Dispatch Report
- C. RAWS Weather Data
- D. LIDAR Maps
- E. Photo Log: Origin Investigation
- F. Photo Log: Equipment and Tree Evidence Collection
- G. Photo Log: Stump collection
- H. Evidence Log Sheet
- I. Evidence Chain of Custody
- J. Drone Flight Imagery
- K. Monroe Fowler LE-71
- L. Fire History Map
- M. McNeil Stump Evidence Collection #1 LE-71
- N. McNeil Stump Evidence Collection #2 LE-71
- O. Albert 911 Caller Interview LE-71
- P. Epperson 911 Caller Interview LE-71
- Q. Flores and Thomas Public Works Interview LE-71
- R. Hassel Public Works Interview LE-71
- S. Nulph 911 Caller Interview LE-71
- T. **W-3** PG&E Supervisor Interview LE-71
- U. Drought State of Emergency Proclamation
- V. DINS Report
- W. McNeil Arboriculture Report
- X. TSH Consulting (Scott Hylton) Report
- Y. Plumas County Assessor's Parcel Map

END OF REPORT



Matthew Palade
Peace Officer #4416
CAL FIRE Butte



PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3B

ATTACHMENT 2

**DIXIE FIRE AGENCY REPORT, ATTACHMENT W
(MCNEIL ARBORICULTURE CONSULTANTS LLC)**

October 10, 2021

Matthew Palade
CalFire Butte Unit
220 Grand Avenue
Oroville, CA 95965-3408

SUBJECT: Observations and assessment of a tree associated with initiation of the Dixie Fire. The purpose of this assessment and report is to assist others in understanding the cause of that fire. McNeil Arboriculture Consultants LLC (see endnoteⁱ page 23) was requested by the California Department of Forestry and Fire Protection to investigate the failure of a Douglas fir onto conductors on July 13, 2021. We inspected the tree and the site on July 15. We collected stump samples for analysis from the Calfire Oroville storage units on August 2 and September 11, 2021.

SUMMARY

We found the tree in the position illustrated to the right in Figure 1, downslope toward the Feather River. The tree rested on conductors next to the vertical pole seen in the photo. The conductors were intact in the spans on both sides of the pole.

The tree was 15.8 inches in trunk diameter and at least 65 feet tall. It was on a sixty to seventy percent grade west-southwest and upslope of the Cresta Dam on the Feather River. It grew approximately north of and about 50 feet from a Pacific Gas and Electric (PG&E) utility pole that supported 12 KV lines that extended downslope to the Cresta Dam. The tree was across the slope and slightly higher on the slope than the pole. Later ring analysis suggests that the tree was about 90 years old and that it grew vertically without a lean. The tree was alive and vital at the time of failure. See endnoteⁱⁱ.

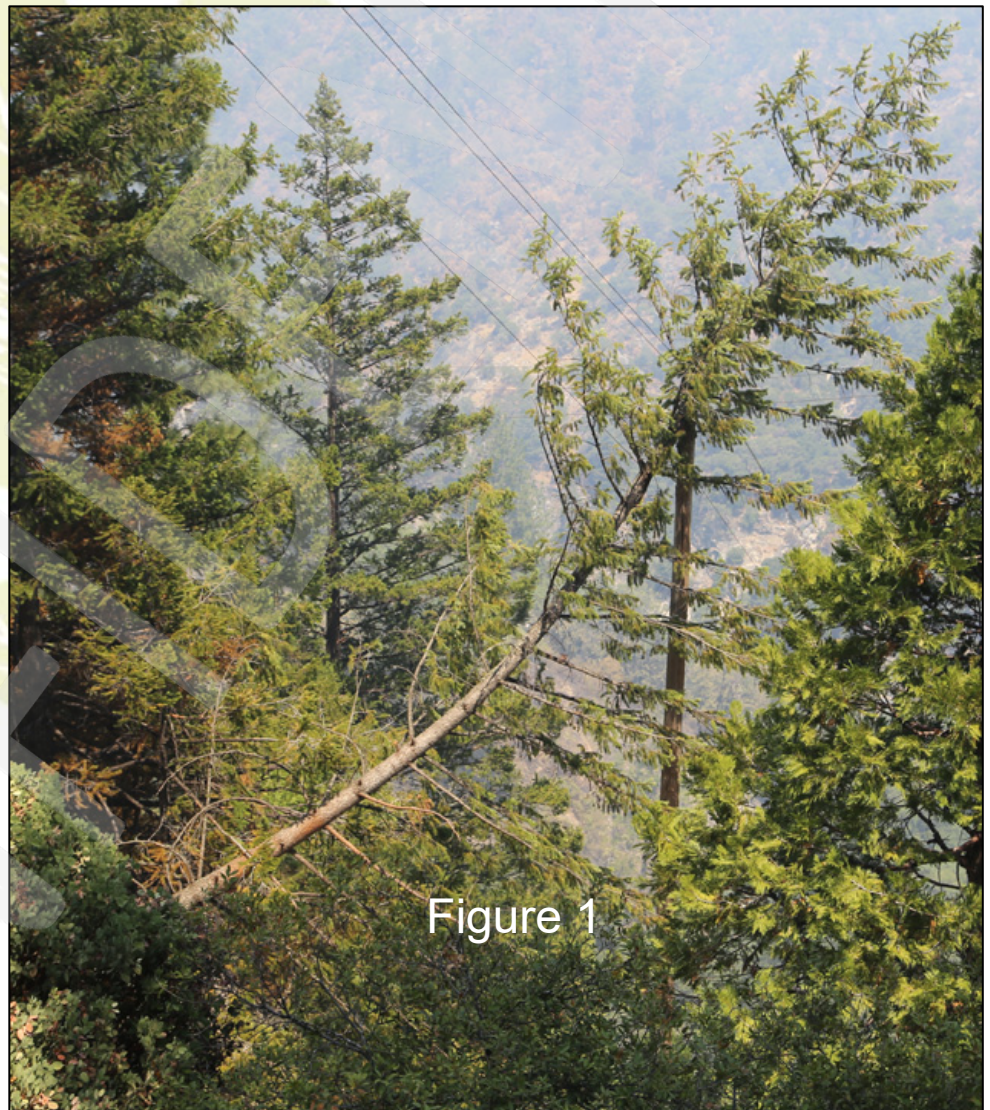




Figure 2

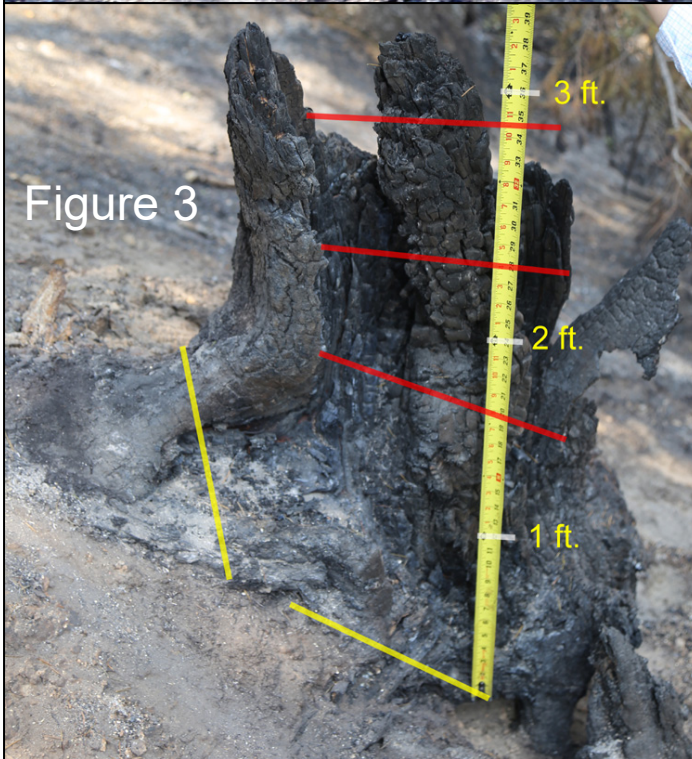


Figure 3

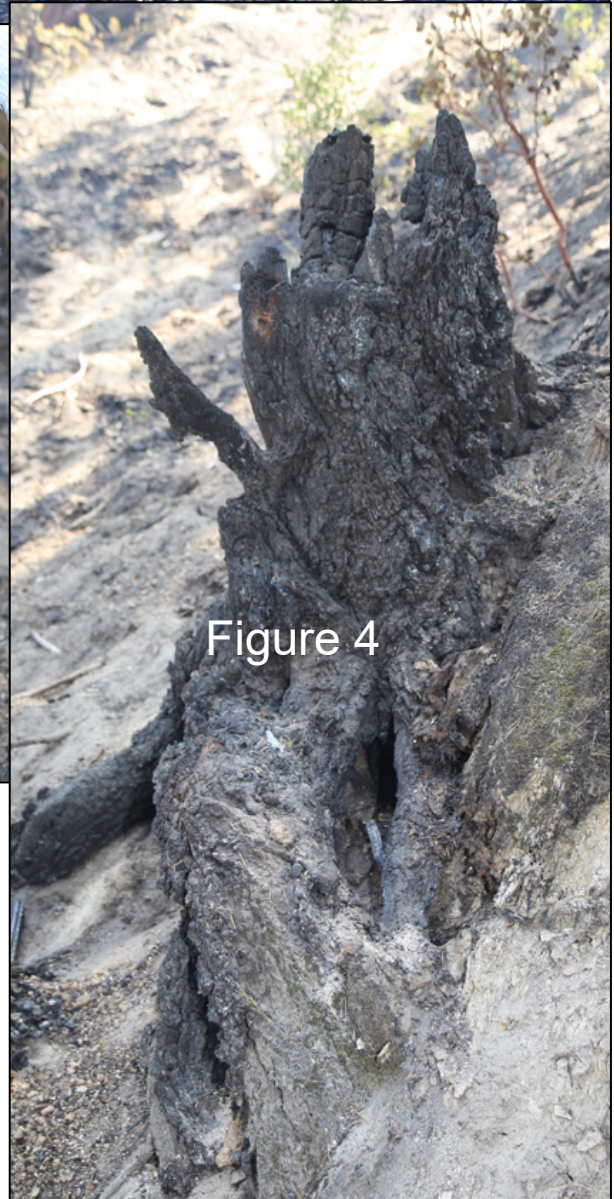


Figure 4

Figure 2 is the lower portion of the bole and stump as seen on July 15. The base of the tree bole had come loose and dislocated downhill from the top of the stump.

Figure 3 is taken across the slope of the south side of the stump, with our back to the conductors.

Figure 4 is of the stump, shot obliquely upslope, to the west.

We verified that the base of the tree was injured by a previous fire, the 2008 Butte Lightning Complex Fire, and later by an unidentified event between 2015 and 2016. Two major buttressing and mechanically supporting roots toward the west side, upslope, illustrated by the left yellow line in Figure 3, and the south side toward the conductors, illustrated by the right yellow line in Figure 3 were burned in the 2008 fire. The heat killed a third to half of the circumference of the roots. The observable burned sides of the roots were on the south side toward the conductors.

Above the roots evidence suggests that the south side of the lower trunk was burned, and killed over more than half the circumference of the trunk, facing the PG&E conductors. This would have formed a wound with no bark cover, visible as exposed and decaying wood. We are confident this wound was visible at least to the height of the lower red line on Figure 3, 18 to 22 inches above the ground. It is highly likely the wound extended at least to the middle red line on Figure 3, 26 to 30 inches above the ground. It is more likely than not that the wound extended to at least the upper red line, 32 to 38 inches above the ground.

Wind at the time of failure was about eight miles per hour, approximately from the north. The tree fell approximately to the south, but we do not have evidence that the wind directly caused the failure. There was not widespread limb or trunk failure of nearby trees. A single nearby tree failed at about the same time, a 9.6 inch trunk diameter¹ ponderosa pine. Small pine limbs may have contacted the Douglas fir when the pine failed, or the two trees may have failed independently. Both were predisposed to fail as they did but only the fir contacted the conductors.

In my opinion the degraded condition of the base of the Douglas fir was the primary cause of failure of the tree and that defect would have been visible without extraordinary discovery effort, from under the conductors. We saw no evidence of short or tall brush in front of the tree that might have impeded visibility. A cursory visual inspection of the base of the tree would almost certainly have revealed the extensive decay. The 2008 Calfire publication Power Line Fire Prevention Field Guide mentions heart rots or open wounds in the base of the bole of the tree. We have documented the defects of the Douglas fir in this report.

OBSERVATIONS

July 15, 2021

We visited the fire initiation site on this date. The tree was located on a 60 to 70 percent downslope from Storrie road, at that point a narrow dirt access road. Measured distance downslope from the edge of the road to the tree was 325 feet, and at the time of our inspection the tree was laying across the conductors near the pole at about a 47 to 50 degree angle, as seen in Figure 1. Trunk diameter was 15.8 inches and the tree was at least 65 feet tall. The tree was alive and vital at the time of failure.

