BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U 39 M) for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2023.	Application 21-06-021
NOT CONSOLIDATED	
Application of Pacific Gas and Electric Company (U 39 M) to Submit Its 2024 Risk Assessment and Mitigation Phase Report.	Application 24-05-008
NOT CONSOLIDATED	
Application of Pacific Gas and Electric Company (U 39 M) for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2027.	Application 25-05-009

COMMENTS OF THE PUBLIC ADVOCATES OFFICE ON PACIFIC GAS AND ELECTRIC COMPANY'S 2024 RISK SPENDING ACCOUNTABILITY REPORT

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September 29, 2025

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I. INTRODUCTION

Pursuant to Decision (D.) 22-10-002,[1] the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) submits these comments on the Risk Spending Accountability Report (RSAR) submitted by Pacific Gas and Electric Company (PG&E) on July 28, 2025 (PG&E's 2024 RSAR).[2]

PG&E's 2024 RSAR reports on PG&E's authorized and actual spending and work completed within the first two years of PG&E's 2023-26 General Rate Case (GRC) period. Activities addressed in the report include safety, reliability, and/or maintenance, in accordance with Public Utilities Code Section 591, Decision (D.)19-04-020,[3] and D.22-10-002.[4] These reports provide the necessary data for the Commission to ensure the safety of the public. When a utility fails to timely complete necessary safety and reliability work, it can cause catastrophic events such as wildfires, pipeline ruptures, and prolonged power outages.[5] It is imperative that the Commission scrutinize PG&E's safety, reliability, and maintenance performance effectively.

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[1] Decision (D.)22-10-002, *Decision Addressing Phase 1 Track 3 and 4 issues*, October 6, 2022. Appendix A, at A-1 sets April 30 as the annual deadline for Risk Spending Accountability Report (RSAR) filings and July 21 as the annual deadline for intervenor comments. On January 31, 2025, Energy Division granted PG&E's request for an extension of time to file PG&E's 2024 RSAR and extended the due date for intervenor comments to September 29, 2025. PG&E filed its 2024 RSAR on July 28, 2025.

[2] P*acific Gas and Electric Company's (U 39 M) 2024 Risk Spending* Accountability Report, July 28, 2025 (PG&E 2024 RSAR). Available at https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=574351120.

[3] D.19-04-020 Ordering Paragraphs 8-14.

[4] D.22-10-002 Ordering Paragraphs 1-5.

[5] *See* Senate Bill 549 (2017) (adding Section 591 to the Public Utilities Code), Bill Analysis by Senate Committee on Energy, Utilities, and Communications, March 20, 2017 at 2:

> "Recent events have revealed that at varying times, utilities have not been expending funds authorized by the CPUC in the general rate case (GRC) for safety-related purposes or diverting funds to non-safety-related purposes or not expended. The author has noted instances where utilities had not expended funds that had been authorized which may have contributed to instances of damage, injury or fatality, including extended power outages in Southern California Edison (SCE) territory during a windstorm and, most notably, the fatal San Bruno Pacific Gas & Electric (PG&E) natural gas pipeline explosion in 2010."

PG&E continues to fall behind in completing its Commission-approved Overhead Conductor Replacement,[6] a necessary program to replace deteriorated overhead conductor that may cause electrocution, reliability or wildfire ignition hazard.[7] Further, the Overhead Conductor Replacement that PG&E has completed is not in alignment with its own asset management standards, as highlighted by PG&E's Independent Safety Monitor.[8] PG&E is simultaneously experiencing elevated instances of wire-down events, as shown in Figure 3 below. These present an immediate electrocution or wildfire ignition hazard to the public and are likely a direct consequence of its failure to timely replace its overhead conductor, as shown in Figure 2 below.[9] Meanwhile, PG&E continues to overspend on its Commission-approved Routine Emergency Replacement program (as shown in Figure 4 below), which includes replacement of broken conductors.[10]

In light of the immediate and ongoing safety hazards to the public caused by PG&E's failure to replace overhead conductor as well as PG&E's resultant cumulative overspending on emergency work by millions of dollars, Cal Advocates urges the Commission to:

- Require PG&E to file a corrective action plan to complete its Commission-approved Overhead Conductor Replacement work and align its Overhead Conductor Replacement program with its own asset management standards.
- Institute a broader oversight process to ensure that PG&E catches up on its incomplete safety and reliability work or justify why such work is no longer needed.

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[6] Major Activity Type (MAT) code 08J, as presented in PG&E's 2023 GRC. See A.21-06-021, Exh. PG&E-04 Volume 1 at 13-28 to 13-31.

[7] See Figures 1 and 2 below.

[8] *PG&E Independent Safety Monitor Status Update Report*, Filsinger Energy Partners, May 15, 2025 (PG&E 2025 Independent Safety Monitor Report) at 38, available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/reports/ism-status-update-report-6_051525.pdf. This May 15, 2025 Filsinger report is attached as Appendix C of these comments.

[9] PG&E 2025 Independent Safety Monitor Report at 37. See Appendix C of these comments.

[10] PG&E 2025 Independent Safety Monitor Report at 38. See Appendix C of these comments.

II. DISCUSSION

A. The Commission should require PG&E to file a corrective action plan to complete its worsening backlog of Overhead Conductor Replacement and decrease its resultant wire-down events.

1. PG&E has failed to complete its Overhead Conductor Replacement for five consecutive years and is not conforming with its own standard for overhead asset replacement.

PG&E has failed to complete its Commission-authorized Overhead Conductor Replacement for at least five consecutive years, as detailed by its 2023[11] and 2024 RSARs.[12] This has resulted in a cumulative underspend of approximately $101 million in 2020-2024.[13] This chronic underspending and corresponding non-completion of work is shown in Figures 1 and 2 below.

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[11] Application (A.)20-06-012, A.21-06-021, A.24-05-008, *Pacific Gas and Electric Company's (U 39 M) Amendment to the 2023 Risk Spending Accountability Report*, June 17, 2024 (PG&E 2023 RSAR), Table 3-4, line 30 at 3-12. Available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M533/K098/533098479.PDF

[12] PG&E 2024 RSAR, Table 3-4, line 30 at 3-11.

[13] Annual underspends of $33,659,987.33 (2020) + $23,087,133.10 (2021) + $16,648,740.95 (2022) + $27,879,259.59 (2023) + $41,932,334.68 (2024) = $101,275,120.97. See PG&E 2023 RSAR, Table 3-4, line 30 at 3-12 and PG&E 2024 RSAR, Table 3-4, line 30 at 3-11.

Figure 1: PG&E's Overhead Conductor Replacement Completion 2020-2024[14, 15]

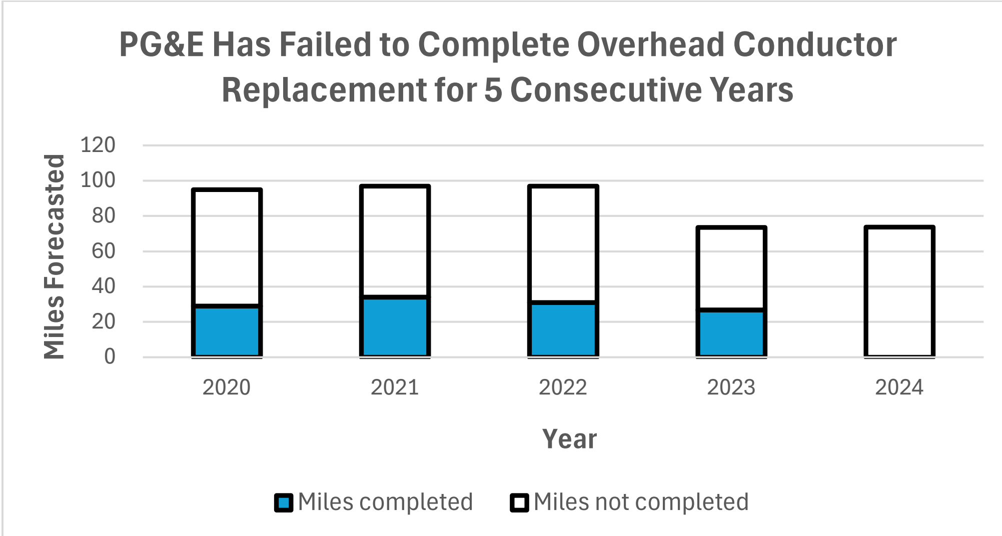
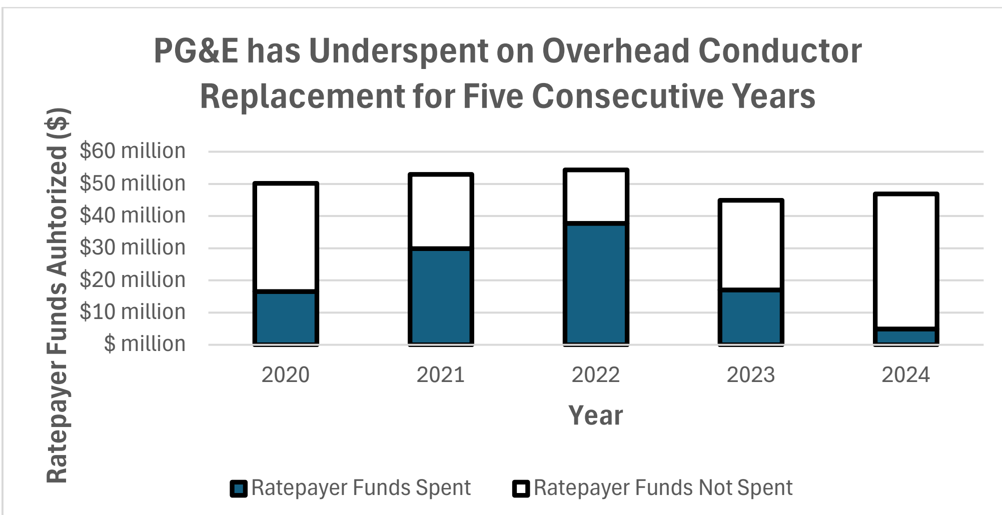


Figure 2: PG&E's Overhead Conductor Replacement Spending 2020-2024[16, 17]



PG&E's Overhead Conductor Replacement program is critical for mitigating wires down. According to PG&E, the Overhead Conductor Replacement Program "proactively replaces overhead conductor in non-high fire threat district areas to address

[14] PG&E 2023 RSAR, Table 3-4, line 30 at 3-12.

[15] PG&E 2024 RSAR, Table 3-4, line 30 at 3-11.

[16] PG&E 2023 RSAR, Table 3-4, line 30 at 3-12.

[17] PG&E 2024 RSAR, Table 3-4, line 30 at 3-11.

elevated rates of wires down and deteriorated/damaged conductors and to improve system safety, reliability, and integrity."[18] Deteriorated conductor is a significant contributor to utility wire-down events, as well as overloads and resultant failure.[19] When such events occur, they present an immediate safety hazard. In 2012, a man died after attempting to protect his family from a downed power line.[20] These failed conductors and resultant wire-down events also represent a significant portion of CPUC reportable ignitions caused by equipment failure, which are at over 30% since 2019.[21]

PG&E has historically had a high rate of wire-down events. In 2013, Liberty Consulting[22] found that, at the time, PG&E had wires coming down on average 8 times a day when averaged over a year.[23] Liberty Consulting found that in 2012, 36% of the time wires remained energized until a trouble person arrived,[24,] [25] which is an electrocution hazard and a wildfire ignition hazard. PG&E at the time created a Wires Down Program to address the root causes of these wire-down events.[26] However, in its evaluation of

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[18] A.21-06-021, Exh. PG&E-04 at 13-28.

[19] PG&E Independent Safety Monitor Status Update Report, Filsinger Energy Partners, April 3, 2023 (PG&E 2023 Independent Safety Monitor Report) at 12-13, available at https://www.cpuc.ca.gov/-/media/cpuc-website/industries-and-topics/documents/pge/oversight-and-enforcement/ism-status-update-report-q1-2023.pdf. Attached as Appendix D of these comments.

[20] San Mateo Daily Journal, "Family Sues After Power Line Death" November 12th, 2012 https://www.smdailyjournal.com/news/local/family-sues-after-power-line-death/article_ff4c65f7-95d8-57aa-96e2-40ed4915e191.html

[21] PG&E 2025 Independent Safety Monitor Report at 37. See Appendix C of these comments.

[22] *Study of Risk Assessment and PG&E's GRC*, The Liberty Consulting Group, May 6, 2013 (Liberty Consulting Report), available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M065/K394/65394210.PDF .

[23] Liberty Consulting Report at 160 states that based on PG&E's system safety metrics, 2673 wire-down events occurred in 2012, resulting in an average, of approximately 8 wire-down events a day.

[24] Liberty Consulting Report at 13.

[25] Liberty Consulting Report at 141, that states, "Liberty considers the percentage of downed energized conductors to be high. Benchmarking data is not readily available in the industry, but we have experience with some other utilities. We know of several major utility systems (23 kV) where downed energized conductors are estimated to be fractions of one percent".

[26] A.18-12-009, *PG&E's (U 39M) 2020 Safety Performance PG&E 2020 Safety Performance Metrics Report In Compliance with California Public Utilities Commission Decision 19-04-020*, March 31, 2021 at 5-2.

PG&E's 2021 Safety Performance Metrics Report, Safety Policy Division noted that "PG&E's performance over the last ten years is stable despite the creation of the Wires Down Program in 2012, which was designed to identify and mitigate the root cause of wires down."[27] This indicates that PG&E's Wires Down Program was ineffective at decreasing the rate of wire-down events.

Wire-down events continue to be a significant problem for PG&E. PG&E's 2024 Safety Performance Metrics report shows that for the last four years PG&E has had more wire-down events annually than it did in 2012, with 3,199 such events occurring in 2024.[28] This is demonstrated in Figure 3 below.

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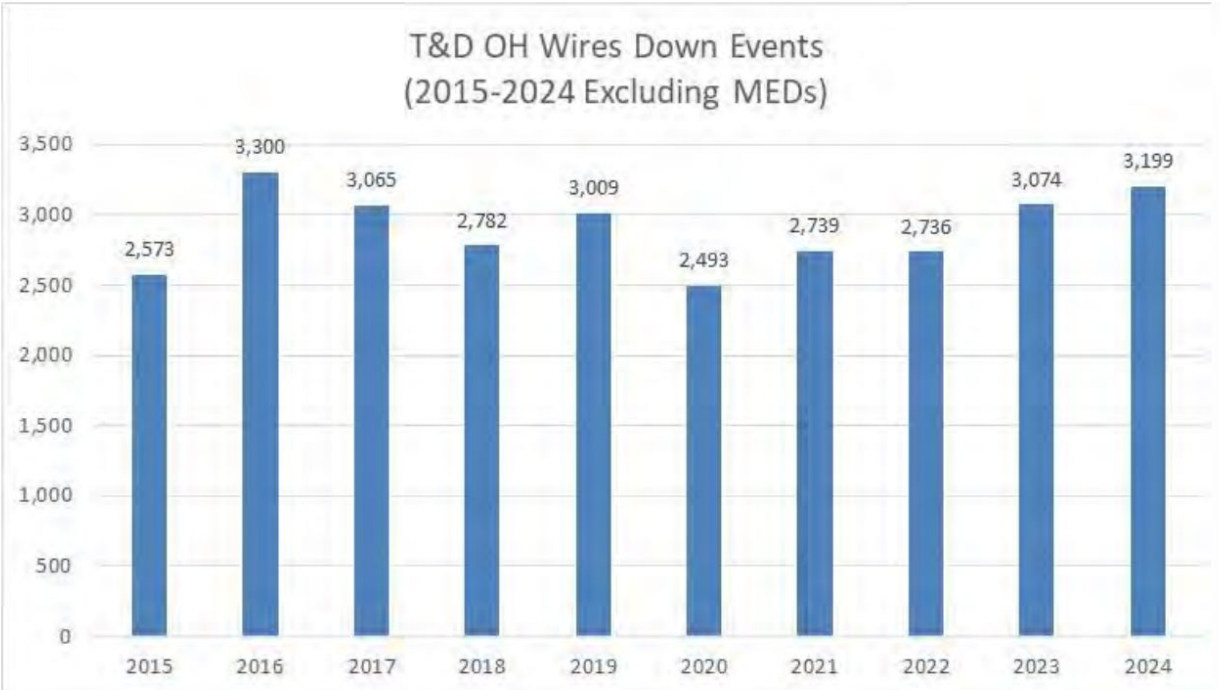
[27] *Safety Policy Division Review of Pacific Gas and Electric Company's 2021 Safety Performance Metrics Submittal Pursuant to D.21-11-009*, January 9, 2023 at 20, available at https://webtraining.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/reports/spd-review-of-pge-2021-safety-performance-metrics_010923.pdf.

[28] R.20-07-013, A.20-06-012, A.21-06-021, *Pacific Gas and Electric Company's (U39m) 2024 Safety Performance Metrics Report In Compliance with California Public utilities Commission Decision 19-04-020 and 21-11-009*, April 1, 2025 (PG&E 2024 Safety Performance Metrics Report), Figure 5-1, at 5-2, available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M562/K084/562084597.PDF.

Figure 3: PG&E's Wires Down Events 2015-2024 (Excluding Major Event Days)[29]



2. PG&E is overspending on Routine Emergency Replacement, including emergency replacement of deteriorated overhead conductor.

During these same years where PG&E has failed to timely complete its Overhead Conductor Replacement and experienced elevated instances of wire-down events, PG&E has significantly overspent on its Routine Emergency Replacement program, which includes replacement of Overhead Conductor.[30] As Figure 4 below demonstrates, PG&E's overspending has grown over the last five years, with PG&E overspending by approximately $220 million in 2024.[31]

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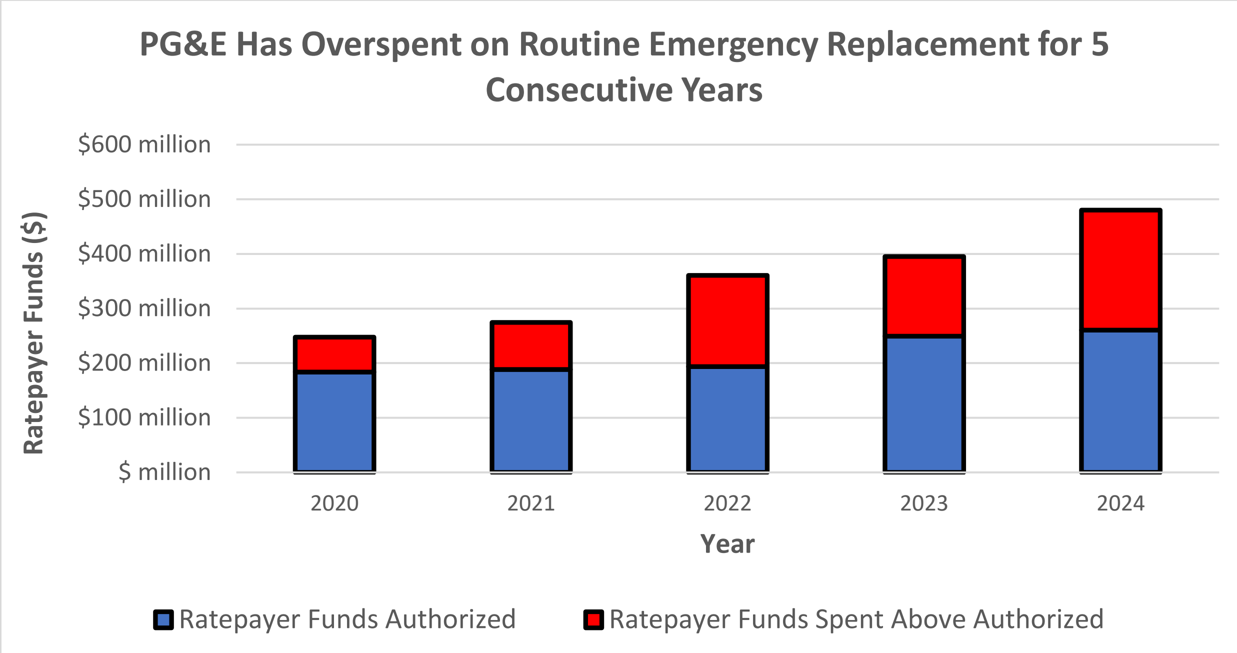
[29] PG&E 2024 Safety Performance Metrics Report, Figure 5-1, at 5-2.

[30] PG&E response to Cal Advocates' Data Request Number 5 Regarding PG&E's 2023 Risk Spending Accountability Report, Question 1. See Appendix B of these comments.

[31] PG&E's 2024 RSAR, Table 3-4, line 48, at 3-12.

Figure 4: PG&E's Routine Emergency Replacement Spending 2020-2024[32, 33]



In a data response to Cal Advocates, PG&E stated that overhead conductor was partially responsible for its overspending on Routine Emergency Replacement:

> PG&E experienced an **increase in failures of covered secondary conductor** due to cracking, corrosion, and abrasion. These failures are an ignition risk to Customer Equipment and Property as well as Wildland Fire Risk, and are required to be immediately remediated. (bold added)[34]

This is confirmed by the PG&E Independent Safety Monitor. In its 2025 report, the Independent Safety Monitor notes:

> PG&E states that its enhanced inspections and more granular assessments of conductors has also led to escalating the urgency of remediation, and an increase in the volume of conductors replaced under emergency compliance notifications.[35]

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[32] PG&E's 2023 RSAR, Table 3-4, line 46, at 3-13

[33] PG&E's 2024 RSAR, Table 3-4, line 48, at 3-12.

[34] PG&E response to Cal Advocates' Data Request Number 5 Regarding PG&E's 2023 Risk Spending Accountability Report, Question 1 (See Appendix B of these comments).

[35] PG&E 2025 Independent Safety Monitor Report at 38. See Appendix C of these comments.

PG&E's Independent Safety Monitor has repeatedly highlighted that PG&E not only has a significantly high backlog in its Overhead Conductor Replacement program, but that its rate of overhead asset replacement (inclusive of overhead conductor) is not in line with its own asset management standards.[36] The 2025 Independent Safety Monitor Report particularly highlights that if PG&E followed its own established targeted age-base of 100 years, it should be replacing approximately 800 miles per year. Instead, PG&E is only replacing (on average), 442 miles per year (inclusive of all programs such as wildfire-related covered conductor installation).[37] Therefore, not only is PG&E not completing more than half of its Commission-approved and ratepayer-funded proactive overhead conductor replacement, but its program as designed is in fact inadequate for conformance with its own targeted age for its assets.

The Commission should require PG&E to file a corrective action plan to mitigate the immediate and ongoing safety risk from deteriorated overhead conductor and associated wire-down events and ensure that PG&E is adequately maintaining its system in conformance with its own standards. This plan should include the following components:

- a plan and schedule (with start date, completion date, and intermediate steps with corresponding dates) for completing its Commission-approved Overhead Conductor Replacement
- a plan and schedule (with start date, completion date, and intermediate steps with corresponding dates) for accelerating its overhead conductor replacement rate to, at a minimum, conform with its own targeted age-base for its assets, as highlighted by the PG&E Independent Safety Monitor.
- a plan and schedule (with start date, completion date, and intermediate steps with corresponding dates) for decreasing its overhead wire-down events as a result of the above two actions and any others PG&E may take.

[36] See PG&E 2023 Independent Safety Monitor Report at 12-13. See Appendix D of these comments.

[37] PG&E 2025 Independent Safety Monitor Report at 38. See Appendix C of these comments.

The Commission can review this corrective action plan, request revisions as needed and then issue final approval within 60 days of submission. Subsequently, the Commission should oversee PG&E's completion of the approved corrective action plan. To do so, the Commission should request regular progress reports from the utility. These can take the form of an advice letter or other update mechanism.

The Commission should take these actions to ensure that PG&E maintains a safe and reliable system for customers and mitigates the risks of electrocution and catastrophic wildfire that come from conductor failure and overhead wire-down events.[38]

B. The Commission should institute an oversight process to ensure that PG&E timely completes safety and reliability work or justify why such work is no longer needed.

PG&E's failure to complete its approved Overhead Conductor Replacement program, align with its own asset management standards, and mitigate resultant safety risks from overhead wire-down events illustrates the need for the Commission to adopt a periodic formal oversight process to ensure utilities timely complete work to mitigate safety and reliability risks that it justified in its General Rate Case and the Commission found just and reasonable to fund through ratepayer bills. As Cal Advocates has highlighted in past comments on PG&E's previous RSAR submissions, PG&E has repeatedly failed to complete work not only in its Overhead Conductor Replacement program but also in important maintenance programs such as Underground Critical Operating Equipment Maintenance, Underground Manhole Inspections, and Intrusive Pole Inspections.[39] These specific programs had large cumulative backlogs as reported in

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[38] Public Utilities Code 451: "Every public utility shall furnish and maintain such adequate, efficient, just, and reasonable service, instrumentalities, equipment, and facilities, including telephone facilities, as defined in Section 54.1 of the Civil Code, as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public."

[39] A.20-06-012, A.21-06-021, A.24-05-008, *Comments of the Public Advocates' Office on Pacific Gas and Electric Company's 2023 Risk Spending Accountability Report*, August 21, 2024 at 8, 9. Available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M542/K974/542974432.PDF

PG&E's RSARs from the 2020-2022 rate case period,[40] and this trend of non-completion continued in year 2023.[41]

Cal Advocates previously recommended in Phase 1 Track 3 of Rulemaking (R.) 20-07-013 that the Commission require the utilities to submit RSAR Action Plans simultaneously with their RSAR filings.[42] The Commission decided that it did not "foresee the need for an RSAR Action Plan at this time."[43] Specifically, the Commission determined that the "completion status" and "cumulative tracking" requirements addressed two key components of the RSAR Action Plan.[44] However, RSAR reports from PG&E over many years demonstrate that important safety work remains incomplete. Commission investigations of catastrophic events caused by utility infrastructure failures have often found incomplete safety, reliability, or maintenance work.[45], [46], [47], [48], [49] Cal Advocates recommends that the Commission require PG&E to

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[40] *Pacific Gas And Electric Company's (U39m) 2022 Risk Spending Accountability Report*, May 1, 2023 (PG&E 2022 RSAR), Table 3-3 lines 42, 76, 168, and 169, and Table 3-4 line 27. Available at https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=507387422.

[41] PG&E 2023 RSAR, Table 3-3 line 58 at 3-5, line 89 at 3-6, lines 202, and 204 at 3-10, and Table 3-4 line 27 at 3-12.

[42] D.22-10-002 at 40.

[43] D.22-10-002 at 41.

[44] D.22-10-002 at 41.

[45] Comments of the Public Advocates Office on Pacific Gas & Electric Company's 2022 Risk Spend Accountability Report (Cal Advocates' PG&E 2022 RSAR Comments), July 21, 2023, at 15. Available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M514/K688/514688308.PDF

[46] CAL FIRE, *CAL FIRE Investigators Determine Cause of the Zogg Fire* (March 22, 2021), https://yubanet.com/california/cal-fire-investigators-determine-cause-of-the-zogg-fire/

[47] Morris, JD. *Camp Fire failure part of PG&E's 'pattern' of poor maintenance, regulators say*(December 3, 2019), San Francisco Chronicle.

https://www.sfchronicle.com/californiawildfires/article/Regulators-PG-E-could-have-prevented-Camp-Fire-14877131.php

[48] *Motion of the Safety and Enforcement Division to Expand the Proceeding Scope to Include the 2018 Camp Fire, Appendix A, SED Incident Investigation Report for 2018 Camp Fire with Attachments*, November 26, 2019, at 16; in I.19-06-015.

[49] Van Derbeken, Jaxon. *PG&E Admits it Broke 2020 Promise to Fully Inspect 50K Poles in High Fire Risk Zones* (May 14, 2021). NBC Bay Area. https://www.nbcbayarea.com/investigations/pge-admits-itbroke-2020-promise-to-fully-inspect-58000-poles-in-high-fire-risk-zones/2545708/.

submit RSAR Action Plans to address a utility's failure to complete necessary safety and reliability work.

The RSAR Action Plan should describe how the utility will either complete the necessary safety, reliability, and maintenance work it reported as incomplete or justify why the work is no longer necessary. If a utility contends that authorized work is no longer necessary, the utility should provide justification. The Commission can evaluate the utility's justification during its review of the utility's RSAR Action Plan. If a utility reprioritizes its safety work, the RSAR Action Plan process will help ensure that the remaining necessary safety and reliability work is timely completed to avoid property damage and/or loss of life or injury caused by utility infrastructure failures.

III. CONCLUSION

To mitigate critical safety risks to the public, improve utility transparency and accountability, and ensure just stewardship of ratepayer dollars, Cal Advocates respectfully requests that the Commission adopt the recommendations contained herein.

Respectfully submitted,

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September 29, 2025

Appendix A

Authorized versus actual costs and work completion for PG&E's Routine Emergency Replacement program[1] and Overhead Conductor Replacement program

[1] PG&E's Routine Emergency Replacement Programprogram is not unitized, therefore only cost information is available for this program.

Figure A-1: PG&E's Overhead Conductor Replacement Completion 2020-2024[1, 2]

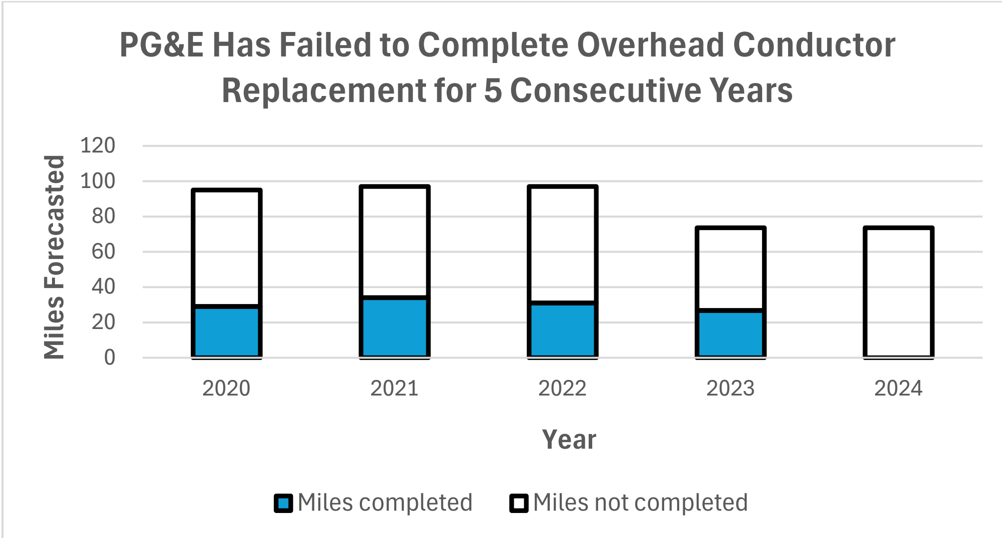
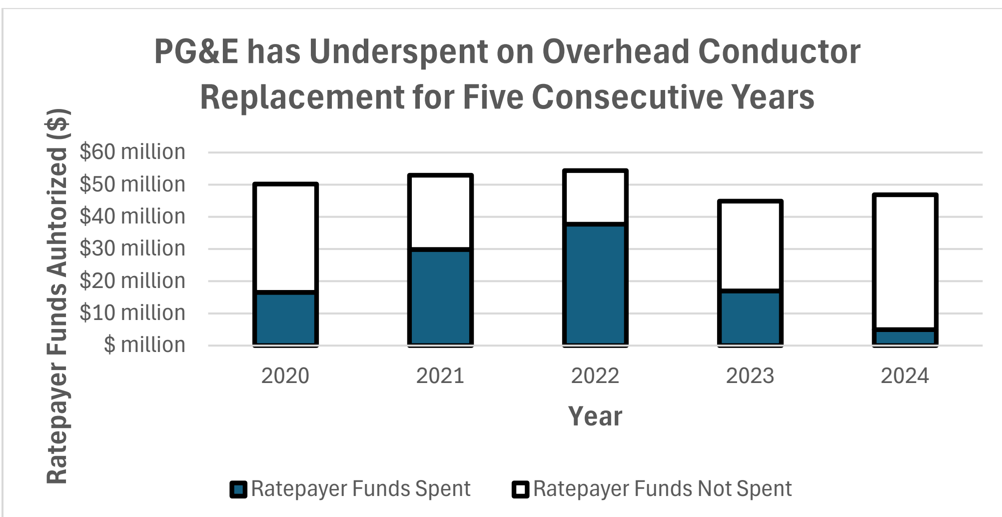


Figure A-2: PG&E's Overhead Conductor Replacement Spending 2020-2024[3, 4]



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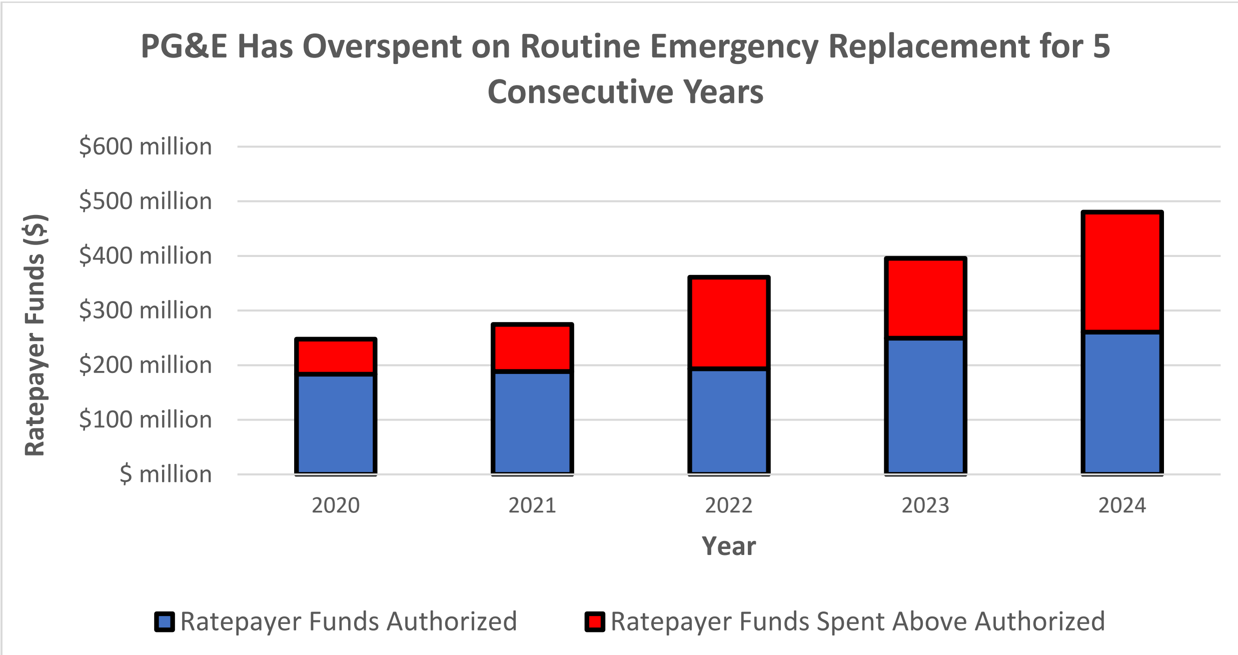
[1] PG&E 2023 RSAR, Table 3-4, line 30 at 3-12.

[2] PG&E 2024 RSAR, Table 3-4, line 30 at 3-11.

[3] PG&E 2023 RSAR, Table 3-4, line 30 at 3-12.

[4] PG&E 2024 RSAR, Table 3-4, line 30 at 3-11.

Figure A-3: PG&E's Routine Emergency Replacement Spending 2020-2024[5, 6]



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[5] PG&E's 2023 RSAR, Table 3-4, line 46, at 3-13

[6] PG&E's 2024 RSAR, Table 3-4, line 48, at 3-12.

Appendix B

PG&E's response to Cal Advocates' 5th Data Request regarding PG&E's 2023 Risk Spending Accountability Report, Question 1

PACIFIC GAS AND ELECTRIC COMPANY
Risk Spending Accountability Report Discovery 2023
Data Response

PG&E Data Request No.:	CalAdvocates_005-Q001		
PG&E File Name:	RSARDiscovery2023_DR_CalAdvocates_005-Q001		
Request Date:	September 17, 2024	Requester DR No.:	005
Date Sent:	October 2, 2024	Requesting Party:	Public Advocates Office
PG&E Witness:	N/A	Requester:	Miles Gordon

SUBJECT: PG&E'S 2023 RISK SPEND ACCOUNTABILITY REPORT

QUESTION 001

In PG&E's response to Question 1(b) of Cal Advocates' Data Request No. 1[1] regarding PG&E's 2023 RSAR, PG&E states that one driver of its prioritization of work in 2023 was "Increased Emergency Replacements". PG&E states "The overall trend of routine emergency repairs is growing above the 3-year average that was used to develop the 2023 GRC request."

In line 46 of Table 3-4 in PG&E's 2023 RSAR, PG&E states that it spent $146 million more than authorized for its Electric Distribution Routine Emergency work. PG&E states that "Program expenditures were above imputed regulatory values due to…a substantially higher volume of emergency work in 2023. The higher volumes of emergency work were largely due to a special emphasis placed in 2023 on identifying & addressing deteriorated OH [Overhead] Service Conductor in HFTD [High Fire Threat District]."

PG&E further states that "PG&E expects to continue to spend more on this program than forecasted in order to address deteriorated OH Service Conductors in HFTDs as a routine emergency,"[2]

a. Please describe what is meant by the term "routine emergency" as used in the above quotation.

b. Please list and describe all drivers of the abovementioned "substantially higher volume of emergency work in 2023".

c. Please state the basis for the "special emphasis placed in 2023 on identifying & addressing deteriorated OH Service Conductor in HFTD."

d. Why does PG&E expect to continue to spend more on this program than forecasted in order to address deteriorated overhead service conductors as a routine emergency?

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1 PG&E's July 17th response to Question 1(b) of Cal Advocates' Data Request No. 1.

2 PG&E's 2023 RSAR, Table 3-4, line 46 at 3-6.

ANSWER 001

a. Routine Emergency is work categorized as an immediate safety hazard to customer outage that occurs during normal conditions. This is also known as “Blue Sky Emergency” (i.e. not related to a fire or storm, or where EOC is not activated).

b. PG&E experienced an increase in failures of covered secondary conductor due to cracking, corrosion, and abrasion. These failures are an ignition risk to Customer Equipment and Property as well as Wildland Fire Risk, and are required to be immediately remediated. PG&E addressed this issue by updating inspection criteria, providing pictures and guidance on how to assess these conditions. This drove special attention to this condition and resulted in an increase in priority A tags; repairs for A tags are conducted under routine emergency in MWC 17. PG&E also increased the frequency of its enhanced inspections in HFTDs also contributing to the increase in electric corrective maintenance notifications.

c. See answer to b

d. In first quarter 2024, PG&E published a revision to our GO 165 Detailed Visual Inspections guidance to provide more granularity for OH service conductor field conditions. In addition, we are conducting aerial inspections in HFTDs resulting in higher find rates of certain conditions not visible from the ground previously, for example pole-top and cross arm abnormal conditions. PG&E expects that these changes will result in a larger volume of Emergency notifications (A and X tags) related to correcting deteriorated OH service conductor. PG&E’s goal is to address these emergent conditions prior to an outage or ignition event.

