

**FILSINGER ENERGY**  
P A R T N E R S

**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)<sup>1</sup>, 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

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<sup>1</sup> 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.

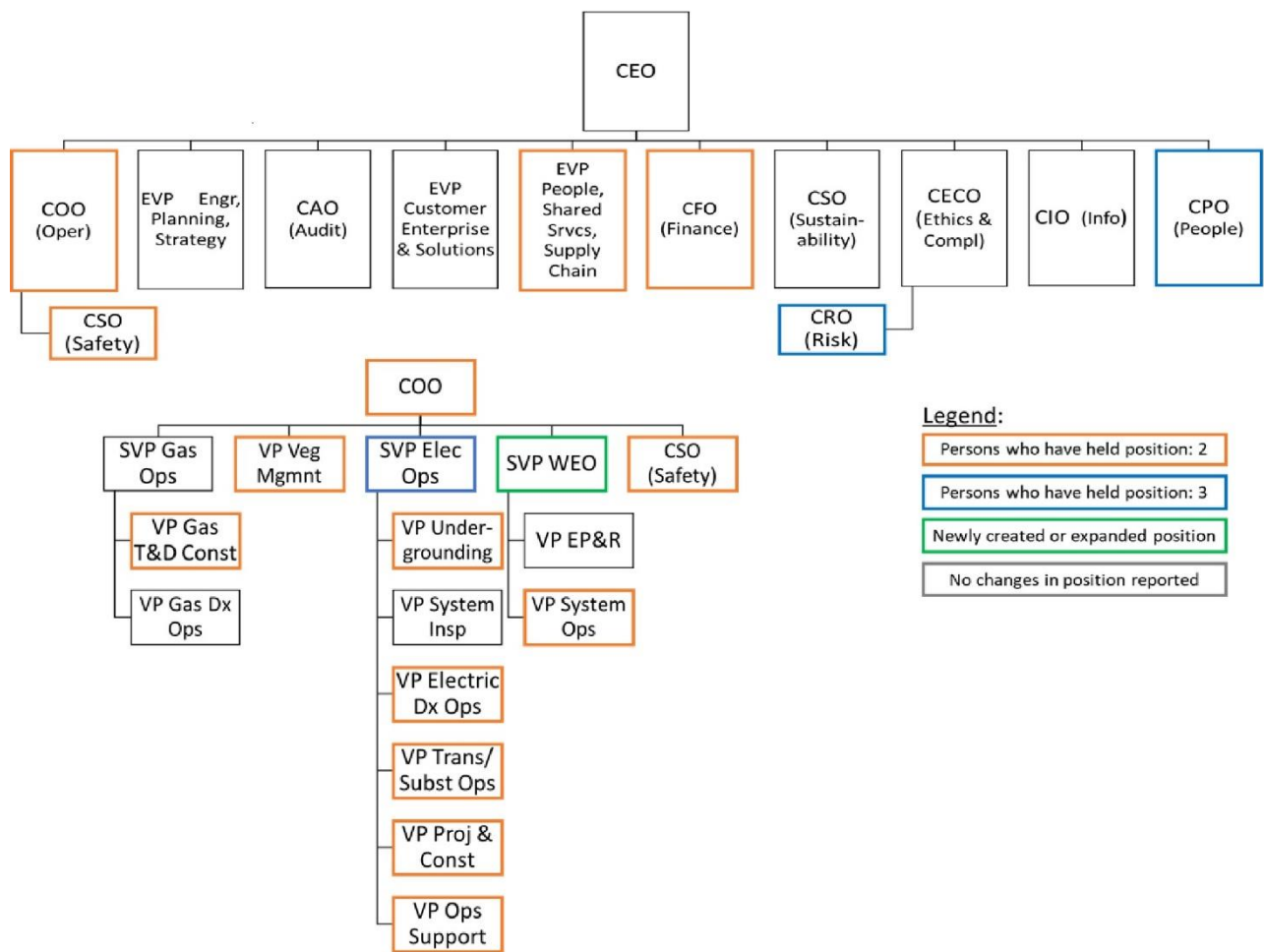


Figure 1: PG&E Senior Leadership Changes Since January 2022

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<sup>2</sup> for both non-HFTD and HFTD areas.

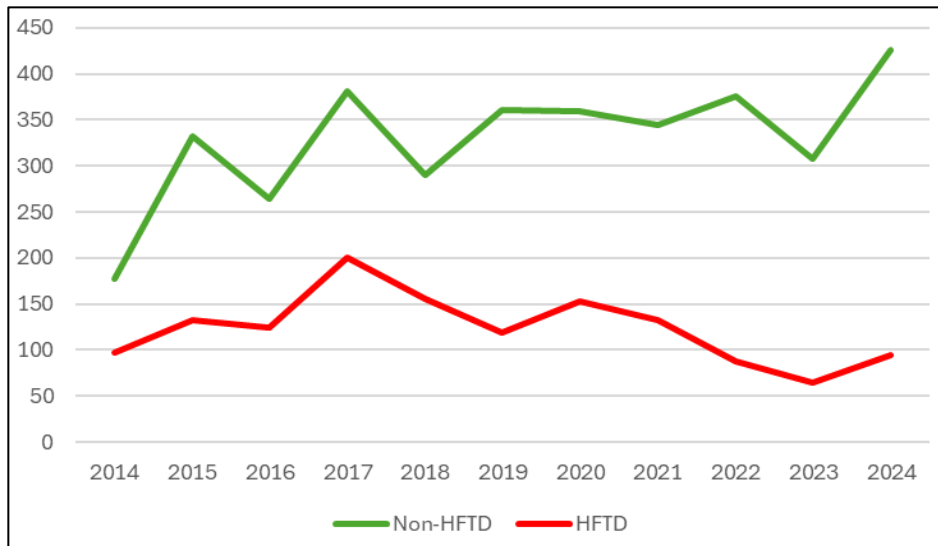


Figure 2: Number of CPUC Reportable Ignitions 2014 - 2024

PG&E also tracks the number of ignitions which occur when the Fire Potential Index (FPI) is R3 or higher.<sup>3</sup> 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).<sup>4</sup>

<sup>2</sup> 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.

<sup>3</sup> 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.

<sup>4</sup> 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.