Its location was west-southwest and upslope of the Cresta dam on the Feather River. It grew approximately north of and about 50 feet from a PG&E utility pole that supported 12 KV lines that extended downslope to the Cresta Dam. The tree was across the slope to the north and slightly higher on the slope than the pole. The trunk of the tree was dislocated from the top of the stump, which was heavily burned and charred as seen in Figures 2-4 and

¹ Measured at the standard 54 inches above grade.

Figure 16. This tree was an anomaly, as all surrounding trees and brush were more lightly burned.

The soil on the site is of granitic origin, decomposed to a fine gravel from the granite parent material. On some parts of the slope the gravel covered the stone below with half an inch of material, and in other places it was deeper. The granite stone was frequently fully exposed.

A ponderosa pine grew to the west and north of the failed Douglas fir. Foliage on this pine was only on one side, toward the fir tree. The pine grew in shallow duff and granite dust about six to eight inches deep on the flat top of a granite boulder. The base of the trunk was about a foot across. In Figure 5, a single root of a similar diameter to the base of the trunk joined the trunk to the side at a right angle. This pine failed directly toward the failed fir.

The pine had only the one root, with no roots supporting against its failure in the direction it fell. Twisting of the single root lifted the entire shallow duff layer in which the pine was rooted. The duff layer offered no resistance to the failure. The absence of debris under the duff layer suggests that the pine failure was close to the time of our inspection, perhaps concurrent with the Douglas fir failure.

An intervening oak tree prevented the pine from falling to the ground, but portions of the pine likely contacted the Douglas fir. Given this, it is possible that failure of the pine, which was predisposed to this type of failure, may have been the proximate cause of the Douglas fir failure. It is also possible that the Douglas fir failed independently of the pine. Both trees were predisposed to failure in the direction in which they failed.

We identified lower portions of the fir tree for recovery and further analysis, including the stump and several feet of the base of the trunk, as seen in Figure 6. Calfire extracted those tree parts to their storage unit in Oroville.



August 2, 2021, September 11, 2021

On August 2 we inspected the lower bole of the tree at the storage facility at the Calfire Butte Unit, 220 Grand Avenue in Oroville. This section, seen in Figure 6 is also seen to the right in Figure 7.

Below, in Figure 8 we cut a disk from the trunk at the two lines in Figure 7. The cut face shown here is identified as E-11-1.1. It is the face illustrated by the black arrow on Figure 7, upward toward the top of the tree.

The upper surface of the trunk after the tree came to rest on the slope was approximately at the 14 ½ inch mark in Figure 8, the right of that figure. The tree may have rotated slightly as it separated from the trunk. Because the stump and the end of the bole were so severely burned we were unable to match the parts for precise rotational orientation. However, the most heavily decayed portion of this cross section was on the side of the trunk approximately toward the conductors, placing this decay in-line with the decay seen in the stump.

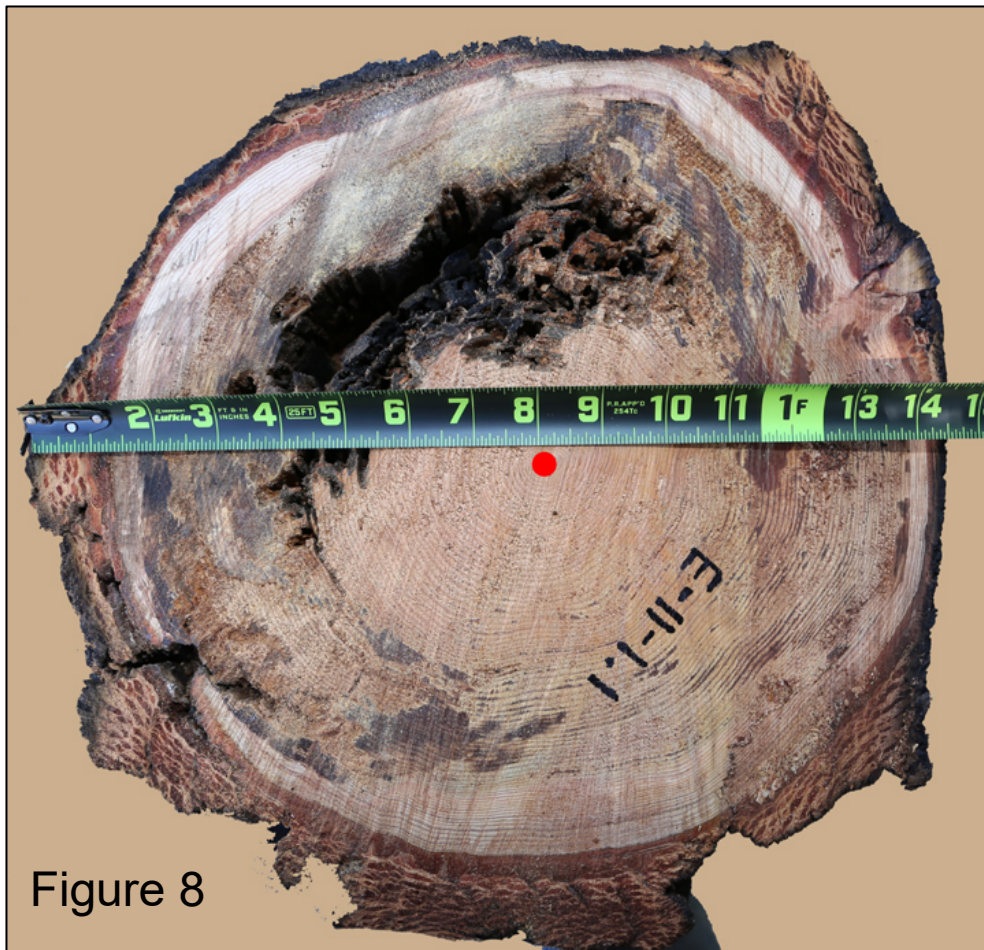


Figure 8

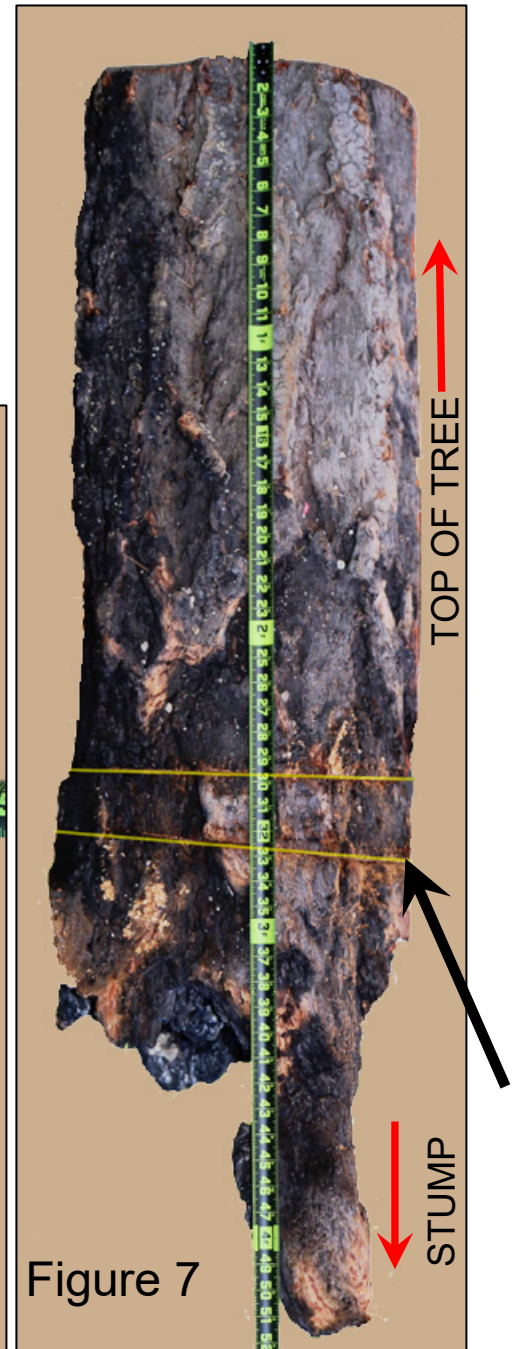


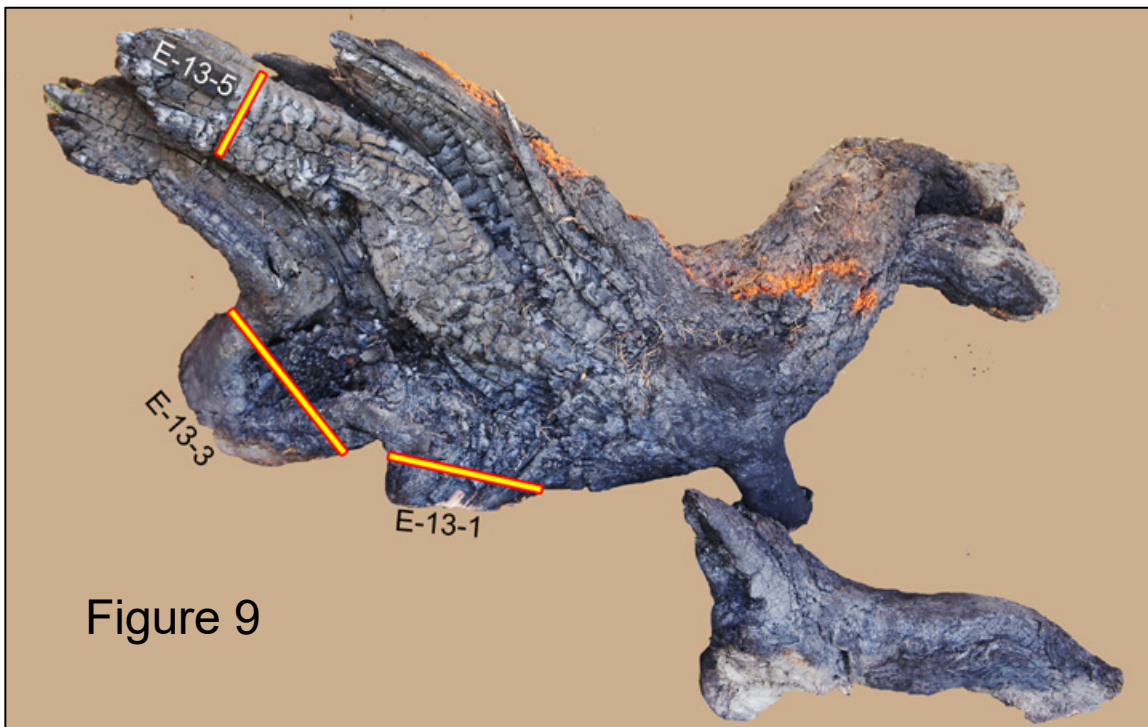
Figure 7

The center of the tree when it was a sapling is marked on Figure 8 by a red dot. It was nearly centered in the tree on the day it failed, as the concentric rings of annual growth are similar in thickness on all sides. This is evidence the tree grew relatively vertically,

without a lean. About 90 annual rings can be seen in this photograph, making the tree about 90 to 95 years old.

Beginning on page 8, the figures illustrate extensive decay in the lower several feet of the tree, the stump. Decay in trees tends to spread most rapidly in a longitudinal direction within the trunk². In this instance the more extensive decay in the stump traveled upward, its intensity decreasing with increasing height. The trunk cross-section at the upper line in Figure 7 exhibits less extensive decay than at the cross-section in Figure 8, just a few inches lower, illustrating a pattern that is consistent with known patterns of decay, and our observations.

On the same day we visited the Calfire storage site on Nelson Avenue in Oroville, where the stump of the tree was sequestered. Figure 9 illustrates the stump and one collected root. We took several cross-section samples E-13-1 through E-13-5 for analysis. We returned on September 11 to collect samples E-13-6 through E-13-9



Three of the sample locations are illustrated above, sample E-13-1, E-13-3 and E-13-5. See the next page, Figure 10 for a more complete index of sample locations. For orientation the three locations seen in Figure 9 are highlighted in Figure 10.

The following illustrations of extracted samples, through Figure 34 on page 19 are intended to demonstrate the locations of injuries to the lower three feet of the tree prior to the initiation of the Dixie fire. Wood present at the time of injury is generally more susceptible to decay from that injury than wood laid down post-injury.

² Shigo, A.L., H.G. Marx. Compartmentalization of Decay in Trees. USDA Forest Service. Washington D.C. Bulletin N. 405, July 1977.

Smith, K.T. Wounding, Compartmentalization, and Treatment Tradeoffs, International Society of Arboriculture, Journal of Arboriculture, 14(9) September 1988 pp 226-229

This is illustrated many times on the following pages. Wood on the outside of the injury, that is toward the bark is more frequently sound as time passes than wood toward the center of the tree relative to the injury.