Appendix C

PG&E 2025 Independent Safety Monitor Report

PG&E

INDEPENDENT SAFETY MONITOR STATUS UPDATE REPORT

May 15, 2025

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LIST OF TERMS AND ACRONYMS

Term/ Acronym	Meaning
AFA	Asset Failure Analysis
AMP	Asset Management Plan
ANSI	American National Standard Institute
AOC	Areas of Concern
ATS	Applied Technology Services
BBCR	Bell-Bell-Chill-Ring
BES	Bulk Electric System
BMP	Best Management Practices
CA	Corrective Action
CAIDI	Customer Average Duration Index
CAL FIRE	California Department of Forestry and Fire Protection
CAP	Corrective Action Plan
CCR	California Code of Regulations
CDE	Critical Data Elements
CEO	Chief Executive Officer
CESO	Customer Experienced Sustained Outage
CGA	Common Ground Alliance
CIRT	Centralized Inspection Review Team
CME	Customer Minutes Enabled
CoF	Consequence of Failure
ComAPS	Communication Assisted Protection Systems
COO	Chief Operations Officer
CPI	Comprehensive Pole Inspection
CMD	Circuit Mile Days
CPUC	California Public Utilities Commission
CPZ	Circuit Protection Zones
CRO	Chief Risk Office
COPRs	Conditional Operating Pressure Reductions
DAR	Data Asset Registry
DART	Days Away, Restricted, or Transferred
DCD	Downed Conductor Detection
DFA	Distribution Fault Anticipation
DIMP	Distribution Integrity Management Program
DVMP	Distribution Vegetation Management Procedures
ECA	Engineering Critical Assessment
EDGIS	Extended Dynamic Geographic Information System
EFD	Early Fault Detection

Term/Acronym	Meaning
EIA	Enhanced Ignition Analysis
EIR	Electric Ignition Report
EPA	Environmental Protection Agency
EPSS	Enhanced Powerline Safety Settings
EOC	Extent of Condition
EORM	Enterprise and Operational Risk Management
EVM	Enhanced Vegetation Management
FEP	Filsinger Energy Partners
FIMP	Facilities Integrity Management Program
FPI	Fire Potential Index
FTI	Focused Tree Inspections
FSR	Field Safety Reassessment
GDAM	Gas Data Asset Management
GIS	Geographic Information System
GO	General Order
GSMES	Gas Safety Excellence Management System
HCA	High Consequence Area
HDD	Horizontal Directional Drilling
HFRA	High Fire Risk Area
HFTD	High Fire Threat District
IGP	Integrated Grid Plan
ILI	In-Line Inspection
ILIS	Integrated Logging Information System
ISA	International Society of Arboriculture
ISM	Independent Safety Monitor
KPI	Key Performance Indicators
LOC	Loss of Containment
LTE	Long Term Evolution (cellular)
MAOP	Maximum Allowable Operating Pressure
MCA	Moderate Consequence Area
MDR	Minimum Distance Requirements
MFL-A	Magnetic Flux Leakage - Axial
MFL-C	Magnetic Flux Leakage - Circumferential
NERC	North American Electric Reliability Corporation
OCN	Operational Change Notification
ORV	Operational Risk Validation
OSHA	Occupational Safety and Health Awareness
PG&E	Pacific Gas and Electric

Term/Acronym	Meaning
PHA	Process Hazard Analyses
PHMSA	Pipeline Hazardous Materials Safety Administration
PIIR	Post Ignition Investigation Report
PMVI	Preventable Motor Vehicle Incidents
PRC	California Public Resource Code
PSEMS	Process Safety Excellence Management System
PSM	Process Safety Management
PSPS	Public Safety Power Shutoff
PTT	Pole Test and Treat
PVD	Partial Voltage Detection
PVFO	Partial Voltage Force Out
QA	Quality Assurance
QEW	Qualified Electrical Worker
QC	Quality Control
QMS	Quality Management System
RAMP	Risk Assessment Mitigation Phase
RCC	Risk and Compliance Committee
RCE	Root Cause Evaluation
REFCL	Rapid Earth Fault Current Limiter
RFP	Request for Proposal
Rx	Vegetation Management Prescription
ROW	Right of Way
SAP	System, Applications, and Products in Data Processing
SGF	Sensitive Ground Fault
SME	Subject Matter Expert
SMYS	Specified Minimum Yield Strength
TAT	Tree Assessment Tool
TIMP	Transmission Integrity Management Program
TOAM	Transformer Overload Accuracy Model
TRAQ	Tree Risk Assessment Qualification
TRI	Tree Removal Inventory
TROPS	Temporary Operating Pressure Reductions
TVC	Traceable, Verifiable, and Complete
UVM	Utility Vegetation Management
VASA	Vegetation Assets Strategy and Analytics
VM	Vegetation Management
VMI	Vegetation Management Inspector
VMOM	Vegetation Management for Operational Mitigation

Term/Acronym	Meaning
VMDIP	Vegetation Management Inspection Procedure
WDRM v4	Wildfire Distribution Risk Model Version 4
WFC v4	Wildfire Consequence Model Version 4
WMP	Wildfire Mitigation Plan
WRGSC	Wildfire Risk Governance Steering Committee
WTRM v2	Wildfire Transmission Risk Model Version 2
WTRM v2.1	Wildfire Transmission Risk Model Version 2.1

EXECUTIVE SUMMARY

The Independent Safety Monitor (ISM) conducted a review of PG&E's activities, providing observations based on fieldwork, data analysis, and discussions with PG&E personnel. This report presents a summary of certain ISM findings related to electric and gas operations, highlighting progress, challenges, and areas requiring continued oversight.

ELECTRIC OPERATIONS

During the current ISM reporting period PG&E's electric operations continued to prioritize wildfire risk reduction through system hardening, enhanced operational controls, and expanded vegetation management initiatives. The ISM observed that while these efforts have contributed to a reduction in ignitions within High Fire Threat Districts (HFTD) [1], ignitions occurring under high-risk weather conditions have seen a slight increase, prompting PG&E to implement additional targeted mitigation strategies.

The ISM also reviewed PG&E's ignition investigation processes, including the Preliminary Ignition Investigation Reports and Electric Incident Reports. These reports provide detailed analyses of fire causes, hazard barrier performance, and corrective actions aimed at reducing ignition risk. Over the current ISM reporting period, the ISM examined 203 PIIRs and 31 EIRs, noting that vegetation contact and equipment failure were the most common ignition sources. PG&E has expanded its investigative capabilities, incorporating data analytics and field inspections to improve its root cause analysis.

PG&E's Enhanced Powerline Safety Settings (EPSS) program remains a key wildfire mitigation tool, de-energizing power lines in response to high-risk conditions. While ignitions on EPSS lines were higher in 2024, partially attributable to extreme weather, the EPSS program continues to show a drop in ignitions since 2021. While frequency and duration of customer EPSS outages remain stable, the ISM observed that PG&E has taken steps to mitigate customer impacts, including the deployment of sectionalizing devices, improved restoration response times, and the integration of advanced sensor technologies such as Downed Conductor Detection and Gridscope monitoring. These technologies have enhanced PG&E's ability to detect and respond to potential ignition events, though the data suggests continued refinements are needed to balance safety and reliability objectives.

Risk modeling and asset management remain part of PG&E's electric operations strategy. During the current ISM reporting period, the ISM reviewed updates to PG&E's wildfire risk models, including refinements to the Wildfire Transmission Risk Model and the integration of new asset failure models. These enhancements improved PG&E's ability to prioritize infrastructure investments and maintenance activities. The ISM will continue monitoring

[1] Unless specifically called out, reference to HFTD includes PG&E's High Fire Risk Areas. HFTD is used by California regulatory agencies to define areas with elevated wildfire risk, and PG&E's HFRA is an extension of HFTD based on more detailed risk analysis by PG&E within their service territory.

PG&E's efforts to refine its risk modeling capabilities and align mitigation strategies with emerging operational risks.

Vegetation management also remains a fundamental component of PG&E's wildfire mitigation efforts. During the current ISM reporting period, the ISM reviewed PG&E's routine vegetation inspections, hazard tree removal programs, and targeted mitigation initiatives. While these efforts contributed to risk reduction, integration challenges between vegetation management data platforms may impact productivity. The ISM observed that PG&E is continuing to work toward improving its coordination across vegetation management operational teams.

GAS OPERATIONS

PG&E continued the implementation of the PG&E Safety Excellence Management System (PSEMS) across its gas operations during the reporting period. The ISM reviewed PG&E's application of PSEMS, which includes risk assessments, incident tracking, and process safety initiatives. PG&E has documented changes to its approach in integrating PSEMS across operational functions and has made modifications to its safety performance monitoring.

The ISM reviewed PG&E's facility integrity management efforts, including its oversight of critical gas facilities and pipeline infrastructure. More recently, PG&E conducted root cause evaluations and implemented corrective actions in response to the Kettleman Incident. The ISM examined PG&E's prescribed corrective actions and will continue to monitor PG&E's facility integrity management and critical facilities.

PG&E maintained its damage prevention initiatives, which include excavation risk mitigation and coordination with external stakeholders. The ISM reviewed PG&E's documentation of industry benchmarking and performance metrics used to assess program effectiveness. PG&E reported updates to its public awareness campaigns and stakeholder engagement efforts related to third-party damage prevention.

PG&E conducted updates to its gas asset data management, including refinements in Maximum Allowable Operating Pressure assessments and the expansion of its in-line inspection programs. The ISM reviewed PG&E's modifications to data integration practices and observed changes in predictive analytics applied to system oversight.

BACKGROUND

In conjunction with 1) California Public Utilities Commission (CPUC) Decision 20-05-053, 2) the Bankruptcy Plan of Reorganization for Pacific Gas and Electric Company and 3) the findings included in the Kirkland & Ellis LLP Federal Monitorship Final Report dated November 19, 2021 (Federal Monitorship Report) a need for a safety monitor was identified. Through Resolution M-4855, the CPUC approved implementation of an Independent Safety Monitor (ISM) of PG&E to fulfill a role that supports the CPUC's ongoing safety oversight of PG&E's activities.

Filsinger Energy Partners, Inc. (FEP) has been engaged to serve as the ISM of PG&E. The ISM contract executed between FEP and PG&E dated January 27, 2022 (the ISM Contract) outlines a scope of work that includes FEP monitoring certain safety and risk aspects of PG&E's electric and natural gas operations and infrastructure. In consultation with the CPUC, the ISM identifies and performs certain monitoring activities associated with areas outlined within the scope of the ISM Contract. The areas of focus are designed to take into consideration the findings from the Federal Monitorship Report; safety related findings from areas identified through the ISM's fieldwork, inspections, and analyses; and provide complementary oversight and monitoring activities that are not unnecessarily duplicative, consistent with CPUC Resolution M-4855.

The ISM's first five reports, hereafter referred to as "ISM Report 1", "ISM Report 2", "ISM Report 3", "ISM Report 4", and "ISM Report 5" (or "ISM Previous Reports", collectively), covered the periods January 27, 2022, through September 30, 2022 (published October 4, 2022), October 1, 2022, through March 31, 2023 (published May 2, 2023), April 1, 2023, through September 30, 2023 (published October 4, 2023), October 1, 2023, through March 31, 2024 (published April 4, 2024), and April 1, 2024, through September 30, 2024 (published October 4, 2024) respectively. The ISM Previous Reports identified work performed in associated focus areas during the respective reporting periods.

This PG&E Independent Safety Monitor Status Update Report, hereafter referred to as "ISM Report 6", covers the reporting period October 1, 2024, through March 31, 2025. It was developed based on the stipulations of the ISM Contract and the reporting directive included within CPUC Resolution M-4855. This ISM Report 6 is designed to summarize the oversight activities performed by the ISM during the reporting period described and the related observations.

This ISM Report 6 also includes a summary of potential emerging risks identified during the oversight activities performed during the current ISM reporting period. With respect to potential emerging risks, consistent with the ISM Contract scope, the ISM has documented the initial observations and performed certain initial monitoring activities. Depending upon the observations, in consultation with the CPUC, it may be determined that the ISM will perform additional monitoring activities.

The ISM's role is not to provide suggestions for addressing the issues identified or rank the order of priority or risk. Relatedly, the ISM monitored PG&E's activities to the extent agreed upon within the confines of the ISM Contract or as otherwise agreed to between the ISM and the CPUC.

The information included in this ISM Report 6 should be considered a "snapshot" of observations during the current ISM reporting period. The ISM may continue to perform monitoring activities related to certain observations noted in this ISM Report 6. Not all topics and/or observations identified in the ISM Previous Reports will be discussed in the current report. If the ISM did not identify new material changes or information during the current ISM reporting period, the topic/observation may be omitted from the current report and reintroduced in the future when material additional changes or information are obtained. Observations may change for various reasons (e.g., additional information becomes available, operational changes are implemented by PG&E, etc.). The ISM derived general facts and information contained within this report from internal PG&E meetings, presentations, data, and external reports which may not always be footnoted. Unless otherwise stated, the ISM did not independently confirm facts and information provided to it by PG&E or any third parties.

GENERAL OBSERVATIONS

The Federal Monitorship Report identified "retaining a core leadership team, in the wake of near constant turnover in recent years" as one of the "most salient challenges PG&E faces going forward."

The ISM monitored and reported specific leadership changes in each of the ISM Previous Reports. During the current ISM reporting period, the ISM reviewed and summarized the leadership changes occurring at the officer level (Vice President and above) since January 2022. The organizational charts included in Figure 1 summarize these changes, highlighting the leadership positions that changed two or three times, and new positions added since the ISM's engagement.

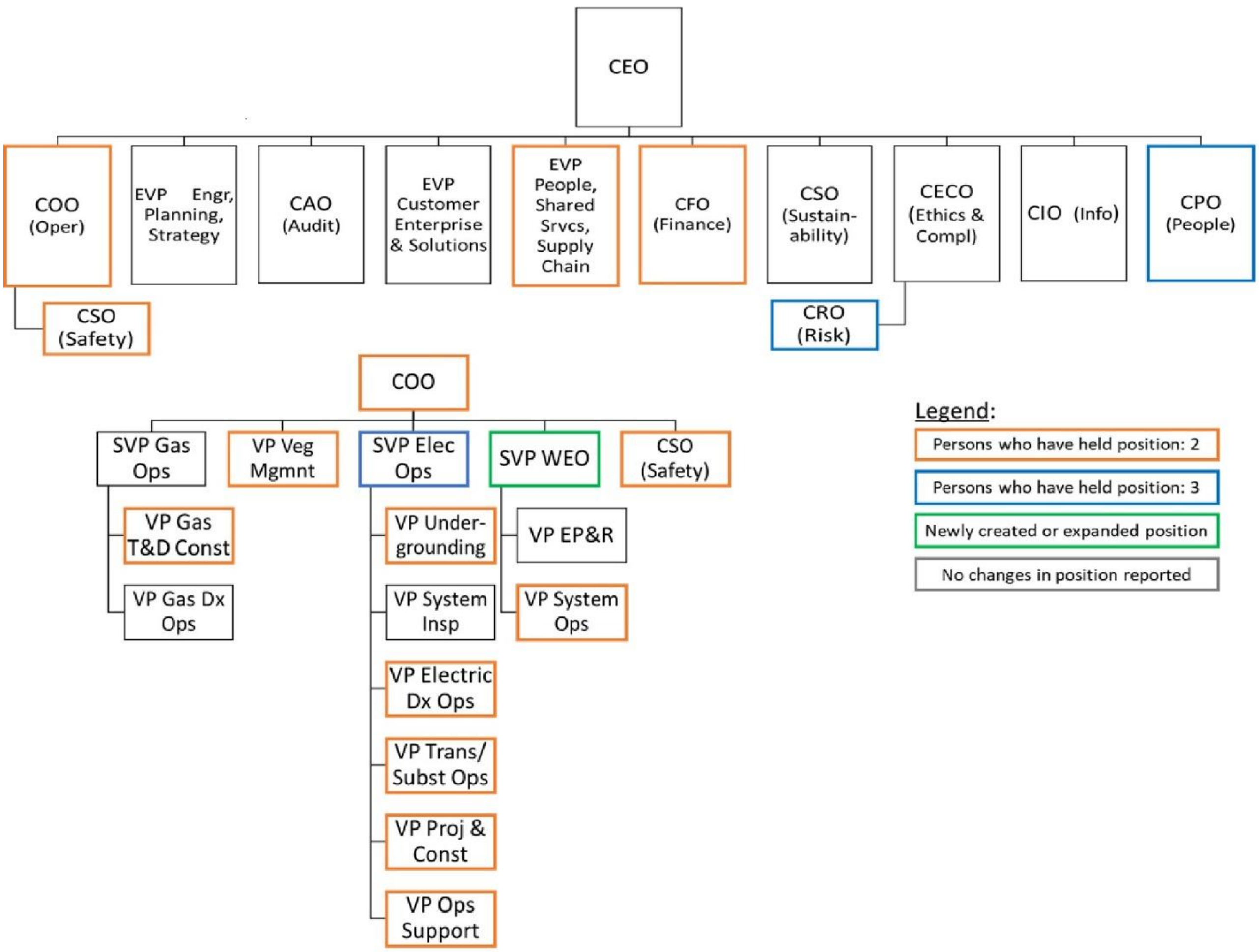

Figure 1: PG&E Senior Leadership Changes Since January 2022

As depicted in the top portion of Figure 1, 30% of the positions reporting directly to the Chief Executive Officer (CEO) had two incumbents, and 10% had three incumbents. As depicted in the bottom left portion of Figure 1, of the positions reporting directly to the Chief Operations

Officer (COO), 20% had three incumbents, 40% had two incumbents, and 20% were newly created or expanded positions. Further, of the remaining position reporting under the COO, 70% had two incumbents.

During each of the respective ISM reporting periods, the ISM interviewed employees, attended meetings, and reviewed data provided by PG&E. As previously mentioned in ISM Previous Reports, through these monitoring activities, the ISM observed that leadership changes have caused some operational disruption. During the current ISM reporting period, the ISM noted fewer leadership changes. At the VP level and above, PG&E made the interim appointment for Vice President of the Undergrounding Program permanent.

The ISM will continue to monitor leadership changes and related potential impacts relative to the areas within the scope of ISM responsibilities.

ELECTRIC OPERATIONS OBSERVATIONS

The ISM's electric operations and infrastructure focus in this ISM Report 6 is directed toward: 1) Reliability Trends, 2) Ignitions Investigations, 3) Fast Trip Programs, 4) Risk Models and Operational Risk Validation, 5) Asset Age and Useful Life, 6) Distribution Infrastructure, 7) Transmission Infrastructure, and 8) Vegetation Management.

IGNITION TRENDS

During the current ISM reporting period, the ISM re-examined longer-term ignition trends presented in ISM Previous Reports.

Figure 2 shows the longer-term trends of CPUC reportable ignitions[2] for both non-HFTD and HFTD areas.

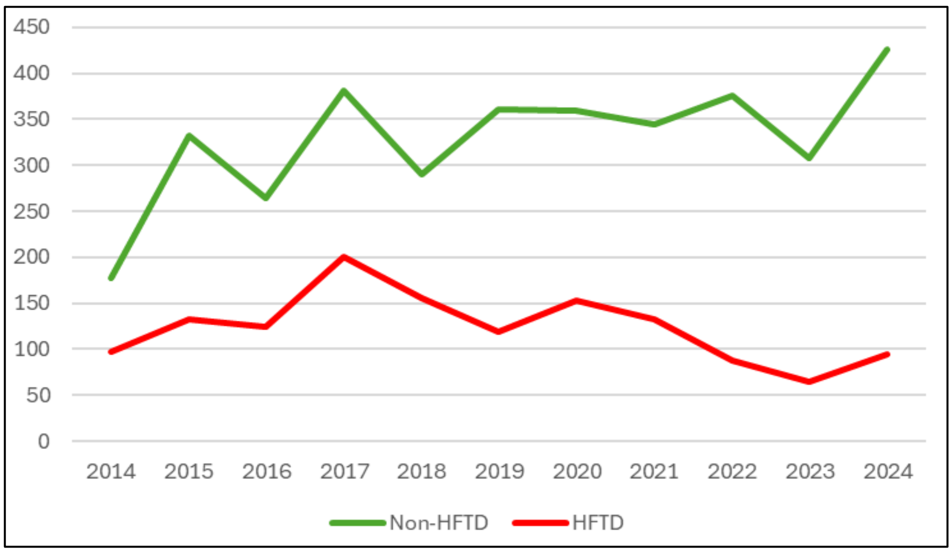

Figure 2: Number of CPUC Reportable Ignitions 2014 - 2024

PG&E also tracks the number of ignitions which occur when the Fire Potential Index (FPI) is R3 or higher.[3] As shown in Figure 3, PG&E experienced an increase in the number of R3+ reportable ignitions in 2024 to 1.41 per 100,000 Circuit Mile Days (CMD).[4]

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[2] A CPUC reportable ignition is an event that meets CPUC reporting criteria including ignitions that are associated with utility equipment and result in a fire spreading beyond one square meter or are otherwise required to be reported under CPUC regulations.

[3] FPI is a model used by PG&E to rate the likelihood of a wildfire becoming catastrophic on a scale of R1 to R5. PG&E notes an FPI of R3 or higher accounts for 95% of the acres burned in its historical dataset, and 100% of the fatalities and structures destroyed.

[4] The number of R3+ reportable ignitions is normalized by the number of CMD experiencing R3+ condition. In 2024 there were 56 R3+ reportable ignitions in HFTD over 3,966,258 CMD. These CMD are calculated as the number of circuit miles that are at R3+ conditions multiplied by the number of days those miles are under R3+ conditions.

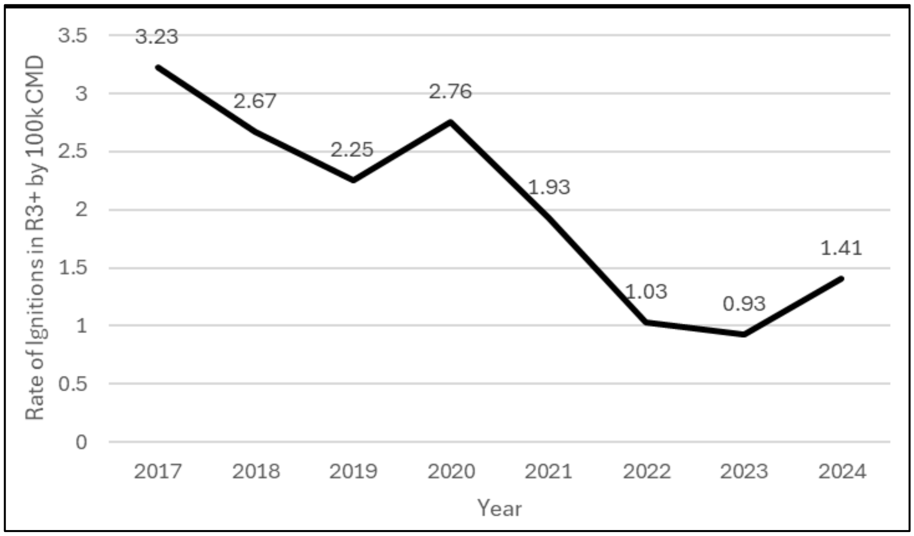

Figure 3: Weather Normalized CPUC R3+ Ignition Rates in HFTD by 100k Circuit Mile Days

One of the reasons for the increase in total and R3+ ignitions was the more extreme environmental conditions and heat events experienced in 2024. PG&E stated that extensive grass crop and vegetation growth arising from the widespread precipitation in the winter of 2023, followed by the intense heat of June and July, created ample dry fuel capable of turning ignitions into larger fires.

Figure 4 shows how the number of reportable ignitions in HFTD and High Fire Risk Areas (HFRA) began to increase over the prior year during the heat events of June and July of 2024.

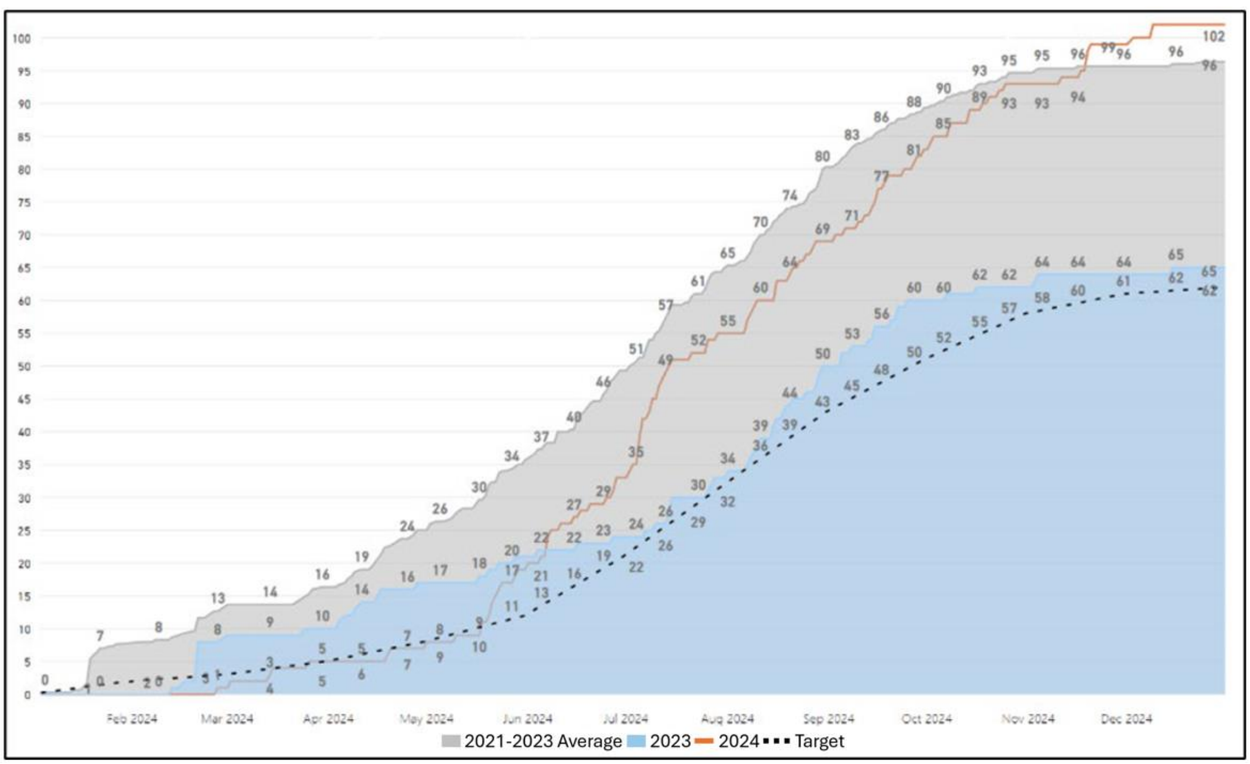

Figure 4: Cumulative CPUC Reportable PG&E Facility Ignitions in HFTD

In reaction to these more extreme conditions, and in an attempt to flatten the slope of this increasing trend, PG&E formed an R3+ Ignitions Task Force in mid-2024 to determine which supplemental mitigations could be deployed in the near term to stem the rise in these higher risk R3+ ignitions.[5] The ISM tracked the progress of these supplemental mitigations through the year, with all but one hitting or exceeding their targets by year end. Despite these incremental efforts, PG&E recorded 102 reportable ignitions in HFTD, exceeding its 2024 target of 62, the number of ignitions in 2023 of 65, and the three-year average of 96.

In addition to tracking annual trends, the ISM also reviewed trends in ignition causes. Figure 5 shows that each category of ignition cause had generally been experiencing longer-term declines, but then either plateaued or increased in ignition counts in HFTD over those in 2023.

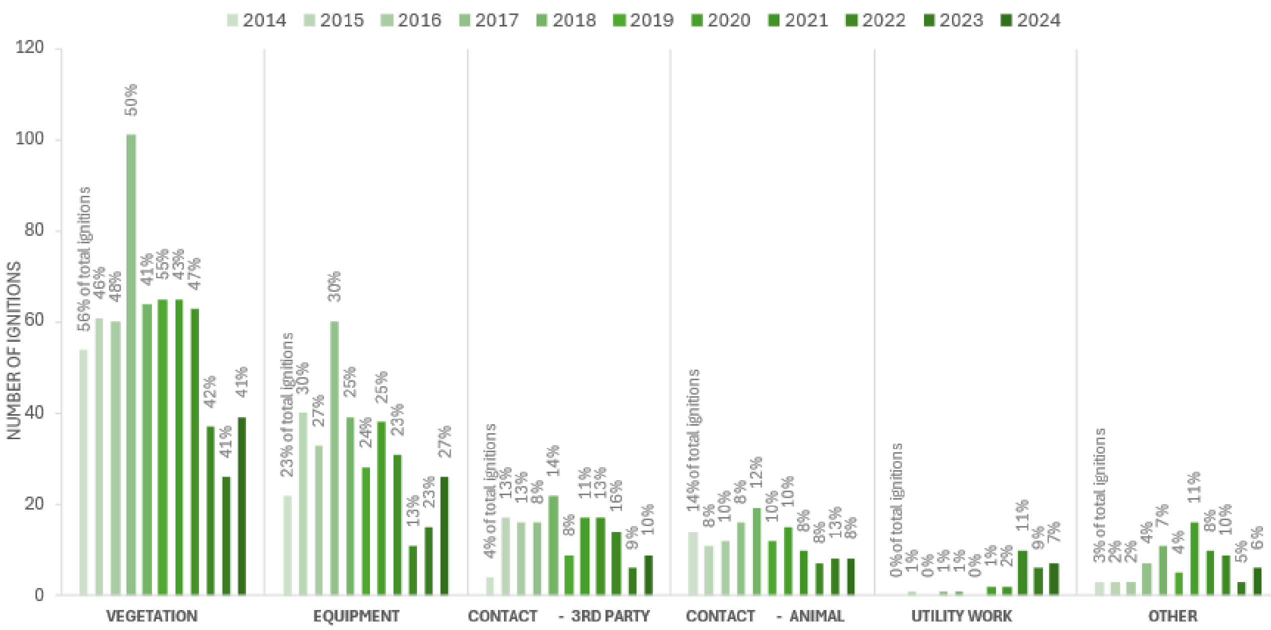

Figure 5: PG&E Facility Ignitions in HFTD by Suspected Initiating Event[6]

The ISM also examined trends in specific equipment component failures that led to both outages and ignitions in HFTD. Over the 2014-2024 period, while the components leading to equipment failure ignitions experienced significant variability year-over-year, in general, other than a decrease in pole and capacitor bank failure caused ignitions over the past few years there were no significant increase or decrease trends over the long term. Over these 11 years, the leading components of equipment failure ignitions in HFTD were conductors (25%), splice/clamp/connectors (14%), fuses (8%), transformers (7%), insulators (7%) and poles (6%).

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[5] The 20 mitigations included in this plan were detailed in ISM Report 5, and included additional pole clearing, additional sensors (also detailed later in this Report 6), accelerated infrared tag completions and e-fuse equipment replacements, and supplemental targeted tree removals.

[6] Height of bars represents the number of ignitions by suspected initiating event each year. Percentages indicate the proportion of each suspected initiating event relative to the total ignitions for that year.

Table 1: Fire Size of PG&E Facility Ignitions in HFTD

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
<1 meter	28	30	23	29	97	66	49	76	38	49	52
1 meter to 0.25 acres	60	94	87	114	99	79	85	94	71	42	62
0.26 to 9.99 acres	32	28	29	56	40	33	58	30	11	18	23
10 to 99.9 acres	1	6	4	13	6	2	7	5	4	3	8
100 to 999 acres	0	0	1	3	1	1	0	1	0	1	1
1.000 to 4,999 acres	1	0	1	3	0	0	0	1	0	0	0
> 5,000 acres	0	1	0	10	1	1	1	1	1	0	1

Finally, the ISM examined trends in fires size over time. As shown in Table 1, many of the fire size categories below 100 acres saw decreases in their numbers over the past few years until 2024. In 2024, these sub-100 acre fire sizes increased in conjunction with the increase in the number of fire ignitions experienced during the more dangerous R3+ fire conditions.[7]

IGNITION INVESTIGATIONS

In 2023, the ISM began reviewing PG&E's Preliminary Ignition Investigation Reports (PIIR) that provide comprehensive investigative analysis into the circumstances and suspected root causes of certain ignitions. In addition, PG&E uses these PIIR to evaluate the effectiveness of hazard barriers designed to mitigate risk, and to document follow-up investigative work that may be performed by its vegetation management team, its Applied Technology Services (ATS) engineering laboratory, and its Asset Failure Analysis (AFA) group. Where the PIIR identified circumstances such as improper construction, missed inspection items, inadequate training, or new emerging equipment failure sources, the PIIR may detail corrective action plans to help mitigate future ignitions. This ISM Report 6 section details the PIIR, the Enhanced Ignitions Analysis team, PIIR structure and distribution, CPUC Electric Incident Reports, and ends with the ISM's observations from its review of select PIIR.

PIIR and the Enhanced Ignitions Analysis Group

PIIR, initiated in July 2021, are PG&E's Enhanced Ignition Analysis (EIA) program's primary deliverables. All fires associated with company assets, regardless of location, can be in scope for this program. PG&E indicated that it generally excludes fires where the suspected cause of the ignition is insulator tracking, where typically only PG&E assets are impacted. In 2024, PG&E scoped its reviews to those ignitions occurring in HFTD and/or HFRA, lines in non-HFTD areas that may be EPSS enabled, and transmission facilities regardless of location. While some non-HFTD, non-HFRA/non-EPSS ignitions were included in the earlier investigations, PG&E stated that starting in 2024 it preferred to direct its EIA team resources to perform more detailed analysis on fewer ignitions, and to focus on ignitions in the higher risk areas where PG&E believes there is more to learn.

PG&E's original ignitions investigation team of two dedicated investigators began to expand in 2020, and the EIA group is currently comprised of 23 PG&E staff with diverse backgrounds,

[7] The one >5000 acre fire in 2024 was reported to the ISM as having occurred in HFTD with a suspected cause of vegetation contact. The fire burned 19,195 acres and no structures or injuries were reported.

including retired CAL Fire and Fire Service personnel, and people with expertise in project management, claims investigation, engineering, medicine and disaster response. PG&E stated that all investigators have completed industry standard fire investigator trainings, including California's Office of the State Fire Marshal Fire Investigator 1A, 1B, and 1C, and the National Wildfire Coordinating Group Wildland Fire Cause and Origin Determination (FI-210).

For investigations involving equipment failure or improper construction, the EIA team works closely with PG&E Applied Technology Services (ATS) department and Asset Failure Analysis (AFA) group. PG&E's San Ramon Technology Center is home to ATS, an in-house department of approximately 130 engineers, specialists, technicians, and support staff dedicated to operational technology advancement and technical problem solving. The ATS team supports all functional areas within PG&E with core capabilities of asset condition assessment, engineering causal evaluation, inspection and equipment innovation, grid & electrification innovation, and engineering consulting. The ISM visited the ATS facility on two occasions. The ISM observed PG&E's original EPSS tripping research using actual high voltage arcs and tree branches on its first visit. On the second visit, the ISM discussed activities associated with overhead distribution transformer failure analysis and testing, aged transmission conductor and connector testing, and progress on pilot programs such as Rapid Earth Fault Current Limiter (REFCL), and Distribution Fault Anticipation (DFA). The ISM frequently observes ATS analyses presented in various internal reports and discussed at Wildfire Risk Governance Steering Committee (WRGSC) meetings for emerging equipment-related wildfire risks, for new technology evaluation, or for evaluating new mitigation effectiveness.

Many of the investigations also involve participation of PG&E's AFA group, where PG&E often sends team members to work in the field to perform extent-of-condition (EOC) investigations following asset failure.

In addition to investigating select ignitions and preparing the PIIR, the EIA team can also be called upon to assist in broader equipment root-cause evaluations in conjunction with ATS and AFA. In one example, AFA conducted a root-cause analysis on some fires associated with fuses exempt from PRC 4292 compliance, and the EIA team coordinated material collection and failure analysis of fuses that failed but were not in HFTD. PG&E stated that this process and EIA's support was key in getting enough examples of failure required to determine a failure mode and to rule out other possible causes (i.e. manufacturing defects). In this example, PG&E determined that the failure mode associated with these exempt fuse failures resulted from internal material handling practices. The ISM followed the emergence of the issue, as well as observed the development and deployment of the corrective actions associated with these fuse ignitions presented at various PG&E meetings.[8]

The PIIRs generated by the EIA team are not typically shared with external groups or agencies unless they are specifically requested. PG&E provided the ISM with the distribution list for the PIIR, which includes 6 senior operational group leaders, and approximately 150 staff across 17

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[8] Corrective actions associated with these fuse ignitions included: PG&E distributing a Critical Product News Flash to purge in-stock units, distributing technical awareness notices to dictate installation practices, modifying or installing new fuse boxes on operations vehicles, replacing select in-service units, and conducting pole clearing at the base of support structures where these fuses had been installed.

different departments. Internally, PIIRs are also shared with a distribution list that varies based on the ignition driver or other factors involved. In addition, the EIA team also sends the PIIR to any owners of corrective actions identified in the PIIR. The ISM has discussed these PIIRs with several groups, who have indicated that they discuss the findings within their departments and are starting to generate their own data analysis based on findings for ignition causes relating to their operational area.

Each PIIR is typically 15-20 pages in length and includes such items as: an EOC summary, a system protection analysis, the ignition impact, the sequence of events, pending work, asset information, the most recent inspections and tests (including a listing of any open repair tags or vegetation management work), potential next steps, associated corrective actions, simple line diagrams, and photos and diagrams of events.

The PIIR also contains a Hazard Barrier Analysis section for each ignition, which evaluates which risk mitigations/barriers were in place (or could have been in place but were not in scope for that asset), the expected versus observed performance of the barrier, and an evaluation of why the barrier did not prevent the ignition event. PG&E uses this analysis as a learning and feedback tool, where the failure of the barrier to perform as expected may lead to corrective actions. Examples of these are provided further in this section.

The EIA team developed a Hazard Barrier Analysis tool in 2023 to collect data that feeds from this section of the PIIR, and PG&E indicated that there are approximately 90 unique barriers that have been evaluated.[9] This tool is designed to allow the team to aggregate data for trend analysis, identification of gaps in mitigations, and evaluation of opportunities. PG&E stated that this new tool is to be used as a broader feedback mechanism, and that subject matter experts (SME) who support the investigations are providing their input as to which barriers to include into the tool.

Electric Incident Reports

One exception to ignitions receiving a PIIR is whether they qualify for an Electric Incident Report (EIR). The CPUC requires that electric utilities report any incident, within two hours during working hours and four hours outside of working hours, that is attributable or allegedly attributable to utility-owned facilities, and which results in: fatality or personal injury requiring in-patient hospitalization, significant public attention and/or media coverage, or property damage to the utility or others if above $50,000. A full report is due within 20 days. As of December 19, 2024, the CPUC amended its requirements, increasing the threshold for property damages from $50,000 to $200,000 and requiring utilities to now submit quarterly reports for incidents with damages between $50,000 and $200,000, even though these individual incidents do not trigger an immediate EIR.[10]

PG&E indicated that EIRs which involve ignitions do not receive a PIIR, and are investigated by

[9] Examples of hazard barriers include vegetation clearing at the base of a pole, EPSS enablement, the use of covered conductor, inspections/patrols, animal protection hardware, lightning arrestors and ground rods, equipment work management, and field safety tag reassessment.

[10] See Resolution ESRB-12

a separate compliance team, although the EIA team will play a supporting role if requested. PG&E also indicated that EIR investigations follow a similar path to the PIIR investigations, and may also include corrective actions, but they do not include a Hazard Barrier Analysis. PG&E stated that they recognize there is a potential missed opportunity with not inputting Hazard Barrier Analysis data associated with EIR ignitions, and the team is exploring process improvements to collect this data in 2025. PG&E also noted if any corrective actions that could help mitigate future ignitions were identified in EIR investigations, these would be provided to the operations groups.

The number of EIR each year has generally been smaller than the number of PIIR generated. PG&E submitted 38 EIR in 2024, 57 in 2023, and 91 in 2022, and completed 113 PIIR in 2024, 125 in 2023 and 154 in 2022.

ISM PIIR and EIR Reviews

During the current ISM reporting period, the ISM reviewed 203 PIIRs, which cover the PIIR produced from the beginning of 2023 through the latter part of 2024. In addition, the ISM reviewed a total of 31 EIR submissions, which included both a review of the Initial Incident Reports as well as the more detailed 20 Day Reports for select EIRs for qualifying ignitions occurring from March 2022 through September 2024.

The suspected cause of the ignitions in these reviewed PIIR were vegetation contact (approximately 41%), equipment failure (24%), animal contact (13%), 3rd party contact (10%), utility work/company operation (5%) and 'other', consisting of high wind, lightning, vandalism, contamination and unknown (7%),

The ISM observed that the PIIRs were consistent in the depth of their root cause analysis and Hazard Barrier Analysis, with EIA investigators working with members of the ATS and AFA groups to determine the ultimate failure mode for equipment failure ignitions and possible EOC. Of the 203 PIIR reviewed, ATS and AFA support was provided in approximately 22% of the investigations.

For vegetation contact caused ignitions, each PIIR documented how vegetation investigation teams performed an analysis to determine whether prior inspections could have potentially identified the tree defect or vegetation grow-in, and to conduct an EOC investigation for similar conditions in the area. These EOC inspections were generally conducted on five spans in either direction of the ignition, but did extend farther in certain instances where the vegetation team continued to find similar conditions extended beyond the standard five spans. The ISM observed that of the 83 vegetation contact PIIR reviewed, 10 did not specifically mention the EOC inspection or findings in the PIIR as part of the vegetation management post-incident investigation, 41 indicated that the EOC inspections did not find any trees requiring remediation, and 32 (approximately 39%) found at least one or more trees in the vicinity of the ignition which required mitigation work, or identified areas where vegetation growth was now within clearance guidelines. These 32 EOCs inspections identified an average of 5.5 trees requiring remediation, with the highest EOC inspection count identifying 21 trees for remediation.

The ISM is beginning to use circuits identified with high numbers of prescribed EOC vegetation work within these PIIR, as well as neighboring circuits, as areas of interest for future ISM vegetation field inspections.