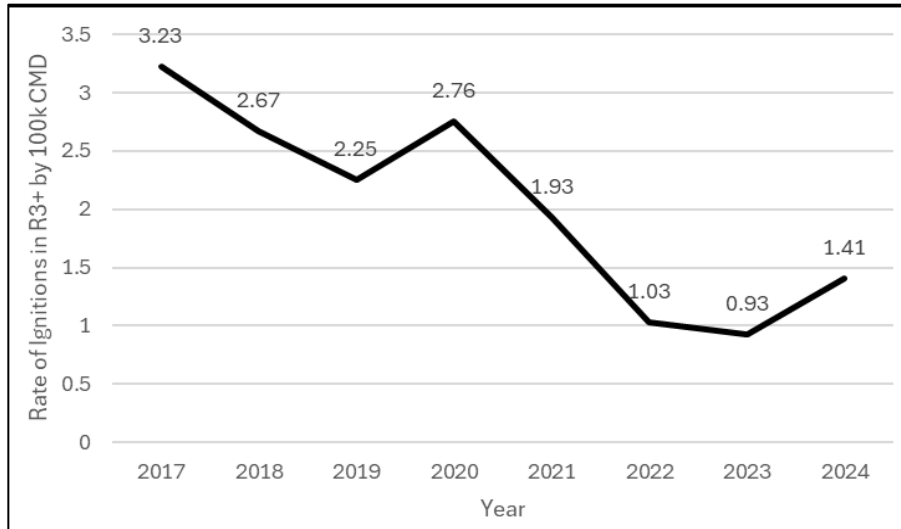


Figure 3: Weather Normalized CPUC R3+ Ignition Rates in HFTD by 100k Circuit Mile Days

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.

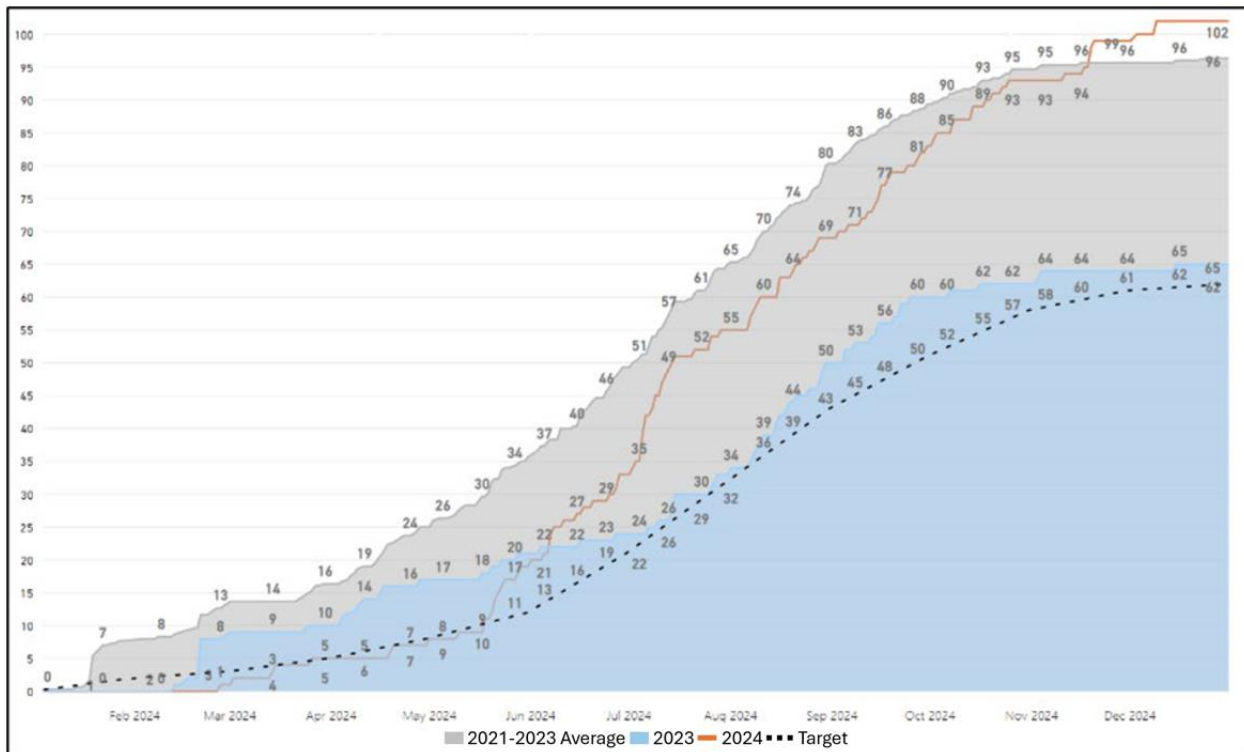


Figure 4: Cumulative CPUC Reportable PG&E Facility Ignitions in HFTD



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.<sup>5</sup> 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.