We intend for visualization of the exhibits by the reader, to place the illustrations in their relative positions in the stump as illustrated in Figure 10, to establish for the reader a visual understanding of the significant³ extent of decay in the base of this tree prior to the Dixie Fire.

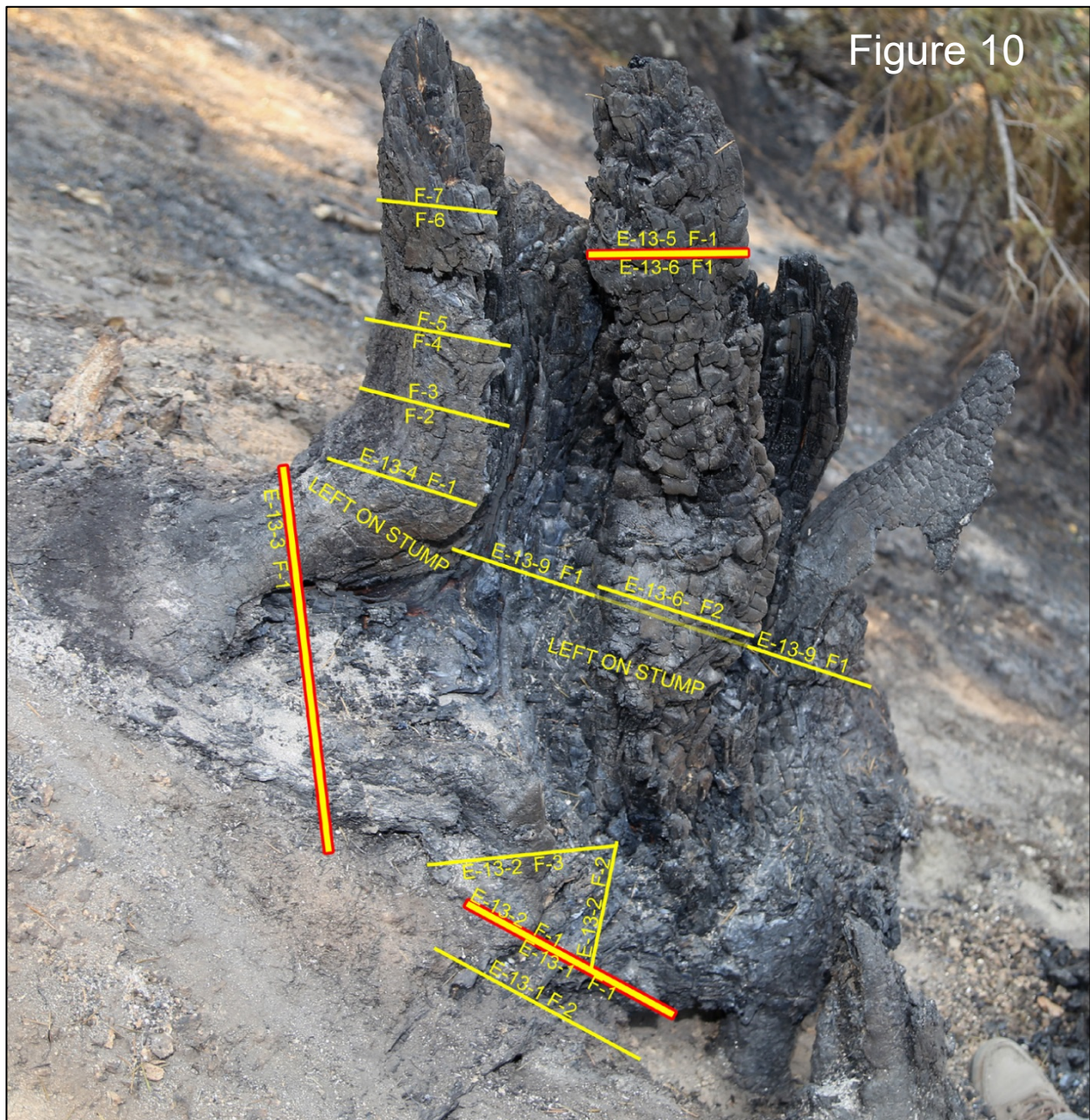
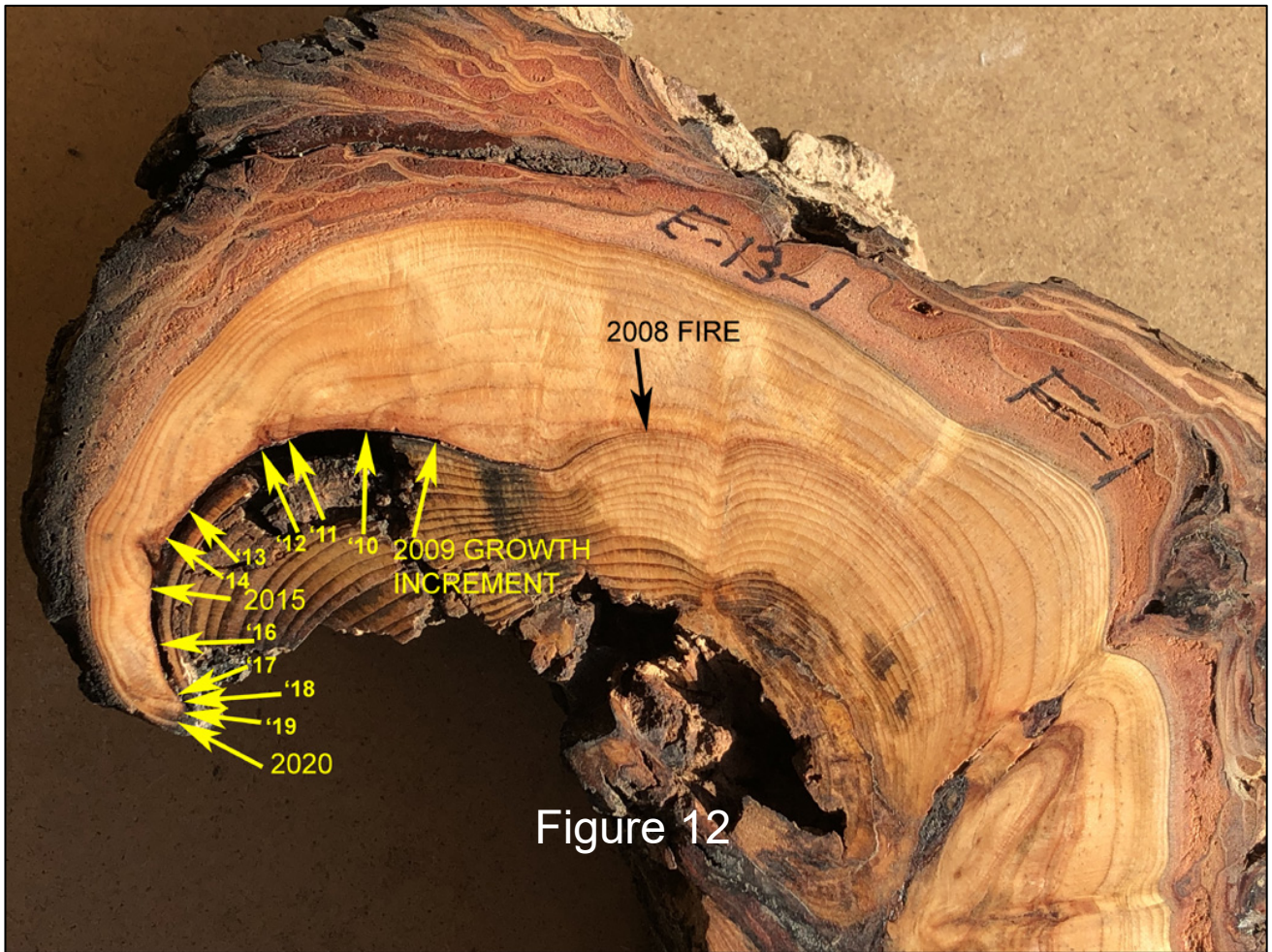
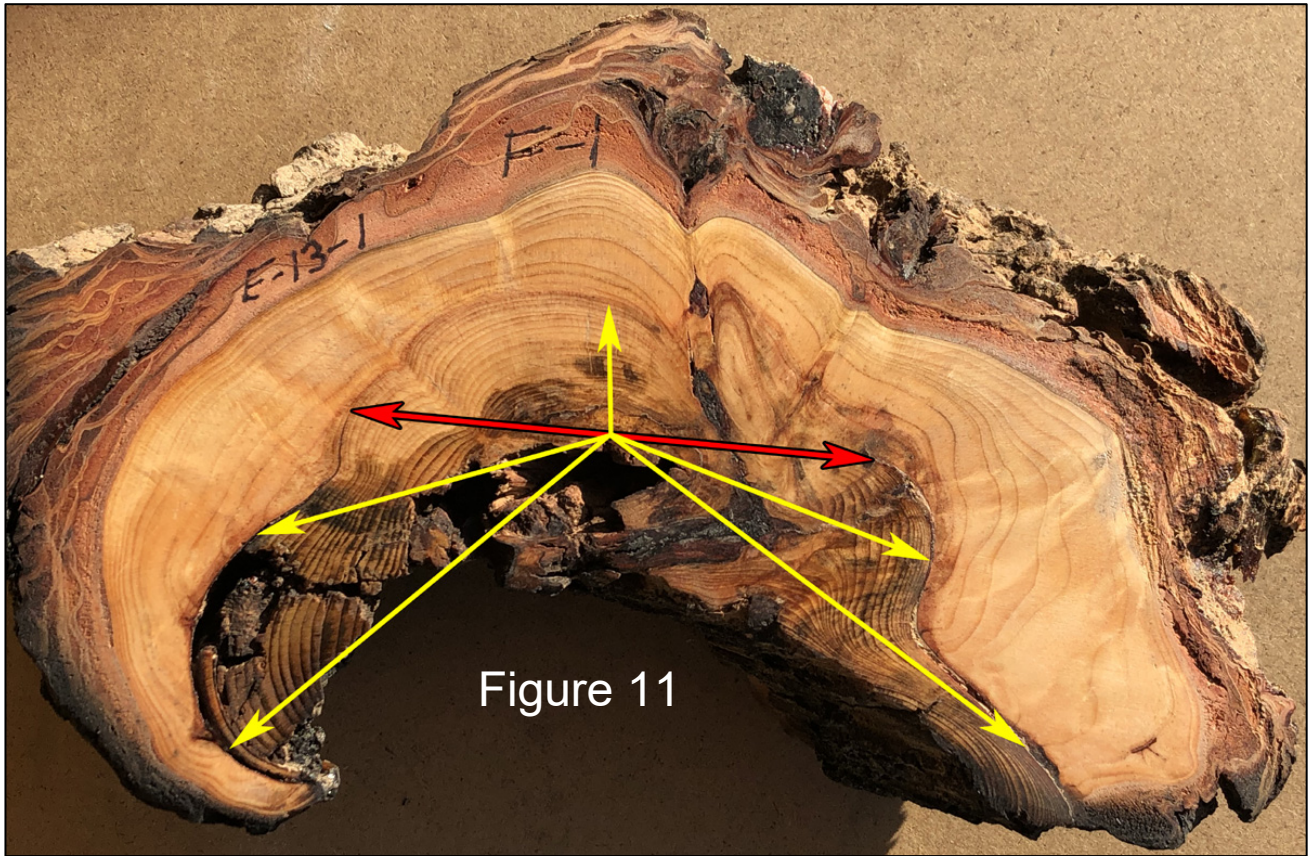


Figure 10 is a key to the samples we collected, some of which are referenced later in this report. All samples from the stump have the prefix “E-13”. This is followed by a sample number, 1 through 9. Some of the samples have two or three sides or faces, denoted by F-1, F-2, or F-3. Samples E-13-7 and E-13-8 are not illustrated here, as they are obscured behind foreground samples. All samples with an “F” designation were to some degree sanded, to allow distinction and analysis of annual growth increment rings.

³ As used in this report, significant designates a degree of severity that could cause or affect cause of an event.

