BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Further Develop a Risk-Based Decision-Making Framework for Electric and Gas Utilities.	R.20-07-013 (Filed July 16, 2020)
NOT CONSOLIDATED	
Application of Pacific Gas and Electric Company (U 39 M) to Submit Its 2020 Risk Assessment and Mitigation Phase Report.	A.20-06-012 (Filed on June 30, 2020)
NOT CONSOLIDATED	
Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2023. (U 39 M)	A.21-06-021 (Filed on June 30, 2021)

PACIFIC GAS AND ELECTRIC COMPANY'S (U39M)
SAFETY AND OPERATIONAL METRICS REPORT

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Dated: April 1, 2025

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PACIFIC GAS AND ELECTRIC COMPANY'S (U39M)
SAFETY AND OPERATIONAL METRICS REPORT

Pacific Gas and Electric Company (PG&E) hereby submits this semi-annual Safety and Operational Metrics Report in compliance with California Public Utilities Commission Decision (D.) 21-11-009. This is PG&E's seventh report which covers the period from January 1 to December 31, 2024. The report is provided as Attachment 1.

To assist in the review of this report, PG&E has identified material changes from the last report in blue font. PG&E has done this as a courtesy to parties. PG&E asks for the parties' understanding should there be any inadvertent mistakes in our good faith attempt at this formatting.

Separately, PG&E is concurrently filing and serving a "Notice of Availability of Pacific Gas and Electric Company's 'Safety and Operational Metrics Report:

Supporting Documentation'" due to the size of the electronic files associated with the material supporting the attached report.

Respectfully Submitted,

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Dated: April 1, 2025

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT 1

PACIFIC GAS AND ELECTRIC COMPANY

SAFETY AND OPERATIONAL METRICS REPORT

APRIL 1, 2024

PACIFIC GAS AND ELECTRIC COMPANY
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SAFETY AND OPERATIONAL METRICS REPORT:
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INTRODUCTION

For this report Pacific Gas and Electric Company is identifying material changes in blue font.

A. Introduction

Pacific Gas and Electric Company (PG&E or the Company) respectfully submits this seventh semi-annual Safety and Operational Metrics (SOM) Report. This report is submitted in compliance with California Public Utilities Commission (CPUC or Commission) Decision (D.) 21-11-009 concerning the Risk-Based Decision-Making Framework proceeding (Risk OIR).

At PG&E, nothing is more important than the safety of our customers, employees, contractors, and communities. We strive to be the safest, most-reliable gas and electric Company in the United States. This SOM report demonstrates PG&E's commitment to overseeing safe operations and, where needed, driving progress to reduce risk and improve performance. SOMs are embedded in our internal processes to give Company leaders visibility into performance to identify negative trends and take swift corrective actions to prevent harm. These metrics are central to safety performance across the Company.

PG&E has approached each SOM on a metric-by-metric basis. More specifically, PG&E evaluated our historical and current year performance and available benchmarking data, and established objectives that align with our commitment to safety. For example, a metric where PG&E already performs in the first quartile may not demand dramatic improvement but could require consistent monitoring to ensure that performance remains at acceptable levels. For metrics that include Major Event Days (MED), PG&E will use the information to help ensure that our infrastructure is adaptable to an environment rapidly changing due to climate change. For some metrics, the Company has found opportunity to continue to drive safety performance through ongoing or future programs that are described in each chapter of this report.

B. Background and Requirements

As part of the decision for PG&E's Plan of Reorganization (D.20-05-053), the Commission envisioned a set of metrics that provides a "holistic quantitative and qualitative 'indicator light' method to evaluate key metrics directly associated with PG&E safe and operational performance."

On November 9, 2021, through the Commission's Risk OIR that began on November 17, 2020, the Commission issued D.21-11-009 (the Risk OIR decision) establishing 32 SOMs. Ordering Paragraph 5 of that decision requires that:

> PG&E shall report its Safety and Operational Metrics as follows. PG&E shall, on a semi-annual basis, serve and file its SOMs report in Rulemaking 20-07-013, any successor Safety Model Assessment Proceeding, and its most recent or current General Rate Case and Risk Assessment and Mitigation Phase proceedings starting March 31, 2022, and continuing annually at the end of September and March thereafter, with the March reports covering the 12 months of the previous calendar year (i.e., January through December) and the September reports providing data for January through June of the current year. PG&E shall concurrently send a copy of its semi-annual SOMs reports to the Director of the Commission's Safety Policy Division and to RASA_Email@cpuc.ca.gov. PG&E shall:
>
> a) Report on each SOM, using data for the preceding 12 months and providing all available historical data;[1]
>
> b) For each SOM, provide a proposed target for the year following the reporting period for each metric and a 5-year target, with the proposed target represented as specific values, ranges of values, a rolling average, or another specified target value, except for our final adopted SOM #s 1.3, 2.3, 3.1, 3.3, 3.5, and 3.6 for which PG&E may provide directional targets;
>
> c) For each SOM, provide a narrative description of the rationale for selecting the target proposed and why a specific value, a range of values, a rolling average or another type of target is selected;
>
> d) For each SOM, provide a narrative description of progress towards the proposed annual and 5-year targets;
>
> e) For each SOM, provide a narrative description of any substantial deviation from prior trends based on quantitative and qualitative analysis, as applicable;
>
> f) For each SOM, provide a brief description of current and future activities to meet the proposed targets; and

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[1] These historic data files are provided through a Notice of Availability (NOA) being filed concurrently with this report. An index of these files is provided as an attachment to the NOA.

g) Provide the Commission's Safety and Policy Division with a copy of any report filed more frequently than semi-annually with the Commission that contains SOMs, at the same time the report is filed.[2]

This report outlines PG&E's 2024 performance and is organized into 32 individual metric chapters as defined in Attachment A of D.21-11-009. Each chapter provides discussion on performance and progress against 1- and 5-year targets.

C. PG&E's Approach to Safety and Operational Metrics Target Setting

PG&E's approach to SOMs was developed around four pillars for developing targets that align with Commission's objective for this report:

1) Targets should be set at levels indicating "insufficient progress" or "poor performance" within the context of the Enhanced Oversight and Enforcement Process;
2) Targets should be set at a reasonable and attainable level, including but not limited to the following considerations:
   a) Historical data and trends;
   b) Benchmarking;
   c) Applicable federal, state, or regulatory requirements;
   d) Resources;
3) Targets should be set at levels where performance can be sustained over time; and
4) Targets should be set and evaluated in consideration of a holistic qualitative and quantitative view including additional contextual information and factors.

With these criteria, PG&E sought to develop targets for each metric that generally maintain performance for well-performing metrics or drive performance improvement to satisfactory levels of safe and reliable service. As required by the decision, within each metric chapter PG&E provides the rationale behind the selection of the 1- and 5-year targets. On their own, metrics can fail to tell a complete story and may not provide crucial detail or context that is necessary for

2 PG&E understands this requirement to not include one-time event triggered reports (e.g., Electric Incident Reports). PG&E can provide such reports upon request. Note that PG&E provided quarterly reports as part of the Wildfire Mitigation Plan to the Commission through June 2021 but are now submitted to the Office of Energy Infrastructure Safety. These reports can be found online at PG&E's Wildfire Mitigation Plan webpage.

a proper evaluation of performance or progress. Recognizing that, the Commission's Risk OIR decision requires PG&E to provide a narrative-driven report that gives the Commission further insight on how PG&E's safety and operational programs are progressing towards targets or if performance is deviating from target and trend, and to state current and future activities that will drive performance towards target or trend.

5) PG&E and the Commission's Safety Policy Division (SPD) continue to participate in monthly meetings to discuss questions arising from prior reports, or, in some instances to preview expected performance or target-setting for upcoming reports. These meetings have proven successful in providing PG&E ongoing guidance for target-setting and as an effective way to resolve questions through metric owner presentations. Additionally, PG&E uses feedback from these meetings to engage leadership and to address SPD recommendations where possible. PG&E will continue to drive performance improvement where appropriate, and prioritize the safety of our customers, contractors, and employees.

D. Summary of Metric Performance Against Targets

This report shows that PG&E is exceeding or maintaining performance expectations against its 2024 targets for 28 of 32 metrics. The following four metrics did not meet expectations:

- SOM 3.11, GO-95 Corrective Actions, saw a performance of 67.9 percent which is below the 2024 one-year target of 69 percent. The root causes of lower performance are (1) lower than expected on-time completions of Transmission corrective tags due to clearance constraints, emergency activations, and rescheduling conflicts, and (2) lower than expected on-time completions of Vegetation Management work due to lower than expected find rates.
- SOMs 3.13 and 3.14, Number and Percentage of CPUC-Reportable Ignitions in HFTD Areas (Distribution), was above target for 2024. PG&E finished 2024 with 89 CPUC reportable ignitions in HFTD attributable to overhead distribution assets (corresponding to a rate of 3.58 ignitions per 1,000 circuit miles). While these results were higher than the previous year (2023) (57 ignitions), the 89 ignitions in 2024 are consistent with the average number of ignitions for the previous three years (89 ignitions).