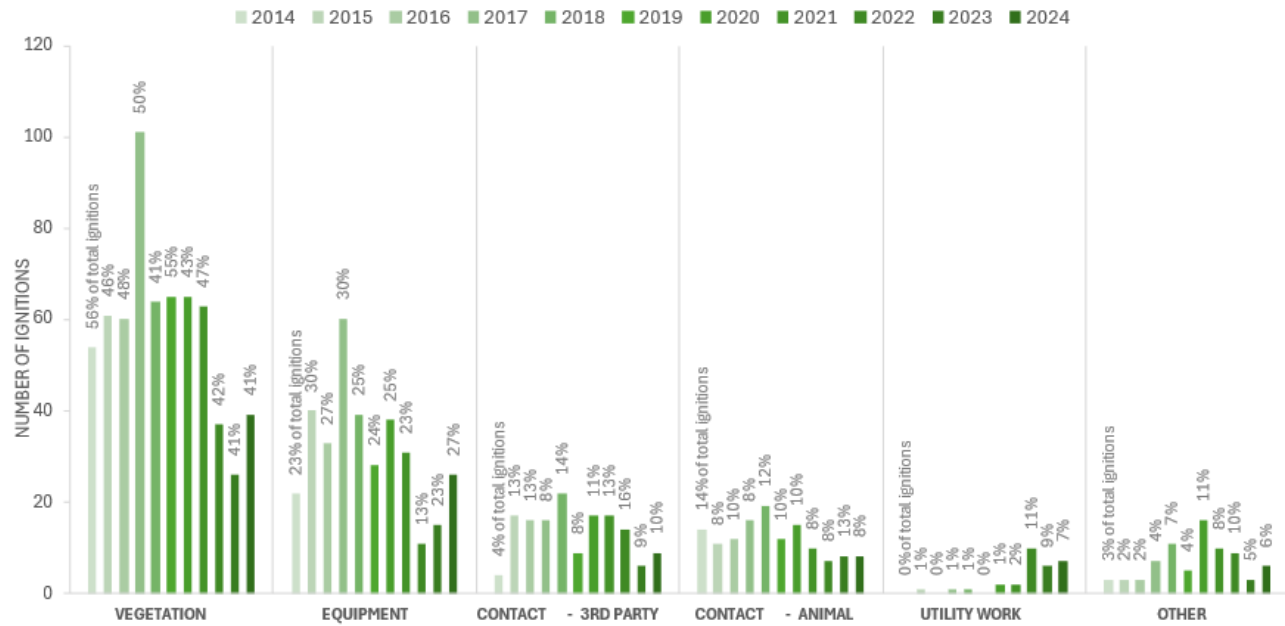


Figure 5: PG&E Facility Ignitions in HFTD by Suspected Initiating Event<sup>6</sup>

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%).

<sup>5</sup> 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.

<sup>6</sup> 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.<sup>7</sup>

## 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,

<sup>7</sup> 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.<sup>8</sup>

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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<sup>8</sup> 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.<sup>9</sup> 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.<sup>10</sup>

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

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<sup>9</sup> 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.

<sup>10</sup> 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<sup>11</sup> 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<sup>12</sup> and copies of PG&E’s Tailboard<sup>13</sup> 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

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<sup>11</sup> 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.

<sup>12</sup> 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.

<sup>13</sup> 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.<sup>14</sup> 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)

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<sup>14</sup> 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.<sup>15</sup> Distribution circuit EPSS enablement covers 100% of the HFTD plus approximately 19,000 buffer area miles<sup>16</sup> 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.<sup>17</sup> 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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<sup>15</sup> EPSS enablement covers 5,235 devices on 984 circuits.

<sup>16</sup> 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<sup>18</sup> (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<sup>19</sup> (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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<sup>18</sup> CAIDI is the average time required to restore service, calculated as total minutes of customer interruption divided by the total number of interruptions.

<sup>19</sup> 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.<sup>20</sup> Another way PG&E seeks to reduce outages on high frequency 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. PVD/PVFO is a SmartMeter™ based program, which can send real time alarms when partial voltage or full/partial loss of phase is detected.

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<sup>20</sup> 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;<sup>21</sup>
- 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 DFA 1) 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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<sup>21</sup> 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<sup>22</sup> 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 programming 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.

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<sup>22</sup> 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 3<sup>rd</sup> 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:

Component group based Bayesian updating: 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,<sup>23</sup> Baywater Tower Program,<sup>24</sup> 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<sup>25</sup> (FSR) of open repair tags, PG&E stated that the assets' remaining strength will continue to get periodically updated.

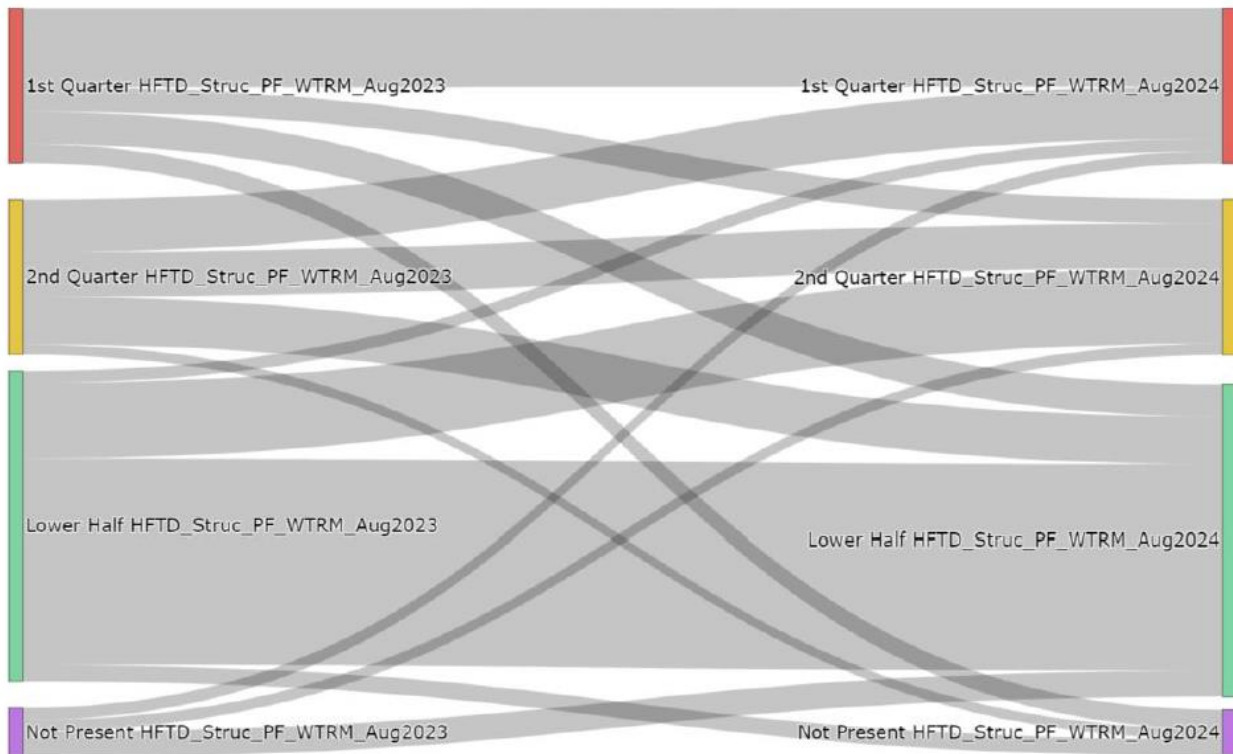


Figure 6: Structure-Level Annual Probability of Failure (PF) WTRM v2.0 versus v2.1

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

<sup>23</sup> 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.

<sup>24</sup> 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.

<sup>25</sup> 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<sup>26</sup> 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

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<sup>26</sup>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 existing 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 cancellation 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<sup>27</sup> – structural failure – 1st
- Support structures<sup>28</sup> – 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%

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<sup>27</sup> 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

<sup>28</sup> 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,<sup>29</sup> 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.<sup>30</sup>

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 1/50<sup>th</sup> 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

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<sup>29</sup> Transmission towers have a higher fill rate of approximately 92% for its approximately 34,600 towers.