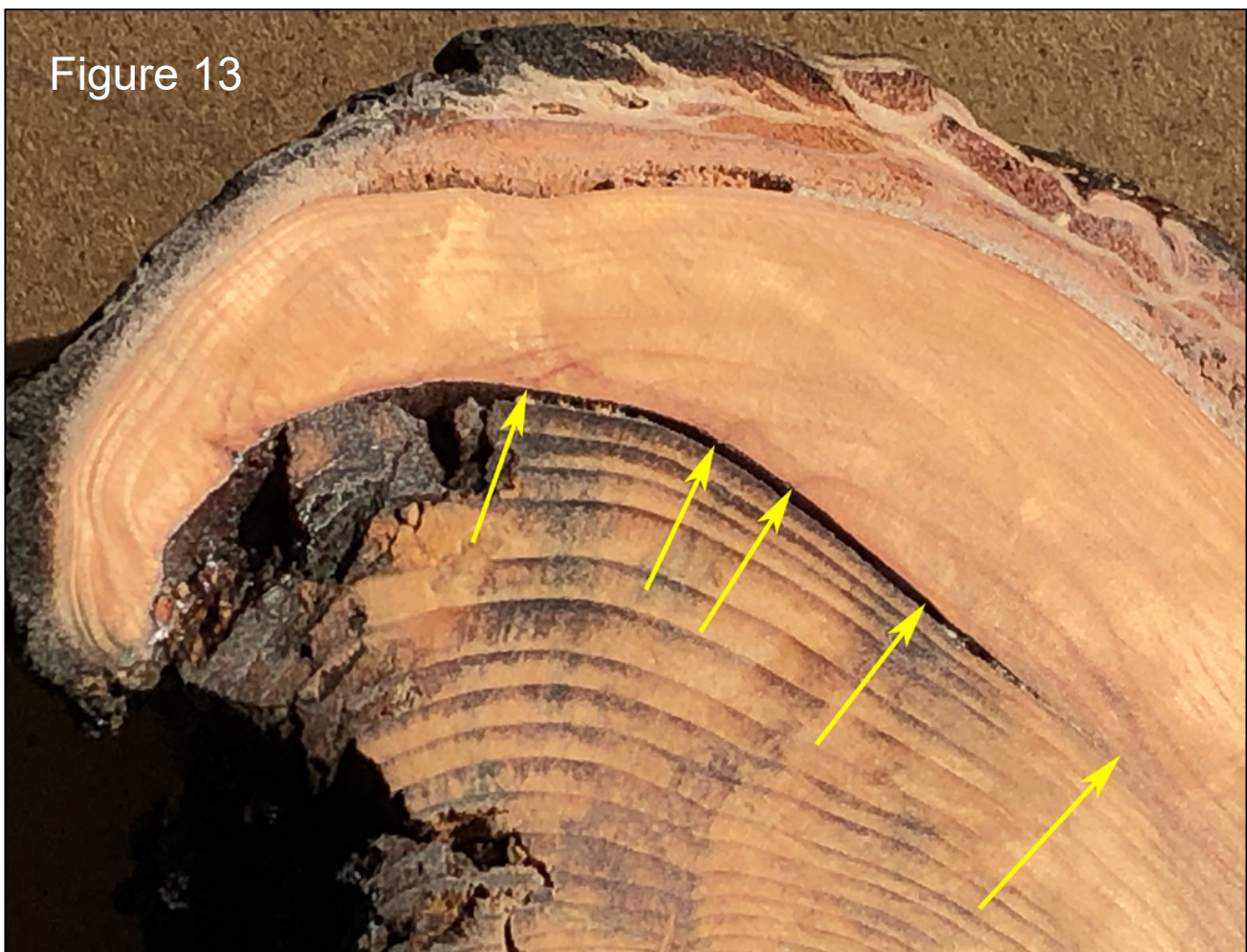


On the previous page, Figure 11 illustrates the entire face F-1 of sample E-13-1. Left is the uphill side. The open face is toward the conductors. The arrows outline the extent of the root prior to the 2008 fire. The red arrow indicates the distance back to which live tissue was killed by the fire.

A single layer of cells called the cambium covers the entire root, trunk, stem and twig system. It creates new bark toward the outside of the tree and lays down new wood over older wood toward the inside. In this instance the cambium was killed back to the red arrow. The cambium at the single arrow at the top, and over to the red arrow tips left at right remained alive. Further to the left and right the cambium was killed, but the wood was not burned. Each year the cambium, starting at the tips of the red arrow extended new woody tissue over the dead substrate, both left and right.

Figure 12 illustrates how this happened on the left, or uphill side. Each arrow represents the incremental growth of new wood over the sound, but dead substrate, year by year from 2008 to 2020. By the time of the Dixie fire the increments had reached the end of the substrate, assuming that older wood did not partially burn away in 2021, and in the future new growth would have curled over and around the older material. This section was at or just above ground level.

Figure 13 is face 3 of sample E-13-2. It is a few inches higher than the face of E-13-1 in Figure 12, but is similar. The 2008 fire and incremental growth since are apparent.



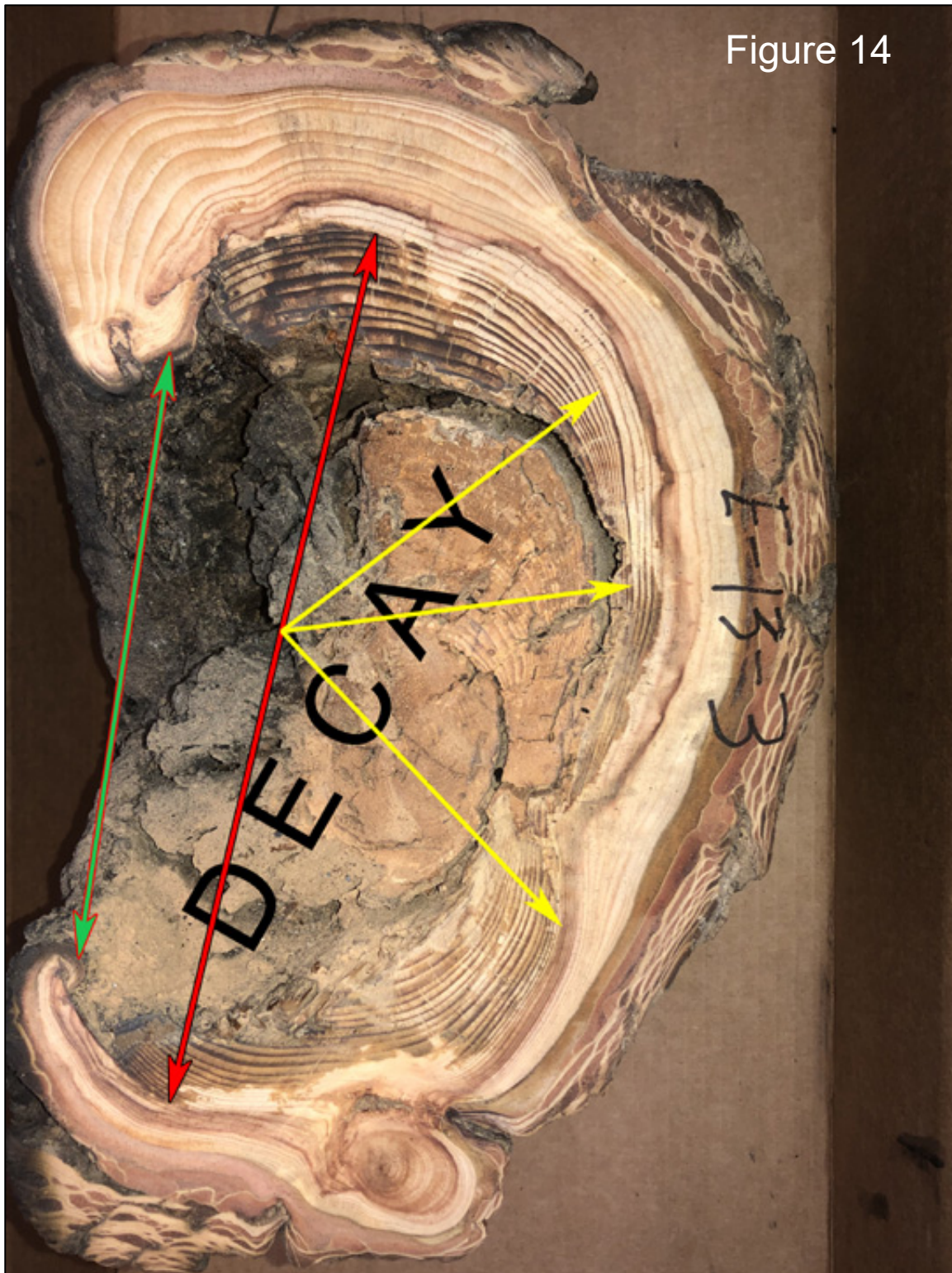


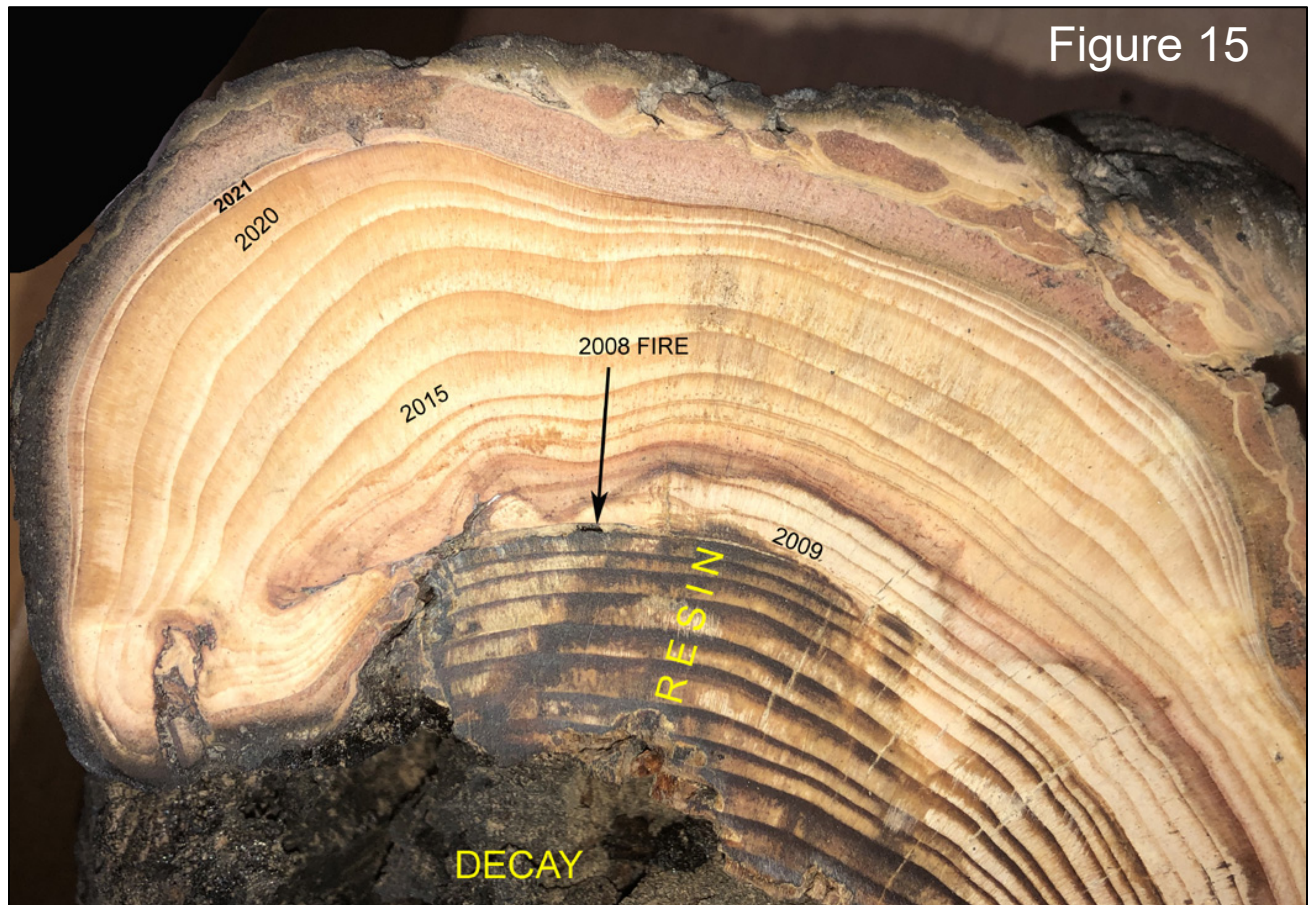
Figure 14

Figure 14 is of the single face of E-13-3 and was well above grade, likely 12 to 18 inches. As with previous figures, the yellow arrows illustrate the outline of the root prior to the 2008 fire. The red arrow describes the limit back to which the live cambium was killed in 2008. The area labeled as decayed represents advanced decay. Between the advanced decay and the tips of the arrow, where annual growth rings can be seen, the wood is sound.

Face E-13-3 is different. On the left, at the margin between decay and the new incremental growth on both the top and bottom, the new growth has grown over decaying wood, then curled around it, forming curls, or rams horns denoted by the green arrow.

Figure 15 is an enlargement of the upper part of the root E13-3-F-1 illustrated in the previous figure. The tree pumped resin into the rings near the burn margin after the 2008 fire as protection against decay⁴. The more central part of the root has decayed. The 2009 growth increments, through early 2021 are visible.

Both the large mechanical roots represented by E-13-1 and E-13-3 were killed over half or more of their circumference, and remained visibly dead on the side toward conductors.