Each PIIR documented the history of asset and vegetation inspections, listed all open and closed repair tags on each structure involved in the ignition, and listed all prescribed tree work recently completed or identified to be completed in the vicinity of the ignition. Seven of the equipment failure PIIR noted open and late repair tags associated with the failed equipment. An additional 4 vegetation contact PIIR indicated that the identified tree work had not been conducted by its prescribed due date due to customer refusals or external agency permitting issues. In two vegetation contact ignitions, the PIIR noted that the trees had failed before their prescribed remediation due dates. The ISM noted only one instance where asset age was specifically identified as a potential contributing factor to the asset failure. This instance was related to the failure of an electrical jumper[11] which showed signs of low cycle fatigue and described as being potentially "well over its end of life potentially over 100 years old (possibly 126)".

Fourteen corrective action plans (CAP) were generated from the 203 reviewed PIIR, where potential improper construction was involved, standards were not met, inspectors had failed to observe the emergent incident, asset, or vegetation condition, or where a documentation issue or prior CAP closure may have mitigated the ignition.

In one instance, a pole test and treat (PTT) inspection final report included a photograph that showed that a conductor was off the insulator and on the crossarm. This situation later resulted in an ignition. In the PIIR, PG&E noted that a CAP was generated to provide additional training for PTT inspectors to be alert to conditions similar to this and other high-risk defects as they perform their PTT inspections. The ISM followed up on the fulfilment of this CAP and received information confirming the CAP was completed[12] and copies of PG&E's Tailboard[13] Details & Attendance sheets where PG&E discussed the materials.

As a follow-up, since aerial drone pilots are also in a position to be the first to potentially see emerging safety hazards in the field, the ISM requested information regarding whether PG&E's drone pilots also receive similar training. PG&E acknowledged that these drone pilots did receive similar training, and the ISM requested and reviewed a similar guide for the drone pilots along with their detailed shot sheets.

Three PIIRs noted ignitions, close together in time at different locations, that involved H-type

[11] An electrical jumper is a short length of conductor that connects two or more points in an electrical circuit. Cyclic fatigue refers to a process where a material experiencing repeated cycles of loading and unloading may fail or fracture.

[12] Completed CAP included updated Utility Pole Visual Inspection guides first published in July 2024 and later updated in September 2024 providing photographic examples and descriptions of 11 high risk, unsafe conditions for PTT inspections to look for during their regular work.

[13] A safety tailboard, also known as a job briefing or toolbox talk, is a meeting held at the start of a work shift to focus on worker safety.

connector failures.[14] PG&E stated that these three failures, as well as other historic H-type connector failures, have been attributed to inadequate crimping, advanced corrosion, and insufficient/thermally damaged tape application. Following this increase in failures, AFA initiated a CAP in September 2024, which led to PG&E providing additional training in October 2024 to the restoration, construction and contract teams making them aware of the increases and reminding the teams of the proper installation/repair actions. The AFA and training materials also noted that the preferred method of construction is to use fired-wedge connectors as per the distribution standards, although H-type connectors were still listed as the approved alternative.

One PIIR detailed circumstances where an existing CAP was not completed. PG&E states that this September 2023 ignition potentially occurred due to the failure of a tree trunk previously marked for removal in November 2022 by an Enhanced Vegetation Management (EVM) inspection. However, the customer refused its removal. This ignition investigation resulted in a CAP initiated in November 2023 intended to address all open EVM customer refusals. The CAP was closed in December 2023, without evaluating trees outside of the ignition location. In July 2024, an ignition with a similar EVM recommended tree removal and customer refusal occurred. PG&E's EIA team stated that if the CAP had been adequately fulfilled, it is potentially possible that the incident tree from the July 2024 ignition may have been identified for mitigation prior to its failure. PG&E's VM leadership proposed integrating EVM-identified and unmitigated trees into existing routine VM patrols until they are completed, but stated that this cannot be currently implemented due to data integration compatibility between PG&E's EVM data and PG&E's OneVM platform used for routine VM inspections. PG&E stated that it is currently working on a solution for integration.

FAST TRIP PROGRAMS

PG&E's Enhanced Powerline Safety Settings program remains a key wildfire mitigation measure, rapidly de-energizing power lines to prevent ignitions. This section provides observations regarding EPSS performance trends, including ignition reductions, customer impacts, and program expansions. It also provides summaries of PG&E's use of advanced detection technologies, such as Downed Conductor Detection (DCD) and Partial Voltage Force-Out (PVFO) and provides updates on PG&E's 5-year plans for EPSS and new technology deployment.

Enhanced Powerline Safety Settings Trends

In ISM Previous Reports, the ISM reported on the initiation and maturing of PG&E's EPSS program, which includes DCD and PVFO enhancements. These fast trip mitigations are designed to more rapidly de-energize power lines when conditions that can lead to ignitions are detected. In this Section, the ISM reported its observations related to: (1) reviewing the performance, ignition reduction, and customer impact trends of these fast trip mitigations, (2)

[14] Various connector types are used to attach jumpers to high-tension power line conductors, including compression, bolted, crimp, wedge, and automatic connectors. The H-Connector is a commonly used compression connector for jumper connections on power lines.

describing PG&E program expansions and modifications, (3) describing PG&E actions that seek to reduce the frequency and duration of fast trip outages, and (4) describing the expanded use of PG&E's new fast trip and sensor technologies.

PG&E made no further expansions in EPSS coverage on distribution circuits since ISM Report 5, and EPSS enablement coverage remains at 43,960 distribution miles.[15] Distribution circuit EPSS enablement covers 100% of the HFTD plus approximately 19,000 buffer area miles[16] and services approximately 1.8 million customers. PG&E continued its expansion of EPSS capability on an additional 14 transmission circuits in 2024, bringing the total to 61 circuits, covering a total of 768 miles. As detailed in ISM Report 3, not all of the 525 transmission lines traversing HFRA are eligible for EPSS implementation. PG&E is planning to expand its transmission EPSS capability to another 13 circuits in 2025, leaving 8 remaining EPSS eligible transmission circuits.

As shown in Table 2, the 2,820 EPSS outages and the 47 reportable fire ignitions on EPSS enabled lines were both 22% and 77% higher than the average of the two prior years. As noted in the Outage, Ignition and Reliability Trends section of this ISM Report 6, 2024 experienced more extreme fire potential conditions and more extreme heat events than during the prior two years. During 2024, PG&E experienced more EPSS enablement due to an earlier start of the typical "peak season" EPSS enablement and a switch to version 5 of the FPI model.[17] These factors resulted in approximately 6.4 million EPSS enabled CMD, versus 6.0 million in 2022 and 5.6 million in 2023. Total EPSS customer enabled minutes (CME) were approximately 350 billion in 2024, versus 258 billion in 2023 and 300 billion in 2022. On a normalized basis, during 2024 PG&E customers experienced an average of 8.1 EPSS outages per one billion CME versus 8.8 in 2023 and 7.9 in 2022.

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[15] EPSS enablement covers 5,235 devices on 984 circuits.

[16] PG&E reports that buffer area miles were selected due to the potential to experience ignitions which could lead to wildfires capable of spreading into the HFRA and to protect system stability

Table 2: EPSS Data 2022 – 2024

	2022	2023	2024
EPSS Enabled Circuit-Days	108,544	96,935	120,600
EPSS Enabled Circuit Mile-Days	6,031,039	5,644,900	6,356,531
EPSS Customer Minutes Enabled (CME, billions)	300.3	257.6	349.8
EPSS Outages	2,379	2,263	2,820
EPSS Outages per 10k CMDs	3.94	4.01	4.44
EPSS Outages per 1B CME	7.92	8.79	8.06
Reportable Fire Ignitions on EPSS Enabled Lines	31	22	47
RFIs per 10k CMDs	0.05	0.04	0.07
RFIs per 1B CME	0.10	0.09	0.13
EPSS CAIDI (min)	176	193	150
EPSS CESO	889	870	818
Response Time Within 60 minutes	89%	91%	93%
Average Response Time (min)	54	45	36
Average Full Restoration Time (min)	351	367	410
% Restorations <= 60 minutes	7.4%	11.6%	13.7%
% Restorations > 12 hours	13.3%	16.0%	13.4%
Total Customers Experiencing EPSS Outages	2,083,985	1,972,285	2,306,579
Unique Customers Experiencing EPSS Outages	770,441	726,708	917,227
Medical Baseline Customers	134,622	129,825	128,828
Life Support Customers	93,876	92,674	93,825
Critical Customers	34,841	33,456	38,327
Schools	4,573	4,301	4,989
Hospitals	185	260	232
Well Water Dependent Customers	2,375	4,344	6,475
Outage Cause (% of total)			
3rd Party	9.5%	9.6%	9.5%
Animal	16.5%	12.2%	12.4%
Company Initiated	4.5%	11.3%	13.2%
Environmental/External	0.5%	3.2%	1.4%
Equipment	12.3%	13.6%	13.5%
Unknown	45.6%	39.2%	38.1%
Vegetation	11.2%	10.9%	11.8%

While ignitions on EPSS lines were higher in 2024, the EPSS program continues to show a significant drop in ignitions since 2021 – the year EPSS was first enabled. PG&E calculated that ignitions saw decreases of 74.1% in 2021, 68.8% in 2022, and 72.7% in 2023 when comparing the number of CMD-normalized EPSS ignitions in the year against the CMD-normalized average number of ignitions from 2018-2020. These analyses were performed on lines that would have met the EPSS enablement criteria given the historical conditions during that period. Starting in 2024, PG&E moved to a stratified effectiveness methodology to understand EPSS effectiveness in reducing the rate of overall ignitions occurring at specific FPI scores. This is similar to how

PG&E began focusing its evaluation on ignitions that occur at the higher R3, R4 and R5 (R3+) FPI conditions, when the catastrophic fires have historically occurred. Using a similar methodology as described above, under R3+ conditions, the EPSS program showed a 65% ignition reduction effectiveness in 2024 when compared to the pre-EPSS 2018-2020 period.

Another way in which PG&E evaluates the benefit of its EPSS program is to track what it calls "good catch" outages, which are outages during R3+ FPI conditions with identified equipment failure, vegetation, animal or 3rd party suspected causes. These represent outages for which similar conditions historically resulted in ignitions. For 2024, PG&E identified 629 "good catches", with 565 of these as EPSS outages, 55 of these as DCD outages, and 9 conditions identified by Gridscope sensors (detailed later in this section). For DCD good catches, PG&E conducts a manually intensive secondary engineering review to determine which DCD outages can be specifically identified as "potential ignitions mitigated". These are only performed on DCD good catches and not on the larger number of EPSS good catch outages due to resource constraints.

Although the number of EPSS outages was higher than in prior years, as shown in Table 2, the Customer Average Duration Index[18] (CAIDI), excluding Major Event Storm days, dropped to 150 minutes per outage (down from 193 minutes in 2023 and 176 minutes in 2022), an approximate 15% decrease from 2022 to 2024. The average Customers Experiencing Sustained Outage[19] (CESO) also dropped to 818 customers per outage (down from 870 in 2023 and 889 in 2022), an approximate 8% percent decrease from 2022 to 2024. Over the 2022 to 2024 period, PG&E's response time within 60 minutes increased from 89% to 93%; PG&E's average response time decreased from 54 minutes to 36 minutes; and PG&E's percentage of restorations completed within 60 minutes increased from approximately 7% to 14%.

In ISM Previous Reports, several programs implemented by PG&E aimed at reducing EPSS related customer impacts, including using storm prediction software to better deploy restoration resources, and installing an increased number of fault detectors. One PG&E program specifically aimed at minimizing customer impacts is increasing line sectionalization, which helps isolate an EPSS outage to shorter circuit segments, which in turn allows for faster restoration of service for more customers. In addition to the 209 sectionalizing devices installed by the end of 2023, PG&E added an additional 186 devices during 2024. The increased use of PG&E's Gridscope sensors also allowed for a more accurate determination of the outage location, which allows for a more rapid response time for patrols and restoration work. These sensors also started to help reduce the number of 'unknown' cause outages, by more specifically identifying the location and sensor signature of the outage, which provide field personnel a better chance to identify animal or vegetation caused outages that can be more difficult to detect. The New Technology Deployment Updates section of this ISM Report 6 further describes Gridscope sensors.

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[18] CAIDI is the average time required to restore service, calculated as total minutes of customer interruption divided by the total number of interruptions.

[19] CESO is defined as the number of customers who experience an interruption in service that lasts more than a specified amount of time (five minutes is commonly used).

The increase in EPSS enablement in 2024 also contributed to an increase in the number of customers experiencing multiple EPSS outages. In 2024, approximately 107,000 customers experienced 5 or more outages on EPSS enabled lines, up from approximately 100,000 customers the prior year. PG&E stated that approximately 20,000 of these customers have experienced 5 or more outages in each of the last three years.

In order to attempt to reduce the impact on customers experiencing multiple EPSS outages, PG&E is looking at pre-season drone inspections of high outage lines, and providing more of these customers with in-house batteries.[20] Another way PG&E seeks to reduce outages on high frequence lines is a continuation of its targeted Animal Mitigation and Vegetation Management for Operational Mitigations (VMOM) programs on lines that historically experienced multiple animal and vegetation contact EPSS outages.

PG&E installed 132 animal mitigations in 2023 on EPSS lines and added an additional 1,840 animal mitigations in 2024. Of the 3,000 animal mitigations PG&E plans to install in 2025 under its Avian Protection Plan, PG&E is currently targeting approximately 1,800 of these on EPSS enabled circuits. For its VMOM program, PG&E completed 9,727 vegetation units in 2024 (versus 8,185 units worked in 2023), comprised of 7,383 proactive units and 2,344 reactive units. VMOM involves conducting EOC patrols adjacent to the location of current-year vegetation caused EPSS outages. PG&E's 2025 targets include conducting approximately 9,000 units of proactive VMOM on 61 distribution circuit segments covering approximately 700 miles, and approximately 3,000 reactive units. The Vegetation Management section of this ISM Report 6 includes further information on PG&E's VMOM program.

PG&E stated that early data from proactive animal mitigations show promise in reducing the number of animal-caused outages on historically higher EPSS outage circuits. PG&E also stated that there is currently insufficient data to determine proactive VMOM program effectiveness. For reactive VMOM, where PG&E identifies similar vegetation defects or clearance issues in proximity to the vegetation-caused EPSS outages under its EOC investigations, PG&E stated that the reactive VMOM work was 80% effective at reducing outages on those lines. PG&E noted that it is seeking to reduce the length of time between a vegetation caused outage and performing the EOC inspection, and to shorten the length of time between an EOC and performing the vegetation work.

DCD and Partial Voltage Detection (PVD) / Force Out (PVFO) EPSS Enhancements

DCD and PVD/PVFO are two EPSS program enhancements used by PG&E. DCD uses electrical sensor information and software to identify the presence of specific electrical characteristics (i.e., signatures or patterns) produced by arcing conductors with the earth's surface, thus initiating trips on circuit interrupting devices. DCD is complementary to EPSS since DCD is designed to identify high-impedance (low current) faults, which may be difficult to detect through EPSS or conventional fault detection schemes. PFD/PVFO is a SmartMeter™ based program, which can send real time alarms when partial voltage or full/partial loss of phase is detected.

[20] 1,446 batteries were installed in 2024, versus 443 installed in 2023.

PG&E continued to expand its DCD capability in 2024, adding 655 DCD line recloser devices to the 1,129 devices previously installed, and 40 DCD circuit breaker devices. To date, DCD is only installed on 3-wire configurations, now covering 20,500 HFRA miles, with the remaining 2,000 HFRA miles of 3-wire targeted for completion in 2025. PG&E stated that ground currents on the 3-wire system are typically very low except when a fault occurs which makes it a suitable candidate for the sensitive ground fault (SGF) protective feature. Ground currents on the 4-wire system are more dynamic as the load imbalance is carried on the neutral, and thus not previously a viable PG&E candidate for SGF protection. PG&E recently examined new hardware that implements more sophisticated algorithms for detecting high impedance faults on 4-wire systems, as compared to a basic SGF element, and will begin installation of these new devices on select sections of 4-wire lines in 2025.

In total, there were 360 DCD outages in 2024, (versus 330 in 2023), and as previously noted, following post-outage patrols and investigations, PG&E identified 55 of these as having likely mitigated potential ignitions. The leading suspected causes of these DCD outages were Company Initiated (44%), Unknown (31%), Equipment Failure (10%) and Vegetation (8%). PG&E previously informed the ISM that the high percentage of Company Initiated outages are mostly "nuisance trips" caused by problems with software algorithms in the devices, as the DCD program was scaled over the larger number of devices in 2023. PG&E has been working with the manufacturer on firmware updates, and installed 542 of these updates in 2024, with 600 updates planned for 2025, with the balance expected to be completed in 2026.

PG&E began implementing its PVD/PVFO program in mid-2022, which covers approximately 90% of its HFRA miles. PG&E experienced 31 PVFO outages in 2024 (with 19 field hazards identified) versus 25 in 2023 and 36 in 2022. PG&E's average response time for the 2024 outages was 29 minutes, versus the 15 minutes experienced during 2023.

EPSS 5-Year Roadmap

During the current ISM reporting period, the ISM held discussions with PG&E leadership on its EPSS 5-Year Roadmap. This is a high-level summary of focus areas within EPSS covering technology/data systems, engineering, operations, and customer experience. This internal roadmap includes:

- researching the use of LTE cellular networks for falling conductor protection;
- advancing the use of Gridscope, and enhancing PVFO tracking capabilities for improved fault detection;
- continuing the use of drone and helicopter patrols to identify cause and trends of outages;
- improving reliability work through continued DCD firmware upgrades and sectionalizing device installations;
- integrating EPSS with Public Safety Power Shutoff (PSPS) for better system coordination;

- implementing new tools to communicate effectively with stakeholders;[21]
- continuing the rollout of Communication Assisted Protection Systems (ComAPS) for network/Bulk Electric System (BES) transmission lines, in addition to expansion of EPSS installation for non-BES/radial transmission lines (both detailed in ISM Report 3);
- performing system optimization of lower SGF thresholds; and
- installation of more sensitive SGF hardware on select 4-wire, primary neutral systems.

New Technology Deployment Updates

Two new technologies PG&E began deploying in 2024 were Early Fault Detection (EFD), and Distribution Fault Anticipation (DFA). Both of these were detailed in ISM Report 5. PG&E moved beyond pilot and into production on both of these technologies, having deployed EFD technology on 103 locations over 6 distribution circuits and DFA technology at 79 substations. PG&E installed DFA at an additional 17 locations in 2024 and plans on installing DFA at an additional 15 locations in 2025. PG&E added two new EFD locations in 2024, and plans on adding EFD at 4 new locations in 2025.

PG&E operationalized two use-cases of DFA1) fault induced conductor slap, which has the potential to cause ignitions, and 2) underground elbow arcing, a sub-cycle fault which causes outages in HFTD when EPSS is enabled. A third use-case, which uses DFA sensor data in combination with PG&E's SmartMeter™ event data is in development.

PG&E stated that its EFD deployment shows the capability to identify incipient faults that could lead to failure and possible ignition. These include, but are not limited to, damaged insulators, broken conductors, broken/loose tie-wires and bonding wire integrity. PG&E further stated that through EFD field use, hard to locate issues that were not typically identified during routine inspections have been identified, with only 1 of the 35 EFD findings having an existing maintenance tag. PG&E noted that it is working with the product vendor to drive development of machine learning based event classification (for severity as well as defect type) so that technology efficacy can be sufficiently improved to support routine field inspections.

Another new program that PG&E began piloting in 2023 involved the installation of Gridscope devices. These are shoebox-sized, solar powered units that mount to a power pole, and are designed to detect anomalies using highly sensitive sensors, including a vibrometer and microphone. By continuously taking real-time measurements at a rate of 6,000 times per second, the Gridscope can observe the grid's environment, stress levels and equipment response. Any deviation from the expected behavior could indicate issues (e.g., a branch falling or a bird strike on the line, a strong wind gust blowing a line down, a car striking the pole, etc.). PG&E began installing these devices in June 2023, and installed a total of 4,000 Gridscope devices as part of its Tranche 1 deployment, covering 375.3 miles by the end of 2024. The R3+

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[21] PG&E developed an outage tool through its Foundry platform to enhance communication with customers and other stakeholders experiencing outages. The tool is designed to improve the visibility of impacted customers, allowing PG&E to track outages at the customer level instead of at a circuit or device level, as was past practice. The new tool also provides outage cause (when available) and is used for resilience targeting of vulnerable customers.

Taskforce[22] directed the accelerated deployment of an additional 6,000 Gridscope devices in 2024.

PG&E stated that these Gridscope devices provided benefit to its operations in several ways. The Gridscope system architecture is being designed to seamlessly integrate with existing PG&E systems, with information received through phone call, email, SMS, web dashboard and application programing that interface directly with PG&E's existing outage management and advanced distribution management systems. PG&E received 611 Gridscope alerts through the end of 2024, and stated that many resulted in insightful information, with 10 specifically flagging conditions that could have resulted in an ignition.

One benefit of Gridscope devices is their ability to detect events that lead to high impedance faults such as trees on lines or lines down. Often these events do not produce any arcing until it is too late and are not detectable by electrical sensors. In July 2024, Gridscope identified a tree falling and hanging on energized lines leading to a high impedance fault on an EPSS enabled circuit. PG&E personnel on site reported if the sensor had not detected the incident, it likely would have led to a forest fire.

Another benefit of these self-powered Gridscope devices is their ability to pinpoint outages, and provide intelligence to operators and trouble workers in the field, including when the power is off. During a major storm in February 2024, Gridscope identified 12 cases of vegetation falling on already de-energized lines on one circuit segment, and an additional 2 similar cases outside of the de-energized segment. In another incident in June 2024, Gridscope identified a direct hit by a tree that failed and contacted the line on its way down. It did no damage but caused an EPSS outage. PG&E stated that this occurred in an area that is difficult to patrol, where the average circuit CAIDI is 283 minutes. With the Gridscope alert targeting the precise location, the CAIDI for this incident was reduced by 70% to 88 minutes.

Finally, PG&E noted that these Gridscope devices allow them to observe changes to the structural integrity of their system. In one instance in April 2024, a Gridscope device identified a broken guy wire caused by a vehicle collision, while in another instance in May 2024 a Gridscope device identified a pole which failed at the base and was being held up by the conductors that were still attached to and supported by adjacent poles, flagging the asset for immediate replacement without an outage or ignition having occurred.

PG&E informed the ISM that while Gridscope has proven to be a valuable addition to its wildfire mitigations, PG&E is currently pausing additional deployment to allow for the development of Standards and Procedures. PG&E stated that these will govern integration of data from Gridscope devices into PG&E's Distribution System Operations and address the long-term asset management strategy for the technology.

[22] PG&E's Wildfire, Emergency and Operations organization initiated the R3+ Taskforce in mid-2024 following significant increases in R3+ exposure and R3+ ignition across the PG&E service territory.

RISK MODELS AND OPERATIONAL RISK VALIDATION

Wildfire Risk Model Updates

The ISM discussed the refinements of PG&E's wildfire risk models over the past five years in the ISM Previous Reports, including details on enhancements incorporated into in the latest version of the Wildfire Distribution Risk Model Version 4 (WDRM v4) and the Wildfire Transmission Risk Model Version 2 (WTRM v2). To calculate the total wildfire risk associated with each facility, PG&E multiplied the ignition probabilities generated by these two models against the projected consequences of an ignition occurring at specific asset locations, which are derived from a separate Wildfire Consequence Model Version 4 (WFC v4). All three of these versions of the models are actively being used in the prioritization of PG&E's wildfire mitigation work planning.

While PG&E released updates to these three main wildfire risk models annually or bi-annually from 2019-2024, PG&E stated that going forward it prefers to have new releases of these main models occur every three years in order to better align with the three-year Wildfire Mitigation Plan (WMP) and general rate case cycles. PG&E stated that a three-year cycle also better aligns with the several years it often takes to plan, design, estimate, permit and construct asset enhancements and line rebuild or underground projects, which were often impacted by more frequent changes to circuit risk rankings. The current versions of the models were approved by PG&E leadership in August 2024 to guide PG&E's 2026 to 2028 WMP.

PG&E noted that while major model updates will guide larger scale and longer-term wildfire mitigation planning over these three-year cycles, PG&E will continue to make refinements to its risk models in between major releases in order to improve model accuracy over time, and will seek to operationalize interim model updates where appropriate.

One such example of an interim model update approved during the current ISM reporting period is the release of the Wildfire Transmission Risk Model Version 2.1 (WTRM v2.1). As part of its model validation process, PG&E engaged an independent third-party to conduct a peer review of its risk models. One of the observations from this July 2024 report was the transmission risk model was overpredicting outages relative to historical data, rendering the model's outputs conservative. To help improve the model's predictive ability, the third-party reviewer recommended parsing out the impact of historical high wind events, adding more component granularity, and adding more accurate asset age data.

Some of these recommendations were already in progress at the time this 3rd party review was issued and were listed in ISM Report 5 as elements being incorporated into WTRM v2.1. New elements that were recently introduced into WTRM v2.1 include:

<u>Component group based Bayesian updating</u>: In WTRM v2.0, all historic outages were pooled together and all asset classes were penalized equally no matter which asset failed (i.e., conductor, insulator, hardware, wood pole and steel structure outages were aggregated when looking at historical wind speed impacts on outages). In WTRM v2.1 PG&E leveraged outage data that contained sub-cause labels to target component-group-specific outage probabilities, resulting in only the asset class that failed getting penalized. PG&E stated that this is a more precise approach where the probability of failure estimates become better calibrated over time

as outage cause labeling improves.

Maintenance tags as an indicator of asset health: In WTRM v2.0 PG&E used inspection-based condition codes (a subjective 1-5 scoring method) to qualify asset health in the model. In WTRM v2.1, PG&E uses more specific maintenance condition tags from a wider variety of tag sources (e.g., ground, aerial, climbing and infrared inspections, Linevue,[23] Baywater Tower Program,[24] patrols, etc.) that are less subjective, and that are in alignment with tag condition and priority guidelines. As maintenance tag statuses change over time, either via repair or through re-prioritization as part of the annual Field Safety Reassessments[25] (FSR) of open repair tags, PG&E stated that the assets' remaining strength will continue to get periodically updated.

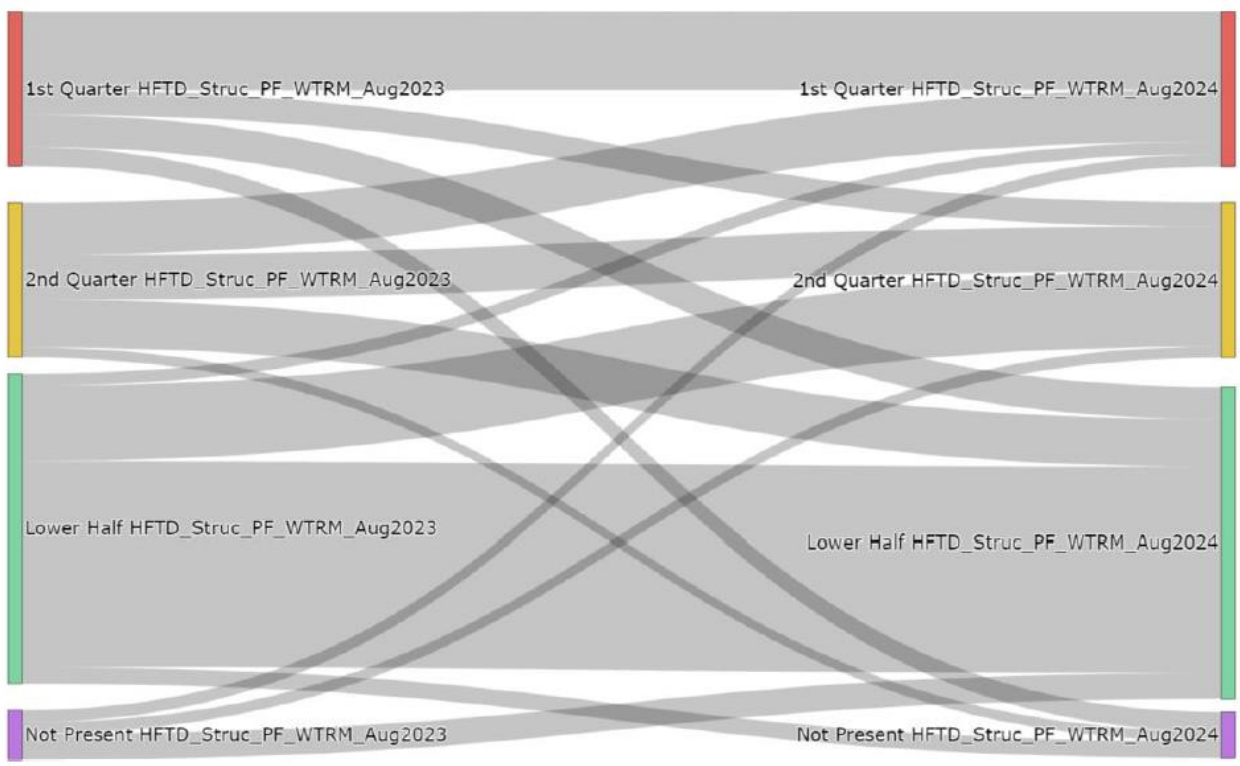

Figure 6: Structure-Level Annual Probability of Failure (PF) WTRM v2.0 versus v2.1

Figure 6 shows how the WTRM v2.0 to WTRM v2.1 model enhancements impact the risk rankings of the transmission structures.

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[23] A remotely operated, non-destructive inspection tool used to measure the remaining cross-sectional area of the steel core wires and identify any local breaks or corrosion pits.

[24] The Baywater Tower Program is a foundation inspection program, performed every 5-years and initiated in 1999, designed to assess the health of tower foundations in the San Francisco Bay and surrounding area.

[25] FSR, a program to reassess the current condition of open repair tags when maintenance cannot be performed within the targeted timeline, has been discontinued for distribution and replaced by the CPI program, but remains an ongoing program for transmission.

In addition to further refining the transmission structure risk ranking, these model enhancements allow PG&E to focus wildfire risk analyses and mitigations among a smaller group of transmission assets. The top 10% of structures with the highest wildfire risk in HFTD are on 210 transmission lines in WTRM v2.1 (versus 345 lines in WTRM v2.0) and 90% of HFTD wildfire risk is on 12% of the structures in WTRM v2.1 (versus 17% in WTRM v2.0).

Table 3: WTRM V2.1 Wildfire Risk by Voltage Class (HFTD)

Voltage Level (kV)	Percentage of WF Risk	Structure Count	WF Risk by Structure (Normalized)
60	74%	22,467	41%
70	3%	1,910	19%
115	12%	11,115	14%
230	10	6,373	20%
500	1%	1,772	7%

When looking at the correlation between transmission line voltage and WTRM v2.1 wildfire risk in HFTD, Table 3 shows that 74% of all wildfire risk in WTRM v2.1 resides on the lower voltage 60kV lines, which also have the largest number of transmission structures. When normalized on a wildfire risk per structure basis, these 60kV lines still remain the highest risk structures at 41%. PG&E leadership stated that this higher wildfire risk in the lowest transmission voltages is primarily due to these lower transmission voltages being carried more frequently on wooden poles, with narrower rights of way, and with greater proximity to vegetation.

As detailed in the Asset Age Data Collection section of this ISM Report 6, PG&E is in the process of continuing to collect and populate asset age data missing from its current records. For current risk modeling, if the age of equipment is not in the current database, the model takes a conservative approach and uses the age of the oldest equipment on that circuit segment as a proxy for the equipment's age. This in turn impacts modeled asset health and can lead to the model conservatism that was noted earlier in this section. PG&E leadership indicated that as additional asset age information is collected, the risk models will continue to be updated.

PG&E leadership believes convergence in wildfire consequence modeling might be seen among California utilities over time. PG&E cited an example from Australia, where the University of Melbourne has created a consequence model that is commonly used by utilities across Australia. In PG&E's participation in wildfire risk modeling workshops with other California utilities sponsored by the Office of Energy Infrastructure Safety, PG&E stated that there is a desire among regulators to see convergence on a more uniform approach to incorporating fire spread, fire suppression, and egress into the utilities' consequence models. PG&E believes this convergence is possible, since the major California utilities are already incorporating a common source of third-party wildfire spread modeling.

Asset Failure Models

In ISM Previous Reports, the ISM noted that PG&E was creating new models designed to forecast equipment specific failures or note areas within its service territories where its assets might degrade more quickly. Several of these models output Design Life Reduction Factors that are integrated into their respective fragility functions and that impact the projected likelihood of failure under more extreme weather conditions.

In ISM Report 5, the ISM reported on PG&E's investigations into whether additional machine learning models could be developed using existing utility data sets to predict electric distribution equipment failures and outages so that corrective action could be taken before either could occur. PG&E stated that transformer models were showing the best predictive ability, as PG&E could identify transformers operating outside of operational standards. PG&E's model, however, was unable to precisely predict when a transformer would fail, making prioritization of transformer replacements difficult.

During the current ISM reporting period, PG&E noted that further progress was being made on the IONA Project[26] and that PG&E was now incorporating voltage, usage, and loading data from its smart meters and its Electric Distribution Transformer Load Manager into the IONA model, along with transformer age, location and weather information. Together with the Transformer Overload Accuracy Model (TOAM), PG&E stated that it is starting to operationalize these transformer models and is generating information on a weekly basis of which transformers have a higher likelihood of failing within an upcoming 6-week period. PG&E also stated that it does not yet have any data correlating its model predictions with actual transformer failure timing. The ISM will continue to monitor the progress and usage of these two models, with one current usage for PG&E's Overloaded Transformer Replacement Work Plan detailed in a later section of this report.

Operational Risk Validation

During the current ISM reporting period, the ISM began monitoring the activities and reporting of PG&E's Operational Risk Validation (ORV) group. PG&E established this group, which reports to PG&E's Chief Risk Office (CRO), following PG&E's Plan of Reorganization, which required that PG&E establish a CRO position that receives regular insight into, and feedback from, operations to appropriately manage risk.

ORV consists of dedicated employees, working in partnership with the functional area, internal audit, ethics and compliance, and enterprise risk management teams, to independently validate and advise on end-to-end key operational actions deployed to mitigate risk, while collaboratively developing solutions to address areas of underperformance. The group's stated primary objectives are to:

- prioritize key processes and utilize a work-system assessment framework incorporating safety, quality, and compliance factors;
- assess and validate end-to-end operational processes and efficacy of risk mitigation actions;
- develop comprehensive and actionable recommendations for addressing significant

[26]The IONA Project is an initiative by PG&E to enhance its transformer predictive maintenance model by incorporating factors such as transformer oil temperature and aging calculations, and utilizing more extensive data for model training.

improvement areas; and
- integrate with exiting governance structures to report on key findings and risk mitigation progress.

During the current ISM reporting period, the ISM observed that over the past 3 years, ORV performed 26 operational risk assessments and validations covering the areas of electric operations (15), gas operations (7), power generation (1), information technology (1), aviation (1), and corporate security (1). Examples of reports generated on the electric operations include tower corrosion, pole set depths, pole restorations, EPSS, electric line undergrounding, residential storage initiatives, dead and live fuel moisture process, and distribution and transmission maintenance. PG&E states that multiple assessments are planned in 2025 utilizing a risk-based approach on areas identified in PG&E operational groups.

Four ORV assessments are currently planned for the electric group in 2025:

- end-to-end validation of risk reduction activities for Substation inspection and maintenance;
- end-to-end review of the third-party, non-utility notification process;
- evaluation of the risk, benefits (capital vs expense) and strategy of portable versus permanent battery storage as a customer mitigation (resources permitting); and
- review of the Centralized Inspection Review Team (CIRT) processes, cancelled tags, resourcing, effectiveness of improving quality and reducing risk, and planned organizational changes (resources permitting).

PG&E stated that for each ORV assessment and risk validation, a summary report and/or executive-level presentation is compiled, inclusive of any findings or recommended actions. Outside of the functional area leadership up to and including Senior Vice President and personnel engaged in the risk advisory, recipients of these reports may vary and may include the Enterprise and Operational Risk Management Vice President, the CRO, and other interested internal personnel if requested.

The ORV team, after reviewing findings, severity, and potential remediation actions with the Functional Area owners, generates:

- **Finding/Corrective Actions**: these are findings from the evaluation that ORV believes diminishes the risk reduction-effectiveness of the mitigation or control which require corrective action. Corrective Actions could also be related to violations of a policy, procedure, standard, or regulatory requirement. Corrective actions are input into the CAP for resolution by the appropriate Functional Area, tracked by ORV in a dashboard, and included in Risk and Compliance Committee (RCC) agenda materials for visibility and action as needed. The ISM observes these monthly RCC meetings, has visibility into the tracking of these CAPs, and also tracks the closing out of select corrective actions through regular WRGSC meetings or through data requests to PG&E.
- **Observations**: these are usually an area for improvement but may not significantly diminish the risk reduction-effectiveness of the mitigation or control.

- **Leadership Support**: these are conditions that ORV believes do not require correction and represent best practices or novel solutions where more reinforcement, funding, or resources may be needed.

Transmission and Distribution Overhead Line Maintenance ORV Assessments

From a selection of ORV Assessments, during the current ISM reporting period, the ISM chose the transmission overhead line maintenance program and the distribution overhead line maintenance program ORV assessments for review. This included a review of the final reports, their executive summary presentations, and the associated corrective actions.

In each of these assessments, the ORV team reviewed the people, processes, process owners, reporting, data accuracy, and technology used by these programs, to determine if each was performing as intended to mitigate operational risk and to prevent asset failures that could lead to wildfires or other catastrophic events. The ORV team also tracked the status of prior CAPs, audits, and quality findings, and conducted field visits to ascertain the current state of these programs, including the status of prior corrective actions. These assessments described the benefits, financial backdrop, and regulatory requirements affecting each program, including WMP commitments. Also evaluated were the effectiveness of available models in predicting the risks that each program is intended to control, and the systems used to deliver the work of each program, inclusive of inspections, work planning, engineering, and construction.

For the transmission line maintenance program assessment, the ORV team interviewed 18 group leaders and operational personnel, and performed three site visits. The primary focus was on the steel tower replacement program and tower coating programs. These site visits included interviews with program managers, project managers, engineers, asset managers, and construction personnel. A total of 16 corrective actions were generated from this assessment in the areas of asset management, inspections, investment planning, risk-based portfolio prioritization framework, tag management, cycle planning, finance, insourcing/outsourcing, quality, and risk modeling. The reports also highlighted several areas of best practice within the transmission group, where broader implementation in other operational areas could help reduce waste, control for risk, and improve efficiency.

The ISM observed the implementation of many of the recommended operational corrective actions since the issuance of the final ORV report in December 2023, including the recommended clearance of the backlog of priority B maintenance tags, high tag cancelation rates versus distribution lines, and the conducting of a pilot study to look at regular climbing of steel structures to better identify corrosion. One corrective action requested an investigation into the circumstances behind “orphan” scores, where inspectors recorded sub-asset condition scores of 4 (Heavy Damage – short duration E Tag required) or 5 (Heavy Damage with safety concerns – A tag required) on the inspection form, but no corresponding maintenance tags existed for that sub-asset. Detailed ground, aerial, and climbing inspection forms require the inspector to assess the overall sub-asset condition on a one to five scale for each sub-asset: foundation, stub/splice plate, guy system, anchors, structure, non-steel framing, conductor, and insulators.

During the current ISM reporting period, the ISM conducted further investigations into the circumstances behind these orphan scores. PG&E informed the ISM that early in 2024, staff identified 162 structures that met these orphan conditions from 2020 to 2023. This represented a 0.1% orphan rate versus the approximately 144,500 condition scores that were created during that period. PG&E indicated that in 151 of the instances, the inspectors accidentally pressed the wrong button on the iPad inspection software creating a "false positive". PG&E noted that the 151 structures were later reinspected with the condition scores set to 2 (Light Damage), and the errors were communicated back to the relevant supervisor for inspector feedback and training. The remaining 11 were identified with lower severity E tags having been created. As was detailed earlier in the Wildfire Risk Model Updates section of this ISM Report 6, these condition scores were removed in WRTM v2.1, with PG&E stating that having the model pull directly from the reviewed and processed maintenance tag notifications was a more accurate and complete dataset for determining asset health than the condition scores.

For the distribution line maintenance program assessment, the ORV team interviewed 15 group leaders and operational personnel and performed one field visit to observe a pole replacement project and to interview the supervisor and foreman on the project. The field visit identified several errors associated with this project, including incorrect base maps and oversized equipment, which were incorporated in the recommended corrective actions.

The ORV team generated 20 corrective actions from this assessment in the areas of WMP commitments, process improvements, asset strategy, technology/innovation, quality, FSR, compliance, resource planning, risk modeling, and guidance documents.