<sup>30</sup> 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 2<sup>nd</sup> 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.

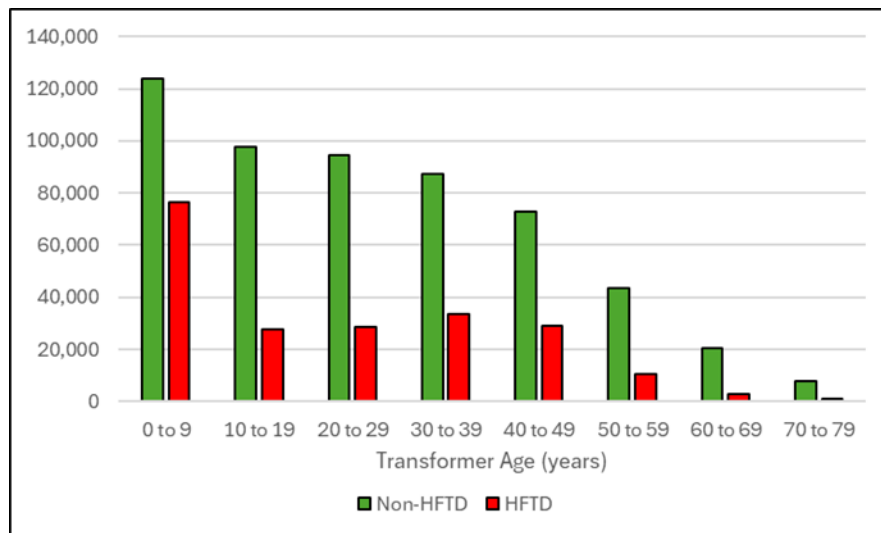


Figure 7: Overhead Transformers by Age and Wildfire Tier

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.

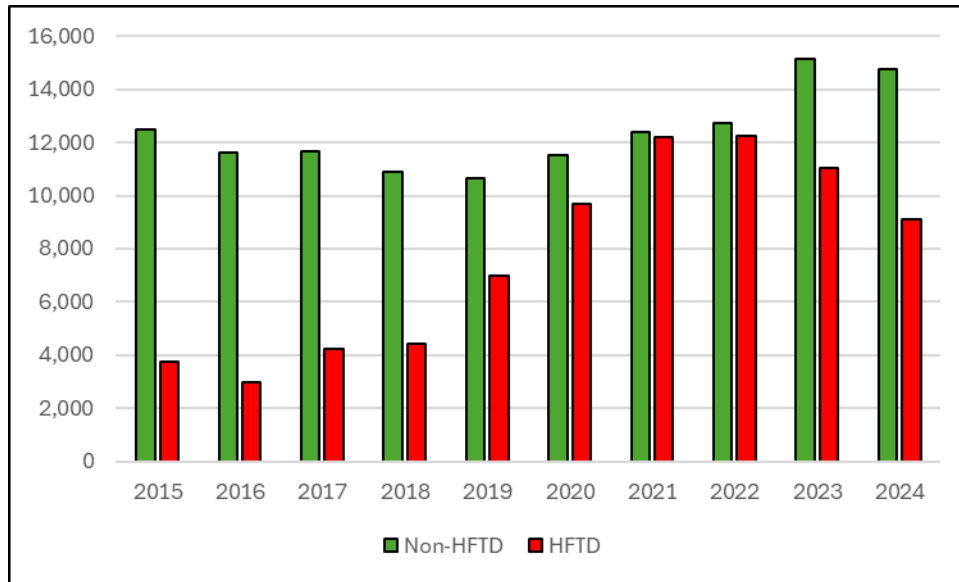


Figure 8: Transformer Replacements by Wildfire Tier

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.<sup>31</sup>

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.<sup>32</sup> 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%.<sup>33</sup>

## 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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<sup>31</sup> 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.

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

<sup>33</sup> 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.

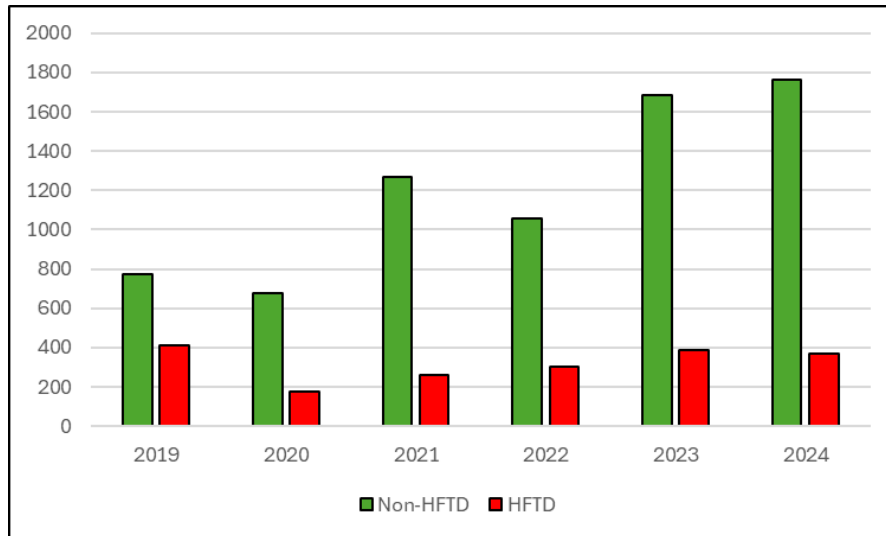


Figure 9: PG&E Pole Equipment Failure Outages by Wildfire Tier

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.