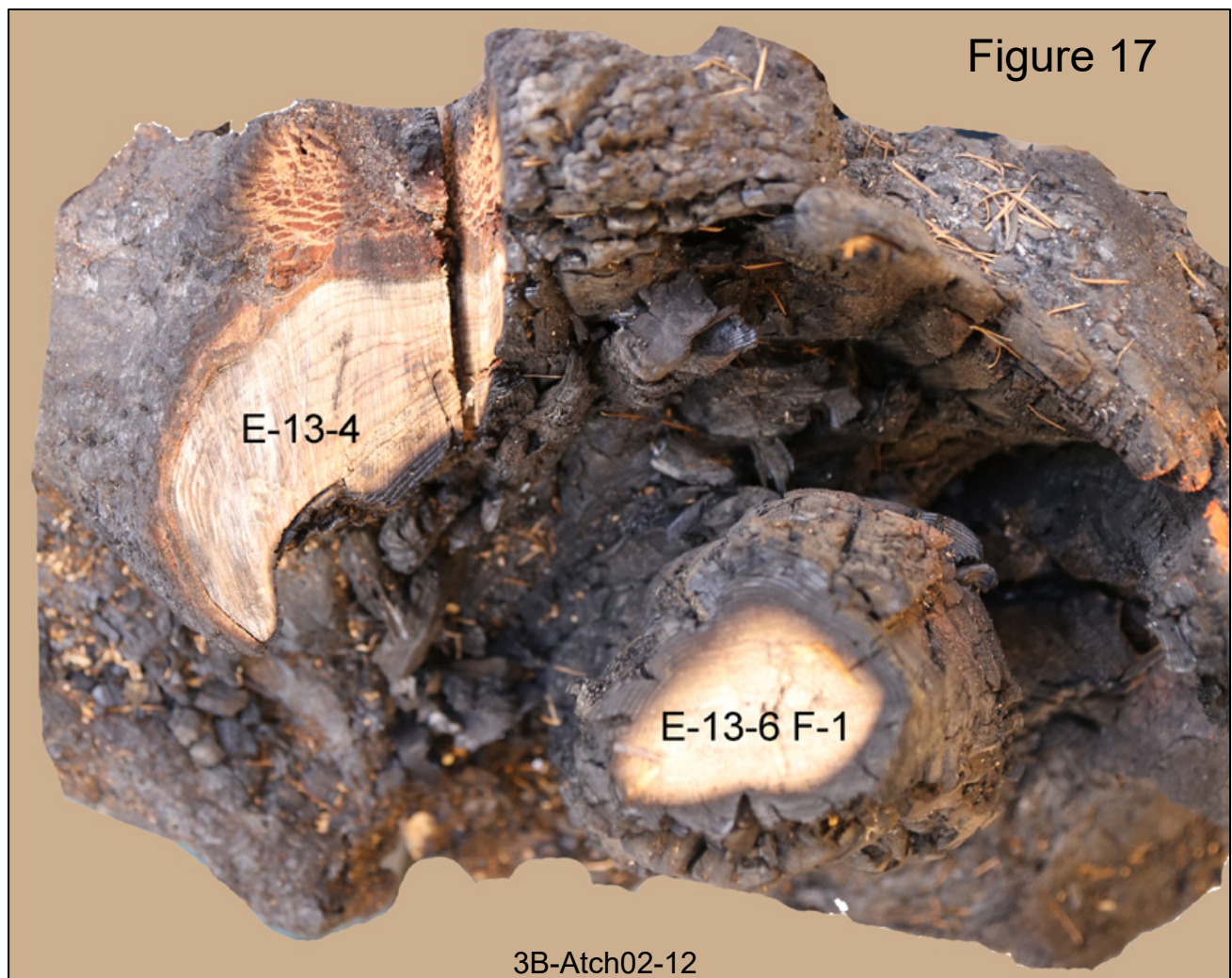
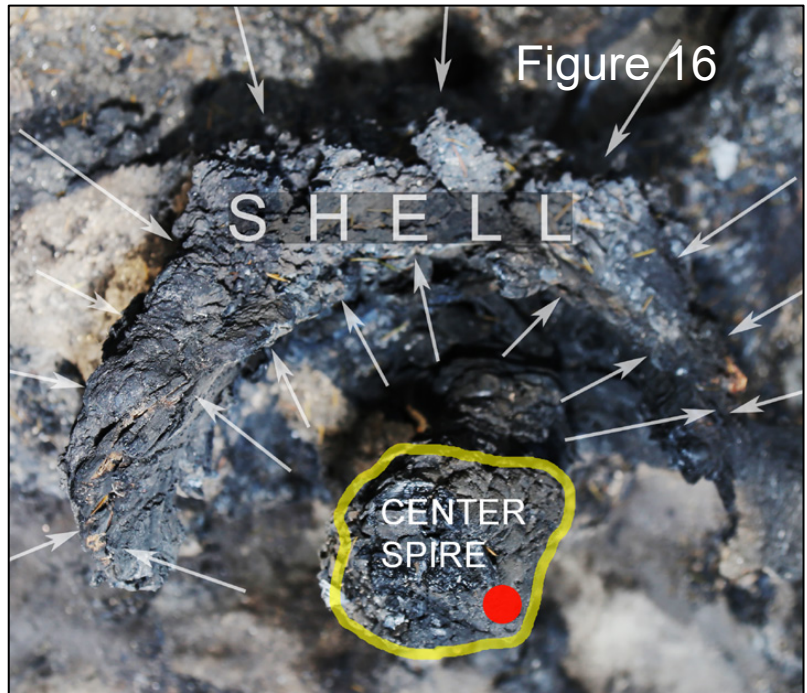


⁴ Conifers produce resin as a physical and chemical barrier to block infection. <https://www.fs.usda.gov/rmrs/science-spotlights/making-scar-how-fire-scars-develop-trees>

Figure 16 is a photo of the stump taken from above on July 15 in the field. The stump remnant was a shell on the north side outlined by the arrows, with a separate spire, outlined in yellow. The red dot is at the original center of the tree. All other woody tissues at this level are burned, decayed or otherwise missing.

Figure 17 is of the stump from the same orientation with samples E-13-4 and E-13-5 removed. This figure is included to provide orientation for sample E-13-4, a 15 inch tall section from the west side of the shell.

The face seen here as E-13-4 has not been sanded or otherwise prepared beyond a rough saw cut. It is the face that mates with E-13-4 F1, Figure 18.



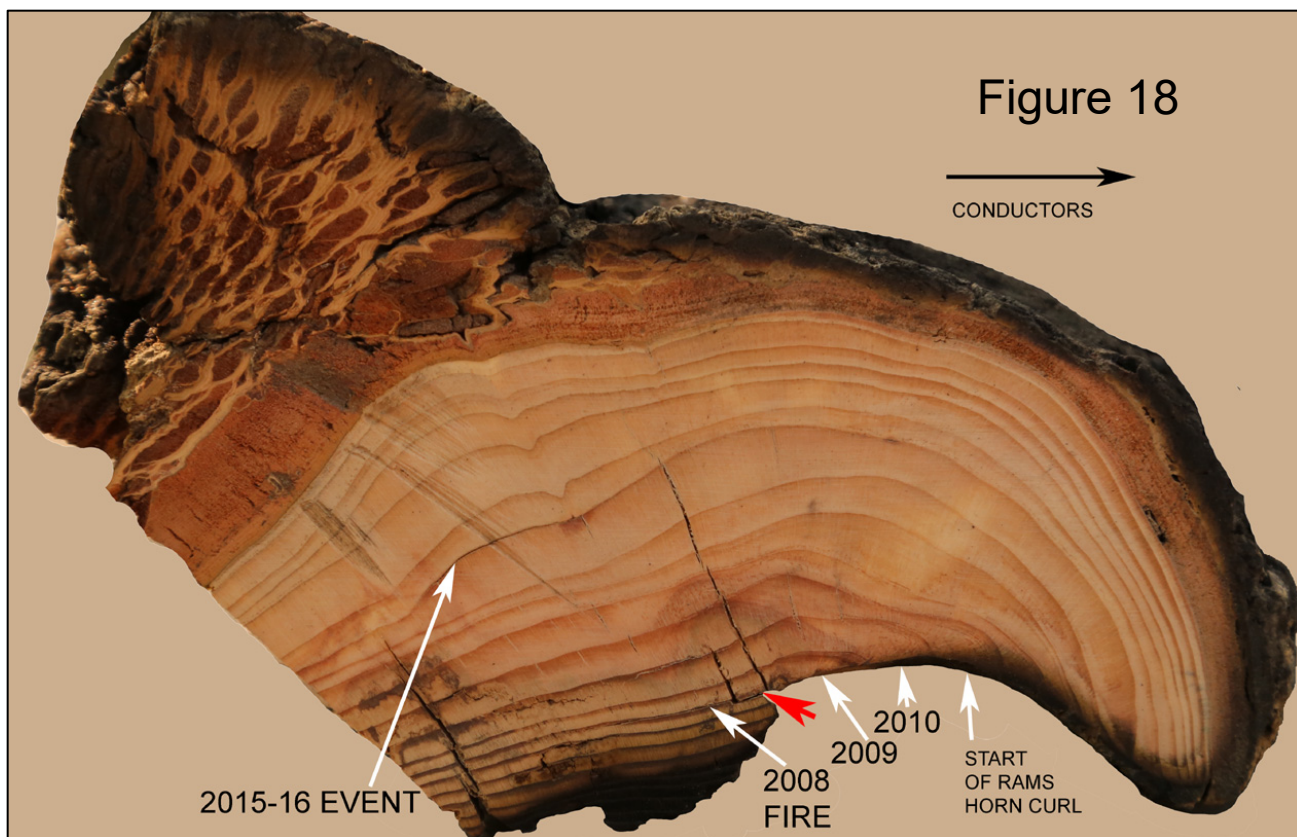


Figure 18 mates with the left side of Figure 17, E-13-4. It is F-1, the first exposed face within this sample, which was cut into four sections along its 15 inch length, as illustrated in Figures 10 and 20. Injury from the 2008 Butte Lightning Complex Fire is evident here. The live cambium of the tree was killed from the right, the south side of the tree toward the conductors, back to the red arrow. The growth increments of 2009 and 2010 are extended relatively straight, suggesting they are growing on a sound, but dead substrate. By 2011 and 2012 the growth begins to form around a smaller radius, suggesting there is no substrate, that the interior of the tree had burned away to that point in 2008 and new growth was curling around itself, forming a ram's horn. The tip of that ram's horn along with any remnant of the pre-2008 substrate to the right of the red arrow was burned away in the 2021 fire. We now see evidence of an event at the boundary between 2015 and 2016. At the time of this report Calfire has not reported a fire in that time period.

We split E-13-4 longitudinally into "A" and "B" sides with a band saw, as seen in Figure 19. This figure is also F-1, the lowest face of E-13-4.