The ISM has observed the implementation of many of the recommended operational corrective actions since the issuance of the final ORV report in February 2023, including several new programs which were discussed and approved at several WRGSC meetings, and which the ISM observed implementation of in 2024. The ORV report recommended significant programmatic changes to handle the maintenance tag backlog, gaps in CIRT and FSR tag reviews, deficiencies in pole condition assessments and pole replacement/reinforcement work, the lack of maintenance tag bundling, the lack of tag conditions in risk models, the large number of duplicate tags in the system, gaps in construction quality control, and the need for improved documentation and standardization of the work planning process. Many of these were addressed by maintenance tag mega-bundling, the elimination of the distribution FSR annual open-tag reviews and its replacement with an expansion of the Comprehensive Pole Inspection (CPI) program, expansions of the CIRT, improvements in pole test and treat methods, detailed tracking of construction quality controls, and refined inspection programs and checklists focusing on higher risk ignition-related emergent conditions, many of which are detailed in ISM Previous Reports.

ASSET AGE AND USEFUL LIFE

The ISM began reporting on the asset age and useful life of PG&E's equipment in ISM Reports 1 and 2. Asset age commonly refers to how long an asset/piece of equipment remains in operational service, while useful life commonly refers to the estimated length of time equipment can be expected to effectively contribute to operations. Asset age is often one of many factors considered when determining when an asset is targeted for replacement. Other factors may include utilization (e.g., number of times equipment operates), performance (e.g., no or minimal degradation if operating as expected), asset wear (e.g., amount of corrosion), etc.

In this ISM Report 6, the ISM provides its observations on PG&E's ongoing efforts to determine the age of its in-service equipment, provides information on the age, replacement rates and replacement strategy for its non-substation distribution overhead transformers, and updates the ISM's prior data on age and replacement rates for PG&E's poles and conductors.

Asset Age Data Collection

Accurate asset age for in-service equipment can be an important factor in assessing asset health, and is often a leading contributing factor in predicting asset failure in PG&E's wildfire risk models. In PG&E's latest WTRM v2.1 model, asset age was the leading contributing feature in predicting above grade hardware failures. As detailed in the Wildfire Risk Model Updates section of this ISM Report 6, where PG&E did not have accurate asset age for a piece of equipment, it used conservative ages as a proxy, which in turn brought extra conservatism to the probability of failure model, which then translated into the model over-predicting historical asset failures.

In PG&E's latest WDRM v4 model, asset age was high on the ranking of covariate features which contributed to the model prediction. Out of the 20+ features that were shown to have predictive influence for each different component, asset age was often a leading feature for predicting asset failure. Examples of asset age contribution rank:

- Fuses – 1st
- Support structures[27] – structural failure – 1st
- Support structures[28] – electrical failure - 2nd
- Transformers - equipment failure – 2nd
- Transformers – leaking – 2nd
- Dynamic protection devices (e.g., line reclosers, sectionalizers) – 4th
- Capacitor banks – 5th

PG&E's records indicate there are approximately 5.19 million pieces of equipment where PG&E tracks equipment age. The installation date is currently known for approximately 4.57 million and unknown for approximately 620 thousand. Accordingly, PG&E's age "fill-rate" is approximately 88%. Some of the equipment with lower age fill-rates include:

- Distribution primary overhead conductors – 73%
- Transmission conductors – 58%
- Transmission poles – 60%

[27] Support structure structural failures occur when the support structure experiences a physical failure to the pole or its crossarm(s) and are often triggered by wind events

[28] Support structure electrical failures often result from contamination on crossarms and insulators that can lead to tracking and arcing, particularly for older and cracked insulators. The failures frequently result in an ignition, but not necessarily an outage, making failures both a wildfire and a public safety concern.

- Transmission insulators – 52% (note: PG&E does not track distribution insulator age in its system as it is not recorded and stored as a featured class in its distribution GIS system).

While the transmission poles have a fill-rate of 60% for its approximately 119,000 poles,[29] the ISM noted that PG&E showed a 98% age fill-rate for its approximately 2.2 million distribution poles. When questioned on the discrepancy, PG&E noted that distribution and transmission poles are maintained in different systems, and that in 2014-2015 PG&E migrated data from several other non-comprehensive databases and engineering documents that contained support structure installation dates into one new transmission GIS database. One of the contributing legacy databases focused primarily on asset type and location, but also held additional attributes, including some installation dates. Other datasets were considered for integration, but were ultimately deemed not to be traceable, verifiable, accurate sources of asset age. Since 2020, PG&E increased its transmission pole age fill-rate from 48% to its current 60%.

PG&E considered several different approaches to continuing to increase its asset age fill rate at an October 2024 WRGSC meeting. One of PG&E's WMP commitments is to populate its asset age data to a 90% weighted average across risk prioritized distribution and transmission equipment by December 31, 2025. To achieve this target, approximately 95,000 additional age dates will be required. To source these age dates from original documents, often in paper copy in storage, PG&E determined that the exercise could take 10 years at a cost of approximately $58 million. The committee instead elected to go forward with populating the remaining age dates with "data-derived" installation years. This process utilizes a hierarchy of alternative data sources, including the year of manufacture, construction completion dates from SAP and project management records, or using the age of related equipment with known age/installation dates.[30]

PG&E stated that it discussed this method with the regulators as a cost-effective and high-confidence alternative to meeting its WMP objective, and is expected to achieve the commitment within the year, at roughly 1/50th the cost of undertaking a historical records search. In testing this data-derived method against known installation dates, PG&E determined that the age proxy was 80% accurate in matching the same installation date. This percentage increased to 90% when seeing if the data-derived age was within 1-5 years younger or older than the known age.

Transformers

PG&E's transformers are the largest contributors to PG&E's equipment failure outages, making up approximately one-third of all such outages. Transformers, however, also have a low outage

[29] Transmission towers have a higher fill rate of approximately 92% for its approximately 34,600 towers.

[30] The PG&E electrical grid is composed of a number of different types of equipment that can be connected in various ways – for example, a transformer is supported by a pole, or a conductor is connected to a switch. The GIS data models reflect these connections by creating database relationships between the two features. PG&E stated that this can be useful in determining estimated ages, because if one feature does not have an installation date, but the related feature does have one, the date of the related feature can be used to estimate the age.

to ignition rate when compared against other assets.

Transformers can fail for equipment related issues such as winding, core and bushing failures, and loss of neutral. Transformers can also fail as a result of cooling oil leaking which can lead to overheated equipment and the failure of the transformer. Transformers that are overloaded for extended periods of time are more prone to failure which is why PG&E developed an Overloaded Transformer Workplan detailed later in this section of this ISM Report 6.

As detailed in the Asset Age Data Collection section of this ISM Report 6, PG&E's risk modeling showed asset age as the 2nd highest correlated feature for equipment failure for both its transformer equipment and leaking sub-models.

The ISM reviewed the age distribution of PG&E's overhead transformers shown in Figure 7 and finds it to be comparable to other utilities. Transformers are considered long-lived assets, and when not overloaded frequently and for extended periods, can often continue to work beyond their estimated useful life.

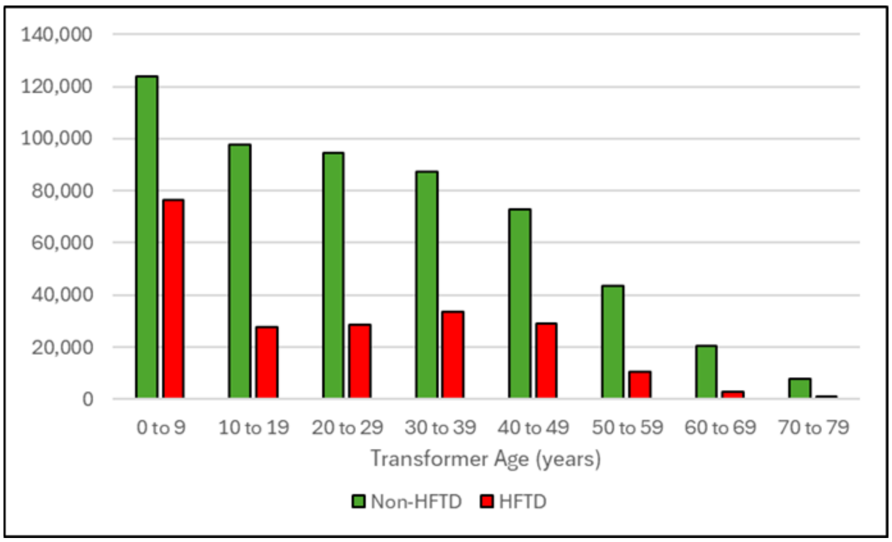

Figure 7: Overhead Transformers by Age and Wildfire Tier

Figure 8 shows PG&E's transformer replacements over the past ten years. Although non-HFTD comprises approximately 70% of the electric lines in PG&E's service territory, Figure shows that replacements in HFTD are much higher on a percentage of total basis, and have been matching those replaced in non-HFTD areas in recent years. While transformer lead times and availability were described as a supply chain concern during the peak of the Covid-19 pandemic in ISM Previous Reports, PG&E stated that it currently has an adequate supply to meet its current projected replacement needs.

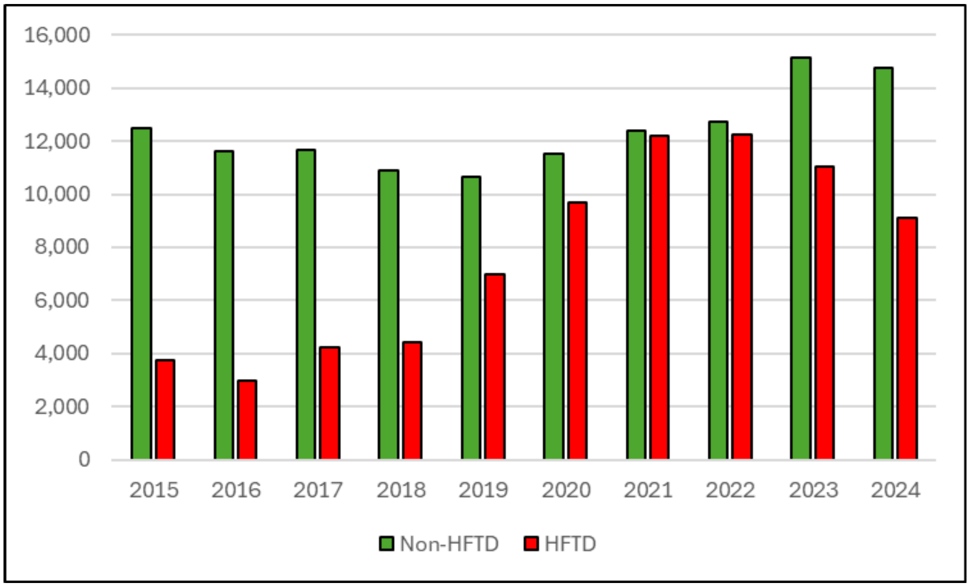

Figure 8: Transformer Replacements by Wildfire Tier

As shown in Table 4, while the percentage of transformer failures as a percentage of all equipment failure outages remained steady in non-HFTD, the HFTD areas' percentage dropped by approximately 50% since 2019 as a result of having a proportionally higher percentage of its transformers replaced over that same period.

Table 4: Transformer Outages as a Percentage of Equipment Failure Outages

	2019	2020	2021	2022	2023	2024
Non-HFTD	30.2%	38.2%	31.1%	34.3%	28.7%	30.6%
HFTD	7.1%	5.7%	5.1%	4.7%	3.9%	3.5%

PG&E's asset strategy group indicated that over the period from 2019 to mid-2024, 16 CPUC reportable transformer equipment-caused ignitions occurred, with none reported in 2023 or the first half of 2024. These ignitions represent 1.5% of total equipment caused CPUC reportable ignitions over that period. PG&E's review provided the following results:

- 3 events involved potentially overloaded transformers;
- 4 events involved deteriorated transformers, loose connections or planned maintenance;
- 4 events were animal, vegetation or third party caused; and
- 5 events cause could not be determined.

PG&E stated that it was unable to provide the ISM with equipment ages for all of the transformer failures and ignitions due to current incompatibility between its databases. PG&E noted that when a transformer failure occurs, an outage record is created in its Integrated Logging Information System (ILIS) outage reporting system. This system, however, does not contain the transformer number and/or the pole SAP ID number. An SAP repair record is created to document the emergency replacement work, and the as-built document attached to the repair record in SAP has a scanned copy of the transformer replacement form, which includes the handwritten model number of the removed and installed transformer. PG&E

stated that this information is not collected in a manner that can be correlated directly to the make/model/age of the failed transformer. In addition, while SAP has an equipment ID for transformers, repair tags are typically linked to the pole that the transformer is on, not the transformer itself. As such, PG&E stated that its current mapping processes do not retire the SAP transformer record to enable historical trending. PG&E noted that it is undertaking a CAP to explore updating its mapping processes to retire transformers to enable historical asset age versus failure trending in the future.[31]

The transformer replacements shown in Figure 8, represent replacement under several different programs, such as Emergency, New Business, Work at the Request of Others, Pole Replacement, Maintenance, etc. One program seeking to proactively replace transformers more prone to failure is PG&E's Overloaded Transformer Workplan. Overloaded transformer replacements have averaged 54 per year from 2015-2023. This number increased to 320 in 2024 (out of 23,874 total transformers replaced), with PG&E forecasting replacements of approximately 400 per year from 2025 to 2027. PG&E noted that it had approximately 58,200 overloaded transformers at the end of 2024.[32] To determine which overloaded transformers to select for replacement, PG&E uses the TOAM model, detailed in the Risk Model section of this ISM Report 6, to determine the higher risk population, and selects transformers for replacement from a population with loads greater than 150%.[33]

Poles

ISM Report 2 provided an overview of PG&E's strategy for the replacement of aging infrastructure, and focused on the asset age, failure rates by age group, and recent replacement rates for its poles and conductors. ISM Report 4 also introduced PG&E's Integrated Grid Plan (IGP). The IGP is a multi-phase approach designed to optimize PG&E's investments over a 10-year planning horizon by integrating wildfire risk reduction, capacity expansion, asset health, and reliability improvements. Wildfire risk reduction focuses on undergrounding, vegetation management, and system hardening, while capacity expansion supports electrification and economic growth by enhancing grid infrastructure. Asset health prioritizes the maintenance and replacement of aging infrastructure, and reliability efforts aim to reduce power interruptions and strengthen grid resilience while balancing the other priorities.

The ISM received several updates to PG&E's IGP development over the past 2 years. PG&E stated that its IGP is beginning to inform future workplans, and the ISM will be reporting its observations on the current status of the IGP in its next ISM Report, as well as its observations as to when PG&E may begin to direct additional funds towards Asset Health projects under this 10-year plan.

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31 PG&E stated that its WDRM v4 modeling team curated an internal dataset linking historical transformer failures to the transformer that failed. This was done using some SAP attribute data that is not readily available within PG&E. PG&E further stated that its modeling team spent substantial time cleaning and reviewing the historical data to develop the dataset to use for wildfire modeling. The modeling team has been enhancing the dataset to meet Level 2 Ontology standards in the Foundry platform to release the dataset more broadly in the company.

32 Approximately 31,900 between 100% and 120%, 17,500 between 120% and 150%, and 9,700 > 150%

33 This equates to PG&E's 2025 work plan targeting 400 of the 9,700 transformers overloaded by 150% or more.

This ISM Report 6 presents an update to the pole and conductor data originally presented in ISM Report 4, which contained figures through the end of 2022.

Pole failures represent approximately 14% of equipment related outages, and as seen in Figure 9, non-HFTD outages have increased since 2019. As previously noted, PG&E shifted expenditures from reliability improvement to wildfire mitigation over the past several years, with the focus of much of this on wildfire mitigation in HFTD.

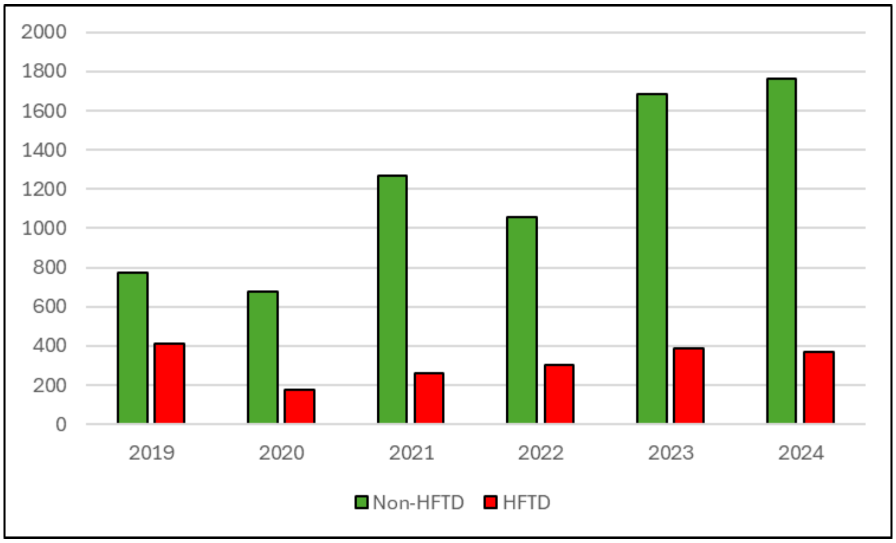

Figure 9: PG&E Pole Equipment Failure Outages by Wildfire Tier

Pole ignitions, which comprise approximately 7% of all equipment failure-caused ignitions over the past ten years, show a flatter trend in both HFTD and non-HFTD.

Figure 10 shows the number of PG&E poles by age, as well as the failure rate per 100,000 poles in each age group. This failure rate was calculated using failures from 2021-2023 and for poles that had an unplanned outage and an associated emergency A tag to replace the pole. PG&E attributes the drop in the failure rate in the 60-70 and the 70-80 age buckets to a variety of contributing factors, including that a) poles 60 years old or more have a greater likelihood of requiring proactive replacement prior to in-service failure, b) poles that do not show evidence of rot during their first 40-50 years of service life are less likely to develop rot later due to treatment type and/or service location, and c) poles have had their useful life extended with internal and external treatments during intrusive inspections. PG&E also noted that for the small number of poles in the 90-100 age group, it does not have a high confidence in the accuracy of the age data. PG&E also cautioned that the number of pole failures in the 80-90 and 90-100 age groups are significantly smaller than the other groups and that these failure rates are not as statistically reliable.

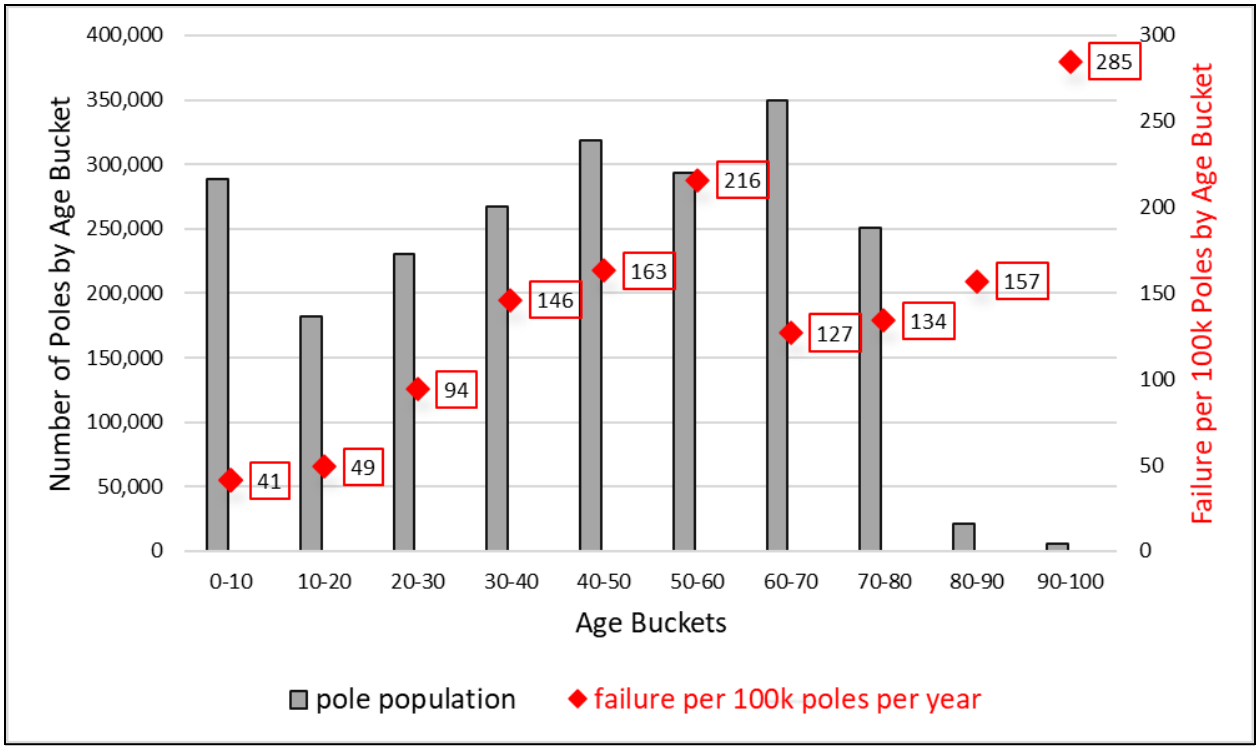

Figure 10: Failure Rate per 100k Poles/Year and Pole Populations per Age Group

Figure 11 shows PG&E doubling its rate of pole replacements over the past ten years. Of the approximately 40,000 poles replaced in 2024, approximately 18,000 of these were deteriorated poles with open repair tags, while the remaining poles were replaced under other PG&E programs such as system hardening or capacity upgrades. PG&E stated that it continues to target poles more prone to failure through enhanced inspections, replacement or removal in system hardening and undergrounding projects, and in pole reinforcements. Pole reinforcements have increased approximately ten-fold from 247 HFTD poles reinforced in 2020 to 2,603 in 2024.[34]

[34] PG&E attributes this increase to several factors, including a) the introduction of risk prioritization for the reinforcement workplan in 2023, b) changes in technical documents and standards from 2020 to 2024 which resulted in a more conservative approach to gas treated poles and an increase in PTT inspections with recommendations to reinforce, and c) the introduction of the CPI program in 2024.

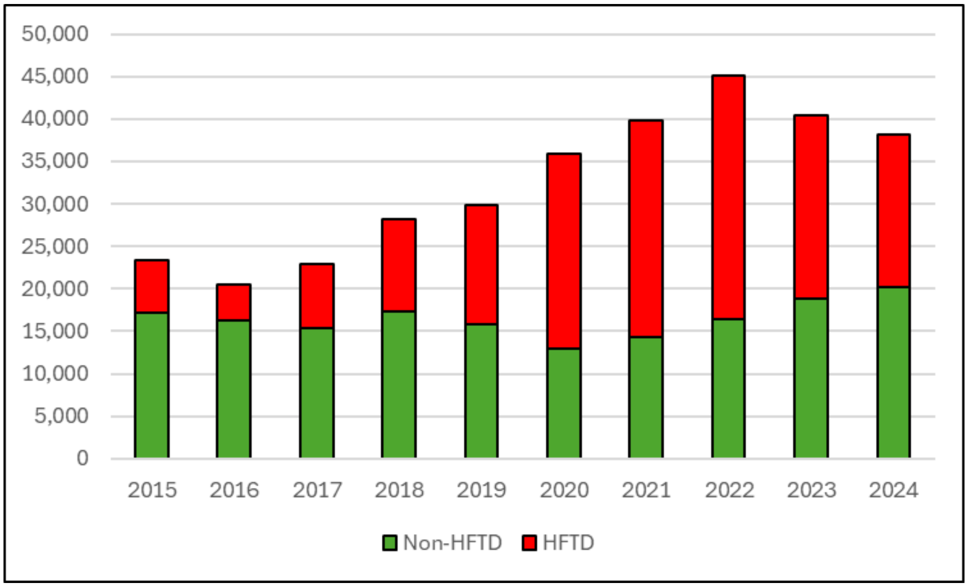

Figure 11: Number of Poles Replaced by Wildfire Tier

Conductors

Conductor failures represent approximately 10% of equipment-related outages. Since 2019, conductor failure outages have remained steady in HFTD, averaging approximately 230 per year. Over this same period, conductor outages in non-HFTD have been fluctuating from a low of approximately 900 to a high of approximately 1,800, with these annual fluctuations averaging approximately 1,300 per year. Failed conductors represent the highest category of equipment failure-caused CPUC reportable ignitions at over 30%. Reportable conductor failure ignitions stayed generally stable in recent years, averaging approximately 7 per year in HFTD and 34 per year in non-HFTD.

Figure 12 shows the number of PG&E conductors by age, as well as the failure rate per 100 miles per year. This failure rate was calculated by PG&E using wire down outages from 2021-2023. As with the poles, PG&E cautions that the number of conductor failures in the older age groups are significantly smaller than the other groups and that these failure rates are not as statistically reliable.

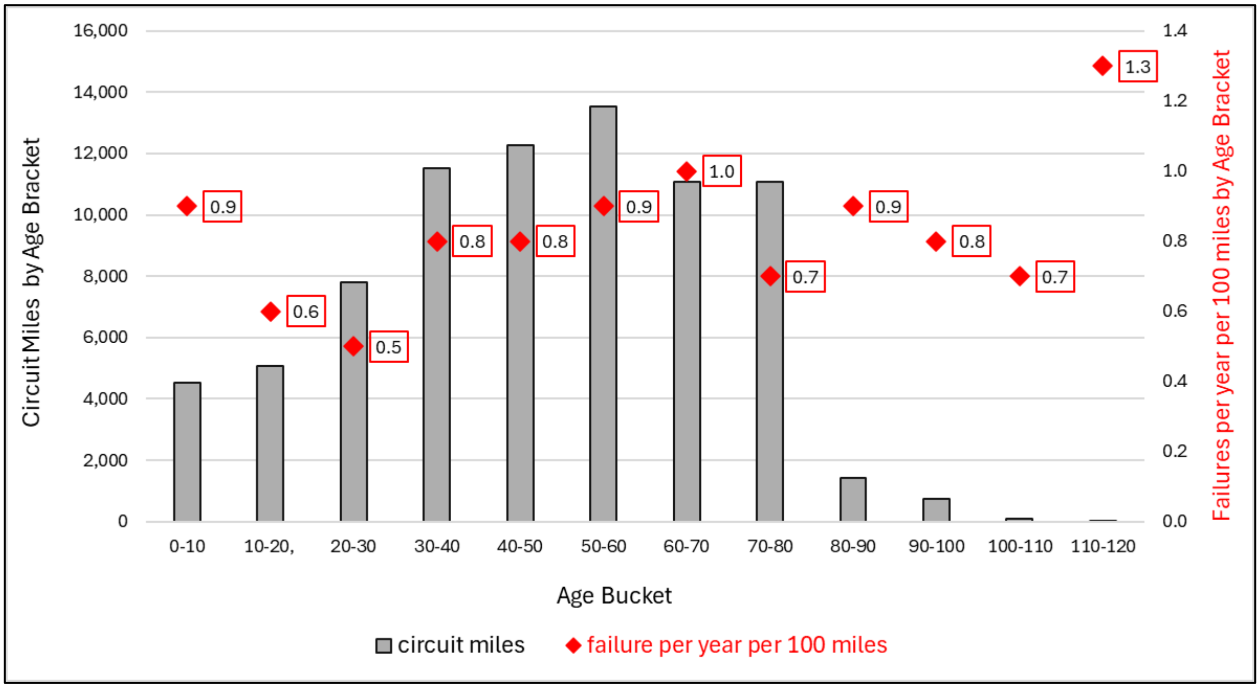

Figure 12: Conductor Failure Rate per 100 Miles/Year and Conductor Miles per Age Group

As was reported in ISM Report 2, for primary overhead conductors, PG&E established 100 years as the targeted age-base to maintain. At this age, the sustainable rate of replacement would be approximately 800 miles per year (80,000 miles/100 years). In comparison to this guardrail rate, over the past nine years, PG&E replaced an average of 442 miles of overhead primary conductor per year, inclusive of all programs. As shown in Figure 13, the miles of conductor replaced under PG&E's Proactive Deteriorated Conductor Replacement Program has averaged approximately 34 miles per year, or roughly 8% of total average annual conductor replacement miles. PG&E attributes the recent decline in miles replaced under this specific deteriorated conductor program to evolving priorities to effectively resource and support increased risk-informed system hardening projects. In addition, PG&E states that its enhanced inspections and more granular assessments of conductors has also led to escalating the urgency of remediation, and an increase in the volume of conductors replaced under emergency compliance notifications.

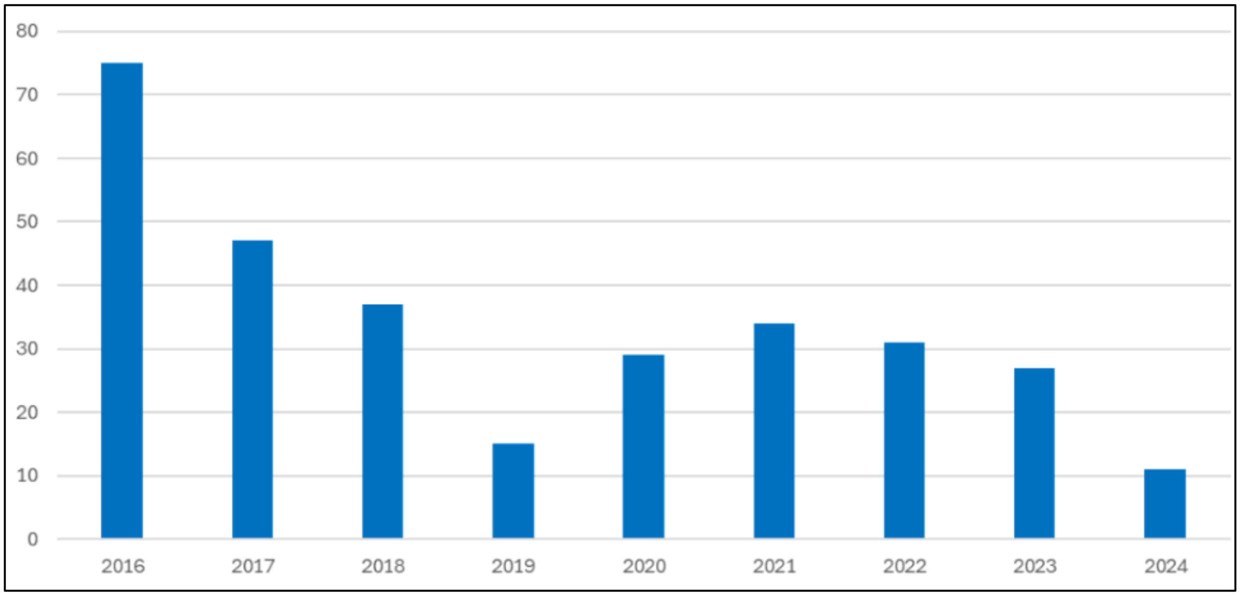

Figure 13: Miles of Deteriorated Conductor Replaced as part of the Proactive Deteriorated Conductor Replacement Program

DISTRIBUTION INFRASTRUCTURE

Distribution Inspections

Inspection Changes and Maintenance Tag Find Rates

In ISM Previous Reports, the ISM reported on the shift in HFTD distribution inspections from predominantly ground-based in 2023 to aerial-based in 2024. PG&E stated that this aerial inspection focus will continue in 2025, with approximately 242,000 aerial inspections and approximately 15,000 ground inspections planned for 2025 in HFTD (versus approximately 211,000 aerial and 10,800 ground inspections in 2024). The ISM also previously reported that PG&E modified its inspection checklists between 2023 and 2024 to allow its inspectors to focus attention on conditions more frequently associated with asset failure.

Table 5 provides a comparison of the find rate percentages (based on total number of inspections) of the different maintenance tag priorities for PG&E's ground inspections in 2023 and 2024, and for its aerial inspections in 2024. Note that PG&E introduced its new 7-day X tags (detailed later in this section of this ISM Report 6) in 2024, so there is no direct comparison in the 2023 ground inspection data. PG&E stated that these X tags provide it with additional flexibility to mitigate higher-risk safety conditions, and can be viewed in combination with the A tag find rate percentages.

Table 5: Distribution Tag Find Rate Percentages by Inspection Type

Maintenance Tag Priority	2024 Average Aerial Inspection Find Rates	2024 Average Ground Inspection Find Rates	2023 Average Ground Inspection Find Rates
A	0.22%	0.18%	0.49%
X	0.39%	0.26%	N/A
B	2.21%	1.90%	3.47%
E	21.30%	9.35%	28.12%
F	0.43%	2.62%	6.73%

PG&E monitors its find rates throughout the year, and presents them in weekly reports which the ISM selectively reviews. These presentations discuss year to date find rates, variances from forecast rates, and the circumstances which might be responsible for any significant variances.

As shown in Table 5, the change in checklist focus in 2024 corresponds with a significant drop in the number of lower priority E and F tags found in ground inspections between 2023 and 2024. These E and F tag find rates were higher using aerial inspections in 2024 versus ground inspections in 2024. PG&E stated that this increase in find rates is a result of aerial inspections looking at the poles in new directions for the first time, and were more likely to find new conditions that may be less obvious to identify from the ground.

PG&E stated that find rates are low for F tags from aerial inspections as these inspections focus on identifying GO 95 Rule 18 Level 1 or Level 2 conditions, following guidance from PG&E's Overhead Job Aid. PG&E's F tags correspond to a Level 3 condition, which are documented by PG&E's GO 165 ground inspection programs.

When comparing the percentages of the most frequent types of damage from the highest priority (A, X and B) tags, the most conspicuous difference between the aerial and ground inspections is that the aerial inspections had a much higher rate in identifying leaking transformers for replacement. These were the highest A tag aerial finds versus ranking as the tenth highest B tag find in ground inspections in 2024. Aerial inspections were also able to identify more hardware framing issues than the ground inspection.

The ISM is also following PG&E's "just-in-time" distribution A and X tag findings trend. Figure 14 provides a view from 2018 through 2024 of 1) the A and X tags found through inspections and 2) A tags identified outside of inspection or by asset failure. The blue bars represent the number of A and X tags where PG&E inspectors determined the equipment to have a high probability of near term equipment failure. The orange bars reflect the number of A tags that occurred in the field.[35] The black line in the figure represents the percentage of finds (trailing 1-year average) from inspections (blue) out of the total A and X finds (blue + orange).

[35] This excludes third party causes (e.g. car pole incidents), and fire related incidents.

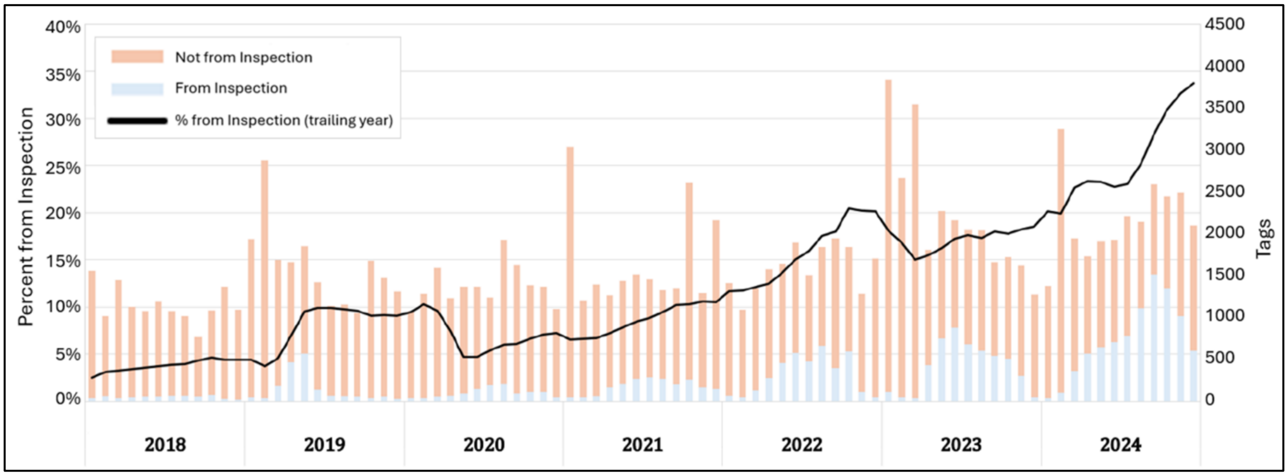

Figure 14: Trailing 1-Year A and X Tag Count and In-Service Failures

PG&E stated that the rising black line percentage reflects an improvement in the effectiveness of the inspection program over time (through increased inspection frequency and improved inspection methodology) in catching just-in-time findings, thus further preventing the negative consequences of in-service failures. Although Figure 14 shows that emergency conditions have doubled over the past 7 years, PG&E states that its improved inspection criteria and tag prioritization system are identifying more conditions prior to failure, and preventing potential ignitions and public safety consequences associated with in-service failures.

X Tags

ISM Reports 4 and 5 provided information on PG&E's new priority "X" maintenance tags introduced in 2024. These new X tags are for Level 2 conditions that require completion within 7 days, and are situated in priority between A, which requires PG&E staff to remain on site until the repair is initiated, and priority B, which requires completion in a range from 30 days to a maximum of six months, depending on the asset condition.

In designing the X tag program, PG&E's original expectations were to:

- prevent work crews from being diverted from ongoing projects for immediate A tag repairs;
- achieve greater flexibility and efficiency by allowing the X tag work to be bundled with other work that may be related to the same assets or in the same area; and
- provide customers with more advance notice of planned de-energizations.

Following a short pilot starting on March 15, 2024 to ensure that the reporting technology was functioning properly, PG&E fully rolled out the X tag program on March 25, 2024. PG&E stated that one of its challenges was getting its inspectors to consistently differentiate between an X tag condition versus a 30-day B tag condition. PG&E achieved this with additional inspector training conducted by members of its Centralized Inspection Review Team.

The program experienced some initial technical difficulties, with 16 X tags missing the 7-day deadline due to IT synchronization issues which were resolved in August 2024. An additional 6 X tags were late by a maximum of 3 days, with issues relating to workforce coordination, work starting late on the final day due to scheduling delays and continuing into the following morning, and issues surrounding load coordination during the July 1 heat event. PG&E decided to amend its X tag procedures later in 2024 by requiring any X tag not completed by its 7-day deadline to immediately convert to an emergency A tag for completion within 24 hours.

A total of 7,230 X tags were completed through the end of 2024, with an average completion time of 3.57 days. X tags were generated for a total of 43 different equipment components, with the most frequent being conductors (42%), poles (20%), cross arms (10%), tie wire (4%) and transformers (3%). No X tag assets failed during the year between when the X tag was issued and when the repair was made, but a total of 209 X tags were converted to A tags during 2024.

Comprehensive Pole Inspection Tag Cancellations

In ISM Report 4, the ISM observed that in response to a growing number of outstanding pole repair/replace notifications, PG&E determined a new CPI program, focused on HFTD assets, was needed to comprehensively re-inspect these poles using a combination of PTT and aerial inspections. In ISM Report 5, the ISM observed that the CPI program was being extended beyond just poles to include all equipment with open maintenance tags. These open tags were previously inspected under PG&E's FSR program.

This FSR program began in 2020, and was intended to ensure that tags which could not be completed by their due dates, received a reinspection to ensure their condition had not changed, which could warrant an expedited repair. With the growing backlog of open and overdue repair tags over the past few years (detailed in ISM Report 4), the FSR program began to experience several problems. As detailed in the Transmission and Distribution Overhead Line Maintenance ORV Assessments section of this ISM Report 6, the ORV undertook a detailed assessment of all distribution maintenance activities, including the FSR process.

Regarding the FSR process, ORV concluded the FSRs contained contradictory condition assessments from different assessors and assessments over time. Additionally, ORV found several thousand tags created in 2019 and 2020 that were only assessed for the first time in 2021 and 2022. PG&E stated that gaps in the annual FSR process were due to challenges in reconciling the inspection and work execution plans. PG&E also stated that as its aerial inspection process matured and demonstrated an ability to provide an improved vantage point of overhead assets, it terminated the distribution FSR program and included both pole and non-pole assets in the CPI program in 2024.

Although the CPI inspections saw a 1-2% escalation in the priority of open tags, for the current ISM reporting period, the ISM focused its review on CPI tag cancellations. The controls over the CPI cancellation process were detailed in ISM Report 4, and as part of its sampling of tag cancellations, PG&E provided the ISM with copies of all documentation relating to each of the cancelled tags reviewed by the ISM.