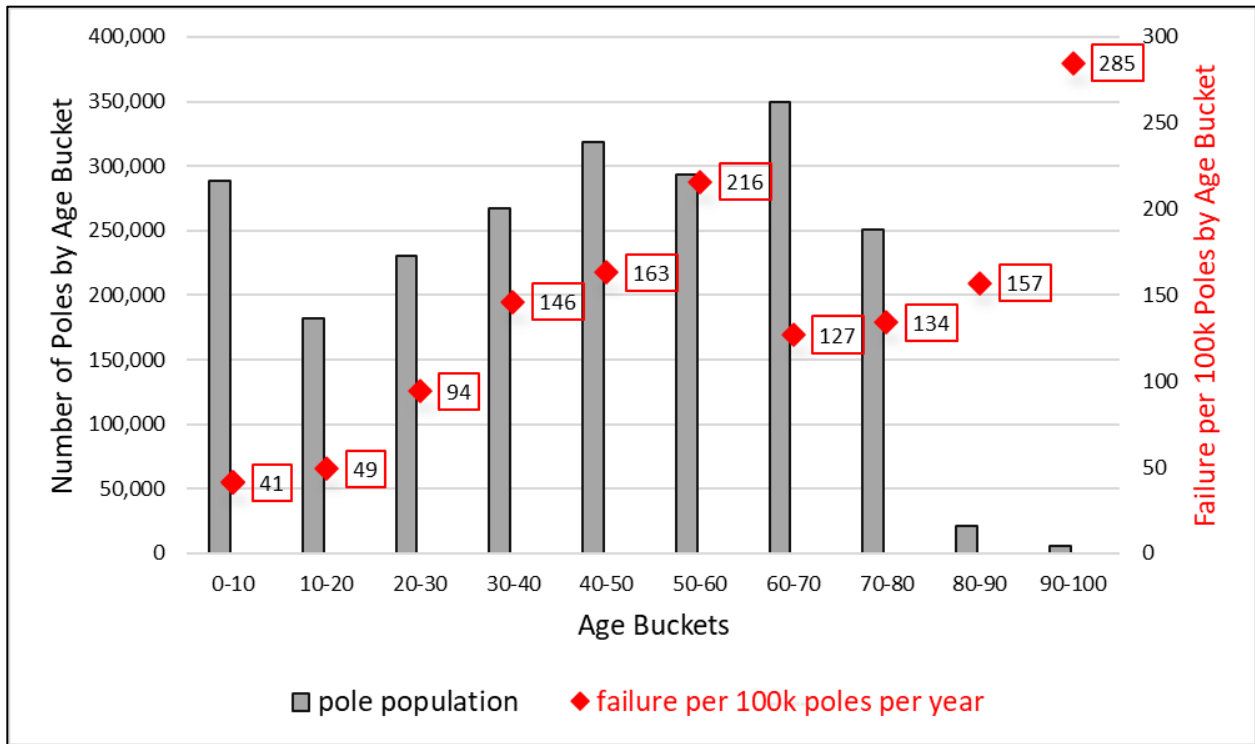


Figure 10: Failure Rate per 100k Poles/Year and Pole Populations per Age Group

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.<sup>34</sup>

<sup>34</sup> 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.

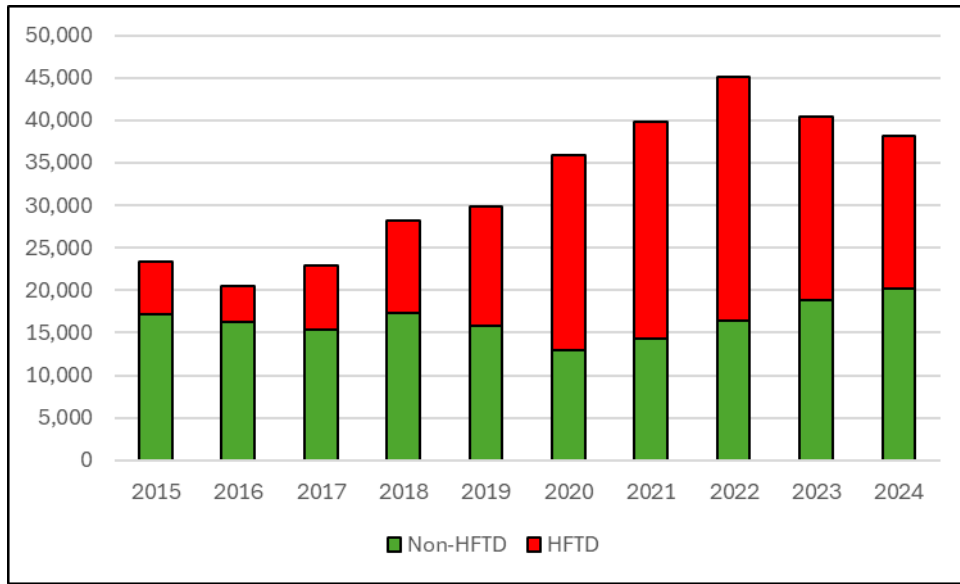


Figure 11: Number of Poles Replaced by Wildfire Tier

## 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.

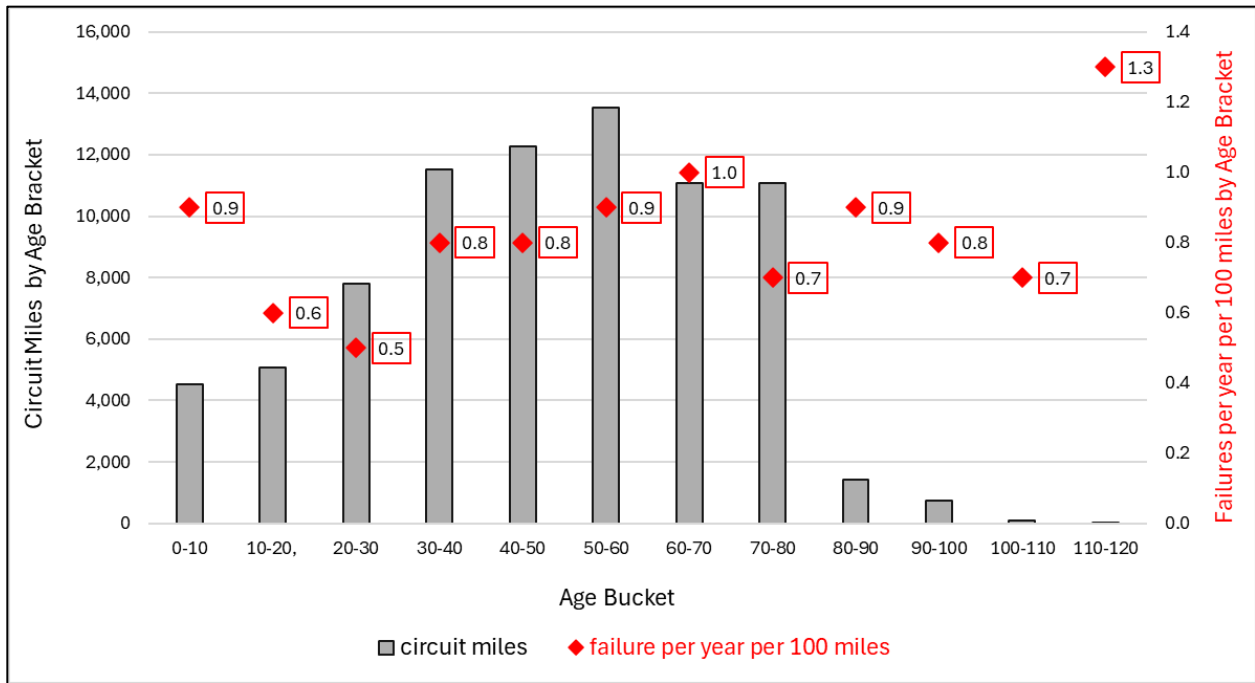


Figure 12: Conductor Failure Rate per 100 Miles/Year and Conductor Miles per Age Group

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.