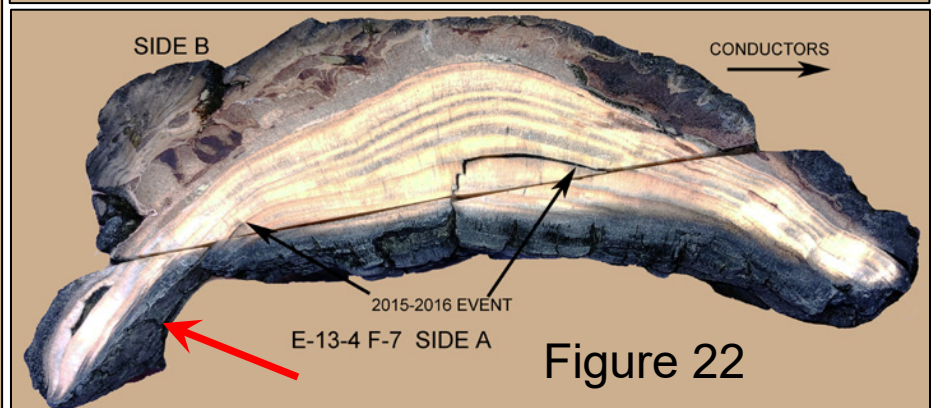
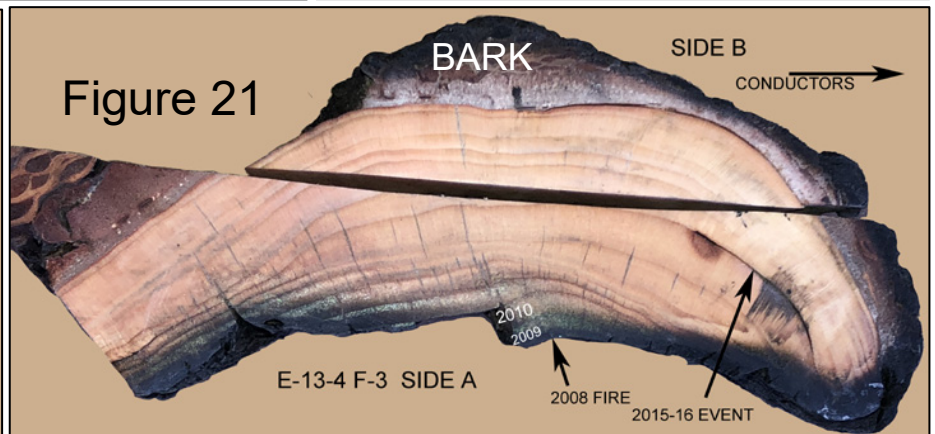
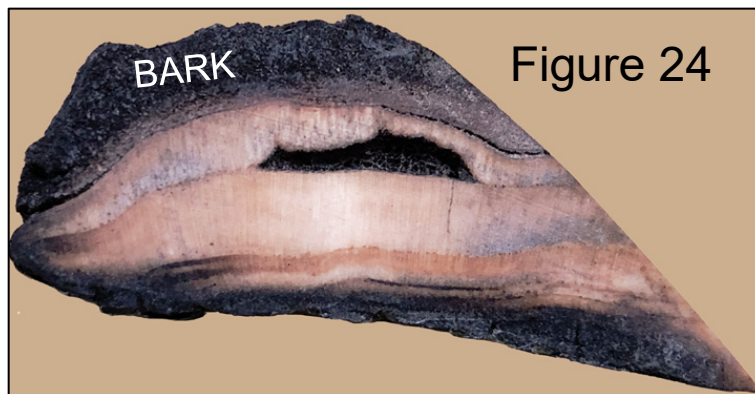
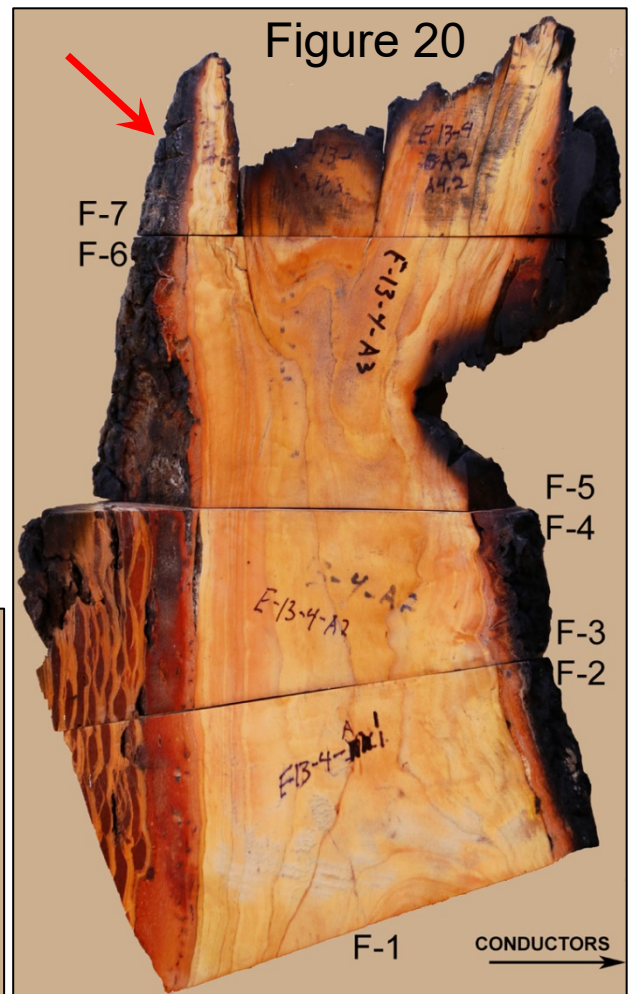


The inside face of side A, sample E-13-4 is illustrated in Figure 20. The divisions into faces F-1 through F-7 are similar to the illustration in Figure 10. The Right-of-Way (ROW) and conductors were to the right in this figure.

In Figure 21 to 2008 fire can just be discerned. It is at the height of E-13-4 F-3 in Figure 10. On the side toward the ROW and conductors the injury from 2015-2016 is prominent.

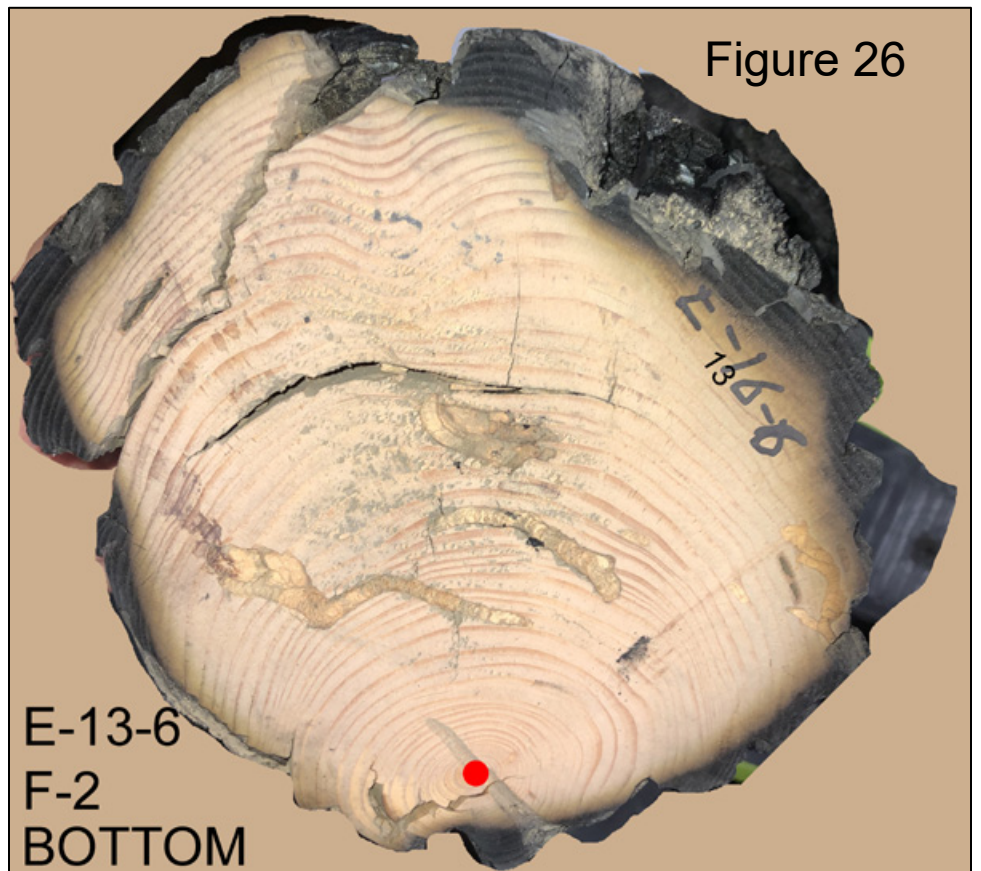
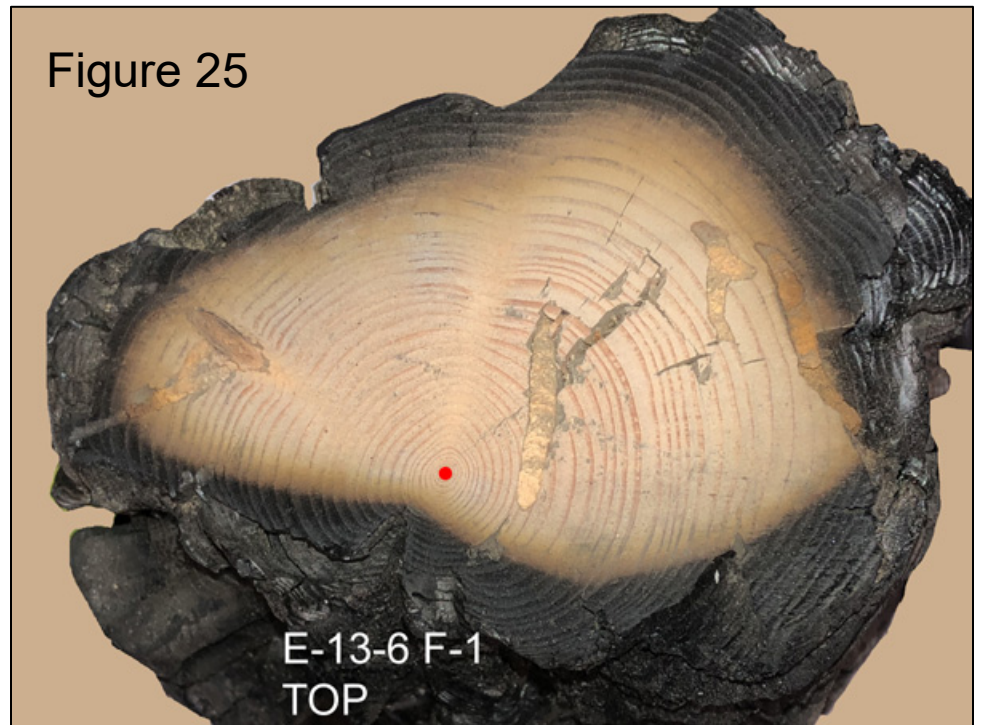
In Figure 22 at the height of F-7 that injury is still evident on the ROW and conductor side of the tree.

The red arrows in Figures 20 and 22 highlight the sample in Figures 23 and 24, which are the Side A and F-7 faces respectively. This sample may be near the top margin of the 2015 injury event as well as near a wound edge on the side away from the conductors and ROW.



Sample E-13-6 is the center spire seen identified in Figure 10. Sample E-13-5 is a cap, the upper several inches of this spire. The surface in Figure 25 mates to the base of that cap.

On each figure, the red dot is the central pith, the original center of the tree. The side toward the conductors, downward in these images, has burned differentially along the length of this central remnant. This suggests it was previously open to that side or decayed or both.



Sample E-13-7 could not be illustrated in Figure 10. It was hidden behind sample E-13-4 in that key.

In Figure 27 sample E-13-4, seen in Figures 19 and 20 has been removed. Sample E-13-5, the cap of the central spire has been removed, exposing the top face of E-13-6, F-1. This illustration is to establish the location of sample E-13-7 between the sides of E-13-4 and E-13-9.

In Figure 28, samples E-13-6 and E-13-7 have been removed from the stump. Sample E-13-9 has been severed from the stump but is still resting on it, shifted back and to the left for illustration and reference.