Of the 64,900 CPI inspections conducted in 2024, 4,400 (approximately 7%) of these resulted in tag cancellations. PG&E stated that many of these cancellations involved assets where prior ground inspections may have reported asset damage which was not as extensive when viewed with a CPI aerial inspection. Photographic examples of these types of conditions were provided in ISM Report 4. A smaller number of tags were cancelled due to the tag being a duplicate, or due to assets either having been removed or replaced under another program at the time of the CPI inspection.

A total of 31 different types of equipment were included in the tag cancellations, with the most frequent cancellations being for poles (75%), conductors (6%), hardware/framing (4%), guy wires (3%) and cross arms (2%).

Of the 4,400 cancellations, 92.6% were priority E tags, 3.9% were F tags, 0.3% were H tags (scheduled for replacement under an upcoming systems hardening project), and only 4 were B tags.

As part of its monitoring, during the current ISM reporting period, the ISM reviewed a sample of these cancellations, as described in the field observations section of this ISM Report 6.

ISM Field Observations

Distribution Field Inspections

Ground inspections of electric distribution infrastructure in HFTD were conducted in parallel with reviews of PG&E's distribution inspections, as detailed in ISM Previous Reports. Over the past three years, the ISM's inspection checklist questions and PG&E's job aid have been refined, reflecting changes in practices and priorities. While PG&E transitioned to primarily aerial inspections in HFTD during 2024, the ISM continued ground inspections which included a review of drone images captured during PG&E's aerial inspection.

The analysis presented in Table 6 focuses on observations made by the ISM's field inspection teams that were not identified in PG&E's inspections. The table summarizes the top observations from the past three years, with a focus on trends and shifts in inspection methodologies.[36] The find rate is defined as the percentage of total inspections in which a specific issue was identified by the ISM (not identified by PG&E), over the total number of inspections performed for the year.[37]

[36] Top finds only include observations for items that PG&E identifies as an E-Tag or more severe. Inventory items have not been included for this review.

[37] Total number of inspections performed in 2022, 2023 and 2024 were approximately 10,000, 6,000 and 10,000, respectively.

Table 6: Top Find Rates of Observations Identified (2022-2024)

Question	2022 Rank[38]	2023 Rank	2024 Rank	2022 Find Rate	2023 Find Rate	2024 Find Rate
Is pole broken, damaged, burnt, deformed, corroded, gunshot, or showing signs of cracking, rotten or decay?	2	1	1	1.9%	3.4%	1.2%
Are crossarm integrity compromised by any of the following: damaged, broken, burnt, decayed, rotten, loose, missing hardware or showing severe signs of bent bolts or brackets that cause the crossarm not to be horizontal, gun shots, insect damage or woodpecker damage, or splitting that compromises the integrity of the crossarm?	8	2	2	0.6%	1.0%	0.4%
Are grounds exposed?	N/A	N/A	3	0.4%	0.2%	0.2%
Is there a tree causing strain or abrasion to secondary conductor or service drop?	3	N/A	4	1.2%	0.7%	0.2%
Is the down guy above insulator grounded (vegetation or other)?	N/A	N/A	5	0.6%	0.5%	0.2%
Is there any loose hardware including bolts and nuts present for equipment attachments?[39]	N/A	N/A	6	0.6%	1.0%	0.1%
Is animal mitigation broken, damaged or missing (if required)?	9	4	7	0.8%	0.8%	0.1%
Does conductor have splices tied in proximity to insulator preventing free movement of splice with conductor?	1	N/A	NA	4.4%	0.0%	0.0%

The question regarding the condition of the pole remained a consistent focus of inspections, with pole damage among the most frequently identified issues. In 2022, ISM inspections recorded a 1.9% find rate for broken, damaged, burnt, or deformed poles, ranking it as the second most common observation that year. In 2023, the find rate increased to 3.4%, making it the most frequently cited deficiency. By 2024, the find rate declined to 1.2%.

PG&E revised the job aid to address potential subjectivity in evaluating the "condition of the pole" by including additional descriptions of damaged poles. The conditions and examples of pole condition section of the 2022 job aid consisted of approximately 20 pages, increasing to over 55 pages in 2024. The revisions include additional descriptions, photographic examples,

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38 The ranking of the questions by year was determined by the ISM by calculating the total number of observations that were made for a question divided by the total inspections performed for the year, and sorted from highest to lowest. The total number for each observation excluded F tags and inventory questions. An N/A Rank indicates that the Question did not rank in the top 10 for that year.

39 In 2022 and 2023 this question was added to identify loose hardware on equipment other than the crossarm.

and flowcharts (example provided in Figure 15 below). PG&E stated that this additional information assists in making evaluations more objective.

As mentioned in Previous ISM Reports, in 2024 PG&E switched to aerial inspection for most of its HFTD inspections. When an issue was identified from the ground, the ISM reviewed aerial photographs provided by PG&E to further assess the extent and significance of the potential issue. These aerial inspections provided an additional perspective, allowing PG&E and the ISM to identify and evaluate issues that might not have been visible from the ground. In some cases, aerial photos provided inspectors with additional information, either revealing issues not previously identified from the ground or indicating that certain ground-identified issues did not require further action.

As mentioned in Previous ISM Reports, in 2024 PG&E also switched to aerial inspection for most of its HFTD inspection. The reduction in the pole condition find rate in 2024 coincided with ISM's use of aerial photographs. When an issue was identified from the ground, the ISM could review aerial photographs provided by PG&E to assess the full extent of potential damage. In some cases, these overhead photos were used to determine that an issue identified from the ground did not require further action.

In comparing the Job Aids, the 2022 Job Aid included four photographs and guidelines relating to woodpecker damage, along with some specific issues to consider related to issuing repair tags. The 2024 Job Aid was revised to include numerous photos with expanded guidelines, an associated flow chart shown in Figure 15 to assist in evaluating specific conditions and corrective actions, and guidance regarding the evaluation of a combination of conditions.

Woodpecker

General Guidance: Visually inspect poles for woodpecker damage based on the flow chart below.

- A through hole counts as two holes
- A filled hole is still considered a hole.
- Consider reframe instead of replacing where possible.

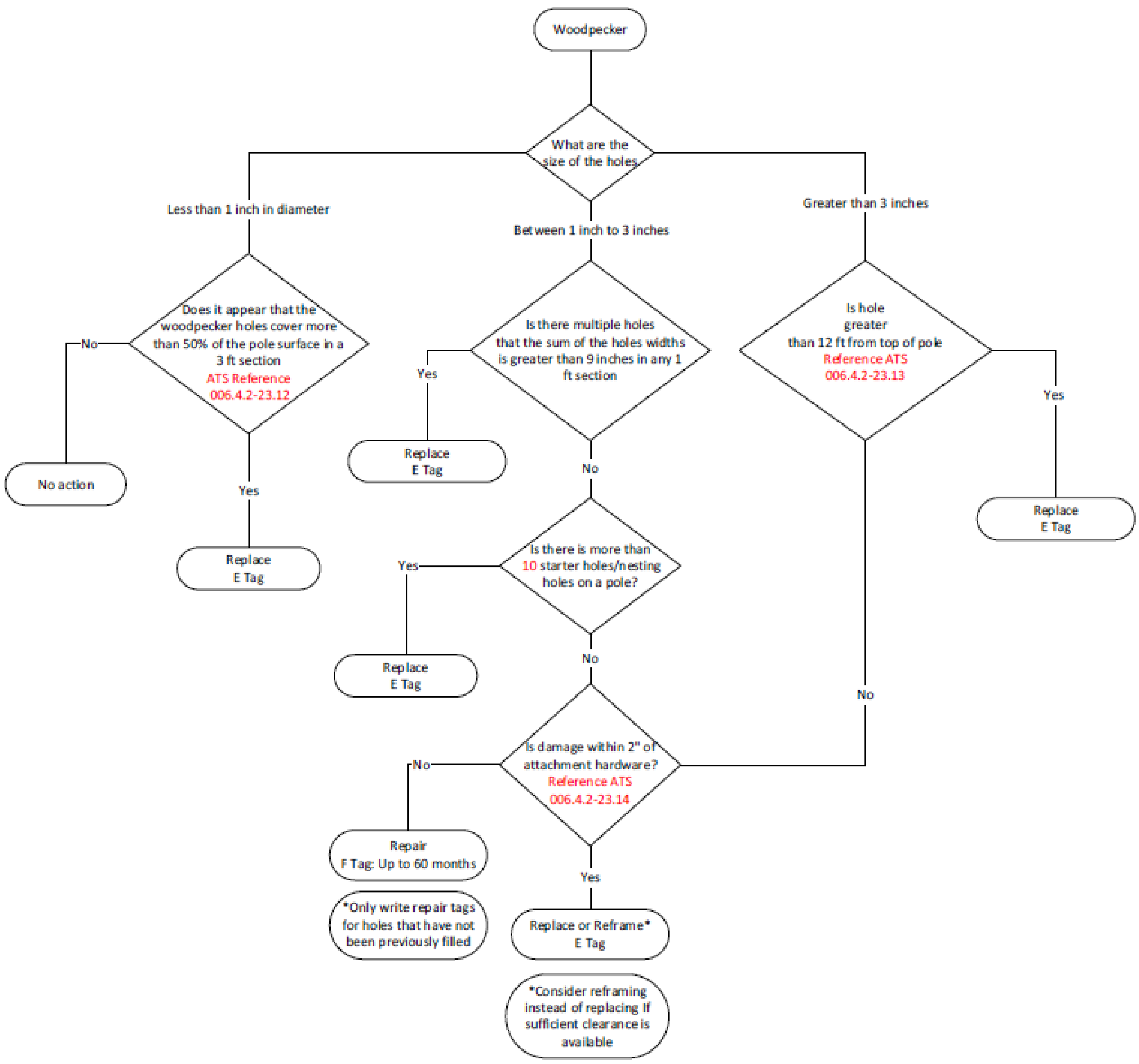

Figure 15: An example of PG&E's 2024 expanded Job Aid with a flow chart for Woodpecker guidance

Crossarm integrity has been another consistent finding, with ISM inspections identifying a 0.6% find rate in 2022. In 2023, this rate increased to 1.0%, ranking it as the third most frequently observed finding that year. However, in 2024, the find rate dropped to 0.4%, coinciding with the use of drone photographs. When ISM inspectors identified potential crossarm integrity issues from the ground, they had access to aerial photographs for comparison, providing additional context for assessing the condition.

The ISM's crossarm integrity findings observed in 2024 were primarily conditions identified from ground inspections. These findings were often due to the visibility of the defect from the ground that may not have been visible from an aerial photograph or when there were insufficient aerial photographs to see the condition. The following photographs in Figure 16 provide examples of conditions identified by the ISM that were not captured in aerial photographs.

Figure 16: This condition was not identified by PG&E aerial inspections. Left: Photos taken during ground inspections show damage to the crossarm. Right: The crossarm damage is difficult to see from aerial photographs.

The ISM also noted instances where crossarm integrity issues are not visible from ground inspections, as depicted in Figure 17 below.

Figure 17: Crossarm integrity issues visible from aerial photos but not visible from the ground.

Vegetation causing strain or abrasion remains a consistent finding, with trees causing strain or abrasion to secondary conductors or service drops ranking among the top findings. In 2022, ISM field teams identified vegetation-related strain in 1.2% of inspections. By 2023, the find rate declined to 0.7%, and in 2024, it dropped further to 0.2%. While this is trending downward, vegetation-related strain ties for the 3rd highest finding in 2024 which could come from the limited perspectives of the aerial inspections in detecting such conditions compared to ground-based evaluations. Since service conductors are below the primary conductors, it is difficult to take aerial photos of the service conductor spanning from the pole to the customer. Example photographs of this condition, taken from the ground, are shown in Figure 18 below. Photographs of these conditions were not captured in the PG&E aerial inspection photographs.

Figure 18: Photos of vegetation causing strain or abrasion taken from the ground. Photos of this condition were not captured in PG&E aerial inspection photographs.

While some findings have fluctuated over time, others have remained relatively stable. Exposed grounds, which pose both safety and reliability concerns, were identified in 0.4% of inspections in 2022. The following year, the find rate remained largely unchanged at 0.2%, with a steady find rate of 0.2% in 2024. Exposed grounds below 8' can be difficult to see from aerial photographs, and PG&E's aerial photographs do not always show these exposed grounds.

The grounding of down guy wires has been another area of focus, with ISM inspections identifying finds in 0.6% of inspections in 2022. The find rate declined slightly in 2023 to 0.5%, followed by a more significant reduction to 0.2% in 2024.

Animal mitigation measures, which are designed to prevent service interruptions and equipment damage, have followed a similar downward trend. In 2022, ISM inspections recorded a 0.8% find rate for broken or damaged animal mitigation installations. The issue persisted in 2023 with a 0.8% find rate but saw a decline in 2024, dropping to 0.1%. The type of animal mitigation used on the transformer high voltage bushings are a clamshell design attached over the bushing. Many of these have been found open or missing which may suggest a design flaw or an installation issue. The aerial photographs provide good evidence of this condition which may be more difficult to see from the ground.

One of the most notable shifts in findings over the past three years is related to conductor splices tied in proximity to insulators. The condition is part of the inspection process to ensure the free movement of the splice with the conductor. In 2022, this issue was the most frequently observed finding, with a find rate of 4.4%. However, in 2023, the issue was no longer identified, coinciding with a change to PG&E's Job Aid. Under the previous Job Aid, a notification was required if a splice was within two feet of an insulator, whereas the updated guidance required a notification only if the splice was within proximity and actively preventing free movement of the conductor. This modification likely reduced subjective or measurement-based errors in reporting. In 2024, the find rate remained at 0%, with no additional changes to the Job Aid.

B Tag Field Review

During the current ISM reporting period, the ISM conducted a field review of 30 distribution assets with assigned B-tags. Of these reviewed, at the time of inspection 24 were completed and the ISM's observations of the repairs did not indicate any open issues. Six tags remained unaddressed and were past their due dates. Five of those six were elevated to B tags due to conditions associated with the fuse cutouts. The remaining B tag associated with the pole replacement appears to still be unaddressed.

CPI Tag Cancellations

As noted earlier in this section, PG&E stopped performing stand-alone visits to assets with open maintenance tags through its distribution FSR program and elected to inspect these assets through its CPI program. Assets with open repair tags continue to be reassessed as part of the detailed ground and aerial inspection processes. Following this transition, the ISM conducted desktop reviews of 50 poles with E tags cancelled from CPI. In certain instances where the ISM's review of the drone photos did not align with PG&E's determination to cancel the pole replacement, PG&E provided additional context for the cancellations. In particular, specific cases such as leaning poles or woodpecker damage remained within acceptable thresholds as outlined in PG&E's 2024 Job Aid.

Additionally, the ISM also evaluated the mitigation recommendations from the PTT results. According to PG&E's PTT assessments, the majority of the poles demonstrated sufficient remaining strength, with many testing at or near 100%. In 10 cases, PG&E recommended reinforcement of the pole rather than replacement.

Based on the review of PG&E's drone imagery and additional documentation including PG&E's PTT results and reinforcement recommendations, the ISM's observations align with the decision to cancel the pole replacements in all 50 cases.

Maintenance

Distribution Bundling

PG&E initiated a maintenance tag consolidation program in 2024 called "Mega Bundling." According to PG&E, a Mega Bundle is comprised of all maintenance work and associated tags for a complete circuit, including lower priority "E" and "F" tags. The stated goal of the Mega

Bundle program is to reduce tag backlog, improve customer reliability by minimizing repair outages, and improve cost efficiency by dedicating resources and improving logistics. Mega Bundles are treated as large projects, where requests for proposals are issued and the project is fully scheduled, permitted, and procured. PG&E also initiated an "Operational Bundle" program that was smaller in scale, focused within isolation zones on a circuit and repairs performed primarily by local maintenance crews.

The 2024 Mega Bundling program targeted circuits within PG&E's distribution network that had the highest Risk Spend Efficiency. The 2024 program closed 8,100 tags, representing approximately 10% of the total tags closed that year. The majority of the work, 99%, was concentrated on 13 circuits. According to PG&E, the program met key objectives, including reducing customer impacts, enhancing safety, and optimizing costs. PG&E stated over 200 customer outage minutes were saved with a reported 50% reduction in outages compared to other areas within PG&E's territory. The year concluded with no significant safety events.

Financially, PG&E reported that the program resulted in cost savings. Using cost per pole replacement as an example, replacement costs outside of the Mega Bundle Program averaged approximately $30,000. Within the Mega Bundle program pole replacements costs averaged $23,000, yielding a $7,000 savings on a like-for-like basis.

For 2025, the program is expanding under a structured 10-step process designed to enhance efficiency. The total number of qualifying units has increased to 18,000, with a greater emphasis on risk-based prioritization and HFTD areas. The program's scope has shifted toward an increase in capital investment, with 50% of planned replacement tags allocated to poles, compared to 30% in 2024. PG&E stated that CPI reviews and system inspections will be conducted early to support planning and procurement activities before the work begins.

Work is scheduled to commence on April 1, 2025, following the completion of WMP inspections on those selected circuits. Mega Bundles are targeted for completion by September 30, 2025.

TRANSMISSION INFRASTRUCTURE

During the Prior ISM Periods, the ISM focused its infrastructure investigations, field inspections, and observations primarily on PG&E's electric distribution, including its primary, secondary and service lines. The reason for this focus is that over 90% of PG&E's ignitions have historically originated from its distribution assets.

Although focused on distribution, the ISM continued to observe the continuing maturity and ongoing implementation of PG&E's transmission wildfire mitigations. These have included wildfire risk modeling, internal audits and ORV assessments, risk-informed inspection planning, the undertaking of WMP commitments, clearing of the maintenance tag backlog, evolving vegetation management practices, the testing and deployment of new technologies, and the introduction of fast trip and PSPS programs to transmission lines.

During the current ISM reporting period, the ISM performed the first of its field inspections on PG&E's transmission lines. Targeted field inspections of higher risk transmission lines will continue in future reporting periods, and the ISM will report transmission related observations in future reports.

VEGETATION MANAGEMENT

PG&E's Vegetation Management (VM) is intended to support compliance with applicable regulatory requirements and PG&E's internal VM Standards and Procedures. Vegetation Management is governed by PG&E's Distribution Vegetation Management Program (DVMP) TD-7102S and Vegetation Management Inspection Procedure (VMDIP) TD-7102P-01 which includes a Routine Patrol and a Second Patrol occurring on two annual utility arboriculture cycles: an Inspection Cycle and a Work Cycle. Three specialized programs that replaced Enhanced Vegetation Management[40] (EVM) are as follows: Focused Tree Inspection (FTI), Tree Removal Inventory (TRI), and Vegetation Management Operational Mitigation (VMOM). These programs are coordinated in conjunction with "Routine & Second Patrol" when possible. PG&E stated this is an effort to minimize customer touch points, increase productivity, and maximize the effectiveness of the VM budget.

Routine Vegetation Management & Second Patrol

"Routine" vegetation management is one component of PG&E's overall VM Program. Per PG&E's DVMP Utility Standard: TD-7102, the Routine VM activities include an annual or Routine Patrol and a Second Patrol[41] occurring in conjunction with an Inspection Cycle and a Work Cycle.

PG&E's Routine VM crews are expected to perform vegetation work activities and prescriptions[42] to ensure compliance with regulatory requirements and PG&E Routine VM procedures and standards. During the current, ISM reporting period, there were no material findings associated Routine VM. The ISM will continue to monitor this area of VM and report on material observations.

Quality Control (QC)

During the current ISM reporting period, the ISM gained visibility into the Quality Control (QC) observations related to VMI and VM vendor-completed work. One component of the QC role is to assess if completed prescriptions related to ANSI-A300 and Minimum Distance Requirements (MDR) conform to PG&E standards. The ISM observed that many PG&E QC comments in the system of record noted non-compliance with ANSI-A300 Standards, BMPs, and MDRs.

ANSI-A300 Compliance/Best Management Practices (BMP)

During the current ISM reporting period, the ISM continued monitoring PG&E's VM practices

[40] The Enhanced Vegetation Management program was a supplemental tree trimming program initiated in 2019 that introduced more stringent tree trimming standards in CAL FIRE'S HFTD areas. Beginning in 2023, PG&E replaced EVM with risk-informed tree trimming, FTI, TRI, and VMOM programs.

[41] The purpose of the Second Patrol is similar to the Routine Patrol - perform scheduled inspections on all overhead distribution facilities to maintain MDR. The Second Patrol occurs at approximately six months offset from the Routine Patrol on distribution facilities in HFTD and HFRA.

[42] Prescriptions refer to a unique plan for VM work on a property that describes the trees to be pruned, removed, treated, etc., and are created by inspectors for each property.

through field assessments. The ISM continued to observe work that did not appear to conform to ANSI-A300 BMPs. The proper application of ANSI-A300/BMPs appears to be regional and/or vendor specific.

ANSI-A300 BMPs favor the removal of brush and small diameter trees (referred to as non-compatible tree species)[43] before they pose a clearance issue with primary conductors. However, the ISM observed that PG&E does not always remove such brush and trees. When identified prior to MDR, tree species become vegetation points and are entered into PG&E's tree inventory database, which then requires ongoing inspections and potential prescriptions. PG&E noted that in 2024, PG&E communicated tree removal guidance to its divisions to increase targeted removals versus pruning prescriptions and to reduce R1 trees encroaching into MDR in future years, with a goal to reduce risk and customer refusals. PG&E stated that development of a more structured approach is planned for 2025 to continue the removal efforts aligned with BMPs.

ANSI-A300 Standards and BMPs also address the proper application of pruning techniques for trees that are approaching or within the MDR. In general, these techniques are designed to minimize sprouting towards the conductor and encourage the re-direction of tree growth. The ISM continues to observe instances where pruning practices do not appear to have been applied in accordance with ANSI-A300 Standards and BMPs which can increase the possibility of vegetation contacts. In the QC system of record, PG&E's QC team has also noted such deviations from ANSI-A300 pruning BMPs.

PG&E stated that inspections occur and are completed in accordance with compliance requirements, standards, and procedures. This includes an assessment of risk, growth rate, and other factors to determine prescriptions. If a condition is identified, the inspector will complete a level 2 inspection and prescribe work accordingly. PG&E VM leadership also stated that increased emphasis is being placed on improving maintaining adherence to ANSI-A300 Standards and BMPs through additional training and vendor compliance monitoring.

During the current ISM reporting period's field assessments, the ISM encountered "Hazard Trees" and "Radial Clearance" conditions. The ISM also observed Wood Management issues. These observations are summarized in Table 7. Hazard trees identified by the ISM are provided to PG&E VM leadership for review.

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[43] Non-compatible tree species are trees growing adjacent to conductors which are known to grow to a height that would interfere with the primary conductor. PG&E advised the ISM that effective 2024 the "Right Tree, Right Place" concept was reestablished as part of the VM program, where PG&E works with stakeholders and customers to encourage the removal and replacement of non-compatible species with compatible species near the electrical overhead facilities.

Table 7: Routine Field Assessment Summary

Attribute	ISM Report 5	Current ISM Reporting Period	Change Between Reporting Periods
Tree Hazard Tree & Radial Clearance	44	112[44]	68
Observation Trees[45]	0	43	43
Number of Level 1 Assessments	13,222	14,238	1,016
Number of Spans Inspected	791	839	48
ANSI-A300/BMP non-compliant (spans)	357	418	61
Percentage of spans with ANSI-A300/BMP non-compliance	45%	50%	5%
Wood Management non-compliant (spans)	4	4	0

Figure 19: Left: Vertical crack below codominant union. Middle Two Photos: Hazard Tree identified by the ISM during a routine patrol with slipping bark. Right: Hazard Tree identified by the ISM on a routine patrol.

Focus Tree Inspection

The FTI program prioritizes vegetation management efforts to address circuit-miles based on Areas of Concern (AOC), particularly those circuit-miles associated with increased outages caused by vegetation or specific tree species. PG&E considers the AOCs as high risk circuit segments that are updated annually.

The FTI program established an inspection target of 1,500 circuit-miles for completion in 2024. PG&E's VM leadership indicated that during these inspections, Level 2 assessments are performed on any tree that could strike PG&E electric facilities (excluding service drops). The FTI Program completed approximately 1,570 circuit-miles in 2024 and established a target of

[44] 95% of trees identified are Hazard Trees with the other 5% being Radial Clearance.

[45] An Observation Tree is a condition that does not rise to the level of a hazard tree or a radial clearance issue, but represents a tree that shows some distress or may encroach within the MDR. The ISM notifies PG&E of such observations to ensure awareness.

1,500 circuit-miles in 2025 to be performed in AOC locations. Work performed in 2023 and 2024 is not included in the AOCs for the 2025 work plan.

There are three inspection roles within the FTI program: VMI, QC, and QA. VMI and QC inspections require an ISA Tree Risk Assessment Qualification (TRAQ) credentialed arborist. The QC function confirms the FTI Project, and PG&E reported that QC inspectors can report findings to VM operations and make formal recommendations. The purpose of the QA inspection process is to address regulatory compliance, and the QA inspector can also report findings to VM operations and make formal recommendations.

The ISM discussed with PG&E VM leadership the process by which the VMI and QC TRAQ Arborists prescribe hazard trees for removal. PG&E stated that inspectors review and prescribe trees according to the distribution inspection procedure, utilizing hazard tree criteria within documents.

In a previous ISM reporting period, certain PG&E VMI's and regional supervision indicated that tree lean is no longer a parameter to be considered regardless of the direction, degree of lean, and/or deflection potential. During follow-up interviews with PG&E VM leadership, PG&E reported that tree lean and deflection are valid parameters, and that these inspection discrepancies will be addressed through additional training. Further, PG&E stated that with the exception of the FTI program, tree lean follows the guidance within the distribution inspection procedure and inspectors will inventory strike trees tall enough to contact PG&E facilities. The ISM did not observe a change in practice regarding these parameters during the current ISM reporting period's FTI focused field inspections.

During the current ISM reporting period, PG&E advised the ISM of a procedural change regarding the FTI Program. A Level 2 inspection is required on all trees being inventoried, both "Strike Potential" & "Hazard Trees". Initially, a copy of the ISA Standard TRAQ Form was required for all inventoried trees, with "Strike Potential" trees being noted in the system of record as "no work required". Current procedures require a Level 2 inspection to be performed on all strike and strike potential trees that could contact PG&E facilities, with a TRAQ form only being incorporated if a work prescription of removal, targeted prune or major dismantle is identified. PG&E also advised the ISM that TRAQ Forms will be digitized in the first quarter of 2025. The ISM has requested access to digitized TRAQ forms when they become available.

PG&E reported to the ISM that the FTI Program will continue in new AOCs for approximately 1,500 circuit-miles of distribution. The ISM will continue to observe the FTI Program in 2025.

Tree Removal Inventory

The TRI program focuses on trees which were previously assessed for EVM using PG&E's Tree Assessment Tool (TAT) or during EVM inspections prior to the use of TAT from 2019 to 2022. PG&E distributed approximately 192,000 TRI vegetation points within associated workplans for review. PG&E indicated that as of year-end 2024, approximately 142,000 were currently inspected and the remaining approximately 50,000 will be inspected in 2025. PG&E also indicated to the ISM that it is planning on mitigating 25,000 vegetation points in 2025.

Trees within the TRI inventory having a mitigation status of "other than Abate" will be reassessed by a VMI. If the VMI does not believe that the tree is likely to impact the facilities, then the tree must be inspected by an ISA Certified Arborist with TRAQ credential.

PG&E's VM leadership stated that under the TRI program, any tree previously assessed as "TAT Abate" will be removed without reassessment if the overhead conductor is still present unless it is part of the "TRI Pilot Project" discussed below. Table 8 shows a breakdown of 2024 TRI work across the PG&E service territory.

Table 8: TRI Program Tree Removal 2024 Summary

TRI Program Summary	Count
TRI Trees removed 2024 (includes worked through other VM programs)	32,459
TRI Trees removed in 2024 through the TRI program	13,627
TRI Trees reassessed by TRAQ Arborist	8,347
TRI Trees removed "TAT Abate" without reassessment	4,639
TRI Trees removed that were reassessed by TRAQ Arborist	150

TRI Pilot Project

PG&E advised the ISM of a reassessment project on TRI vegetation points with the status of "TAT Abate, TAT Do Not Abate, and Other" which PG&E refers to as the "TRI Pilot Project". The reassessment is intended to review the accuracy of the TAT and introduce changes to correct the mitigation prescriptions. The "TRI Pilot Project" was initiated on June 28, 2024, with a scope that includes reassessing 8,400 trees that have a TAT result. Any tree that is delisted must have a second opinion by an ISA Board Certified Master Arborist with the ISA TRAQ credential.

PG&E reported that there are currently 38 ISA Certified Arborists and 5 Board Certified Master Arborists reassessing trees listed with a "TAT Abate, TAT Do Not Abate, and Other" in the "TRI Pilot Project" area. PG&E indicates this staffing consists of internal and external personnel comprised of multiple vendors.

Table 9: TRI Pilot Project Summary

TRI Pilot Summary	Count
TRI Trees Reassessed by TRAQ Arborist	7,154
TRI Trees Removed	70
TRI Trees Removed after Reassessment by TRAQ Arborist	66
TRI Trees Recommended for Delist after Reassessment	5,755[46]
TRI Trees Pruned	16
TRI Trees Removed by other programs at time of reassessment by TRAQ Arborist	1,903[47]

[46] Recommended for Delist after Reassessment by TRAQ Arborist and pending Board Certified Master Arborist Review. 243 reviewed by Board Certified ISA Master Arborist and pending closure in the system of record.

[47] Trees were no longer present at time of reassessment.

During the current ISM reporting period, the "TRI Pilot Project" area indicated an 80% "delisting" reevaluation of trees that were previously classified as "ABATE" under the TAT result during the EVM Program. Table 9 above reflects PG&E's findings through January 2025.

During the current ISM reporting period, the ISM performed inspections on a sample of random TRI vegetation points. Observations by the ISM generally aligned with the VMI reassessments which are shown in Table 10. The ISM will continue to monitor the TRI program and the TRI Pilot Project.

Table 10: TRI Program Summary

		TAT Result			PG&E Reassessment		
Tree Assessment	Quantity	Abate	Do Not Abate	Other[48]	Abate	Do Not Abate	Already Removed
TAT Do Not Abate or Other	51		3	48	19	25	7
Mitigated by Removal	43			43			43
TAT Abate	5	5			5[49]		
Totals	**99**	**3**	**5**	**91**	**24**	**25**	**50**

Vegetation Management for Operational Mitigation (VMOM)

PG&E created VMOM to help reduce outages and potential ignitions based on historic vegetation outages on EPSS-enabled circuits. VMOM is comprised of two key components: "Proactive and Reactive".

The VMOM "Proactive Project" includes patrols for entire Circuit Protection Zones (CPZ) identified by the Vegetation Asset Strategy and Analytics (VASA) team. "Proactive" projects address historic vegetation-caused outages and include tree failure history for the circuit. In 2024, approximately 7,400 trees were mitigated, which exceeded the established goal of 6,500 trees. PG&Es goal for 2025 for the "VMOM Proactive" is mitigating a similar level of trees on 61 circuit segments covering approximately 700 miles.

"VMOM Reactive" projects will be implemented within the VMOM Program to evaluate circuits post-EPSS outage incidents or ignitions. In such instances, an inspector will examine the circuit for at least 5 spans in each direction from the point of ignition or outage. PG&E's VM leadership notes that not all post-inspections are conducted by an ISA Certified Arborist or an ISA TRAQ credentialed arborist. These inspections and investigations may be performed by personnel with "arboriculture" or related experience. In 2024, "Reactive VMOM" mitigated approximately 2,300 trees which involved vegetation caused EPSS outages.

When an ignition occurs and includes various parameters, PG&E develops a PIIR that may include both Electrical Infrastructure and/or Vegetation Management. The vegetation component of the PIIR is part of the "VMOM Reactive" program. In a sampling of PIIRs, the ISM noted instances where trees identified for mitigation were determined to be the root cause of

[48] Other – Prior to TAT or Tree has been Removed

[49] PG&E not Reassessed due to TAT Abate Result

the outage or ignition. Some trees were classified as "constrained" that failed prior to work execution and trees that were not identified on Routine or Second Patrol. Additional information on the PIIR reports can be found earlier in the Ignitions Investigation section. The ISM will continue to review PIIRs potentially associated with the VMOM Program.

Tree Connects

PG&E reported that approximately 20,000 trees function as "Tree Connects". Tree Connects are considered and tracked within the SAP system of record as units of electrical infrastructure functioning as a pole and may have multiple attachments and equipment. PG&E indicated that while there is no specific program to replace Tree Connects, approximately 1,200 tree connects are replaced with poles per year through system hardening, mega bundling, and undergrounding projects.

PG&E stated that there are approximately 16,200 Tree Connects mapped in the system of record EDGIS. The mapping process began in 2022; but the type of tree connect is not tracked. The system of record does not contain information as to whether a tree has been topped to pole height or remains a living tree.

Tree Connects may contain distribution and secondary electrical infrastructure, and such equipment (i.e. insulators, transformers, and guy attachments, etc.) are defined and regulated.[50] Tree Connects are partially regulated the Board of Forestry and Fire Protection which provides the following description: "Tree Line or Tree Connects are electric conductors and subordinate elements fastened to 'living and sound trees', commonly referred to as tree lines, the requirements of PRC 4292 and 4293 shall apply the same as to a pole or tower line."

Tree Connects are also addressed in the California Power Line Fire Prevention Field Guide under Tree Connections that provides the following, "Standard unprotected conductors (for primary distribution lines) and self-supporting aerial cable can only be attached to trees in accordance with CCR Title 14, Sections 1257 and 1258. However, in no case are conductors of any kind to be mounted to snags or dead trees."

PG&E VM leadership stated Tree Connects are inspected per the distribution inspection procedure, with tree connects located in HFRA and HFTD receiving both annual and second patrol inspections within the year. PG&E advised the ISM that VM inspections are conducted as a "Green Tree" pursuant to "Routine and Second Patrol". If VM observes an abnormal condition for a "Tree Connect" when inspecting for conductor clearance or tree health, VM will report the condition to Electric Operations for follow up and proper mitigations. PG&E reported that tree removal or topping to pole height is performed when the tree is determined to be declining or dead.[51]

Tree Connect assets are inspected based on GO 165 requirements which require an inspection of overhead conductors and cables at least every five years. PG&E's 2024 Job Aid Overhead

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[50] Tree Connects are defined under Title 14 of the California Code of Regulations (14 CCR), Division 1.5, Chapter 7, Subchapter 4, Article 4 Utility Clearance Exemptions, 2019 § 1258

[51] Note, topping a tree may create a hazard tree that may not meet the criteria of "living or sound" as stated in the regulations.

Assessment states that if the tree is dead/dying an “A”, “X”, “B”, or “E” tag is to be created based on field conditions. PG&E VM noted that System Inspections performs a “visual assessment” to determine if a tree appears dead or dying but the focus of the inspection is on attached infrastructure. For trees that appear dead or dying, the System Inspector may request an inspection from a VM Arborist to confirm an assessment, which then may lead to the creation of an EC tag.

During the current ISM reporting period field assessments, the ISM observed a total of 190 “Tree Connects.” A summary of observations is provided in Table 11. In one 8-mile section, the ISM observed and performed Tree Risk Assessments on 79 Tree Connects with the following notations:

- 62 Tree Connects were assessed as “Live & Sound” pursuant to regulations.
- 1 Tree Connect was assessed as a potential Hazard Tree (whole tree).
- 12 Tree Connects were topped to pole height creating potential Hazard Trees.
- 3 Tree Connects were removed and replaced by new poles.
- 1 Radial Clearance condition was created due to the location of a new pole and the removal of a Tree Connect.

Figure 20: Left: Tree Connect observed November 2023. Middle: Same tree observed July 2024. Right: Same tree observed November 2024. [52]

[52] November 2023 observation: Tree dead and slipping bark with decay in progress. July 2024 observation: Tree connect removed and new pole and guy installed. Dead snag now a Hazard Tree to conductor, pole, and guy wire. November 2024 observation: Dead snag topped below conductor height but still has strike potential to new pole and guy wire.

Table 11: Total Tree Connects Observed for Reporting Period

Total Tree Connects Observed	Tree Connects Assessed as Live & Sound	Potential Hazard Tree	Tree Topped to Pole Height	Pole Installed - Tree Connect Removed
190	150	6	26	8
% of Total	*79%*	*3%*	*14%*	*4%*

OneVM

OneVM is a work planning and management platform with GIS integration to support the creation and management of vegetation management projects, supporting work coordination including constraint case management and work closure activities. PG&E began the transition to OneVM in 2023 with the intention of consolidating all VM programs into a single platform. The transition is expected to occur over multiple years.

PG&E is nearing the two-year milestone for integration with OneVM. PG&E continues to migrate programs to the OneVM platform, and until completion some programs will exist within other applications. These programs include QA/QC located in Survey 123, and Transmission located in the legacy VMD application. Additionally, the TRI Program is maintained in Field Maps with no plans to migrate the data to OneVM. PG&E has not set specific goals on when or if QC and Transmission will be integrated into OneVM platform and will continue to explore options to determine areas of focus for vegetation management.

Digitized TRAQ Forms are not currently available in OneVM. PG&E creates a digital record of historical TRAQ forms by uploading the handwritten forms (scanned images from paper forms), and they remain in digital format to be available in OneVM. The ISM does not yet have visibility to the TRAQ Form in the Data Viewer and has limited visibility to various VM platforms. PG&E to coordinate all relevant access through data requests.

The ISM will continue to monitor the implementation of various platforms into OneVM.

GAS OPERATIONS OBSERVATIONS

The ISM monitors safety and risk aspects of PG&E's natural gas operations and infrastructure, where certain observations and programs become topics presented in the semi-annual ISM Report(s). These topics may evolve over time to reflect new or changing gas safety operations and programs. As outlined in the scope of the ISM Contract and in consultation with the CPUC, the ISM's gas operations and infrastructure focus in this ISM Report 6 is directed toward: 1) Safety Excellence Management System Implementation, 2) Critical Facilities and Facilities Integrity Management, 3) Kettleman Incident Root Cause Evaluation, 4) Compliance Work Management, 5) Damage Prevention, 6) Gas Asset Data Management, 7) Maximum Allowable Operating Pressure, and 8) In-Line-Inspection Program Updates. The ISM will continue to monitor these programs and provide updates in future reports, as appropriate.

PG&E'S SAFETY EXCELLENCE MANAGEMENT SYSTEM IMPLEMENTATION

PG&E Gas Operations reported on the transition of its Gas Safety Excellence Management System (GSEMS) to ~~a~~ the PG&E Safety Excellence Management System (PSEMS) to provide a structured framework to manage assets, public, employee and environmental safety risks, ensure regulatory compliance, and drive continuous improvement. The purpose of PSEMS is to integrate policies, procedures, and performance metrics to establish standardized asset management and safety practices, improving risk identification, process consistency, and accountability. In large organizations, maintaining uniform execution across departments can be challenging. Standardized methods and documentation reduce variability, enhance reliability, and improve efficiency.

PSEMS Background

PSEMS refers to a comprehensive safety framework used by organizations like PG&E to proactively identify, assess, and mitigate safety risks across their operations. PSEMS is intended to go beyond basic compliance and actively promote a culture of safety through continuous improvement and industry best practices. PG&E reported that the goal of its PSEMS framework, based on the GSEMS that was established after the San Bruno incident, is to scale the safety management system across all PG&E operations. PSEMS related data collection and analyses are intended to enable PG&E to optimize asset lifecycle resources, processes, and drive informed decision-making.

PSEMS primarily focuses on prevention, encompassing all aspects of a process (design, operations, maintenance, training, and management systems), to allocate resources and actions based on potential risks, monitor results, and incorporate regulatory reviews to drive "continuous improvement." According to PG&E, continuous improvement is embedded in PSEMS through structured performance evaluations and corrective actions that help streamline operations, efficiently allocate resources, and enhance productivity.

As stated above, PSEMS's primary focus is prevention. An example is PG&E's "Energy Wheel" that is used in the field as a safety risk identification tool during pre-job briefings or tailboards. The Energy Wheel, shown in Figure 21 below, is intended to facilitate discussions about high-energy safety hazards - hazards that, when released or transferred to an unprotected person, would most likely result in a life-altering, life-threatening, or life-ending injury. PG&E reports that the Energy Wheel has raised awareness of high energy safety hazards from 45% to over 70%[53].

Figure 21: PG&E's Energy Wheels used during pre-job briefings or tailboards

PG&E's natural gas operations began its transition to PSEMS in the fourth quarter of 2023. As more fully discussed below, PG&E reported that natural gas operations will continue to maintain certifications specified by industry and international standards for asset management, pipeline safety management and process safety performance indicators.