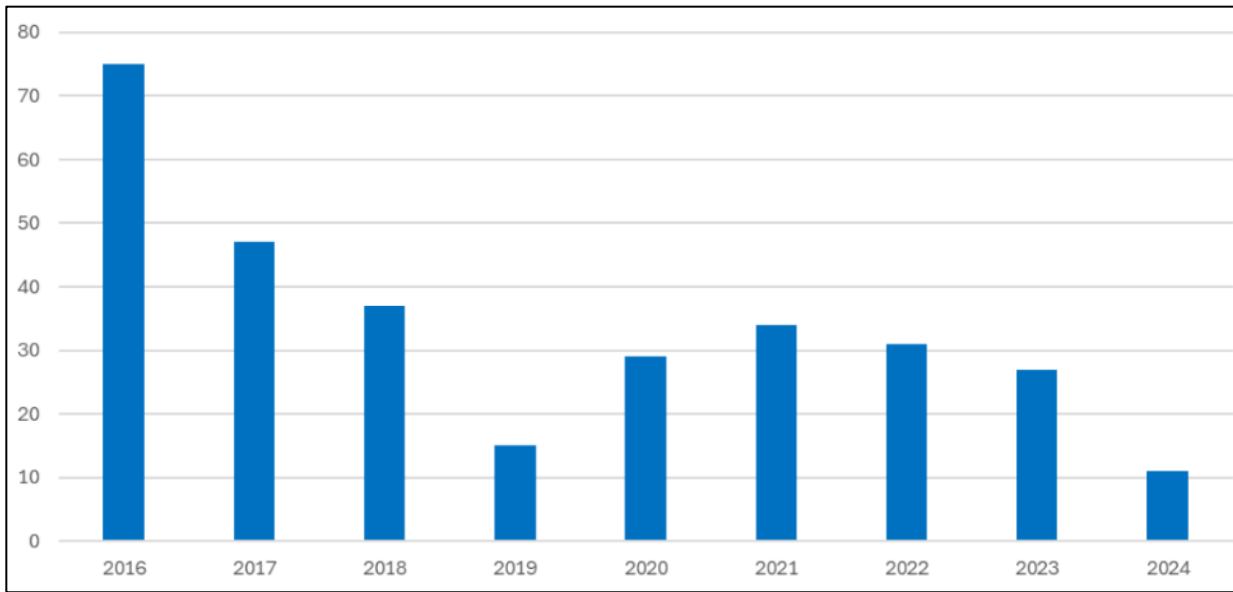


Figure 13: Miles of Deteriorated Conductor Replaced as part of the Proactive Deteriorated Conductor Replacement Program

## 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.<sup>35</sup> 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).

<sup>35</sup> This excludes third party causes (e.g. car pole incidents), and fire related incidents.

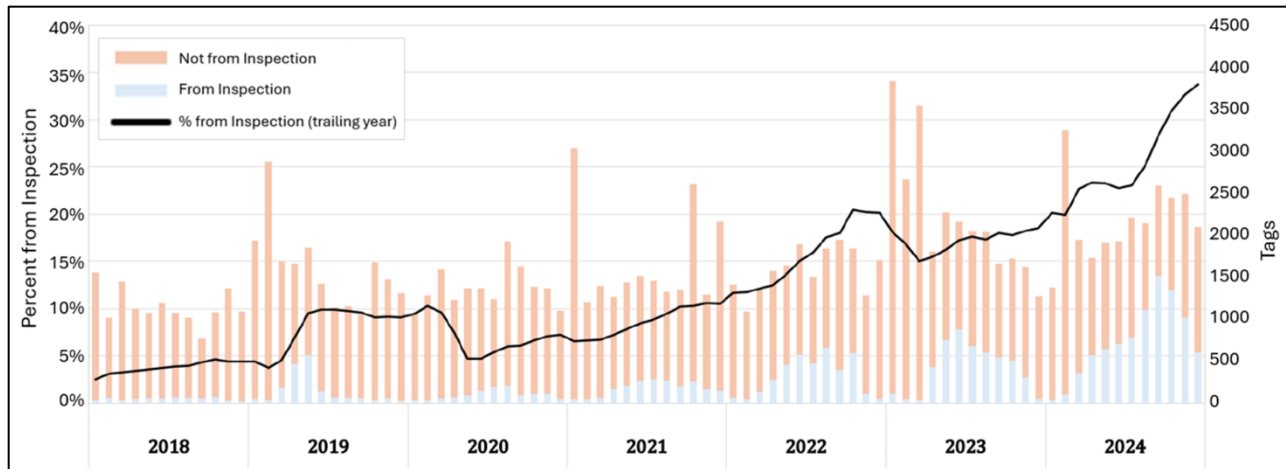


Figure 14: Trailing 1-Year A and X Tag Count and In-Service Failures

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.<sup>36</sup> 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.<sup>37</sup>

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<sup>36</sup> 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.

<sup>37</sup> 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 <sup>38</sup>	2023 Rank	2024 Rank	2022 Find Rate	2023 Find Rate	2024 Find Rate
<i>Is pole broken, damaged, burnt, deformed, corroded, gunshot, or showing signs of cracking, rotten or decay?</i>	2	1	1	1.9%	3.4%	1.2%
<i>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?</i>	8	2	2	0.6%	1.0%	0.4%
<i>Are grounds exposed?</i>	N/A	N/A	3	0.4%	0.2%	0.2%
<i>Is there a tree causing strain or abrasion to secondary conductor or service drop?</i>	3	N/A	4	1.2%	0.7%	0.2%
<i>Is the down guy above insulator grounded (vegetation or other)?</i>	N/A	N/A	5	0.6%	0.5%	0.2%
<i>Is there any loose hardware including bolts and nuts present for equipment attachments?<sup>39</sup></i>	N/A	N/A	6	0.6%	1.0%	0.1%
<i>Is animal mitigation broken, damaged or missing (if required)?</i>	9	4	7	0.8%	0.8%	0.1%
<i>Does conductor have splices tied in proximity to insulator preventing free movement of splice with conductor?</i>	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,

<sup>38</sup> 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.