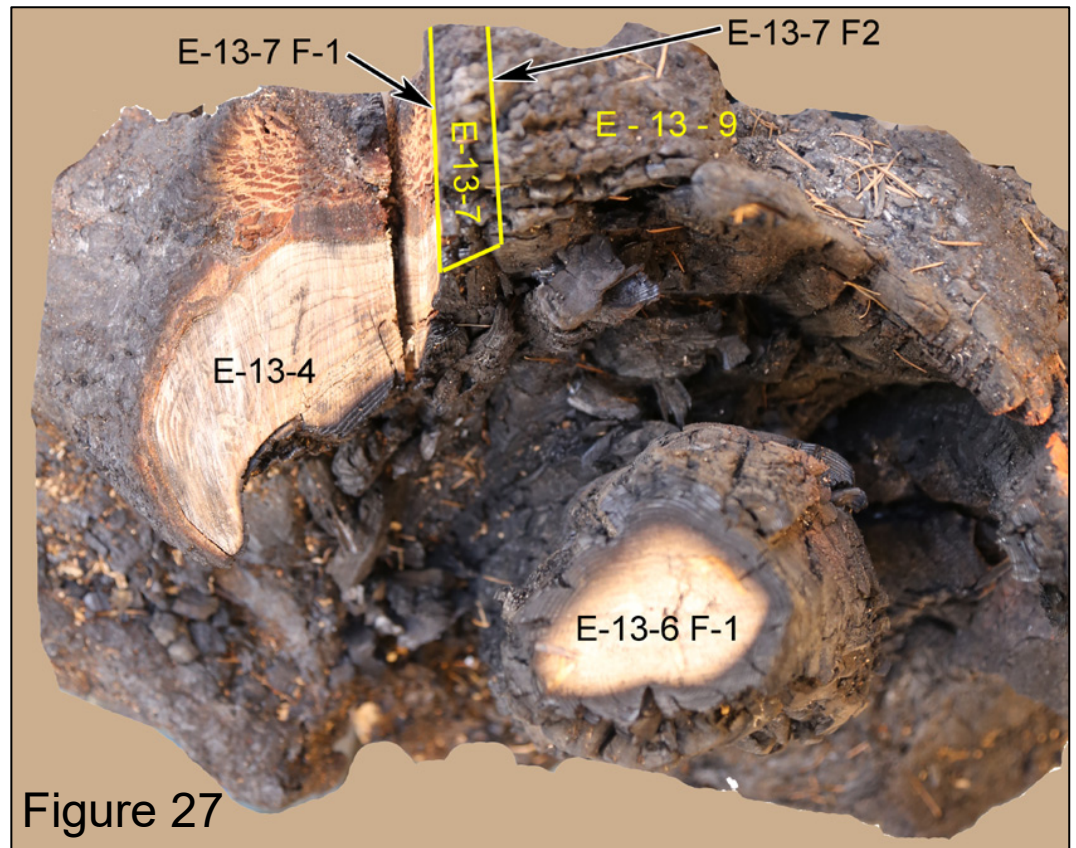


Figure 27

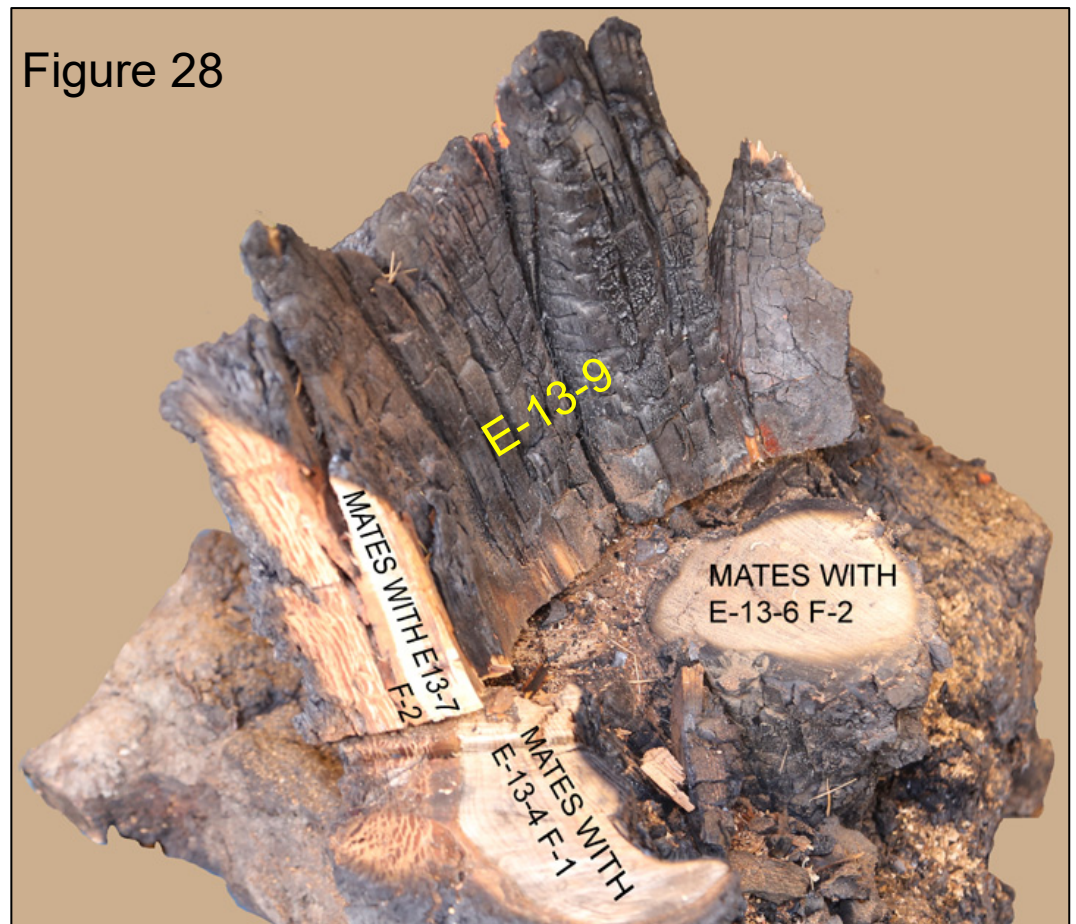
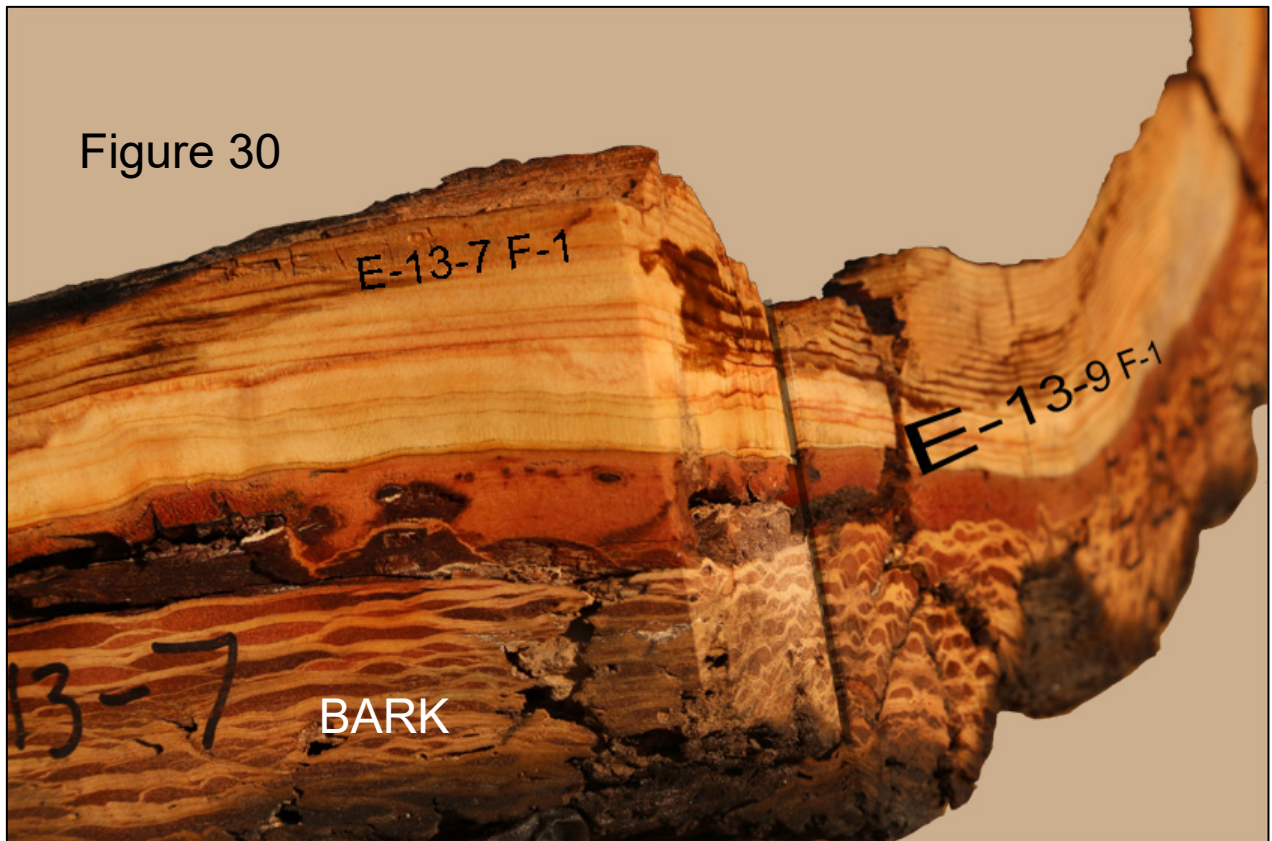
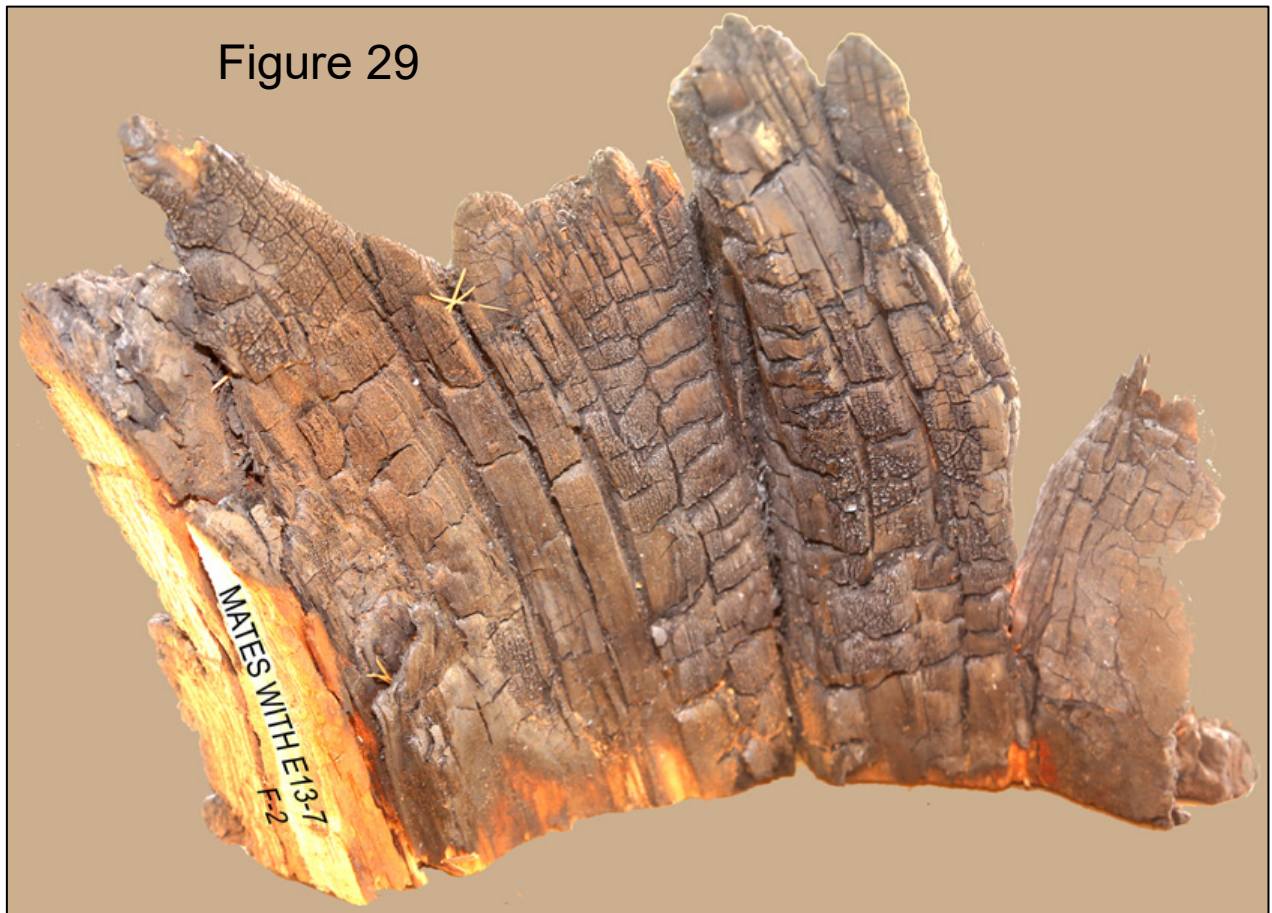


Figure 28

Figure 29, freestanding E-13-9. The exposed face to the left mates with face E-13-7 F-2. In Figure 30, sample E-13-9 is on its back, samples E-13-7 and E-13-9 are placed together as in the tree, E-13-7 F-1 is exposed.



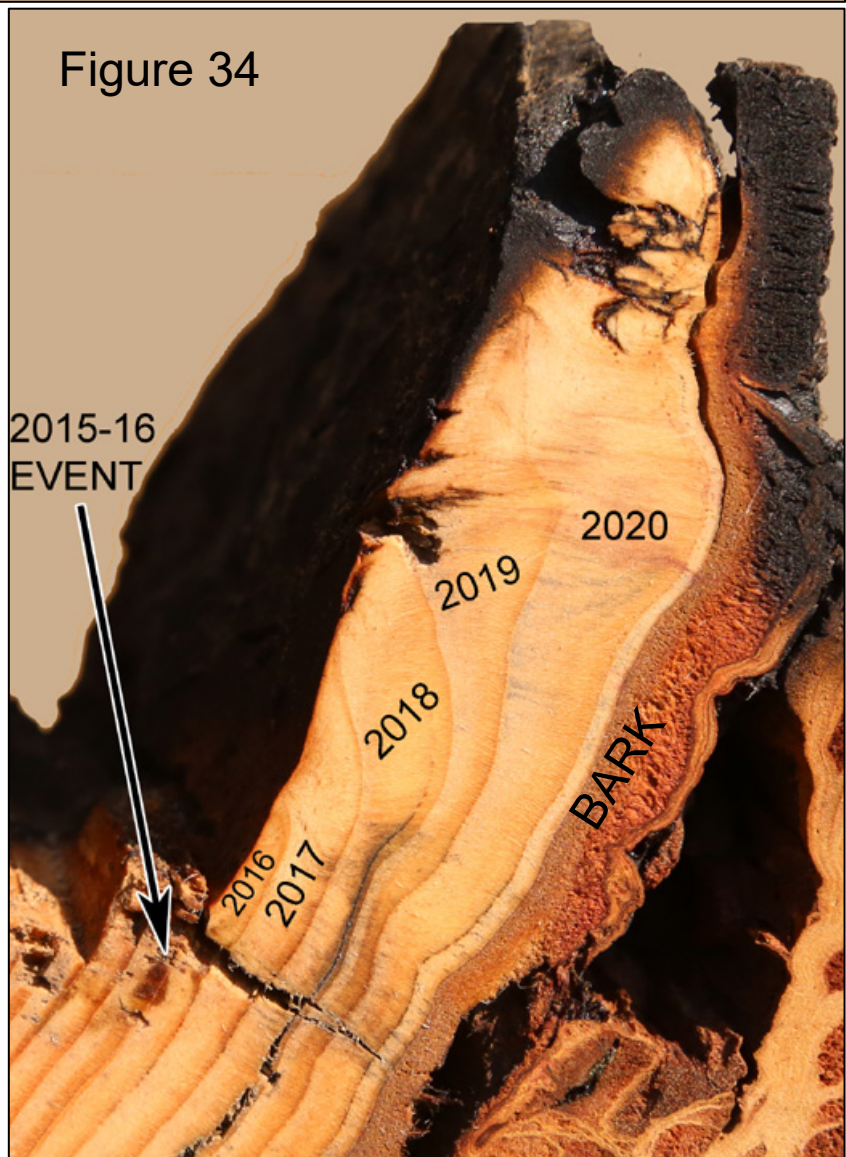
In Figures 31 and 32 both faces of E-13-7 indicate the 2015-16 event. The uneven growth of both sides since 2015 suggests the live cambium was killed by this event to a point shown within these photographs, below the arrow in Figure 31.