Current Update

Based on the ISM's interviews and associated observations during the current ISM reporting period, the following summarizes the current status and key developments in PG&E's implementation of PSEMS. PG&E continues to oversee the transition of its GSEMS to the company-wide PSEMS program. PG&E reports, as depicted in Figure 22, that the alignment of the GSEMS elements[54] to the PSEMS framework is complete, supporting consistency across company operations.

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[53] PG&E Document: PSEMS/SIF Capacity & Learning – PLAYBOOK, Enterprise Contractor Safety (public).

[54] In 2018, PG&E published a GSEMS manual to integrate gas safety standards into 16 elements to improve assessment of system maturity and effectiveness. GSEMS elements established requirements to address risks inherent to Natural Gas Operations and provided a model to manage governance, policies, processes, and procedures.

GSEMS Elements	PSEMS Elements
Element 1: Leadership Commitment, Accountability and Employee Participation	**Element 1:** Leadership, Commitment & Engagement
Element 7: Communication and Stakeholder Engagement	**Element 2:** Communication & Stakeholder Awareness
Element 3: Risk Management	**Element 3:** Risk Management
Element 2: Asset Management and Life Cycle Planning	**Element 4:** Strategy, Objectives & Planning
Element 6: Operational Planning and Controls	**Element 5:** Operational Control
Element 10: Training Competency and Awareness	**Element 6:** Training & Competence
Element 13: Emergency Preparedness and Response	**Element 7:** Emergency Preparedness & Response
Element 4: Incident Investigation and Corrective Action	**Element 8:** Incident Reporting, Investigation & Corrective Action
Element 9: Contractor Management and Third-Party Services	**Element 9:** Contractor Management & Third-Party Services
Element 11: Management of Change	**Element 10:** Management of Change
Element 8: Information, Documentation and Records Management	**Element 11:** Information, Documentation & Records Management
Element 12: Monitoring and Measurement **Element 15:** Continuous Improvement **Element 16:** Management Review	**Element 12:** Performance Evaluation & Improvement
Element 14: Auditing **Element 5:** Compliance with Legal, Regulator and other Operational Requirements **Element 15:** Quality Management	**Element 13:** Assurance

Figure 22: GSEMS Alignment to PSEMS

PG&E reported that it integrates aspects of various safety and operations focused programs to align with industry benchmarks. Key programs highlighted through the PSEMS program include, but are not limited to:

Asset Management

- PAS 55 / ISO 55001 Asset Management
- ISO 9001 Quality Management
- ISO 14001 Environmental Management Standard

Safety Culture

- ISO 45001 Occupational Health and Safety
- ISO 45003 Psychological Health and Safety
- API RP 1173 Pipeline Safety Management Systems

Process Safety

- API 754 Leading and Lagging Process Safety Indicators

In 2019, PG&E Gas Operations began to conduct biennial assessments of GSEMS system maturity. PG&E reported that these internal assessments help identify opportunities to improve system maturity. During the current ISM reporting period, the ISM observed that PG&E was in the process of assessing the management system. The assessment will potentially serve as the new baseline assessment of the current state of the system, identify areas for improvement, and guide future enhancements. PG&E Gas Operations indicated that the next gas operations maturity assessment is scheduled for the fourth quarter of 2025. The ISM will continue to monitor the maturity assessment of the natural gas operation's PSEMS program and provide updates in future reports, as appropriate.

CRITICAL FACILITIES & FACILITIES INTEGRITY MANAGEMENT PROGRAM

The Facilities Integrity Management Program (FIMP) is a comprehensive program related to the safety, reliability, and operational integrity of critical facilities, including compressor stations, measurement and control stations, storage facilities, and complex control systems. PG&E utilizes multiple methods for identifying "critical" facilities, based on the types of risks which are being managed. Various teams within PG&E have responsibilities associated with the various critical facilities. PG&E's various teams seek to integrate Process Hazard Analyses (PHAs), condition-based maintenance, asset management strategies, and continuous monitoring to mitigate risks and support compliance with safety and regulatory standards.

Management and oversight responsibilities within FIMP are distributed across multidisciplinary teams, which include process safety specialists, asset owners, operations personnel, engineers, and process owners.

Support Services for Critical Facilities

PG&E's Process Safety team supports the hazard analysis and safety assessments for critical facilities. PG&E has various operational facilities which are subject to structured process safety management. PHAs are performed for each of these identified facilities on a four-year cycle with four assessments completed annually. PG&E utilizes a detailed node-by-node analysis method for higher-risk facilities to identify and mitigate major hazards. Lower-risk facilities utilize a structured PHA checklist to classify safety concerns as Priority 1 or Priority 2, enabling timely intervention and correction. Lower risk facilities use a PHA checklist to classify safety concerns as Priority 1 or Priority 2. Project specific PHAs involve collaboration among lead engineers, SMEs, and clearance supervisors to ensure comprehensive risk identification and development of CAPs.

PG&E's Engineering team manages asset management, condition-based maintenance, obsolescence management, and capital project execution for critical facilities. Engineers provide regional oversight, maintain asset integrity for compressors, control facilities, and measurement systems, and proactively address asset condition before failures occur.

The engineers take ownership of CAPs and capital project execution. PG&E indicated that all projects undergo a PHA process. PG&E's engineering teams are tasked with hazard identification, troubleshooting abnormal operating conditions, and developing impairment plans for critical safety systems. These teams execute transmission projects, with specialized support of facilities' project engineering, controls engineering, and environmental engineering. An Obsolescence Program managed by the engineering team addresses aging equipment, controls, and valve actuation systems, with multiple facility rebuild projects currently underway to enhance equipment efficiency and reliability.

PG&E's Measurement and Control Station team oversees approximately 5,000 measurement and control stations, applying hazard-based assessments and response planning methodologies to maintain facility integrity. Facilities are evaluated for exposure to risks such as seismic events and over-pressurization. The team utilizes qualitative risk assessments to classify and manage critical sites, applying engineering solutions aimed at mitigating high-risk conditions through preventive measures and system modifications.

FIMP Program and Process Owners are tasked with ongoing safety, compliance, and funding for integrity management initiatives. The process owners provide oversight of critical facility integrity expense programs, including: Maximum Allowable Operating Pressure (MAOP) Confirmation Program, Station Over-pressurization Prevention, Relief Valve Installations, and Project Management and Execution.

Process owners coordinate with Engineers, Asset Owners, and Operational Owners, working on alignment of project designs with overall FIMP objectives. Funding and spend tracking are monitored, and program execution and performance insights are maintained through tracking and huddle boards.

ISM Observations

PHAs and risk assessments are important elements to PG&E's program, as process hazards can result in fires, explosions, or toxic releases at critical facilities. Node-by-node and high-risk PHAs are designed to address major failure points, which emphasize their importance to risk assessment and mitigation. Without proper monitoring and PHA checklists, Priority 1 and Priority 2 safety issues might not be addressed, leading to equipment failures. PHAs and associated CAPs are also components of OSHA, EPA, and other regulatory standards, and non-compliance may result in fines, penalties, or facility shutdowns.

The ISM will continue to review PG&E's PSM documentation, including documents pertaining to the PHA for identified critical facilities related to compliance with industry safety standards, regulatory requirements, and risk mitigation best practices. This ongoing review will include key PSM elements like hazard management, asset reliability, incident prevention, and emergency preparedness across PG&E's critical infrastructure. Root-cause and corrective actions associated with the recent Kettleman facility incident, a critical facility (detailed in the next section), will be incorporated into future ISM observations, as appropriate.

KETTLEMAN INCIDENT ROOT CAUSE EVALUATION

On July 9, 2024, an incident (Kettleman Incident) occurred while supporting valve replacement work at the Kettleman Compressor Station, in Avenal, CA. While returning the system to service, a mixture of air and natural gas ignited, resulting in serious injury to one worker, and minor injuries to others nearby.

The valve replacement work required the compressor station and associated piping to be removed from service, which includes purging natural gas from the system by displacing it with air, or "establishing clearance." Establishing clearance is the process of ensuring the area where the purge is to take place is safe and free of hazards, including avoiding explosive mixtures of air and natural gas, and confirming the area is free from potential ignition sources. Once work is completed, the air is then purged from the system by re-introducing natural gas, or "removing clearance to restore the system".

During the Kettleman valve replacement project, while establishing clearance and purging natural gas from the system, it was reported that workers were concerned about exceeding allowable levels of natural gas in the surrounding area. To avoid this, a blind flange (a solid plate used to seal the end of a pipe) was removed from the piping in order to allow additional air into the system for purging of the natural gas. Ultimately, this blind flange was not replaced prior to the reintroduction of natural gas, while removing clearance to restore the system. After work was complete and the system was being returned to service, natural gas was re-introduced to the piping to displace and purge the air. It is suspected that a partially open valve directed additional natural gas toward the open pipe where the blind flange had been removed.

The natural gas exiting the blind flange flowed directly into an opposing blind flange, which deflected the gas in all directions, including into the excavation below. The air/gas mixture ignited, resulting in a serious injury to one worker, and minor injuries to others nearby. The precise ignition source could not be determined with certainty. The Root Cause Evaluation (RCE) identified several potential causes of the ignition, including an electrostatic discharge from the dust cloud generated, from the pipeline itself, or from an employee in the vicinity, or a spark from debris exiting the pipeline or kicked up by the venting gas. Emergency services were called, PG&E personnel were notified, and the Kettleman Compressor Station was secured and made safe until further direction was received.

Kettleman Root Cause Evaluation

PG&E performed a RCE on the Kettleman Incident. A RCE is a systematic process to review an incident and determine the underlying causes that led to it. The goal of a RCE is to gain an understanding of why an incident occurred so that changes can be made, and effective solutions can be implemented to prevent a similar incident from occurring again. The Kettleman RCE identified the root cause, or the fundamental reason the incident occurred, as well as three contributing causes, or factors that, while not the main reason for the incident, contributed to the problem, exacerbated the problem, or made it more likely to occur.

The root cause was identified as the failure to achieve effective change in safe behaviors and the implementation of essential controls to mitigate high-energy hazards (Figure 21 - Energy Wheel depicts high-energy hazards). The RCE identified areas where improvements can be made related to adherence to safety procedures, stopping work when conditions change, planning for high-risk work activities, and leadership engagement.

Three contributing causes were identified. The first was that configuration control is not rigorously applied when executing clearance work. This refers to the ability to remove a specific component or system from service in a way that allows for precise control throughout the work being performed. For example, the blind flange that was opened was not considered in the work plan, and may have affected configuration control during the clearance work.

The second contributing cause was related to gas worker fundamental knowledge and proficiency challenges. The RCE identified gaps in worker training and knowledge related to purging and clearance work activities. For the Kettleman incident, some workers interviewed were not familiar with the guidance document related to purging procedures.

The third contributing cause was the failure to recognize risk and address causes of repeating events. The RCE identified gaps in trending and assessing incidents and problems to improve performance and decrease the likelihood of future incidents. For example, previous corrective actions related to clearance work were identified, with required follow up actions that were not completed.

Prescribed Corrective Actions

The RCE prescribed several Corrective Actions (CAs), or specific actions to be taken to address the root causes and contributing causes identified in the RCE.[55] Because many of the following CAs are programmatic, the CAs will influence the evolving PSEMS program, as appropriate. The

[55] Unless otherwise specified, all root causes and contributing causes have a due date before year end 2025.

ISM will monitor PG&E's progress on each CA in regards to scope and schedule.

PG&E will develop a five-year Safety and Culture Achievement Plan to provide a unified vision, direction, and goals for the prioritization of safety. In addition, a leadership development program is to be established for all gas leaders in order to align leadership on essential safety behaviors and actions. This CA has a due date of September 2030. PG&E indicated that it onboarded staff, and a team is being built to support the plan.

PG&E will implement Exclusion Zones (areas around purging activities) to ensure that no people, impedances, or sources of ignition are in the vicinity of air/gas plumes while performing blowdown or purging work. PG&E indicated that it drafted the definition of Exclusion Zone Requirements, and a plume study is underway to help determine Exclusion Zone requirements.

A related CA addresses the installation and staging of permanent vent stacks where exclusion zones, worker safety, or public safety may be challenged. PG&E indicated that it implemented interim measures, but to further define vent stack requirements, the results of the plume study (mentioned above) will be required. PG&E's engineers will begin screening stations for potential vent stack installations by reviewing criteria such as blowdown height, ignition sources, location of valves, among others.

PG&E will implement a Risk Identification and Readiness Reviews process, which PG&E reports will be incorporated into PSEMS, to improve early coordination of risk identification, hazard mitigation, and adherence to work processes during clearance and purging work. This CA is intended to aid PG&E in identifying and tracking conditions that could lead to unsafe conditions during clearance activities. PG&E indicated that it completed a draft project risk readiness template, and review meetings are scheduled to review clearances on a weekly basis.

PG&E will evaluate Configuration Control Devices to be used specifically for clearance operations. This CA will ensure maintaining robust tagging (labeling) devices to prevent unapproved changes to equipment configuration during clearance and purging operations, keep track of situations during clearance activities in which a change to the system has been made, and ensure workers remain aware of such changes and their impact on Configuration Control. To support the development of this CA, PG&E has begun benchmarking current practices.

PG&E will evaluate Clearance Supervisor Roles and Responsibilities to identify whether opportunities exist to further refine the roles and responsibilities of clearance supervisors. PG&E indicated that progress achieved related to this CA includes reviewing regulatory standards and internal PG&E standards, benchmarking the PG&E clearance process, and defining roles and responsibilities.

PG&E reported that it will implement a clearance and tagging event monitoring process[56] to encourage prompt reporting, learning and communication for instances where a clearance

[56] While a monitoring process already exists, this CA is intended to evolve the process.

event had the potential to, or did result in a hazardous situation. PG&E indicated that it initiated benchmarking, within and outside of the pipeline industry.

PG&E reported that it will enhance its training programs for clearance operations and clearance supervision, and for purging operations. PG&E indicated that it established a training evaluation team to review current training practices, develop new training, and provide a revised job-aid document for blowdown, purging and venting work. PG&E performed a gap analysis on the current purging related guidance documents, and is in the process of drafting the updated/new job-aid.

PG&E Gas Operations stated that it intends to implement trending and performance monitoring through evaluation of safety-related CAPs entered in the Corrective Action Program system. Topics such as occupational safety, process safety, and organizational culture will be communicated to PG&E's Gas Operations leadership for organization-wide learnings. PG&E Gas Operations indicated that it will model this trending process after the Diablo Canyon Power Plant trending process within PG&E. Performance monitoring is captured in element 8 (Incident Reporting, Investigation and Corrective Action) and 12 (Performance Evaluation and Improvement).

PG&E reported that it will develop "Quality Improvement for High-Risk Programs" to include development of a Quality Improvement Plan Process and self-assessments, with a focus on high-risk tasks. Assessment results will include actions for improvement at all levels of the organization. PG&E confirmed that it is developing the initial framework for this plan, along with the mechanisms to track specific Quality Improvement Plan deliverables.

The ISM intends to continue monitoring the progress of each CA from the RCE, how these CA's influence the maturity of the PSEMS program, and monitor any actions taken as a result. Reporting of activities related to CAs will be reported in future ISM Reports, as appropriate.

DAMAGE PREVENTION PROGRAM

As part of the ISM's ongoing review of the Damage Prevention Program,[57] the ISM conducted an interview with the leadership team to assess progress, challenges, and future initiatives. This update reflects the key observations regarding program enhancements, "locate error" reduction efforts, monitoring initiatives, performance metrics, and future areas of focus of the Damage Prevention team. The ISM intends to continue to monitor, and report as appropriate, these activities with a focus on data-driven results regarding the activities discussed below.

Mitigation Efforts

PG&E's Damage Prevention team implements proactive outreach and risk mitigation strategies to minimize excavation-related damage. An example includes neighborhood notifications designed to create awareness about PG&E's "Call 811" locate program. PG&E performs 811 workshops, where it discusses with the public the 811 program and ways to prevent dig-in

[57] The Damage Prevention Program is designed to minimize excavation-related damages, improve compliance with industry best practices, and increase stakeholder awareness of Call-Before-You-Dig best practices.

damages. PG&E targets at least 250 such workshops per year. Another example is that PG&E participates in local outreach every August 11th, on "8-11 day", where it partners with local fire departments and news organizations on a campaign to bring awareness of the program to the public. The damage prevention program's performance dashboard allows tracking of damage prevention metrics, providing visibility into trends and identifying areas requiring further attention.

The year-over-year trends indicate progress in reducing locator at-fault dig-ins, with "mismark" and "no mark" locate errors decreasing from 126 in 2019 to 89 in 2022, and dropping further to 55 in 2023. PG&E's team is refining its processes and leveraging data-driven insights to identify risk factors contributing to these incidents. For example, after performing an analysis of every at-fault dig-in, PG&E made modifications to its training in an effort to enhance training for locators, which incorporates classroom training, training at PG&E's Winters facility, and on-the-job training. Efforts are underway to incorporate modeling and AI-driven analyses, using ticketing information, to predict and prevent locator at-fault dig-ins more effectively.

When a locate error occurs, PG&E conducts a process failure analysis to determine the cause and how to prevent similar issues in the future. In 2022 and 2023, P&GE identified a key recurring issue for inspectors related to the steel-to-plastic transition. Where a steel main and plastic main are connected, there is a transition fitting. At these transitions, PG&E found that sometimes the tracer wire was not properly attached, or could become disconnected, making these transitions difficult to accurately locate. In response, PG&E incorporated a new training module specifically addressing this challenge. PG&E indicated that after which the locate errors around steel-to-plastic transition points dropped significantly.

PG&E also monitors and analyzes performance metrics for all dig-in incidents. To enhance visibility into all dig-in incidents, PG&E tracks the metric of dig-ins per 1,000 locates and categorizes them based on factors such as whether notifications were issued. PG&E also benchmarks this metric against the industry through the Common Ground Alliance, and indicated that PG&E typically ranks within the top 10% - 25% industrywide. Additionally, PG&E investigates every damage incident, and completes formal reports for each case to determine that corrective actions are implemented where necessary.

Performance Metrics and Industry Benchmarking

The ISM team received damage prevention performance data and reports from the PG&E Damage Prevention team. In 2016, PG&E reported that there were approximately 1,800 reported gas dig-ins, peaking at approximately 1,900 in 2017. PG&E indicated that the number of dig-ins has steadily declined through continuous improvement initiatives including the public awareness programs discussed above, with approximately 1,300 in both 2023 and 2024.

Since 2018, PG&E ranked in the top quartile for damage prevention performance based on AGA benchmarking. In 2022, PG&E achieved top decile performance among large utilities nationwide. Additionally, PG&E presented key findings and strategies at the Common Ground Alliance (CGA), a national nonprofit organization dedicated to preventing damage to underground utilities and promoting excavation safety.

In 2024, PG&E's Damage Prevention Program reported the following results to CGA covering the period 2019 to 2023:

- 26% reduction in total damages due to developments in damage prevention strategies;
- 58% decrease in locate no-marks, dropping from 77 cases in 2019 to 32 in 2023 by expanding locate response effectiveness and accountability; and
- 53% reduction in locate mis-marks, with incidents declining from 49 in 2019 to 23 in 2023.

Future Focus Areas

Based on data provided by PG&E, mapping errors emerged as the leading cause of at-fault damages for PG&E. Maps are a key component to locating pipe, and if a locator is unable to mark a pipe due to map error, it is a PG&E at-fault damage, but not a field locator error. Mapping data accuracy has become a critical factor in preventing excavation-related damages, and PG&E reported to the ISM that it is working on initiatives to address this issue, including:

- Enhanced GIS and mapping verification processes to improve data accuracy; and
- Cross-functional collaboration with engineering, GIS, and damage prevention teams to refine records.

PG&E's Damage Prevention team is seeking ongoing reduction of locator at-fault dig-ins, with a focus on maintaining improvements below the three-year average goal of 102.6 incidents per 1,000 locator at fault dig-ins, expanded excavation safety education and outreach to further engage stakeholders, and performance-based incentives and industry benchmarking alignment, supporting continued adherence to best practices. The ISM will continue to track developments related to mapping accuracy, excavation safety outreach, and damage prevention initiatives. Ongoing data analysis and program assessments will be reviewed to evaluate trends and overall program effectiveness. As PG&E's programs evolve, further updates will be reported in future ISM Reports, as appropriate.

GAS ASSET DATA MANAGEMENT

During the current ISM reporting period, the ISM interviewed PG&E's Gas Data Asset Management (GDAM) team to review its operations and focus areas. This group works to recognize gas data assets on an equivalent level of importance to physical gas assets, providing focus on the structure and implementation of gas data management and governance, and to enable more effective work execution and risk prioritization. Data Assets are one member of PG&E recognized nine Asset Families. Business critical data is defined by PG&E as data vital to the successful operation of the organization and associated with at least one PG&E critical or mission-critical process. According to PG&E, if critical data is not effectively managed, that critical data could pose a significant legal, financial, safety or regulatory risk to the organization.

The PG&E GDAM team published an update to its data asset management plan (AMP) that identifies evolving data asset registry and assessment of data asset quality requirements related to PG&E work execution and data-related risk prioritization. PG&E's AMP includes an overview of critical data assets, reduction/elimination of redundant data, enhancements in risk modeling, quantifying risk reduction, and improved risk forecasting. PG&E maintains a data asset registry (DAR) that lists critical datasets within gas operations, and the AMP identified approximately 1,300 critical datasets for inclusion in DAR. Identifying and validating critical datasets is ongoing, where approximately 130 unique data locations have been identified in multiple data sources and approximately 1,400 critical data elements (CDE) have been identified within the critical datasets. Data quality rules and data health score calculations are in progress for approximately 90 datasets with another approximately 60 datasets under pending certification. PG&E is performing a detailed review of CDE, and reduced the number of critical datasets where PG&E determined redundancy.

PG&E identified multiple transmission and distribution pipeline loss of containment (LOC) gas operation risk drivers referenced within approximately 150 and approximately 220 associated DAR critical datasets, respectively.[58] According to PG&E, risk data quality is not easily characterized as discrete risk, as datasets typically apply across multiple operation risks and processes, thus risk data quality is classified as a "cross-cutting" risk driver. Inadequate data collection, storage, or data accessibility increases the likelihood of risk by reducing the ability to apply trusted data within decision-making. By assuming data quality as a proxy for risk likelihood, improvement of data quality reduces likelihood of risk as an effective gas operation risk mitigation strategy as discussed in ISM Previous Reports.

Within PG&E's Strategic Risk Management Plan risk management process, gas operations applies PG&E's Enterprise and Operational Risk Management (EORM) framework to manage both enterprise and operational risks. According to PG&E, the EORM model promotes greater consistency in risk-informed decision-making across PG&E, providing repeatable and consistent methods to identify, assess, rank, and mitigate risk across its asset families.

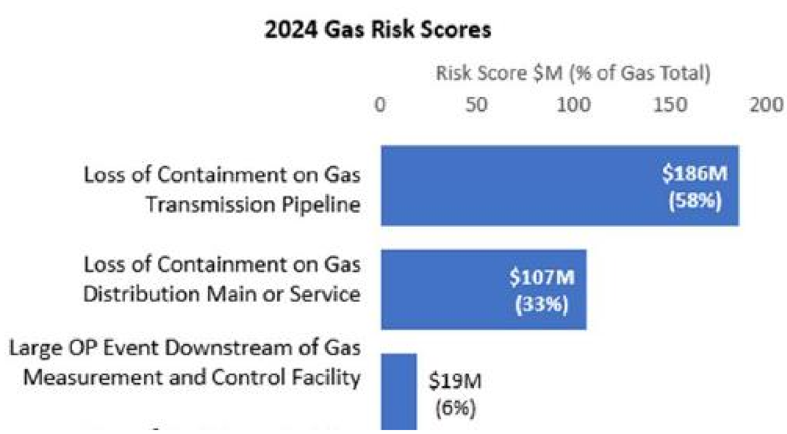

Figure 23: Three Top Gas Operation Risks

PG&E recognizes three top gas operations risks as part of the 2024 Risk Assessment Mitigation Phase (RAMP) Filing, including LOC on transmission pipe, LOC on distribution pipe, and large

[58] One such example of a risk driver would be the threat of external corrosion of the walls of a transmission pipeline. As an example, a critical data element to predict this risk could be the thickness of the pipeline's wall.

over pressure events downstream of gas measurement and control facilities as shown above in Figure 23.

In 2023, PG&E selected a commercial meta-data framework to support calculation of critical dataset data quality. Due to that framework's meta-data management bottlenecks, related system overhead expense, and framework requirement to operate on dataset "snapshots" versus active datasets, PG&E identified a new commercial framework supporting calculation of data quality while also performing the essential function of critical dataset system of record while operating on active critical datasets.

Current meta-data models and their active data connections will be maintained until the new commercial framework is completely operational and represents all active critical datasets. Additionally, eliminating the requirement to synchronize meta-data with active data eliminates data model algorithmic errors and meta-data management overhead to ensure data models and data record synchronization reflect active 'real time' data. The ISM will continue to monitor GDAM's progress in alignment with PG&E's enterprise requirements.

MAXIMUM ALLOWABLE OPERATING PRESSURE

As highlighted in ISM Reports 4 & 5, PHMSA introduced the Mega Gas Rule, effective July 1, 2020, with amendments effective May 24, 2023. The rule mandates the confirmation or reconfirmation of MAOP for pipelines in high and moderate consequence areas by July 2035. During the current ISM reporting period, PG&E provided updates on its MAOP reconfirmation efforts in accordance with the rule, which provides for six methods to reconfirm MAOP: pressure test, pressure reduction, Engineering Critical Assessment (ECA, specified in Section (§) 192.632), pipe replacement, pressure reduction for pipeline segments with small potential impact radius, and alternative technology. PG&E intends to use all six MAOP reconfirmation methods.

PG&E reported that approximately 1,100 miles of HCA Transmission Audit and Integrity compliance work will be conducted for 2025 and 2026. PG&E continues to refine its prioritization of pipeline segments and testing methods, aiming to finalize plans after internal analysis is completed. The ISM has not identified any notable changes in PG&E's MAOP reconfirmation approach and will continue to monitor and review its progress in subsequent reports.

IN-LINE-INSPECTION (ILI) PROGRAM UPDATE

PG&Es overall transmission asset knowledge management plan requires capturing and maintaining traceable, verifiable, and complete (TVC) pipe material records. These records include pipe diameter, wall thickness, grade, and seam type along the pipelines entire length. Beyond placing the pipeline in-service following pipeline construction, pipeline operations may include incremental pipe segment replacements, pipeline segment relocation, and administrative changes of how pipeline records are stored that affect the consistency of TVC compliance.

To support pipeline material TVC compliance, PG&E's 2025 ILI runs with ROSEN vendor will include sensors with traditional ILI tool operations to support pipeline integrity management, MAOP reconfirmation, and pipeline material verification. The ROSEN tool vendor designed new pipeline material ILI tool, RoMat, will measure pipe material properties in high-resolution concurrently with a traditional axial magnetic flux leakage (MFL-A) ILI tool used to measure internal and external pipe metal loss anomalies. The RoMat tool can be mechanically linked to the traditional MFL-A ILI tool during traditional ILI pipe inspection operations eliminating the requirement of separate ILI runs to capture pipe material properties. The RoMat tool suite is designed to operate in a variety of pipeline configurations and conditions from 6-inch to 56-inch pipeline diameters and to directionally accommodate a minimum 1.5 pipeline bend diameter. The ROSEN RoMat tool captures, processes, and analyzes pipeline material data, including pipe material, wall thickness, tensile stress, and yield strength, before delivering the results to the pipeline inspection client. ROSEN reports the tool provides this data with 80 percent certainty, as specified in ROSEN's tool measurement standards.

To meet regulatory compliance for pipeline integrity assessments, PG&E's ILI project schedule estimates of ILI project mileage are as follows:

Table 12: PG&E's ILI Project Schedule (Miles)

Project Year	Traditional Project Miles	Non-Traditional Project Miles
2024	358.25	8.22
2025	514.57	7.31
2026	555.07	9.49

For 2025, 26 traditional ILI projects are scheduled including 17 non-traditional ILI projects. The usual number of annual scheduled Traditional ILI projects is approximately in the low 20's per year. PG&E notes this only shows known work, but has allocated funding to cover up to 9 total miles of non-traditional robotic ILI projects depending on individual project scope development.

Table 13: ILI Gas Transmission Upgrade Project

Project Year	ILI Upgrade Projects
2025	3
2026	4
2027	4
Future	47

As shown in Table 13, PG&E is designing and planning a number of ILI gas transmission upgrade projects over the next several years to improve pipe inspection project execution as included in the chart below. PG&E expects the execution of these upgrades to help create more contiguous ILI project inspection run performance, reducing requirements to run ILI projects utilizing multiple tools, enabling the combination of segments across different concurrent pipe lengths, eliminate reliance on short pipeline segment non-traditional ILI tool runs and utilization of less effective integrity assessment techniques for identified threats.

Appendix D

PG&E 2023 Independent Safety Monitor Report

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PG&E
INDEPENDENT SAFETY MONITOR STATUS UPDATE REPORT

April 3, 2023

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BACKGROUND

In conjunction with California Public Utilities Commission (CPUC) Decision 20-05-053, the Bankruptcy Plan of Reorganization for Pacific Gas and Electric Company (PG&E)[1] and the findings included in the Kirkland & Ellis LLP Federal Monitorship Final Report dated November 19, 2021 (Federal Monitorship Report)[2], through Resolution M-4855[3] the CPUC approved implementation of an Independent Safety Monitor (ISM) of PG&E to fulfill a role that supports the CPUC's ongoing safety oversight of PG&E's activities.

Filsinger Energy Partners, Inc. (FEP) has been engaged to serve as the ISM of PG&E. The ISM contract executed between FEP and PG&E dated January 27, 2022 (the ISM Contract) outlines a scope of work that includes FEP monitoring certain safety and risk aspects of PG&E's electric and natural gas operations and infrastructure. In consultation with the CPUC, the ISM identifies and performs certain monitoring activities associated with areas outlined within the scope of the ISM Contract. The initial areas of focus were designed to take into consideration the findings from the Federal Monitorship Report and provide complementary oversight and monitoring activities that are not unnecessarily duplicative, consistent with CPUC Resolution M-4855.

The six initial focus areas for PG&E's electric operations and infrastructure include aspects of 1) System Inspections and Repair; 2) Vegetation Management (VM); 3) System Hardening; 4) Situational Awareness; 5) Public Safety Power Shutoff (PSPS) and Enhanced Powerline Safety Settings (EPSS); and 6) Implementation of Corrective Action Plans initiated as a result of the Enhanced Oversight and Enforcement Process (EOEP).

For PG&E's gas operations and infrastructure, the six initial focus areas include aspects of 1) Transmission Integrity Management Program (TIMP) and Distribution Integrity Management Program (DIMP); 2) Leak Survey Program; 3) Pipeline Replacement Program; 4) Locate and Mark Program; 5) Pipeline Patrols; and 6) In-line Inspection (ILI) program.

The ISM's Initial Report, hereafter referred to as "ISM Initial Report", covered the period January 27, 2022, through September 30, 2022, and was published October 4, 2022. The ISM Initial Report identified work performed in the above referenced areas during the reporting period and the related areas to be monitored going forward. The following topics were included:

- Critical Spares and Inventories
- Substation Asset Age
- Underground Transformer Asset Age

[1] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M338/K816/338816365.PDF.
[2] https://s1.q4cdn.com/880135780/files/doc_downloads/wildfire_updates/2021/11/1524-1.Exhibit-Monitor-Report.pdf.
[3] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M397/K322/397322603.PDF.

- Training
- Core Leadership Changes
- EPSS Criteria Change
- Infrastructure – Distribution Inspections
- Infrastructure – Field Review of Inspections
- Variability of Distribution Risk Ranking in Model Updates
- Gas Storage Operations
- Pipeline Integrity Management
- Data Management and Recordkeeping

This PG&E Independent Safety Monitor Status Update Report, hereafter referred to as "Q1 2023 ISM Report", covered the period October 1, 2022, through March 31, 2023. It was developed based on the stipulations of the ISM Contract and the reporting directive included within CPUC Resolution M-4855. The Q1 2023 ISM Report is designed to summarize the oversight activities performed by the ISM during the period described and the related observations.

This Q1 2023 ISM Report also includes a summary of potential emerging risks identified during the oversight activities performed during the current reporting period. With respect to potential emerging risks, consistent with the ISM Contract scope, the ISM has documented the initial observations and performed certain initial monitoring activities. Depending upon the observations, in consultation with the CPUC, it may be determined that the ISM will perform additional monitoring activities.

The ISM's role is not to provide suggestions for addressing the issues identified or rank the order of priority or risk. Relatedly, the ISM has only monitored to the extent agreed upon within the confines of the ISM Contract or as otherwise agreed to between the ISM and the CPUC.

The information included in this Q1 2023 ISM Report should be considered a "snapshot" of observations during the current reporting period. The ISM may continue to perform monitoring activities related to certain observations noted herein. Observations may change for various reasons (e.g., additional information becomes available, operational changes are implemented by PG&E, etc.). General facts and information contained within this report have been derived from internal PG&E meetings, presentations, data, and external reports which may not always be footnoted.

ISM REPORT STRUCTURE

As stated previously, the period of the Q1 2023 ISM Report encompasses October 1, 2022, through March 31, 2023. This is consistent with the ISM schedule of report submittals at the end of calendar quarters one and three, with each report covering activities in the previous six months. The compilation of reports summarizes the totality of work performed during the ISM's engagement and should be read as such in order to obtain an accurate depiction of how observations made by the ISM may have changed from period to period.

The following four types of observations are documented within the report:

- Observations from the previous report that are finalized during the current reporting period, where the ISM does not intend to continue monitoring activities unless an issue is brought to the ISM's attention in the future.
- Observations from the previous report that are not finalized during the current reporting period, where the ISM intends to continue monitoring activities.
- Observations from the current reporting period that are finalized during the reporting period, where the ISM does not intend to continue monitoring activities unless an issue is brought to the ISM's attention in the future.
- Observations from the current reporting period that are not finalized during the reporting period, where the ISM intends to continue monitoring activities in the future.

Consistent with the previous ISM report, the Q1 2023 ISM Report is structured as follows:

- General Observations – ISM observations that may have been identified during an analysis or review of information associated with a specific division or function of PG&E (e.g., Electric, Gas, etc.) but may potentially have broader impacts (e.g., corporate wide).
- Electric Operations Observations – ISM observations that stem from specific activities performed by the ISM in specific areas within Electric Operations and which primarily impact Electric Operations.
- Gas Operations Observations – ISM observations that stem from specific activities performed by the ISM in specific areas within Gas Operations and which primarily impact Gas Operations.
- Emerging Observations – ISM observations that have been recently initiated or are planned for initiation in the near future.

GENERAL OBSERVATIONS

CORE LEADERSHIP CHANGES

The Federal Monitorship Report identified "retaining a core leadership team, in the wake of near constant turnover in recent years" as one of the "most salient challenges PG&E faces going forward."

In the previous ISM report, the ISM observed three changes in PG&E's senior leadership (including a new Senior Vice President of Electric Operations, Senior Vice President of Gas Engineering, and Vice President of Electric Engineering, Asset and Regulatory). The ISM interviewed each new leader; each indicated that they did not intend to significantly change the overall priorities established by the previous leadership for their respective areas of responsibility.

These leaders were only in their new roles for approximately one month at the time of their previous interview. The ISM followed up with each during the current reporting period regarding progress toward achieving their operational and safety related priorities.

During the follow up discussions with these leaders, the ISM noted they each: 1) identified what they considered to be the most pressing issues of the respective departments, 2) determined and/or confirmed their areas of focus, 3) had developed initial plans to achieve these goals/objectives, and 4) were in the process of implementing processes to achieve these objectives. A goal for each department was creating processes that were flexible enough to manage potential unplanned work without creating unnecessary impacts to internal/external resources, customers, and the related budgets (including unnecessary cost increases).

During the current ISM reporting period, the ISM observed the following additional senior leadership changes:

- In November 2022, David McCulloch was appointed as Vice President and Chief Marketing and Communications Officer. This position was vacant during the ISM's previous reporting period.

- In January 2023, PG&E created two new senior leadership positions that reported to the Executive Vice President, Chief Risk Officer (CRO) and Chief Safety Officer (CSO).
    - Matt Hayes – Vice President of Enterprise Health and Safety
    - Russ Prentice – Vice President of Wildfire and Enterprise Risk Management

- In February 2023, PG&E announced that Adam Wright, Executive Vice President, Operations and Chief Operating Officer (COO) was moving to a different company.

- As a result of the move noted immediately above, also in February 2023 PG&E announced that, effective March 1, 2023, Sumeet Singh, Executive Vice President, CRO and CSO would transition to the role of Executive Vice President, Operations and COO.

- As part of the transition plan, the CRO and CSO roles were separated.
- Matt Hayes, Vice President of Enterprise Health and Safety, assumed the role of CSO.
- Stephen Cairns, Vice President, Chief Audit Officer, assumed the additional role of Interim CRO.
- A new position, Senior Vice President, Wildfire & Emergency Operations (SVP, WEO) was created and reports directly to the COO. This role is responsible for overseeing the Emergency Preparedness & Response organization residing in Operations, and the team responsible for Wildfire Preparedness & Operations previously in Safety & Risk. In March 2023, the position was filled internally by Mark Quinlan, who was previously Vice President, Electric System Operations.
- The prior Enterprise Risk Management organization within Safety & Risk was split into two organizations as follows:
    - Wildfire Preparedness & Operations will be part of the organization led by the new SVP, WEO.
    - Enterprise & Operational Risk will remain under the Vice President, Enterprise & Operational Risk, reporting to the CRO.
- In March 2023, it was announced that PG&E's Chief Financial Officer (CFO), Christopher Foster, will be leaving to assume a similar position at a different company, effective May 5, 2023. PG&E has named Carolyn Burke as its new CFO, also effective in May 2023.

Additionally, during the current ISM reporting period, PG&E implemented an organizational structure change involving the 10,000-Mile Undergrounding Program. The program was moved from "Engineering, Planning and Strategy" to Operations in order to increase the focus on the operational implementation and scaling of the program. The new organization of "Undergrounding, Vegetation Management and System Inspection" is called "Major Infrastructure Delivery".

During the previous ISM reporting period, the ISM observed that PG&E had initiated a Voluntary Separation Program (VSP) to facilitate staffing adjustments related to system changes and/or business efficiency improvements. During the current ISM reporting period, per discussions with PG&E leadership, the VSP did not significantly impact senior leadership positions nor PG&E's operational safety capabilities.

The ISM will continue to monitor the leadership changes and related potential impacts relative to the areas within the scope of ISM responsibilities.

SUPPLY CHAIN

Critical Spares and Inventories

As discussed in the previous ISM report, the outbreak of the Novel Coraonavirus-2019 (COVID-19) pandemic has impacted the global supply chain of goods and services across numerous industries. Impacts on the U.S. electric and gas utility sectors continue to be experienced into 2023, with lengthened lead-times associated with ordering and receiving various goods, limited availability for unscheduled manufacturing production, and limited quantity of goods available for purchase, which in turn has impacted inventory levels of goods on hand.

In the previous ISM report, several observations related to PG&E specific supply chain issues were identified by the ISM following participation in meetings, document reviews, and follow-up interviews. These observations included: 1) an inability to source quantities of certain supplies that, according to PG&E, "could create risks for [their] Wildfire Mitigation Plan (WMP) commitments"[4]; 2) a shortfall of critical spares within certain electric departments; 3) a lack of equipment required to perform select monitoring activities; and 4) a general lengthening of time required to source supplies.

As part of the ISM's initial review into PG&E's efforts at addressing supply chain issues, PG&E indicated that several mitigation strategies were being deployed across all impacted areas as needed to drive recoveries associated with global supply chain challenges. PG&E stated[5] that their mitigation plans include:

- Partnering with line of business to determine highest priority work and allocating available supply accordingly.
- Referring jobs to available substitute materials where possible to consume surplus inventory and reduce backlog on short materials.
- Requesting additional capacity allocation and prioritization of PG&E orders with suppliers.
- Enhanced communications with suppliers.
- Greater visibility with senior leadership regarding potential manufacturing and/or order delivery performance delays.
- Placing advanced orders ahead of standard lead time to lock in production capacity and expediting critical materials to minimize transit time.
- Partnering with engineering to prioritize and expedite the qualification/onboarding of new sources of materials where PG&E is currently at or exceeding sourced capacity.

[4] Data request response received from PG&E.
[5] Internal PG&E report.

Since the ISM's engagement, it has tracked and observed the effectiveness of these enhanced supply chain management programs in several areas of PG&E's electric and gas operations.

On June 30, 2022, PG&E informed the ISM that it was experiencing material limitations with nine types of electrical equipment, and that there was the possibility that six of its WMP commitments for 2022 were at risk of not being completed by their target dates[6]. Throughout the balance of the year, the ISM observed PG&E's efforts at managing its equipment requirements through focused catch back plans with its suppliers, and through reprioritizing limited equipment supplies within the company. PG&E has represented that by year end all six of these at-risk wildfire mitigation work streams were completed, with the last of these equipment dependent commitments achieved in the final week of the year[7].