<sup>39</sup> 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.

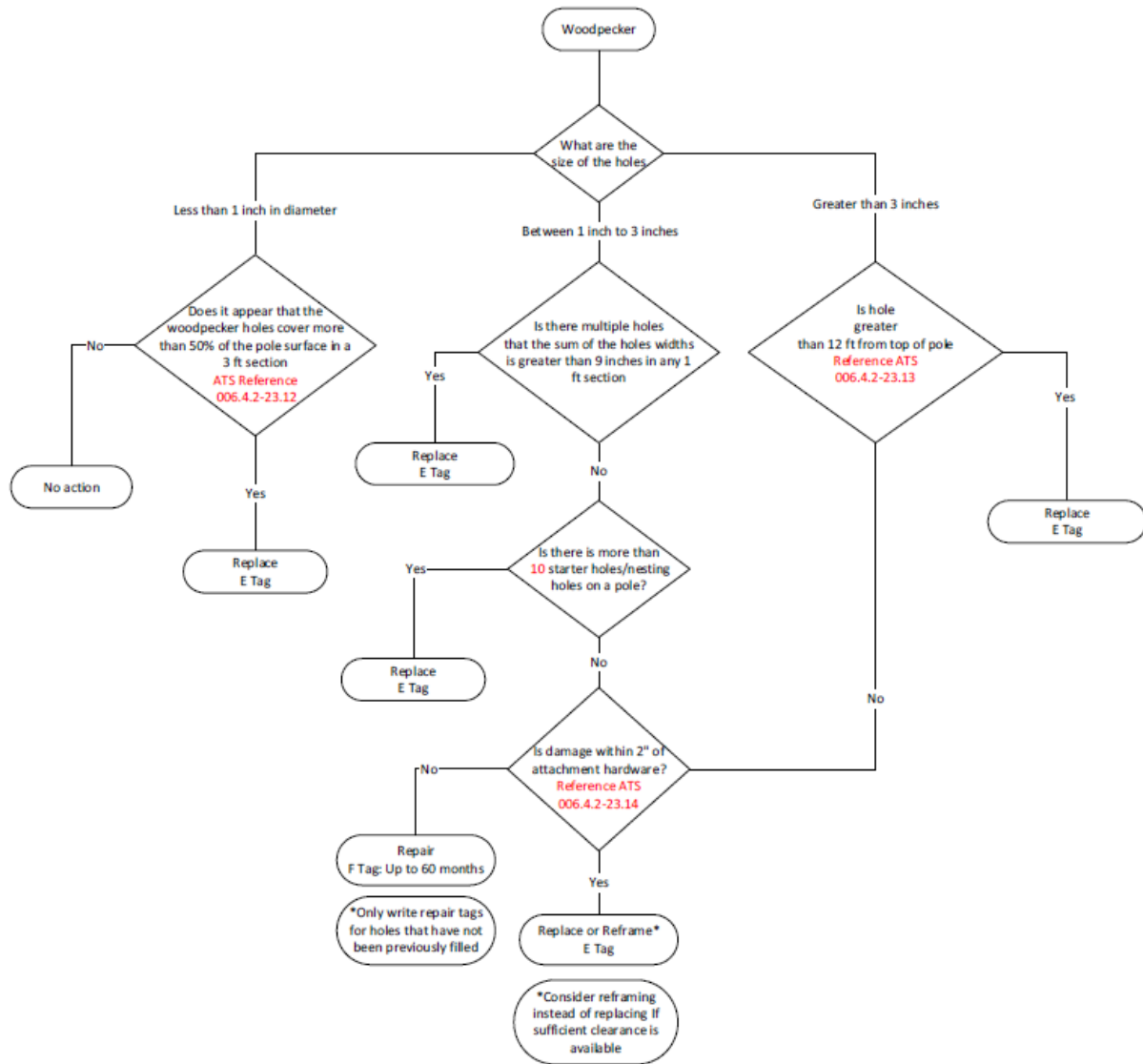


Figure 15: An example of PG&E's 2024 expanded Job Aid with a flow chart for Woodpecker guidance

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 3<sup>rd</sup> 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<sup>40</sup> (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<sup>41</sup> 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<sup>42</sup> 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

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<sup>40</sup> 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.

<sup>41</sup> 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.

<sup>42</sup> 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)<sup>43</sup> 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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<sup>43</sup> 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 <sup>44</sup>	68
Observation Trees <sup>45</sup>	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

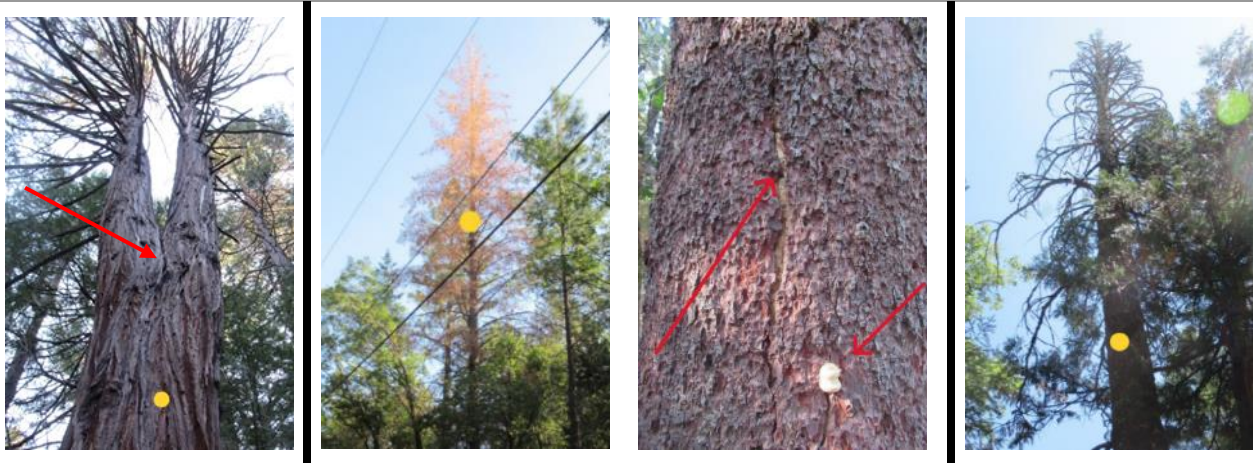


Figure 19: Left: Vertical crack below codominant union. Middle Two Photos: Hazard Tree identified by the ISM during a routine patrol with slipping bark. Right: Hazard Tree identified by the ISM on a routine patrol.