Figure 33 is the base of sample E-13-9. Figure 34 is a close-up of the right, or downhill tip of that face.

The 2015-16 event killed live cambial tissue back to the tip of the arrow. The growth from that period onward did not curl into a ram's horn, but was laid down on a supportive substrate. The evidence within annual ring growth is the relatively straight line along which the 2016-2020 tissues were laid down. The substrate tissues likely decayed, as the pre-2016 rings have, near the tip of the arrow. That tissue was then susceptible to the 2021 fire and is now absent.



CONCLUSION

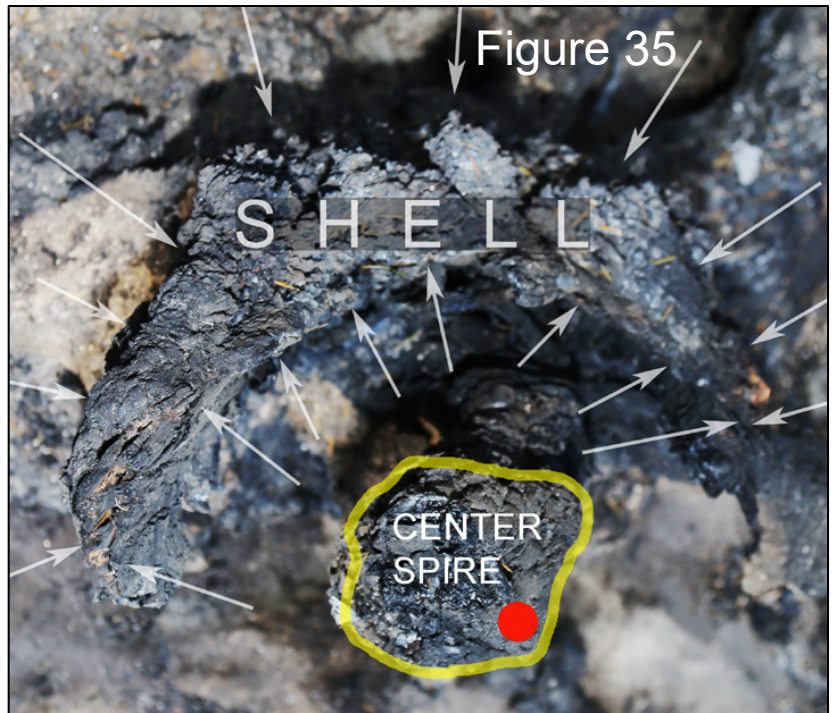
The Douglas fir that failed on July 13 and came to rest on PG&E conductors was about 15.8 inches in diameter and at least 65 feet tall. It grew approximately north of and about 50 feet from a PG&E utility pole that supported 12 KV lines that extended downslope to the Cresta Dam. The tree grew across the slope and slightly higher on the slope than the pole. Ring analysis suggests that the tree was about 90 years old and that it grew vertically without a lean. The tree was alive and vital at the time of failure.

The tree was significantly injured by the Butte Lightning Complex Fire of 2008 and by an unidentified event of 2015-2016. Figure 35 is a reprint of Figure 16, the stump of the tree taken on site on July 15, 2021. The arrows outline a remnant standing shell of wood, with bark on the outside. The yellow outlines a free-standing spire or column, once at the center of the tree. The red dot is at the pith, or original center of the tree. The photograph is oriented so that downhill is approximately right, the PG&E conductors are toward the bottom of the photo, 50 feet away.

Figure 36 is of similar orientation, taken in the storage facility on September 11, 2021 after removal of samples E-13-4, E-13-6, E-13-7 and E-13-9. On the left or uphill side the red arrow illustrates the point back to which the live cambium was killed by the 2008 Butte Lightning Complex Fire. Growth since that time has curled inward, forming the beginning of a ram's horn as the interior of the tree decayed and disappeared. This is illustrated in Figure 18.

On the right or downhill side the red arrow illustrates the point back to which live cambium was killed by an event in late 2015 or early 2016. Nearly all of the wood that formed prior to 2008 on the uphill side of the central column and that formed prior to 2015 on the downhill side of the central column was decayed and is missing.

The pith or center of the tree is present in the central column, at the base as illustrated here, right up to the burned tip. Nearly all the wood in that column to the south, toward the conductors is missing. It is my opinion that the missing wood throughout this stump was in a state of advanced decay, as seen higher in the tree trunk in Figure 8, and was



either consumed completely by decay organisms or was so susceptible to combustion that it quickly burned in the 2021 fire.

We verified that two major buttressing and mechanically supporting roots toward the west side, upslope, illustrated by the left yellow line in Figure 3, and south side toward the conductors, illustrated by the right yellow line in Figure 3 were burned in the 2008 fire. The heat killed a third to half of their circumference. The observable burned sides of the roots were on the south side toward the conductors.

Above the roots evidence suggests that the south side of the lower trunk was burned and killed over more than half its circumference. This would have formed a wound with no bark cover, visible as exposed and decaying wood. The extent of this wound is well-illustrated in Figures 35 and 36. It is my opinion that most of the sound wood supporting the tree is represented graphically in Figure 36. The absence of sound wood where expected elsewhere is dramatic.

I am confident this condition was visible as a wound at least to the height of the lower red line on Figure 3, 18 to 22 inches above the ground. It is highly likely the wound extended at least to the middle red line on Figure 3, 26 to 30 inches above the ground. It is more likely than not that the wound extended to at least the upper red line, 32 to 38 inches above the ground.

After the fire of 2008 the only live tissue on the lower trunk, the tissue that was keeping the tree canopy green was on the side away from the conductors. The live tissue of the lower three feet of the tree at that time constituted at most half the circumference of the tree. The event of 2015-16 killed much of that live cambial tissue, but enough remained to keep the tree canopy alive through initiation of the 2021 fire. However, after 2015 more than half the tree in the lower three feet was dead, open and decaying on one side with a ring of decay extending behind the center, around the remainder of the lower trunk interior. This left insufficient wood to support the tree mechanically.

Wind at the time of failure was about eight miles per hour, approximately from the north. The tree fell approximately to the south, but we do not have evidence that the wind directly caused the failure. There was not widespread limb or trunk failure of nearby trees. A single nearby tree failed, a 9.6 inch trunk diameter ponderosa pine, predisposed to that failure. Small pine limbs may have contacted the Douglas fir when the pine failed, or the two trees may have failed independently. Both were predisposed to fail as they did.

In my opinion the degraded condition of the base of the Douglas fir was the primary cause of failure of the tree and that defect would have been visible without extraordinary discovery effort, from under the conductors. It would have been visible as a catface, an open injury on the trunk. A cursory visual inspection around the base of the tree would have revealed the poor mechanical condition of the tree. A pre-inspector who was close to the tree for a brief visual inspection for any reason should have discovered the decay.

The 2008 Calfire publication Power Line Fire Prevention Field Guide specifically mentions heart rots or open wounds in the base of the bole. On page 1-21 the document notes, "Basal fire scars...are a major entry point for butt and heart rot." Continuing, §14.1 steps to identification are itemized, such as, "Open wounds showing visible rot.",

and “Old wounds that have partially or fully healed over.” And “Hollow trunks detected by rapping on the tree trunk...”

In the same document, “If any indication is noted of butt, heart or sapwood rot in the lower trunk, the extent of damage should be estimated. A quick, rough estimate can be made by tapping the trunk with an ax handle...to determine whether...it sounds hollow...He/she [the inspector] should check the orientation of conks, flat areas, splits, crotches and other deformities in relation to the direction of the power line from the tree and to the prevailing wind direction.” and, “An inspector should develop the habit of looking to both sides and to the rear as well as ahead.” It continues, “...the inspector should make occasional side trips outside the cleared right-of-way. This is particularly true in dense conifer stands. The screening vegetation along the edges of the right-of-way will often hide evidence of defects in trees.”⁵ We found no evidence or scorched remnant of intervening screening vegetation.

California Public Resources Code §4293 requires any person operating an electrical transmission or distribution line to maintain specified minimum clearance between vegetation and conductors. “Dead trees..rotten trees...which may contact the line from the side or may fall on the line shall be felled, cut...so as to remove such hazard.”

It is my opinion that the defect in the base of the tree which is the subject of this report could have been seen from under the conductors, and that having seen the defect, a pre-inspector could have confirmed extensive decay. The International Society of Arboriculture has adopted a tree Risk⁶ assessment protocol within their Tree Risk Assessment Qualification program. It is my opinion that such an assessment, following the protocol would have resulted in a risk rating of High for this Douglas fir tree.

⁵ §19, p 1-24

⁶ Risk is defined as the probability of an event in a given time period combined with adverse consequences of that event. It is determined through a structured process followed by us and described in the American National Standards Institute A-300 (part 9) Standard, *Tree Risk Assessment*. Risk is described on a scale of, Low, Moderate, High, or Extreme.

CERTIFICATION AND LIMITING CONDITIONS

I certify that the observations and recommendations in this document are complete and correct, to the best of my knowledge and belief, and are made in good faith. They reflect the conditions of the tree as we analyzed it. We do not certify that the tree in question was the cause of the Dixie Fire, but we do certify the condition of the tree as described above. Calfire personnel directed us to specific trees of interest to them relative to the Dixie Fire, but we were not instructed regarding what observations to make or which data to collect. The purpose of this document is limited to providing our opinion regarding the condition of the base of the tree and visibility of that condition prior to initiation of the Dixie Fire.

The observations, analysis, and conclusions are not intended to be a formal or informal Risk analysis of trees on the site, either pre or post fire, other than the subject tree. We are not trained dendrochronologists, nor did we consult with any. However, our training and experience with tree ring analysis and dendrochronologists is sufficient to support the conclusions offered in this report.

Sample E-13-8 is not illustrated. It fell from the back of sample E-13-9 during sampling. It is retained but is so decayed that it provides no useful information.

Directions, as noted in this report are approximate and estimated. Trunk diameters were measured by hand with a Spencer loggers tape. As additional information becomes available we may alter our opinions accordingly. This report may be reproduced only by Calfire, only in its entirety and only in color.

Sincerely,

Joseph McNeil
Board Certified Master Arborist #WC-0102B
Registered Consulting Arborist #299, ASCA
ISA Qualified Tree Risk Assessor
ASCA Qualified Tree and Plant Appraiser

¹ Members of McNeil Arboriculture Consultants LLC are Joe McNeil, Todd McNeil and Rita McNeil. All members participated in construction and editing of this document, with Joe McNeil as principle author. Joe McNeil and Todd McNeil performed the site visit on July 15, 2021 and the sample collection on August 2, 2021. Joe McNeil and Rita McNeil collected samples on September 11, 2021.

¹¹ Health and mechanical stability of a tree are separate, and not necessarily dependent on one another. The vascular portion of a tree is in the inner live bark and the outer live wood. Interior wood may contribute structurally, but be biologically inert. Stability and potential to fail may depend on structural architecture, exposure, soil conditions, or organisms that may decay structural tissues while leaving live vascular parts around the outside of the tree unaffected. The foliar canopy of a tree with as little as thirty to forty percent of its live exterior circumference remaining active may appear fully live and vital independently of whether the interior of the tree is decayed. Conversely, stresses, insects or diseases may cause a tree to die, and be dead in appearance, while remaining mechanically sound for a time, or even becoming less prone to failure for a year or more, so long as the tree remains free of decay.