Another means by which the ISM has been able to track PG&E's supply chain impacts was through its review of reports on PG&E's emergency and critical spares inventory readiness. These reports include a readiness percentage which takes into account current usage rates and inventory levels, and the ability to replace these materials in a timely manner as used, in order to maintain a minimum safety supply quantity/level.

While supply chain management indicated during an interview with the ISM in July 2022 that PG&E's average readiness percentage for all inventory items has historically been in the 97-98% range, the ISM observed that this percentage had dropped to 95.8% in August 2022, at which time 5.5% of the inventory items were shown with a score of less than 100%. During the current ISM reporting period, the percentage has remained consistent, with the January 2023 report[8] showing an average readiness percentage of 95.6%, and 6.0% of the inventory items having a score of less than 100%. One item to note, during the current ISM reporting period the average planned delivery times have continued to lengthen slightly, from an average across the roughly 3,200 inventory items of 48 days in August 2022 to 52 days in January 2023. While the planned delivery timelines reported for two of the longest lead time items (out of approximately 3,400 inventory items being tracked) increased from 392 days to 532 days during the same period, both of these items were still calculated at 100% emergency readiness when factoring in the quantity of supplies on hand, and their anticipated usage rates, resupply times, and safety stock requirements.

During the previous ISM reporting period, the ISM also started receiving and reviewing a weekly dashboard related to material planning. In August 2022 eight categories of electric materials were being tracked as items of potential supply chain concerns with work impact/delays recorded for seven of these eight categories ranging from two to six weeks, and with two of the categories reported to have sourced capacity for 2022 being below its 2022 demand.

During the current ISM reporting period, the ISM has tracked the progress of PG&E's supply chain management on these electrical items, with each week providing a trend analysis against

[6] Data request response received from PG&E.
[7] Internal PG&E report.
[8] Data request response received from PG&E.

the prior week, a description of the root cause behind the original constraint, the recovery enablers that were being pursued, the owner of the recovery actions, and the estimated recovery date. As noted in PG&E's weekly reports, many of the causes were cited as labor/component and raw material constraints, increase in product demand and corresponding long lead time to ramp up production, and in one instance a quality issue which led to a new design by the manufacturer.

During the current ISM reporting period, PG&E reported progress in addressing and managing its electrical supply constraints. Whereas the trends in August 2022 were primarily for no change or worsening conditions each week, by January 2023 three of the eight categories were removed from the weekly dashboard citing improved conditions for those items, with the remaining five categories showing steady or improving trends. While current work impacts and delays are still forecast at two to six weeks, two of the remaining five categories have estimated full recovery dates in the first quarter of 2023, with the other three estimated to have full recovery dates prior to the end of the second quarter of 2023. The primary recovery enablers that have led to a stabilization of supply chain conditions over this period include the onboarding of new domestic and international suppliers, reallocation of supplies within PG&E, resolution of component delays, and short-term engineering and design variances to allow for modified raw material usage.

Supply chain issues were not having the same impact on PG&E's gas operations as compared to electric operations. During the previous ISM reporting period, the August 2022 Materials Planning Dashboard was tracking eight categories of equipment that were experiencing supply constraints. All eight, however, were still projected to have sourced capacity in excess of their 2022 demand. During the current ISM reporting period, the number of equipment categories exhibiting supply constraints was reduced to only three which demanded extra attention. The focus resided on creating recovery work plans to secure additional suppliers aimed primarily at reducing current work impact/delays that are still reported between two and ten weeks for these remaining three categories.

During the previous ISM reporting period, in addition to the above reports, the ISM also started to receive a supplemental weekly report which tracks the progress on sourcing materials specifically for PG&E's 10,000-mile electric distribution undergrounding program. Since this is a long-term program which requires increasing quantities of materials as the annual mileage of this program increases, this report focuses on ensuring that suppliers will be able to meet PG&E's growing demands. During the current reporting period, the ISM observed that PG&E has taken the following steps to ensure that sufficient quantities of materials are available: 1) conducting requests for proposals for new suppliers, 2) having planning and check-in calls with leadership of its vendors to ensure that ramp up plans are achievable, and 3) in certain instances, touring the factories of key suppliers. For 2023, PG&E has established materials readiness targets for rolling 1-, 3- and 6-month future periods of 98%, 94% and 90% respectively. As of early March 2023, PG&E was exceeding its targets for the upcoming months with readiness scores of 99.3%, 98.0% and 95.3% respectively.[9]

[9] Internal PG&E report.

In the previous ISM report, it was noted that the electric transmission engineering, substation equipment, and asset management group were managing inventory and supply chain activities separately from PG&E's main supply chain group and its Computer Managed Maintenance System inventory tracking systems. The report further noted that several long lead time items were at inadequate critical supply levels. During the current reporting period, the ISM observed that the underground transmission group has put in place a plan to enhance its supply levels over the next three-year period, and that the timing of underground cable inventory replenishments is based on an assessment where areas of higher operational risk are to receive additional critical spare supplies earlier in the 2023-2025 period.

ASSET AGE AND USEFUL LIFE

Asset age commonly refers to how long an asset/piece of equipment has been in operational service, while useful life commonly refers to the estimated length of time equipment can be expected to effectively contribute to operations. Asset age is often one of many factors considered when determining when an asset is targeted for replacement. Other factors may include utilization (e.g., number of times equipment operates), performance (e.g., no, or minimal degradation in operating as expected), asset wear (e.g., amount of corrosion), etc.

The previous ISM report referenced the Federal Monitorship Report, including PG&E's Conditions of Probation, Condition 7, "Asset Age Condition" for "certain critical transmission tower components in High Fire Threat Districts". This was highlighted as a condition for which PG&E needed to provide a reasonable record of age and installation data for those components. PG&E notified the ISM that completion of asset age data collection on all High Fire Threat District[10] (HFTD) transmission circuits by the end of 2022 was off track but was believed to be recoverable through increased resources and a one-month cushion which had been included in the plan.

During the current ISM reporting period, PG&E reported that all requirements of Probation Condition 7 had been met, which included conducting a reasonable data search and recording the age and date of installations of critical components in HFTD. PG&E also developed a Transmission Composite Model and an associated Wildfire Transmission Risk Model V1 which is a component used in the determination of asset useful life. PG&E has stated that it will continue to improve asset data and risk models; however, V1.5 of the model is now expected to be completed and approved by Q3 2023.

As stated in the previous ISM report: 1) the ISM has observed numerous PG&E asset ages that are older than the related industry average useful life and the related PG&E average age of asset failure, and 2) the emerging risk relates to the volume of assets that have the potential to fail within close time proximity to one another.

As also discussed in the previous ISM report, PG&E has stated that asset age is one of many

[10] HFTD includes areas of the State designated by the Office of Energy Infrastructure Safety and CAL FIRE to have elevated wildfire risk, indicating where each utility must take additional action (per GO 95, GO 165, and GO 166) to mitigate wildfire risk. (Source: PG&E's 2022 Wildfire Mitigation Plan Update).

factors considered when determining asset replacement. PG&E uses asset age and other factors (e.g., component type, threats, hazards, environment, etc.) to determine condition and failure risk of assets. Failure risk information is used in conjunction with the consequence of failure data to implement various mitigation activities such as, but not limited to, monitoring, repair, life extension, and replacement.

Substation Asset Age

In the previous ISM report, the ISM observed certain equipment up to 20 years older than the industry average and up to 56% of this equipment exceeding PG&E's average age of failure.[11] The ISM will continue to monitor PG&E's average age of substation equipment and the associated allocation of resources associated with mitigating/remediating the identified gaps.

As noted above, PG&E states that asset age is one of many variables it analyzes to determine potential failure and replacement.

Underground Transmission Asset Age

In the previous ISM report, the ISM reported that underground cable failures can result in long duration outages, especially if conduits are damaged. Further, the ISM observed that 60% of certain PG&E underground transmission assets exceed their useful life.[12] PG&E stated that it intends to purchase certain quantities of assets to serve as spares, including full length cables to avoid unnecessary splicing. During the current ISM reporting period, PG&E reported cross functional processes to prioritize the purchase of additional underground asset spares, and that PG&E does have additional spares of certain transmission cable available that would be utilized in emergencies to address outages. Further, PG&E stated that in addition to asset spares, there are proactive equipment replacement efforts in progress, including but not limited to, replacement programs under Major Work Category[13] (MWC) 72Z[14], and various underground capital replacement projects.

The ISM will continue to monitor PG&E's efforts to increase like-kind inventories as well as determine PG&E's efforts directed toward modernizing their underground transmission cable system.

The ISM will also continue to monitor and analyze the effects that asset age, useful life, and spare equipment – coupled with longer lead times and reduced availability of certain equipment due to the global supply chain issues, have on outages and the related safety concerns.

[11] Internal PG&E report.
[12] Internal PG&E report.
[13] PG&E organizes operational activity and cost forecast by Major Work Category (MWC), for its operational planning, budgeting, and managing purposes.
[14] Replacement programs under MWC 72Z include such things as cable replacement, corroded cable racks, and cathodic protection improvements.

Overhead Distribution Asset Age and Asset Replacement[15]

PG&E's overhead distribution electric system covers an area of approximately 70,000 square miles and is comprised of approximately 161,500 miles of overhead lines, 2.25 million wood poles, and over 669,000 transformers. In order to manage the asset failure risk of these assets, PG&E is heavily dependent on regular condition monitoring. During the current ISM reporting period, the ISM participated in meetings where several PG&E managers reported that a shift in strategy is required as the PG&E distribution asset base ages more towards its end of life, and that elevated investment levels will be required to adequately control and mitigate the associated risks.

Parts of the overhead distribution system are currently stressed or are forecast to become stressed. Examples of this include:

- Over one-third of overhead distribution conductor lines qualify for asset health replacement in the next 10 years.
- While half of the distribution circuits have good reliability, approximately 20% of the circuits are responsible for 50% of the average customer outage duration across the distribution system.
- There is a considerable backlog of distribution asset maintenance and/or upgrade items needing to be addressed, including approximately 120,000 poles tagged for replacement.

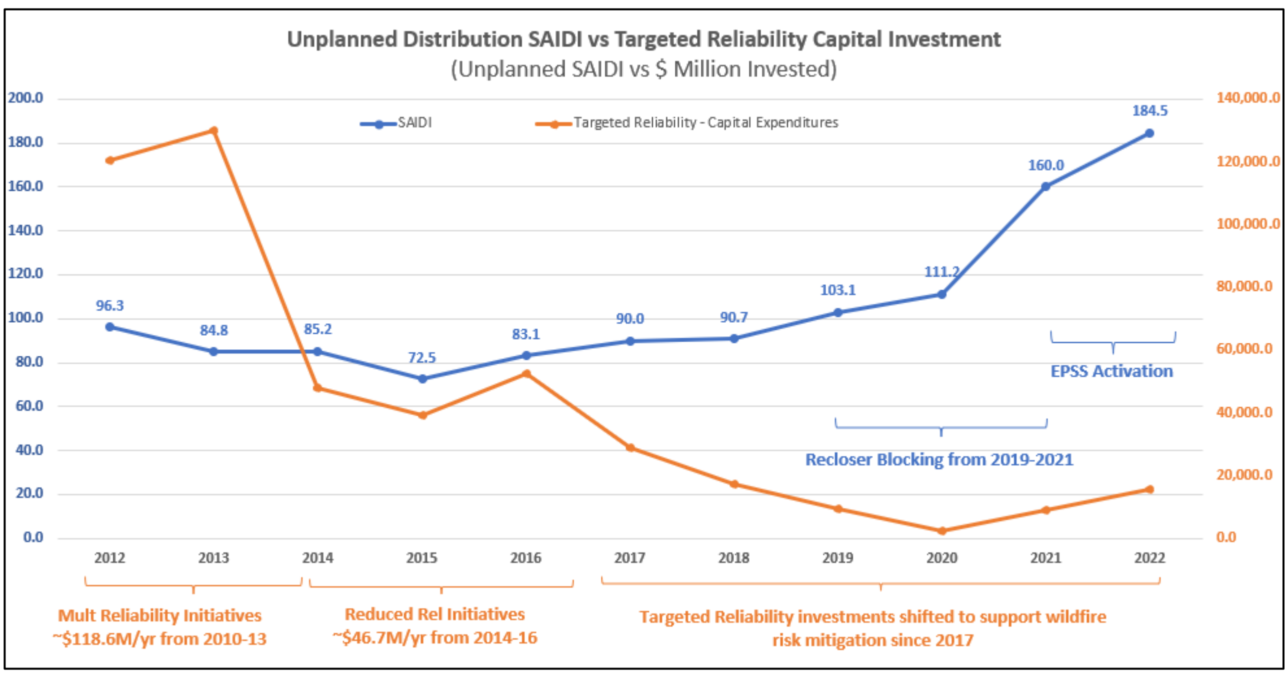

Figure 1. Unplanned Distribution SAIDI vs Reliability Capital Investment

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[15] Unless otherwise noted, all references in this section are sourced from internal PG&E reports.

As seen in Figure 1, and as has been expressed by several PG&E managers during meetings attended by the ISM and interviews held by the ISM, capital expenditures on reliability-oriented projects have seen a drop over the past ten years, with targeted reliability investments shifted to support wildfire risk mitigation since 2017. During the five-year period from 2015 to 2020, unplanned distribution System Average Interruption Duration Index (SAIDI), an outage duration measure, increased by 53% during the period when reliability capital was in decline. The introduction of the PSPS and the EPSS programs in 2018 and 2021, respectively, have also contributed to these rising SAIDI figures. During the current ISM reporting period, the ISM observed that PG&E's unplanned distribution SAIDI increased by an additional 66% since 2020, and PG&E sits in the fourth quartile for SAIDI as compared to all other U.S. based electric utilities. PG&E has stated it is working on improving the SAIDI metric through their Integrated Grid Plan, a multi-year plan and strategy to provide stability, achieve balance, and engage external and internal stakeholders throughout the process from planning to construction. The ISM will continue to monitor the development and implementation of the Integrated Grid Plan.

The ISM also notes that since 2017 the number of reportable ignitions in HFTD attributed to PG&E equipment failure has been in steady decline; from 59 in 2017 to 14 in 2022, for a 76% decrease. As detailed later in this report, the largest contributing factor for this decrease in the last two years has been the introduction of EPSS enablement across all of PG&E's HTFD distribution circuits in 2022.

While reducing wildfire risk is a high priority for PG&E, the increase in the overall number and duration on unplanned outages could have financial and safety impacts on PG&E's customers (see the EPSS section further detailing the number of outages that have been impacting sensitive customers such as Medical Baseline, Life Support and Critical Customers, as well as hospitals and schools).

Overhead conductors have been responsible for 101 (55%) of the 183 equipment failure ignitions reported in the High Fire Risk Area[16] (HFRA) between 2017 and 2022. PG&E has indicated that it believes "Wire down rate is a key indicator of public safety. Wire downs per year has stayed steady over the past five years. However, we expect the number of wire downs to increase as conductors are aging faster than the replacement rate." Determining the age of PG&E's conductors has been difficult, and PG&E has reported that age data is missing for 53% of its primary conductors, while secondary conductors have 88% of their ages missing. While age is only one factor in determining conductor failure, this missing data limits the predictive power of PG&E's risk models. (Note: other factors can include, but are not limited to, corrosion, geographical location, high fault currents, number of fault currents, and number of splices).

PG&E has proposed using the guardrail approach to asset lifecycle management for primary overhead conductors. This is a flexible approach that establishes a targeted asset age-base to maintain. Therefore, when the age-base of the assets is above or below the guardrail, PG&E reduces or increases the number of assets replaced in order to maintain the targeted asset age-

[16] HFRA is mapping terminology that aligns with other California utilities' use of maps supplemental to the High Fire Threat District (HFTD) Map. (Source: PG&E's 2022 Wildfire Mitigation Plan Update).

base. For primary overhead conductors, PG&E has established the targeted age-base to maintain as 100 years. At this age, the sustainable rate of replacement would be approximately 800 miles per year (80k miles/100 years). In comparison to this guardrail rate, over the past seven years (as seen in Figure 2) the miles of proactive replacement of deteriorated conductor have averaged approximately 40 miles per year.

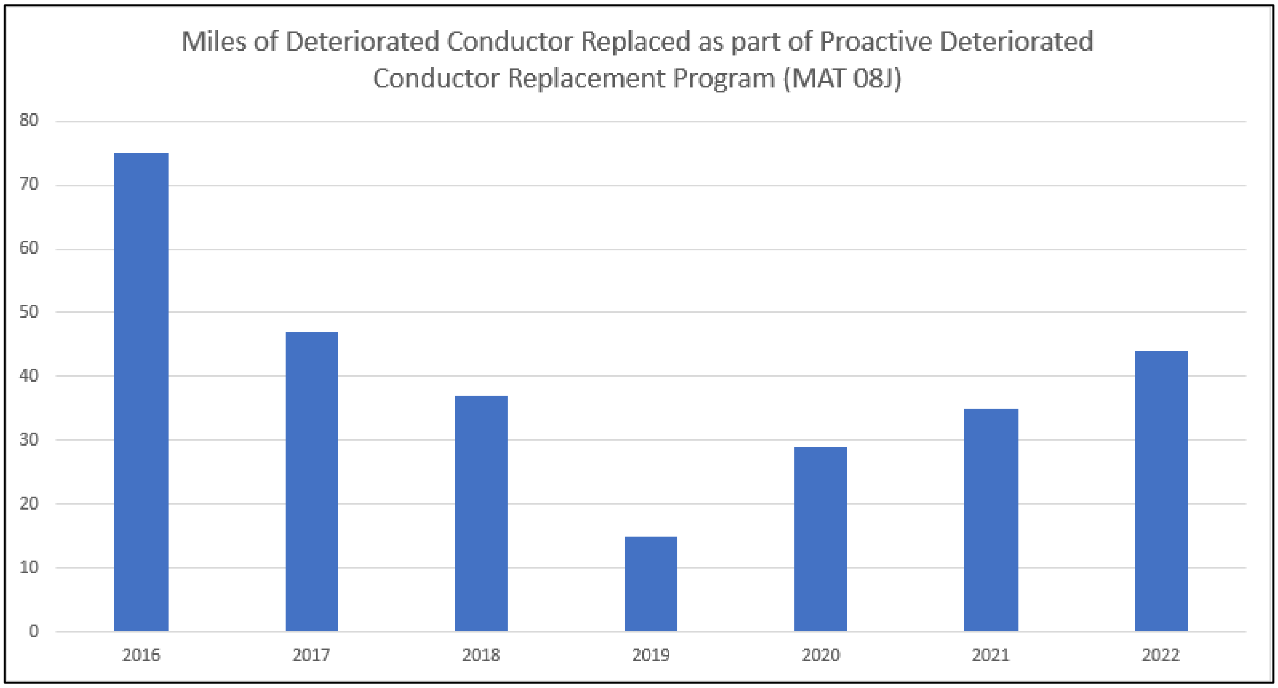

Figure 2. Deteriorated Conductor Miles Replaced

A similar situation exists with poles, where pole failure rates jump approximately ten-fold as the pole population reaches approximately 80 years in age. PG&E has noted that the guardrail approach to asset lifecycle management for primary overhead poles would be to maintain the age of the pole asset base at 80 years. At this age, the sustainable rate of replacement would be approximately 28,000 poles per year (2.25M/80 years). In comparison to this guardrail rate, over the past seven years, as seen in Figure 3, PG&E has been increasing the number of deteriorated structures replaced with open tags per year from a low of approximately 6,000 in 2016 to approximately 19,600 in 2022, with the average over this seven-year period of approximately 12,000 per year.

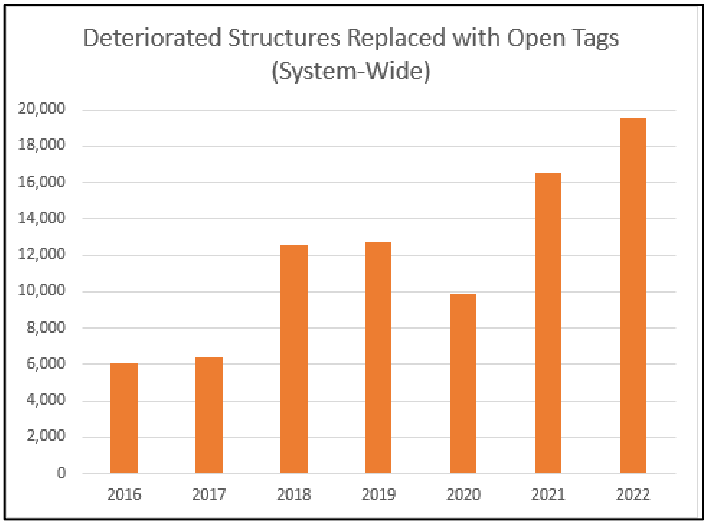

Figure 3. Number of Deteriorated Structures Replaced with Open Tags

For both the conductors and poles, PG&E has noted that the proposed guardrail levels may be inadequate, and that "given the aging population and need to also prioritize locations with other key risks, significantly higher ramp up would be required."

In meetings attended by the ISM, concern was expressed by PG&E leadership that the magnitude of capital needed for asset replacement programs was far in excess of the amount of capital believed to be available.[17]

According to PG&E leadership, asset replacement programs have been continuously reprioritized for other higher risk programs (e.g., wildfire risk management), and given the aging asset base, there is a need to prioritize proactive replacement of assets. As examples, personnel cited that there are approximately 150,000 open pole corrective maintenance tags and approximately 327,000 open non-pole corrective maintenance tags in the system (of which approximately 90,000 and 80,000, respectively, are in HFTD).

In response to a requirement by the Office of Energy Infrastructure Safety (Energy Safety) in a Revision Notice, PG&E has refocused its efforts on addressing its asset backlog, including developing strategies for managing wear-out failures. These strategies include:

- Continuation of regular condition-based monitoring (e.g., ground inspections, pole treatment testing, infrared).
- Ramped up replacement of aging assets (Integrated Grid Planning).
- Deployment of the following reactive asset management strategies:
    - Fail safe (e.g., Downed Conductor Detection (DCD))
    - Precision inspection tools (which minimizes human judgement)

[17] Internal PG&E meeting discussion.

- Real time monitoring and analysis.

Several of these work streams have recently been introduced, such as the Integrated Grid Plan (an emerging item planned for future monitoring) and DCD (described in the EPSS section of this report). The ISM will continue to monitor PG&E's overhead distribution asset management strategies as they continue to evolve.

CONTRACTOR MANAGEMENT

In the previous ISM report, the ISM observed that PG&E substantially relies on its contract workforce to perform wildfire mitigation efforts with approximately two-thirds of PG&E distribution inspectors being contractors in 2022. In 2023, PG&E is changing its system inspection work plan (see section on Distribution Inspections) which will both reduce the number of HFTD structures receiving ground inspection and spread out the time over which its HFTD inspections will be conducted. PG&E has stated it believes this will result in a reduced dependence on a contractor workforce and an increase to risk mitigation as inspection schedules are shifted to address assets based on risk.

Training

In the previous ISM report, the ISM performed certain activities to monitor contractor training and stated that the ISM would continue to monitor these training activities and the related results.

During the current reporting period (and into the next reporting period), the ISM is continuing to observe certain contractor management activities (e.g., reviewing field inspections, analyzing errors/corrections, monitoring enhancements and commitments, conducting interviews, observing the 2023 trainings, etc.). The ISM will continue to monitor these training initiatives and the related results.

Vegetation Management

During the current ISM reporting period, the ISM held interviews with various vegetation management (VM) contractors who perform tree-work, pre-inspection work and work verification for PG&E. During the interviews, contractors reported that they were instructed to halt routine work due to budgetary constraints well before the end of 2022 (as early as November 1). The contractors indicated that in most years they are required to halt VM work prior to the end of the year. However, in 2022, the contractors stated the work stoppage was earlier than usual and occurred with minimal notice. Additionally, some of the VM contractors noted that PG&E halted "wood management"[18] in the later part of the year. Each of the contractors said that, as a result, it either laid-off employees or had to find other work for them to perform to avoid losing qualified resources. PG&E has stated that it was able to secure all necessary contract resources for their 2023 work plan.

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[18] Wood management" allows the contractor to haul off large tree trunks when the customer allows the removal of hazard, dead, and/or dying trees.

Additionally, the VM contractors described a lack of communication between the PG&E VM Construction group, the PG&E VM field organization, and the VM contractors. While the contractors indicated they have very good relationships and communications with the PG&E field organization, they said there seemed to be little or no communication between the other VM groups charged with making all VM decisions.

The ISM held interviews with PG&E leadership regarding these issues. PG&E described that budget is one of many factors which goes into its decision-making process. PG&E stated that all 2022 vegetation management compliance and Wildfire Mitigation Plan work met or exceeded original commitments, and these programs were not stopped due to budgetary constraints. It instead stated that the halting of work at the end of 2022 was due to the early completion of compliance work for 2022. Additionally, PG&E explained its intent is to build more stable and predictable workplans. PG&E stated its goal is to work collaboratively to reduce risk and reiterated that contract resources are flexible and can be adjusted based on business need. PG&E further stated that it welcomes the contractors' feedback about how to improve its communications, including the transparency of its decision making, and will take those concerns into account in 2023 and future work years.

During the current ISM reporting period, the ISM observed that in 2022 and past years, the VM contractors were under a "defined scope" contract with PG&E, which allowed a contracting company to manage an area at a given annual fee (with some allowance for "add-in" tree work). While the defined scope contract was set for a five-year contract term, PG&E is terminating the contract early to move to a "unit price" contract. "Unit pricing" sets a specific price for the various types of tree pruning, removals, wood management, etc.

Finally, during the current ISM reporting period, PG&E notified the ISM that it was ending its Enhanced Vegetation Management (EVM) program at the end of 2022. Additionally, it was noted that the 2023 VM budget has been reduced to $1.4 billion from $1.8 billion in 2022. However, the overall wildfire budget is expected to remain constant at approximately $6 billion[19], although it will be allocated differently to reflect PG&E's risk-informed shift to operational mitigations like EPSS, Downed Conductor Detection (DCD), and System Hardening. One of the results of this shift is that fewer VM contract resources will be needed in 2023. PG&E has stated it has identified operational efficiencies that will be addressed using additional internal staff rather than contractors. PG&E has provided the ISM an update of these operational programs and the ISM requested that PG&E provide its VM guidelines that address any new VM wildfire mitigation strategies in light of the ending of the EVM program.

[19] PG&E's 2023-2025 Wildfire Mitigation Plan submitted March 27, 2023; Table 4-1, "Summary of WMP Expenditures".

ELECTRIC OPERATIONS OBSERVATIONS

ENHANCED POWERLINE SAFETY SETTINGS (EPSS) PROGRAM

2022 EPSS Program Overview

EPSS is a program that increases the fault detection sensitivity on enabled powerline circuits such that when a change in current on the EPSS enabled powerline is identified, the EPSS equipment will quickly deenergize the powerline. In the previous ISM report, the ISM observed that following the implementation of a pilot EPSS program in 2021, PG&E made the decision to expand its EPSS program in 2022 to encompass all HFRA distribution circuits in its service territory. EPSS enablement is designed to reduce the risk of wildfires (which PG&E has indicated is one of its highest priorities). While PG&E's EPSS and its PSPS programs both provide the benefit of ignition and wildfire reduction, their use also correlates with increasing average customer duration of unscheduled and planned outages (in the event of EPSS and PSPS events, respectively) for its customers that can also result in other types of public safety concerns.

Due to the combination of reduced spending on reliability related capital programs in order to shift spending more towards wildfire mitigation programs (as was noted earlier in this report) and the introduction of EPSS, PG&E's average unplanned distribution SAIDI has more than doubled over the last five years, placing PG&E in the fourth quartile for reliability in comparison to other U.S. based electric utilities.[20]

In the previous ISM report, the ISM observed that Energy Safety requested that PG&E take the following actions in Revision Notice #22-32 and Revision Notice #22-12: 1) explain how it will analyze EPSS deployment and modify settings; 2) reassess customer impacts associated with more widespread use of EPSS; 3) explain its EPSS customer impact mitigation plan; 4) detail its customer outreach plan; 5) present an EPSS staffing and resourcing plan; 6) detail an EPSS benchmarking plan; and 7) submit monthly EPSS data reports through the end of 2022. The ISM did not review PG&E submissions associated with these seven requests from Energy Safety as doing so would be unnecessarily duplicative in nature. The ISM has, however, tracked the data provided in the monthly EPSS data reports, conducted follow-up interviews with senior management, and requested and reviewed supplemental data to better understand root causes of certain types of EPSS related outages, restoration policies, and other actions that PG&E has been conducting through 2022 aimed at reducing the impact of these EPSS related outages on its customers.

From a wildfire mitigation point of view, the EPSS pilot program in 2021, which covered approximately 45% of the circuits in HFTD, saw a 74% reduction in CPUC reportable ignitions on EPSS enabled circuits as compared to the prior 2018-2020 three-year average. The 2022 program, which expanded coverage to all of the HFTD circuits, in comparison experienced 31 CPUC reportable ignitions on EPSS enabled lines in HFTD, which was a 68% reduction in CPUC reportable ignitions in HFTD where EPSS settings were enabled. Note that this 68% reduction

[20] EIA Annual Electric Power Industry Report, Form EIA-861 for 2021.

calculation for 2022 versus the 2018-2020 three-year average incorporates weather normalization such that PG&E did not include ignitions in the denominator (2018-2020 average) where, based on historical meteorology data, it estimated that it would not have had EPSS enabled given criteria in place at the same time of year in 2022.

Of these 31 reportable fire ignitions on EPSS enabled circuits in HFTD in 2022, all of the fire sizes were reported at less than 100 acres in extent, and PG&E's average response time for these 31 fire ignitions was 49 minutes.[21] Across all of HFTD, including times when EPSS was both enabled and disabled, total CPUC reportable ignitions in 2022 were 89 versus the three-year average prior to the start of any EPSS enablement of 143.

For 2022, 574 PG&E circuits experienced a total of 2,375 EPSS outages, with approximately 2.1 million customer outages. The ISM observed that during the year, 58% of the customers (approximately 1.1 million) serviced by these EPSS enabled circuits experienced no outages, while 42% (approximately 770,000 customers) experienced one or more EPSS outage. Of these 770,000 customers, approximately 283,000 experienced only one outage, 365,000 experienced two to four outages, 131,000 customers experienced five to nine outages, and approximately 8,100 customers experienced ten or more outages, with one of the EPSS enabled circuits experiencing 20 EPSS outages in the year.

PG&E has been tracking EPSS outages experienced by customers with special sensitivity to outages. The ISM observed that of the approximate 2.1 million customer EPSS outages during 2022, approximately 135,000 of these customer outages were classified as Medical Baseline, 94,000 as Life Support, and 35,000 as Critical Customers. PG&E has also identified that there were 185 hospital EPSS outage events and 4,573 school EPSS outages during the year.

During the peak in September 2022, approximately 37,000 distribution miles were EPSS enabled on approximately 760 circuits, covering a peak of just under 1.3 million customers at any one time. In addition to covering circuits in the HFTD and HFRA areas, in September 2022, PG&E also approved enabling EPSS in an EPSS buffer zone under minimum fire potential conditions, where a fire, up to one mile distance outside the HFRA boundary that traverses burnable fuels, has the potential to spread into a high fire threat district.

Additionally, during 2022, to enhance its EPSS program, PG&E also began implementing two new technology operational mitigations: 1) Partial Voltage Detection (PVD) — a Smart Meter alarm notification automatic service to distribution control centers, and 2) Downed Conductor Detection (DCD) — a protective relay enhancement.

PVD detects low voltage service to customers using PG&E's SmartMeter network, which covers approximately 90% of HFRA miles. The use of PVD was initiated in June 2022, and a total of 36 partial voltage outages were experienced with an average response time of 11 minutes through the end of 2022.

DCD uses electrical sensor information and software to identify the presence of specific

[21] Internal PG&E report.

electrical characteristics (or patterns) produced by arcing conductors with the earth's surface, thus initiating trips on circuit interrupting devices. A total of 16 DCD outages occurred in 2022. At the end of 2022, PG&E had DCD capability on 411 devices covering 5,372 miles (of which approximately 3,700 miles are in the HFRA), with plans to add 507 additional devices in 2023 and an additional 595 devices in 2024. This would increase the HFRA coverage to approximately 20,500 HFRA miles where DCD enablement is feasible. Prioritization of the DCD implementation is being based on the WDRM V3 risk model.

Table 1 provides an overview of the 2,375 EPSS outages broken down by identified cause, and Figure 4 provides a breakdown of the cause type as a percentage each month for the more active May to November period. As seen in Table 1 and Figure 4, nearly half of the outages occurred without an identified cause, with all cause types generally seeing a consistent percentage throughout the year.

Table 1. EPSS Outages by Cause–2022[22]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD	Percent
3rd Party			1	1	9	42	38	40	43	39	12		225	9.5%
Animal			1	4	16	67	76	86	61	71	9		391	16.5%
Company Initiated					8	15	15	25	19	18	6		106	4.5%
Environmental/External						4	1		3	1	3		12	0.5%
Equipment				2	28	60	28	58	75	24	18		293	12.3%
Unknown	1		1	12	63	170	180	208	226	139	77	6	1083	45.6%
Vegetation				4	15	59	43	39	61	28	14	2	265	11.2%
	1		3	23	139	417	381	456	488	320	139	8	2375	

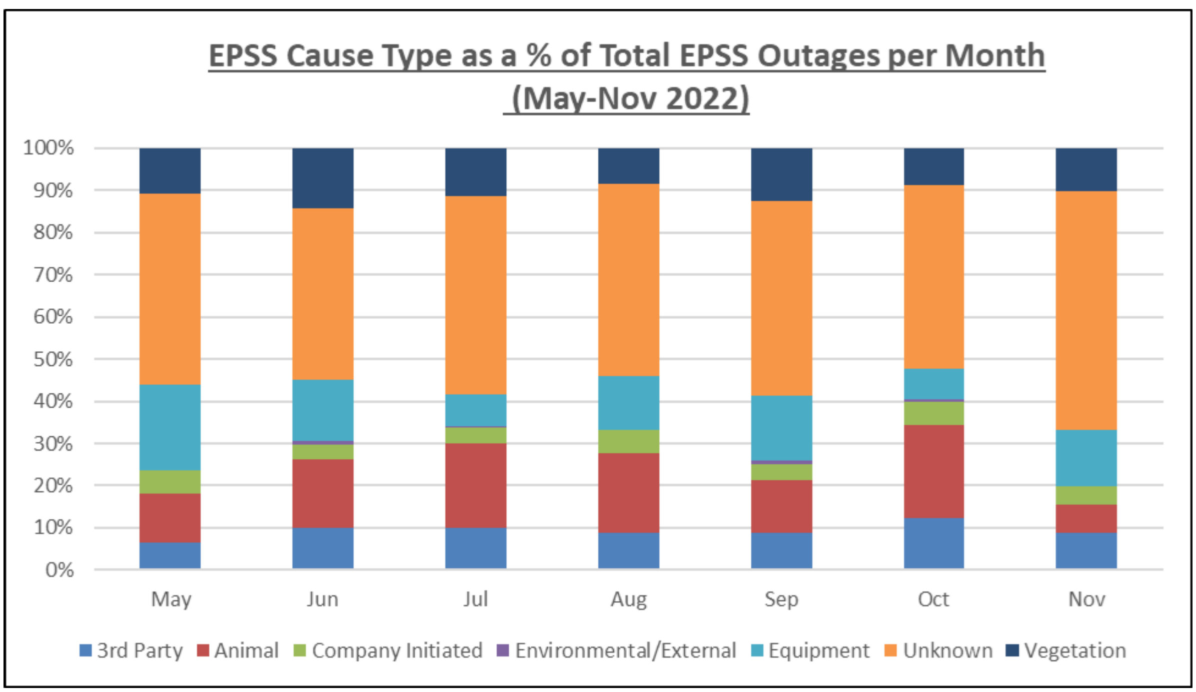

Figure 4. EPSS Outages by Cause – May through November 2022 [23] *(calculated as %)*

[22] PG&E report to CPUC.
[23] Ibid.

In an interview with the ISM, PG&E personnel described that the 45.6% "Unknown" cause for EPSS outages in 2022 was approximately 10% higher than what normally is experienced for outages with no cause attribution on these same lines without EPSS enablement. PG&E personnel indicated that the likely causes for most of the "Unknown" EPSS outages are bird, animal, or tree branch contacts where the patrols are unable to find any evidence of such contacts.

Non-EPSS enabled circuits normally have auto-reclosing enabled. This assists in reducing the number of "Unknown" outages in two ways. While momentary contacts from bird, animals, or tree branches might cause an EPSS circuit to trip and lead to an "Unknown" cause determination, if the same brief contact occurs on a non-EPSS enabled line, these lines would auto-reclose and quickly restore service, with no evidence of the contact. With auto-reclosing, blown fuses also allow for sectionalizing of the faulted area. Such sectionalization, along with the use of fault indicator sensors, can narrow down the area that needs to be patrolled and searched for a cause, increasing the opportunity for PG&E to identify the source of the power interruption.

PG&E personnel also indicated that additional targeted vegetation management (as described later in this report) on EPSS enabled circuits should help reduce both vegetation contact (11.2% of 2022 EPSS outages) and "Unknown" cause EPSS outages in the future, as will their efforts at focusing future tree work on species that are more prone to shed branches in higher winds. Finally, PG&E personnel indicated that the EPSS group has been allocated an additional $50 million in funding. This additional funding will be directed to targeted vegetation management and other activities aimed at reducing "Unknown" outages (e.g., avian guards, critter animal protection) as well as other customer resilience activities such as battery purchases.

Further information regarding PG&E's new Vegetation Management for Operational Mitigation program aimed at reducing vegetation caused outages on EPSS enabled circuits, as well as the ISM's investigation into the root causes behind EPSS outages attributed to company initiation (4.5%), are presented later in this report.

As was noted in the prior ISM report, given the increase in EPSS-enabled miles, the change in EPSS enablement criteria, and the projected increase in customer impact as a result of increased usage of EPSS in 2022, the ISM requested information on the cost/benefit analysis behind the decision-making process. PG&E noted that while it had originally calculated a Risk Spend Efficiency[24] (RSE) for EPSS settings of approximately 103-105 (based on the 2021 EPSS pilot data of ignition reduction), PG&E had not conducted any updated RSE calculations prior to implementing its EPSS enablement criteria changes in June 2022. PG&E noted that it was awaiting the conclusion of the 2022 full expansion year before recalculating a new RSE for the

[24] Risk Spend Efficiency (RSE) is a calculation of the net present value of ((Risk Reduction X Lifetime of Benefit) / Total Cost); similar to a cost/benefit analysis. Additional information on PG&E's approach for computing RSE for wildfire mitigations measures can be found in section 7.1.4 of its 2023 WMP. PG&E's 2023 General Rate Case Prepared Testimony Exhibit 4 Table 3-3 includes RSE scores for its distribution wildfire mitigation initiatives. As a point of reference, Table 3-3 lists an RSE of ~6 and ~5 for overhead hardening and undergrounding, respectively.

expanded and modified program.

During the current ISM reporting period, PG&E completed the updated RSE analysis and has indicated that its updated RSE for EPSS is now calculated at approximately 171, based on 2022 EPSS data and forecasted end-of-year program financials. PG&E has attributed this change in RSE primarily due to lower outage reliability impacts than originally forecast, and projected 2022 program costs coming in lower than forecasted in the 2023 General Rate Case Supplemental Filing and 2022 Wildfire Mitigation Plan (WMP).

EPSS Response and Restoration Times

During the current ISM reporting period, PG&E reported[25] that on average 877 customers were impacted by each of the 2,375 EPSS outage events in 2022. With each EPSS outage, PG&E has been able to restore many of its customers earlier in the restoration process based on the event location being narrowed and isolated, with the remaining customers having to remain without power for the full duration of the restoration process. PG&E has reported that for 2022 its overall EPSS Customer Average Interruption Duration Index (CAIDI) was 173 minutes, meaning that for the 2.1 million EPSS customer outage experiences, the average restoration time was just under three hours.

As seen in Table 2 and in Figure 5, over the course of 2022, PG&E was able to reduce both the average time to restore 100% of the customers who experienced an EPSS outage ("Full Restoration Time") and the average EPSS outage time experienced by a customer ("EPSS CAIDI").