### 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

<sup>44</sup> 95% of trees identified are Hazard Trees with the other 5% being Radial Clearance.

<sup>45</sup> 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

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

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

<sup>46</sup> 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.

<sup>47</sup> 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

Tree Assessment	Quantity	TAT Result			PG&E Reassessment		
		Abate	Do Not Abate	Other <sup>48</sup>	Abate	Do Not Abate	Already Removed
<i>TAT Do Not Abate or Other</i>	51		3	48	19	25	7
<i>Mitigated by Removal</i>	43			43			43
<i>TAT Abate</i>	5	5			5 <sup>49</sup>		
<b>Totals</b>	<b>99</b>	<b>3</b>	<b>5</b>	<b>91</b>	<b>24</b>	<b>25</b>	<b>50</b>

### 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&E’s 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

<sup>48</sup> Other – Prior to TAT or Tree has been Removed

<sup>49</sup> 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.<sup>50</sup> 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.<sup>51</sup>

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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<sup>50</sup> 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

<sup>51</sup> 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.<sup>52</sup>

<sup>52</sup> 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

<b>Total Tree Connects Observed</b>	<b>Tree Connects Assessed as Live &amp; Sound</b>	<b>Potential Hazard Tree</b>	<b>Tree Topped to Pole Height</b>	<b>Pole Installed - Tree Connect Removed</b>
190	150	6	26	8
<i>% of Total</i>	<i>79%</i>	<i>3%</i>	<i>14%</i>	<i>4%</i>

### 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%<sup>53</sup>.

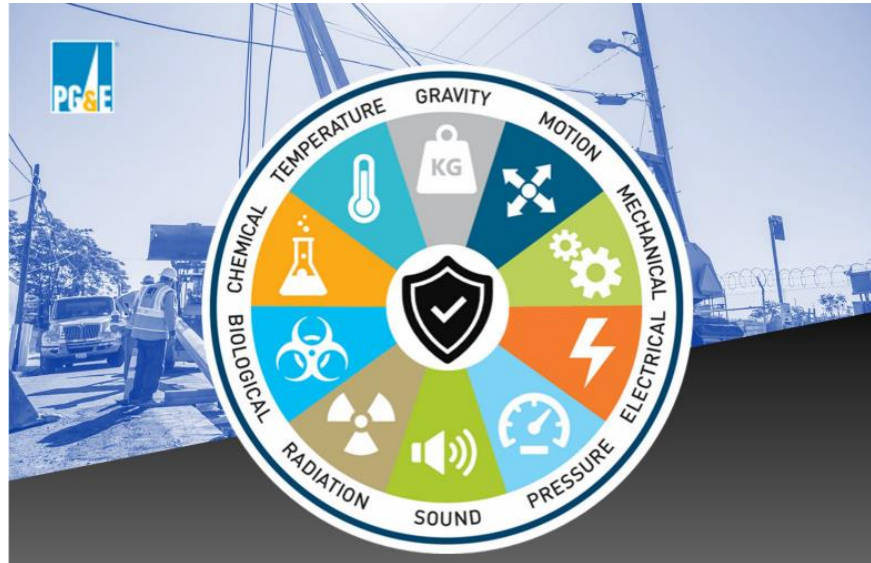


Figure 21: PG&E's Energy Wheels used during pre-job briefings or tailboards

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<sup>54</sup> to the PSEMS framework is complete, supporting consistency across company operations.

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

<sup>54</sup> 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
<b>Element 1:</b> Leadership Commitment, Accountability and Employee Participation	<b>Element 1:</b> Leadership, Commitment & Engagement
<b>Element 7:</b> Communication and Stakeholder Engagement	<b>Element 2:</b> Communication & Stakeholder Awareness
<b>Element 3:</b> Risk Management	<b>Element 3:</b> Risk Management
<b>Element 2:</b> Asset Management and Life Cycle Planning	<b>Element 4:</b> Strategy, Objectives & Planning
<b>Element 6:</b> Operational Planning and Controls	<b>Element 5:</b> Operational Control
<b>Element 10:</b> Training Competency and Awareness	<b>Element 6:</b> Training & Competence
<b>Element 13:</b> Emergency Preparedness and Response	<b>Element 7:</b> Emergency Preparedness & Response
<b>Element 4:</b> Incident Investigation and Corrective Action	<b>Element 8:</b> Incident Reporting, Investigation & Corrective Action
<b>Element 9:</b> Contractor Management and Third-Party Services	<b>Element 9:</b> Contractor Management & Third-Party Services
<b>Element 11:</b> Management of Change	<b>Element 10:</b> Management of Change
<b>Element 8:</b> Information, Documentation and Records Management	<b>Element 11:</b> Information, Documentation & Records Management
<b>Element 12:</b> Monitoring and Measurement <b>Element 15:</b> Continuous Improvement <b>Element 16:</b> Management Review	<b>Element 12:</b> Performance Evaluation & Improvement
<b>Element 14:</b> Auditing <b>Element 5:</b> Compliance with Legal, Regulator and other Operational Requirements <b>Element 15:</b> Quality Management	<b>Element 13:</b> 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.<sup>55</sup> Because many of the following CAs are programmatic, the CAs will influence the evolving PSEMS program, as appropriate. The

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<sup>55</sup> 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<sup>56</sup> to encourage prompt reporting, learning and communication for instances where a clearance

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<sup>56</sup> 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,<sup>57</sup> 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

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<sup>57</sup> 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 11<sup>th</sup>, 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.<sup>58</sup> 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

<sup>58</sup> 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&E's 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)*

<b>Project Year</b>	<b>Traditional Project Miles</b>	<b>Non-Traditional Project Miles</b>
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*

<b>Project Year</b>	<b>ILI Upgrade Projects</b>
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.