Table 2. 2022 EPSS Outages[26]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
EPSS Outages	1		3	23	139	417	381	456	488	320	139	8	2375
Avg. Full Restoration Time/EPSS outage (min)	284		521	409	407	431	327	326	343	291	368	96	
EPSS CAIDI (min)	187		209	199	212	193	182	177	164	151	166	87	
CESO/EPSS Outage	129		405	509	715	928	906	970	968	701	692	467	
Count of Full Restoration Times > 12 hours			1	3	24	70	50	43	65	38	23	1	318
As a % of EPSS outages					17.3%	16.8%	13.1%	9.4%	13.3%	11.9%	16.5%	12.5%	13.4%
Count of Full Restoration Times <=60 min			1	2	9	20	30	25	40	25	21	5	178
As a % of EPSS outages			33.3%	8.7%	6.5%	4.8%	7.9%	5.5%	8.2%	7.8%	15.1%	62.5%	7.5%

[25] PG&E report to CPUC.
[26] Ibid.

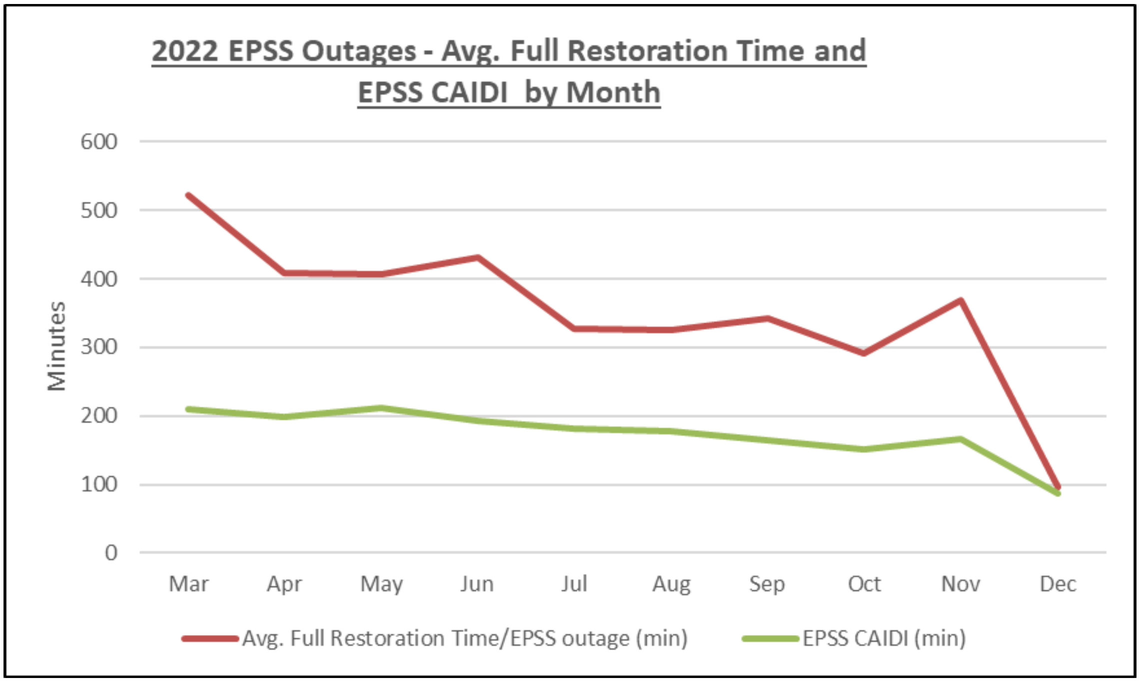

Figure 5. 2022 EPSS Outages – Average Full Restoration Time and Average CAIDI[27]

One of the contributors in achieving more rapid restorations was the expanded installation of fault indicators, which allows the patrolling personnel to more quickly identify the section of the line which was the location of the EPSS outage.

Another contributing element to this trend was PG&E's efforts over the course of the year to reduce the time it took for its staff to respond to the outages and have personnel on site to investigate the cause of the outage, and if required, to patrol the impacted distribution lines. PG&E set a target at the beginning of 2022 to have its personnel on site within 60 minutes of the EPSS outage in excess of 80% of the time. PG&E was able to meet its target, with a 2022 average of 88% of responses meeting this 60 minute or less target.

During the early months of the year, several divisions were unable to consistently meet this target, with reasons for failing to meet the target cited as extended travel times (employees not being in the vicinity of the location or stationed near remote areas), difficult terrain, resource constraints and crew availability, or staff not responding until morning for outages that occurred during the night, which as previously noted was experienced in the early months of the year and has been mitigated. In order to improve average response time, PG&E undertook root cause analysis with each of the underperforming divisions and came up with specific plans to improve performance. Prior to the introduction of the root cause analyses (RCA), the average restoration time was 188 minutes; post-RCA, the average restoration time was reduced to 157 minutes with more uniform consistency across all operating divisions in achieving the targeted response time.

As part of its review, the ISM performed monitoring activities to determine whether there were

[27] Ibid.

any trends in longer restoration times in excess of 12 hours duration. As seen in Table 2, the monthly figures fluctuated evenly around the annual 13.4% level. As part of its monitoring, the ISM also reviewed the circumstances behind several of the longest duration outages. In September 2022 the ISM selected 15 longer duration outages (the ten longest plus the next five longest animal and third party caused outages), ranging from 20 hours to 10 days, for review and requested from PG&E a description of the circumstances behind each of the restorations. The information provided by PG&E from the related data request[28] indicated many of the long duration outages involved unique circumstances of weather, access, rugged terrain, and fire activity.

The ISM also noted that, on average, 7.5% of the outages on EPSS enabled circuits were fully restored within 60 minutes. In order to understand PG&E's restoration procedures, the ISM requested and reviewed PG&E's EPSS outage patrol and restoration procedures. The ISM observed that effective in November 2022 PG&E amended its EPSS restoration procedure. A change which was included in this new policy is, "*IF picking up or dropping load during planned switching is determined to be the cause of the EPSS outage, THEN the DO [Distribution Operation] may restore the outage without conducting a patrol.*"[29] Under the original policy, all EPSS outages required patrolling. This change allows PG&E the ability to restore these specific outage instances faster.

To monitor the rapid EPSS outage restorations and to observe whether PG&E followed its EPSS restoration procedures, in September 2022 the ISM also requested that PG&E provide a description of the circumstances behind 20 short duration EPSS outages (the 15 shortest plus the next four shortest of "unknown" cause plus the shortest vegetation caused outages), ranging from 7 to 37 minutes.

The information provided by PG&E from this data request indicated that EPSS restoration procedures were not followed in one of the selected restorations for an "Unknown" cause outage. PG&E indicated that this incident occurred early in the 2022 EPSS season, and that the operators inadvertently followed the normal restoration procedure, which did not require a physical patrol of the line in that circumstance.

After PG&E's further investigation of the selected EPSS related outages, PG&E removed three "Unknown" cause outages from the EPSS outage list, citing two instances as incorrect flagging of the outage in its system, and noting that one outage occurred after EPSS-disable instructions were issued, but before the circuit was actually EPSS disabled.

As a follow-up, the ISM also requested information on how PG&E records incidents where EPSS restoration procedures were not followed. PG&E provided copies of its logs for such events, and an example of a Corrective Action Plan (CAP). One other incident was noted in the logs where the EPSS restoration procedure was not followed in October 2022. In this instance, the ground patrol only took place within HFTD, whereas the procedure required patrolling the protection zone both within and outside HFTD. The CAP for this incident involved the issuance

[28] Data request response received from PG&E.
[29] Ibid.

of supplemental documentation to the inspection group, and discussions with the specific operator and supervisor.

Company Initiated EPSS Outages

During the current ISM reporting period, the ISM also requested a description of the circumstances behind 65 EPSS outages that were identified as "Company Initiated". These outages were further subdivided into the eight categories included in Table 3.

Table 3: Company Initiated EPSS Outages through 9/5/2023[30]

CI	**65**
Construction Activity/equip, company	12
Contact with High Voltage, company	1
Coordination failure	18
Dig in, company	1
Improper Construction	1
Operating error	5
Personnel, company	25
Return Circuit Normal	2

The information provided by PG&E from the related data request[31] indicated that PG&E was aware that its staff and operations were the cause of the outages. Restoration times in these instances were much quicker (average CAIDI of 103 minutes) since in many instances staff were already on site. In three instances, after further review, PG&E indicated that it was changing the cause from "Company Initiated" to "Unknown". These company-initiated outages were cited as the cause for 4.5% of the EPSS outages during the year and the number of these types of outages remained between 4% and 6% each month throughout the year.

During interviews with the ISM, PG&E staff noted that they do not expect the number of company-initiated outages to decrease in the future. This is because most of the outages occur during tap line work where planned clearances which require dropping or picking up customer load as work progresses (or is completed) causes the EPSS protective device to trip due to the sensitivity of the setting. When doing normal switching operations, however, PG&E indicated that it disables EPSS in advance in order not to cause an outage.

The ISM will continue to monitor response/restoration times and resource allocations, as well as their combined impacts on customer outage durations as the EPSS program continues.

INFRASTRUCTURE OBSERVATIONS

Distribution Inspections

In the previous ISM report, the ISM stated that for the past three years, as part of its annual WMP commitments, PG&E has been inspecting 100% of all HFTD Tier 3 distribution structures

[30] Ibid.
[31] Ibid.

annually, and one-third of its HFTD Tier 2 structures, as part of a three-year inspection cycle that began in 2020. For each of these past three years, PG&E's WMP commitment was to complete its HFTD inspections by July 31 of the respective year. In the previous ISM report, the ISM reported that in 2022, due to inspections not beginning until March, delays in transitioning to a single party contractor, and contractor related delays, PG&E was required to increase its inspection volume from approximately 15,000 inspections/week in April 2022 to a peak of 40,000 inspections/week by July 2022 in order to meets its July 31 WMP target. This push to meet its WMP target date also required PG&E to rapidly expand and train its contractor workforce active in the HFTD areas from 188 inspectors in April to 374 in July. With these additional contractors, and with many contractors working several weeks without interruption during June and July, PG&E reported that it achieved its WMP distribution inspection target in the final week of July.

Both PG&E and the ISM are conducting further analysis on the effectiveness of the inspection program in being able to reduce wildfire risks, and on the rates with which both PG&E's employees and its contractors have been able to identify conditions that could lead to equipment failure and/or ignition risk. This ongoing work by the ISM includes the impact that rapid escalations in inspection rates, such as what occurred in 2022, may have had on deficiency identification rates. The ISM anticipates being able to present the results of both PG&E's internal analysis, as well as its own independent observations, in its next ISM report.

For 2023, PG&E is implementing several distribution inspection program modifications that are expected to help reduce increases to short term staffing like those experienced in 2022. These include shifting to a more risk-informed approach to its inspection planning and spreading out inspections of its HFTD inspections throughout the entire calendar year period.

PG&E's latest plan presented to the ISM is to conduct ground inspections on a total of over 230,600 higher-risk HFTD distribution structures in 2023, which is a reduction from the roughly 398,000 HFTD structures which received ground inspections in 2022. Aerial drone inspections, which covered approximately 7,000 HFTD structures in a 2022 pilot program, are currently planned to increase to 37,000 higher risk HFTD structures in 2023.

In addition to reducing the number of structures planned for inspection in 2023 (while increasing the 'eyes on risk'[32] level from 55% in 2022 to 60% in 2023), PG&E is also intending to expand the time frame over which its HFTD inspections will be conducted. In 2023, PG&E intends to inspect those HFTD structures with wildfire consequence risk scores[33] classified as extreme, severe, and high (collectively, approximately 42,400 structures) by July 31, those classified as having a medium risk (approximately 30,000 structures) by September 30, and those classified as having a low risk (approximately 162,000 structures) by December 31. PG&E informed the ISM that changes to the 2023 workplan were driven by observations,

[32] "Eyes on risk" refers to the percent of the cumulative risk score of the Distribution assets in HFTD which were inspected by ground or aerial drone.

[33] Wildfire consequence risk scores are generated by the Wildfire Consequence Model, which is a historically calibrated model that estimates the impact and consequences of an ignition and fire spread at relevant PG&E infrastructure locations. The model relies on historical fire damage, simulations of fire propagation, and the Fire Potential Index Model, which incorporates weather and fuel conditions.

feedback, and cross-functional deep-dives with internal and external stakeholders. The ISM will provide observations on the 2023 inspection program as it progresses throughout 2023. The Wildfire Consequence Model (a component of PG&E's Wildfire Distribution Risk Model) calculates the estimated impact and consequences of an ignition at relevant PG&E infrastructure locations. The model relies on historical fire damage, simulations of fire propagation and the Fire Potential Index (FPI) Model.

The risk-classified structures will also be placed into their own cycles, regardless of which HFTD Tier they are located in. Those classified as having extreme or severe wildfire consequence scores will be inspected by ground every year, those classified as high risk will receive ground inspections every other year, and those classified as low risk will receive ground inspections every three years. As PG&E continues to expand its aerial drone program, its intention is to have the extreme and severe risk areas aerially inspected every year, the high-risk areas inspected every other year (in the off-year of the 2-year ground inspection cycle) and every three years for low-risk areas (also in-between ground inspection years).

The previously referenced aerial drone inspection program was piloted in 2022. The implementation of the expanded program in 2023 will continue to be a point of observation for the ISM in the coming months.

Through a combination of PG&E's eyes on risk levels, reduced number of HFTD structures being inspected in 2023, and by spreading out the inspections over the course of the year, PG&E anticipates being able to rely on more of its own employees to conduct the majority of its HFTD ground inspections. Since PG&E's employees are also able to immediately make many types of repairs in the field as they inspect (contractors can only make limited repairs), PG&E anticipates this current schedule will allow for a more rapid correction of certain conditions.

EVOLUTION OF THE VEGETATION MANAGEMENT PROGRAM

EVM Program History

EVM was initiated by PG&E in 2019 as an additional vegetation management program to reduce the risk of vegetation caused fire ignitions from energized distribution power lines.

Prior to 2019, PG&E had three core VM resiliency programs: Routine Vegetation Management (compliance driven), Mid-Cycle Patrols (Tree Mortality), and Pole Clearing. In 2019, EVM was introduced targeting greater radial clearances, substantially greater overhang clearances, and enhanced strike tree removal in HFTD areas.

As seen in Table 4, the EVM program has worked on over 1.1 million trees over the past four years, with an annual minimum target of approximately 1,800 miles per year. As a result of PG&E being placed into Step 1 of the CPUC's Enhanced Oversight, PG&E shifted to a more systematic approach by having its annual plans executed in a more risk-informed manner. Table 4 reflects how, as PG&E's wildfire risk models evolved over time, and the company began to introduce tree weighting into its risk ranking determination, the number of trees worked and the average trees per mile have increased in recent years.

Table 4: PG&E EVM Inspections[34]

YEAR	HFTD MILES COMPLETED	INSPECTED STRIKE POTENTIAL TREES	TREES WORKED	AVG. TREES PER MILE	% OF MILES IN TOP 20% OF RISK	ACTUAL SPEND	AVG. UNIT COST (TREES)
2019	2,498	836,949	200,390	80	55%	$470.4 (M)	$2,348
2020	1,878	1,092,800	167,765	89	43%	$451.4 (M)	$2,691
2021	1,983	1,149,581	335,543	169	97.8%	$770.4 (M)	$2,296
2022	1,924	1,519,099	396,502	206	99.5%	$816.9 (M)	$2,060
TOTAL	**8,283** *32% of total HFTD miles*	**4,598,429**	**1,100,200**				

EVM work during 2021 and 2022 was guided by risk ranking from PG&E's tree-weighted prioritization to Version 2 of its Wildfire Distribution Risk Model (WDRM V2). Version 3 of the WDRM model (WDRM V3), which contained numerous enhancements, and which resulted in shifting of the risk rankings of the company's circuit segments from Version 2 (both of which were described in the previous ISM report) was not approved for use until April 2022[35]. According to PG&E, the decision to use the Version 2 tree-weighted prioritization for 2022 was for consistency and planning purposes.

The 2021 EVM plan required PG&E to focus its EVM work on distribution circuit segments ranked from 1 to 100 by the tree weighted WDRM V2 model. In addition, the company also included nine lower ranked circuit segments selected due to prior community commitments or ignition potential. PG&E's 2022 EVM plan continued its progression through the risk ranking, focusing on circuit segments ranked from 101 to 253 using the same model. In addition, PG&E's 2022 EVM plan included 12 lower ranked circuit segments selected due to recommendations from PG&E's local public safety specialists due to ignition risk potential. The ISM reviewed the actual EVM miles performed in both 2021 and 2022 and confirmed that PG&E's work was performed in accordance with these plans.

In performing its EVM, and with the increase in tree removal volume, PG&E informed the ISM that it had experienced an increase in negative customer interactions. PG&E also reported that the higher volume of customer refusals from its increased tree work was impeding its ability to reduce risk associated with removing identified hazard trees. To address the issue, PG&E stated that it implemented a centralized constraints resolution team to oversee identification and ultimate resolution of constraints. In the first year of this effort in 2021, PG&E reported that it had successful resolution of approximately 390 miles that had previously been constrained. Using lessons learned from program implementation, PG&E reported that it was able to increase its constraint resolution to approximately 703 miles in 2022.

34 Internal PG&E presentation.

35 See "E3 Review of PG&E's Wildfire Risk Model Version 3" for additional information on PG&E's WDRM. Access document via: https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=53553&shareable=true

In order to address these customer interactions, and as a result of the effectiveness of newly introduced wildfire mitigation programs such as the EPSS program which was implemented across all of its HFTD service territory in 2022, PG&E elected to end its EVM program at the end of 2022. As described in the following sections, PG&E has indicated that its preferred approach is to: 1) continue to rely on new programs such as EPSS, which it believes is more effective at reducing wildfire risk, 2) continue to evolve its existing routine vegetation management programs, and 3) replace EVM with more targeted vegetation management programs.

Effectiveness of EVM Compared to EPSS

PG&E provided the ISM with an internal analysis comparing the historical effectiveness of its EVM and EPSS programs which are both aimed at reducing ignitions. The ISM's initial observations generated questions regarding the analysis and the methodology utilized to evaluate the effectiveness of vegetation caused ignition reduction across both programs. As a follow-up, the ISM has requested a review of a third-party assessment of this analysis which was commissioned by PG&E as well as a more in-depth review of the analysis with PG&E personnel.

Replacement Vegetation Management Programs

With the evolution away from EVM, PG&E proposed to modify its existing routine vegetation management program and identify targeted areas in a risk-informed manner; however, as of the date of this report, the existing routine VM program remains in effect within the HFTD.

The ISM will be monitoring how PG&E intends to adjust its routine vegetation management programs in areas that have recently been covered as part of the EVM program and have received enhanced clearing beyond that which is required under the current routine program. In addition, PG&E is also proposing three new vegetation management programs for 2023: 1) Vegetation Management for Operational Mitigation (VMOM), 2) Focused Tree Inspections (FTI), and 3) Tree Removal Inventory (TRI). PG&E reports that these programs are intended to assist in the reduction of outages and potential ignitions using a risk-informed, targeted plan to mitigate potential vegetation contacts based on historic vegetation outages on PG&E circuits.

The objective of VMOM program is to reduce customer impacts due to vegetation outages on EPSS enabled devices in the following prioritizations:

- Tranche 1: Work in Progress (approximately 4,500 trees).
- Tranche 2: Based on 2023 EPSS outages (tree numbers TBD based on 2023 activity).
- Tranche 3: Customer impact with EPSS Customer Experiencing Multiple Interruptions (CEMI) of eight or more outages (approximately 9,000 trees).

The FTI program prioritizes miles based on areas of concern – specifically miles associated with increased vegetation related outages and/or including particular tree species. PG&E

approved an initial 300-mile, risk-ranked pilot program for 2023. Depending on the results of the pilot, it could authorize additional miles of FTI through the balance of 2023.

The TRI focuses on an inventory of approximately 385,000 trees at the end of 2022 that have been identified and previously assessed using PG&E's Tree Assessment Tool (TAT) or during an EVM inspection prior to the use of the TAT. Of these trees, approximately 176,000 trees would be removed based on the prior TAT "ABATE" result, and approximately 209,000 non-ABATE trees are in the process of being re-inspected by a Tree Risk Assessment Qualified (TRAQ) inspector. Additionally, PG&E indicated that the trees will be worked based on priority using their WDRM V3 model, with a target of removing 15,000 of these trees in 2023 and increasing incrementally in subsequent years.

FIELD REVIEW OF INSPECTIONS

In the previous ISM report, the ISM documented observations regarding in-field reviews of approximately 500 electric distribution structures and over 200 miles of PG&E's EVM inspected circuits in HFTD areas which had been inspected by PG&E in 2022.

The ISM continued to observe PG&E's vegetation management and system inspections through the end of the 2022 year. Observations from this reporting period are included in the following section.

Observations of PG&E's Distribution Inspections

As represented in Figure 6, the ISM conducted field observations on over 1,100 structures in 2022. Of the structures observed, approximately 20% had at least one observation that was not identified by PG&E's inspection team which, according to PG&E, is consistent with what their own quality verification team found. The top four types of observations identified by the ISM team, but not identified by PG&E (i.e., inconsistencies) were: 1) pole broken, damaged, burnt, deformed, corroded, gunshot, or showing signs of cracking, rotting or decay; 2) conductor with splices tied in proximity to insulator preventing free movement of splice with conductor; 3) down guy above insulator overgrown with vegetation and in need of trimming; and 4) tree causing strain or abrasion to single-service drop (open wire/triples/quad)[36].

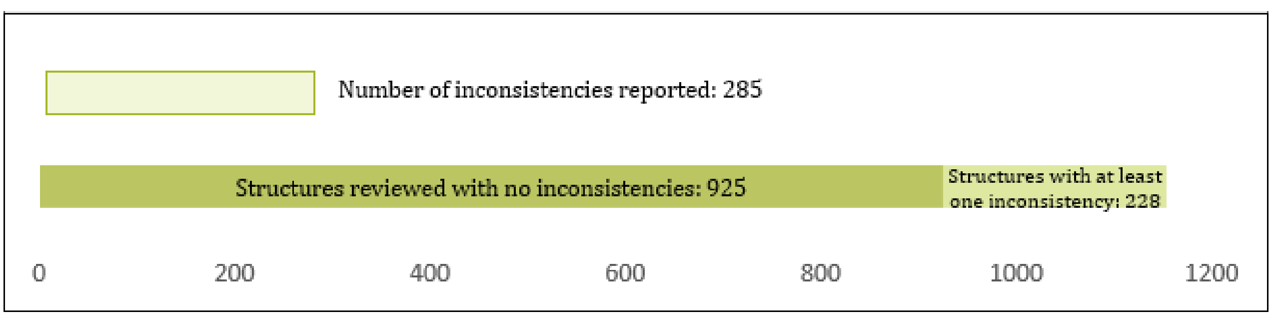

Figure 6. 2022 ISM Identified Observations of PG&E's Distribution Inspections

[36] The types of observations identified come from a PG&E specific form the inspectors use in the field.

As noted in the previous report, observations #1 and #2 identified above align with PG&E's most commonly occurring identification failures during their own quality verification process. These top four types of observations that were not identified by PG&E make up one-third of all such observations identified by the ISM. PG&E informed the ISM that it is revising its Job Aid and training to reduce the subjectivity associated with observation #1 and amending the inspection question related to observation #2 to identify splices tied into the insulator or splices in contact with the tie wire, preventing free movement of splice with the conductor.

PG&E believes the above actions will provide inspectors with more specific questions and reduce the potential subjectivity resulting in failed identification. PG&E indicated it will be holding additional reviews to align on ISM observations, which may lead to further clarifications and updates to observations based on PG&E standards and procedures.

Observations of PG&E's EVM Program

The ISM conducted field observations on a relatively small sampling (approximately 350 miles) of PG&E 2022 EVM worked miles. Of the miles observed, there were 61 trees observed as potentially requiring trimming or removal that were not identified by PG&E's inspections. According to PG&E calculations based on historical data, this would have resulted in an estimated find rate of 0.04% when comparing ISM observations to mileage reviewed. Of the identified inconsistencies, 11 were radial clearance trees (i.e., branches breaching the specified clearance distance around the equipment) and three were overhang trees (i.e., branches overhanging equipment which could result in contact with the equipment if the branches fell). The remaining 47 were identified as hazard trees (i.e., trees that pose a risk to equipment due to location, disease, or dying); Ponderosa Pine and Blue Oak species were identified 75% of the time.

Observations of PG&E's Routine VM Program

With the ending of the EVM Program, going forward the ISM plans to place additional focus on routine VM inspection, including both the changes in the routine program and the quality of PG&E routine inspections.

RISK MODEL UPDATING

In the previous ISM report, the ISM discussed the considerable refinement of PG&E's wildfire risk models over the past five years, (e.g., incorporating such things as advanced machine learning, the introduction of increasing sources of historical ignitions, greater geographic granularity and environmental inputs, updated ground fuels, and the use of more advanced wildfire spread and consequence formulation over time).

While the wildfire model enhancements are allowing PG&E to better target its wildfire mitigation efforts to areas deemed higher in risk for wildfire, as was detailed in the previous ISM report, the company has been seeing considerable variability in the risk ranking of its distribution circuits between Version 1 (2019), Version 2 (2021) and Version 3 (2022) of its

Wildfire Distribution Risk Model (WDRM). With these historical large changes in circuit risk ranking, some of the earlier wildfire mitigation work that was prioritized based on earlier versions of the risk models was later seen to have been done on circuits and circuit segments that later versions of the model were showing as having lower risk.

This historical shifting of risk rankings had impacts related to system hardening planning, where it may take several years to scope, estimate, and permit the work. With this approach, by the time a project is ready for construction, the latest version of the risk model may have confirmed, or substantially increased or decreased the risk rank of these circuit segments from when they were originally selected for system hardening. In the past, when updated models generated what PG&E considered to be significantly lower risk rankings for system hardening work that was already in the planning and permitting phase, PG&E elected to abandon and expense certain pre-construction system hardening projects. During this ISM reporting period, PG&E adjusted this policy and now continues with an approved system hardening project to completion, regardless of any subsequent risk recalculation, and does not abandon and expense any in-process preparatory work.

As PG&E prepares to release its WDRM V4 model (projected for presentation/approval in April 2023), the ISM has been monitoring the further enhancements that are being introduced to the model, and their potential impact on future risk rank volatility.

Two of the more substantive changes to the risk model, requested by Energy Safety for inclusion in the 2023 WMP, are the introduction of an egress and a wildfire suppression modifier to the wildfire consequences portion of the model. These elements are being introduced into the wildfire risk models of two other large California utilities, and these initial modifiers are to be used as a starting point for collaboration with Energy Safety and the other utilities as a unified approach to egress and fire suppression modeling is developed.

Egress is the evacuation of people who must evacuate a fire, and the egress calculation includes fire burn area relative to populated areas. PG&E's egress modifier is based upon resident mobility impacts rather than road egress as PG&E's analysis of historical data determined that age and disability were stronger correlating factors than road egress. After analyzing several population variables, PG&E elected to use the fraction of population over 80 as a proxy for mobility issues.

Wildfire suppression is the difference in area burned and structures destroyed between an unsuppressed wildfire and a wildfire with human intervention. It is a measure of the likelihood, feasibility, and effectiveness of firefighting after an ignition event, and includes ingress considerations (i.e., the ability for fire resources to access an area). PG&E has stated that the challenge to modeling wildfire suppression is that it is impossible to acquire real world data for model development, and that consequence adjustment development relies on "what if" modeling of non-suppressed fires initiated at locations of historical fires with highly variable interventions. After reviewing several options, PG&E has elected to incorporate a feature called the Terrain Difficulty Index, which is a composite index that integrates data on topography, terrain, and road networks.

PG&E's preliminary modeling results shared with the ISM have shown that the egress and wildfire suppression modifiers both exhibit higher consequence scores in areas already being modeled as having high consequence scores in the prior version of the model. PG&E is projecting that the adjustments to risk rankings are expected to be relatively small after introducing these two new modeling elements.

In addition to the two new wildfire consequence modeling elements noted above (plus the introduction of climate forecasting and community vulnerability which the ISM has not yet had an opportunity to review), WDRM V4 is also introducing several new features in calculating the probability of ignition. These include more granularity on equipment failures (e.g., capacitors, switches, and voltage regulators) as well as additional contact from object drivers.

While the ISM has not yet seen how these new features may change the probability of ignition risk ranking, the ISM is not expecting the overall risk score (which multiplies the probability of ignition score with the consequences of ignition score) to show the same degree of volatility in circuit segment risk rank changes as has been seen between prior versions of the models. This is due to consequence scores having been scaled, such that they have a much larger influence on the combined risk scores. The lower projected volatility of the consequence scores, after taking the new egress and fire suppression modifiers into consideration, should therefore result in a lower volatility of the combined risk scores in WDRM V4.

PG&E has also shared with the ISM certain modeling limitations that continue to exist, and the list of improvements that are in progress. Modeling limitations include missing data attributes (e.g., missing asset age, secondary conductor type, conductor splice count, transformer electrical loading for prior year), missing outage information (e.g., exact location, cause unknown, equipment type failed) and missing ignition information (e.g., sub-cause, equipment type).

Other upcoming model improvements that have been noted by PG&E include:

- Asset Failure Data Collection – improvement of asset failure location and cause/sub-cause information.
- Foundry Asset Failure Investigation Tools – automatic correlation and trending information of failed assets from multiple sources and creates an asset failure database.
- Import of previously collected inspection data to their GIS mapping system – incorporation of asset attributes such as non-exempt equipment locations (e.g., surge arresters) and splices into GIS so that it can be leveraged for modeling purposes.
- LiDAR Conflation – improvement of asset information for secondary voltage conductor network that operates at less than 600 volts, and includes open wire, triplex, and quadruplex type of conductors.

GAS OPERATIONS OBSERVATIONS

PG&E is the owner and operator of one of the largest natural gas transmission and distribution systems in the United States. PG&E operates an integrated transmission, storage and distribution system comprised of over 6,000 miles of backbone and local transmission pipeline, three gas storage facilities and over 40,000 miles of distribution pipeline. PG&E's gas operations have been under external oversight and scrutiny since the San Bruno pipeline explosion in 2010. During the period of heightened regulatory oversight, PG&E was required to change and/or implement several policies, programs, and processes to enhance gas operation integrity and increase public safety. The ISM has and continues to perform various monitoring activities supporting regulatory oversight of these policies, programs, and processes.

GAS STORAGE OPERATIONS

In the previous ISM report, the ISM provided observations associated with: 1) interviews with PG&E leadership and personnel within gas storage operations; 2) meetings regarding various gas storage operations; 3) ISM site visits to each of PG&E's three gas storage facilities (McDonald Island, Los Medanos, and Pleasant Creek); 4) review of PG&E gas storage risk models, procedures, policies, and programs; and 5) review and analysis of gas storage well conversion and direct casing inspection operations.

During the current ISM reporting period, the ISM interviewed members of the PG&E gas storage group. During this interview, the ISM was informed that the PG&E Pleasant Creek gas storage facility is in the process of asset transfer to a third party. PG&E anticipates that the asset transfer will require at least six months of regulatory approval to complete.

During the current ISM reporting period, the ISM continued: 1) interviews with PG&E leadership and personnel within gas storage operations; 2) attending meetings regarding various gas storage and/or operations; 3) performing ISM site visits to three of PG&E's gas transmission facilities (including Delevan and Bethany compressor stations and Brentwood terminal); 4) performing reviews of PG&E gas operation's program, policy, and risk assessment documents; 5) review and analysis of gas storage well conversion and direct casing inspection operations; and 6) review of certain components of PG&E's Tee Cap Replacement Program.

Gas Operational Changes

In the previous ISM report, the ISM reported PG&E's installation of a new SVP of Gas Engineering, and that PG&E was reviewing the gas operation's organizational structure, budget, and headcount. During the current ISM reporting period, the ISM held follow up discussions with the SVP of Gas Engineering, who indicated that the gas storage asset group was adjusting to operational changes in group leadership and improving internal and third-party vendor wellbore conversion and inspection resource availability. Further, the SVP of Gas Engineering reported completion of implementing organizational structure changes and obtaining approval to hire additional required gas operation staff.

As reported in the previous ISM report, PG&E's gas storage operation's minimal staffing allowed continued coverage of required daily gas storage operations; however, it delayed performing gas storage employee training. During the current ISM reporting period, members of the PG&E gas storage group informed the ISM of effort to hire four additional professional team members and efforts to add web based professional training courses leveraging PG&E SME training advisory support. The professional training is expected to include both operational and regulatory compliance instruction. The ISM will continue to monitor PG&E's gas storage operational requirements and review delays performing the gas operations training.

Gas Storage Wellbore Conversions

During the previous ISM report, the ISM observed that PG&E's most recent wellbore conversion schedule included conversion of all remaining gas storage wellbores to a tubing and packer configuration with gas flow through tubing with 21 conversions scheduled for 2023 and 19 scheduled for 2024. During the current ISM reporting period, PG&E reported that three well service rigs have been contracted to perform the 2023 wellbore conversions to be completed by November 2023. The ISM also confirmed the "California Geologic Energy Management Division" (CalGEM) requirement for PG&E to perform wellbore direct casing inspections on a 24-month interval. During the current ISM reporting period, the ISM performed additional interviews with gas storage management. PG&E indicated that all CalGEM required gas storage wellbore initial direct casing baseline inspections with the magnetic flux leakage (MFL) direct contact tool will be completed by the end of 2023.

CalGEM has previously required at least two wellbore direct casing baseline inspections prior to considering extending the 24-month per well direct casing inspection schedule. In the previous ISM report, PG&E asserted that as a result of increased competition for well service rigs and crews choosing to provide service to conventional oil and gas operations in other states there was a scarcity of well service rigs with the United States Department of Transportation "Pipeline and Hazardous Materials Safety Administration" (PHMSA)/CalGEM qualified crews within California to perform the regulated wellbore conversion and inspection operations. During the current ISM reporting period, PG&E reported that it has located well service rigs and crews to support the current CalGEM approved pace of its baseline wellbore conversion and inspection schedule. PG&E reported that it has contracted two well service rigs and will add a third rig in the near future to complete required 2023 wellbore conversion with associated direct casing inspections by November 2023.

Additionally, during the current ISM reporting period, PG&E's gas storage management informed the ISM that a report summarizing gas storage wellbore direct casing inspection evaluation results was provided to CalGEM on January 20, 2023. This is part of PG&E's request for an extension of the 24-month per well casing inspection schedule due to PG&E's concern with potential mechanical damage which might occur during direct casing inspections.

The ISM will continue to monitor PG&E's above ground gas storage safety, integrity, and surface operations and the related completion of wellbore conversions.

Gas Storage Inspections

In the previous ISM report, the ISM observed that CalGEM performed an inspection of PG&E's three gas storage facilities (McDonald Island, Los Medanos, and Pleasant Creek) and that the inspection results had not been officially issued by PHMSA for the 2022 inspection period. During the current ISM reporting period, PG&E management indicated that the official inspection results are still pending.

The ISM will continue to monitor the status of the official inspection results and PG&E's associated actions.

PIPELINE INTEGRITY MANAGEMENT

PG&E's Pipeline Integrity Program includes the Transmission Integrity Management Program (TIMP), Distribution Integrity Management Program (DIMP), and Gas Safety Plans.

Gas Transmission Integrity Management

During the current ISM reporting period, the ISM performed a site visit to three gas transmission facilities including two compression facilities and one transmission terminal facility and completed several interviews with key PG&E facility operation personnel at each facility (i.e., Delevan and Bethany compressor stations and Brentwood terminal). During those facility management personnel interviews the ISM engaged in a brief discussion with a PG&E manager who described a PG&E initiative to review transmission compression facility inventory and operating equipment obsolescence. In response to the ISM's inquiry regarding the PG&E obsolescence review PG&E responded that reports or documents identifying observations or findings are still pending.

Can't Get In (CGI) Tickets

In the previous ISM report, the ISM observed a high risk of potentially large volumes of overdue "Can't Get In" [37] (CGI) tickets in the near future. The anticipated increase in volume was the result of the expiration of the M-4845 waiver. The waiver allowed for exclusion of CGIs that were not completed ahead of their original compliance dates due to reasons associated with the COVID-19 Pandemic. The waiver had been extended through the end of 2021 and gave until the end of 2022 to complete any backlog existing at the end of 2021. While the total number of overdue CGIs avoided through the waiver did increase as a result of the COVID-19 Pandemic (24,935 in 2020; 24,196 in 2021; 10,374 in 2022), PG&E has indicated that it has been able to address the majority of these, and as of January 1, 2023, the CGI backlog consisted of 1,963 Leak Survey CGIs and 1,180 Atmospheric Corrosion CGIs, for a total backlog of 3,143 CGIs. These numbers include any outstanding CGIs that had previously been avoided through the waiver.

[37] "Can't Get In" is a ticket status for work orders were PG&E is not able to gain immediate access to perform emergency or scheduled maintenance work.

The COVID-19 pandemic and other health related concerns caused increases in the number of customer refusals and therefore the number of CGIs. Beginning in 2020, PG&E worked to counteract this through enhanced technology and processes[38], and by increasing customer awareness and understanding of the importance of its gas meter safety work. These mitigating actions decreased the backlog of CGIs from approximately 39,450 in January 2021 to approximately 3,143 in January 2023.

Tee Cap Replacement Program

On October 8th, 2022, there was an explosion at 2793 River Plaza Dr., a residential area in Sacramento, California, with no injuries or fatalities reported. A root cause analysis (RCA) is being performed, and PG&E is awaiting the results of this analysis. The ISM will review the results of the RCA once completed and made available.

Since 2013, PG&E has replaced an average of 1,000 Tee Caps per year through the end of 2022 under the most recent rate case. PG&E has submitted Tee Cap replacement within the current 2023-2026 General Rate Case seeking approval for the proactive replacement of 4,660 Tee Cap units (1,165 per year).

In addition to PG&E's current rate base replacement request, PG&E has polled the American Gas Association (AGA) SOS program which allows AGA members to inquire of its peers to better understand how other utilities are addressing similar Tee Cap replacement issues. PG&E's poll requested peers' failure experience with similarly constructed Tee Caps, characterization of those failures, mitigating actions taken, and best-practice repair methods. PG&E has reviewed the results provided by AGA peers and discussed them with the ISM. PG&E has stated that it is one of the few operators in North America that has a proactive Tee Cap replacement program.

The ISM interviewed PG&E regarding the current frequency of the DIMP risk-based Tee Cap replacement program, other than replacement of Tee Caps associated with existing plastic main replacement programs. Based on PG&E's described annual risk assessment of Tee Cap failure considering location-based consequence of failure, gas service volume, and region Tee Cap failure history, PG&E characterizes the current rate case Tee Cap replacement frequency as appropriate to minimize risk of Tee Cap failure.

The ISM will continue to monitor certain activities associated with PG&E's gas operations and observe additional pipeline integrity testing.

GAS TRANSMISSION AND DISTRIBUTION GEOHAZARD MONITORING

During the recent California 'atmospheric river' heavy rains event across the state, there was ISM interest regarding PG&E's preparation to identify and monitor adverse weather related

[38] PG&E employed new strategies to address the large number of new CGIs, including enhanced customer interaction such as an online portal for communication and scheduling of service, and eventually disconnecting customers' electric service after multiple refusals to schedule gas service. In addition, PG&E stated it has taken steps to enhance internal communication and CGI tracking methods.

geohazard impacts on pipeline reliability and safety. The geohazards affected by the recent heavy rains and adverse weather include susceptibility to landslides, heavy erosion, and excessive flooding that may impact PG&E's reliable and safe gas operations. The ISM's recent access to PG&E's ArcGIS system enabled the ISM to review PG&E's proactive measures to prepare for these unique weather events. Included in this data was a gallery of unique ArcGIS web applications created by PG&E asset teams to display specialized views of GIS and gas operation information.

PG&E's identification of various geohazard susceptibility locations mapped into accessible ArcGIS web portals provides the opportunity for PG&E personnel to efficiently focus pipeline operation geohazard event monitoring and response along specific pipeline segments.

The ISM will continue to monitor activities associated with PG&E's gas transmission and distribution geohazard monitoring initiatives.

GAS OPERATIONS DATA MANAGEMENT AND RECORDKEEPING

The ISM has initiated a review of PG&E's data management and recordkeeping practices**.** The ISM is in the process of regularly interviewing key PG&E personnel across its Gas Asset Knowledge group, as well as gaining access to several data repositories within PG&E's information system to better understand data access and organization of essential gas operation data and recordkeeping and their associated data acquisition and management processes.

EMERGING OBSERVATIONS

In addition to the areas covered in this current period ISM report, the ISM will continue to perform activities consistent with the ISM Contract (e.g., tracking, inspections, validations, analyzing, etc.) to monitor developments in other areas including but not limited to Integrated Grid Plan, Gas Distribution Integrity Management, and Gas Leak Management.