- SOM 5.1, Clean Energy Goals Compliance Metrics (CEM), is off track as of June 2024. CEM reports PG&E's progress towards meeting the procurement obligations in the following CPUC decisions: (1) D.19-11-016, (2) D.21-06-035, and (3) D.23-02-040; together, the Integrated Resource Planning (IRP) Decisions. From 2019 - 2023, PG&E signed contracts with enough new-build resources to meet its 2024 CEM SOM target. However, after execution, several projects with expected online dates by June 1, 2024, have encountered delays, causing the Utility to now fall short of the 2024 CEM SOM target for some months. PG&E is actively pursuing qualified bridge resources to close all gaps and has a reasonable expectation of doing so. PG&E updates the CPUC Energy Division regularly on all IRP procurement, including the CEM.

PG&E has updated the one-year targets for 20 of the 32 metrics evaluated in this report. 12 metrics carry the same one-year targets from the previous year and PG&E includes a justification, on a case-by-case basis, on why maintaining metric performance is the appropriate approach.

Below is a summary of each metric 2024 performance and 2025 targets. The details for each metric can be found in each of the metric report chapters that follow.

TABLE 1-1
SUMMARY OF 2024 METRIC PERFORMANCE AND TARGETS

#	Metric	2024 Performance	2024 Target	2025 Target
Safety				
1.1	Rate of Serious Injury or Fatality (SIF) Actual (Employee)	Rate: 0.059	Rate: 0.060	Rate: 0.06
1.2	Rate of SIF Actual (Contractor)	Rate: 0.041	Rate: 0.100	Rate: 0.10
1.3	SIF Actual (Public)	2	Demonstrate progress towards 0	Demonstrate progress towards 0
Reliability				
2.1	System Average Interruption Duration (Unplanned)	3.77 hrs.	3.71 – 5.73 hrs.	3.68 – 5.69 hrs.
2.2	System Average Interruption Frequency (Unplanned)	1.630 outages per customer	1.435 – 2.219 outages per customer	1.555 – 2.405 outages per customer
2.3	System Average Outages due to Vegetation and Equipment Damage in High Fire Threat District (HFTD) Areas MEDs	117 CESO due to 5 MEDs	Maintain	Maintain
2.4	System Average Outages due to Vegetation and Equipment Damage in HFTD Areas (Non-MEDs)	1,713 CESO	1,523 – 1,980 CESO	1523 - 1980 CESO

TABLE 1-1
SUMMARY OF 2024 METRIC PERFORMANCE AND TARGETS
(CONTINUED)

#	Metric	2024 Performance	2024 Target	2025 Target
Electric				
3.1	Wires Down MED in HFTD Areas (Distribution)	3.10wires down (WD) events/1,000 mi. due to 2 MEDs	Maintain/65.94	Maintain/65.69
3.2	Wires Down Non-MED in HFTD Areas (Distribution)	22.19 WD events/1,000 mi.	Maintain/41.30	Maintain/40.25
3.3	Wires Down MED in HFTD Areas (Transmission)	2.962 WD events/1,000 mi, due to 5 MEDs	Maintain/8.433	Maintain/<8.433
3.4	Wires Down Non-MED in HFTD Areas (Transmission)	3.147 WD events/1,000 mi.	Maintain/≤4.440	≤ 4.440
3.5	Wires Down Red Flag Warning Days in HFTD Areas (Distribution)	0.00017 WD due to 15 WD events	Maintain/0.00057	Maintain/0.00057
3.6	Wires Down Red Flag Warning Days in HFTD Areas (Transmission)	0 WD due to 0 WD events	Maintain	Maintain
Patrols and Inspections				
3.7	Missed Overhead Distribution Patrols in HFTD Areas	0%	0% – 4%	0% – 4%
3.8	Missed Overhead Distribution Detailed Inspections in HFTD Areas	0%	0% – 2%	0% – 2%
3.9	Missed Overhead Transmission Patrols in HFTD Areas	0.00%	0.00% – 0.03%	0.0% – 0.03%
3.10	Missed Overhead Transmission Detailed Inspections in HFTD Areas	0.00%	0.00% – 0.03%	0.0% – 0.03%
3.11	GO-95 Corrective Actions in HFTDs	67.9%	69%	73.8%
3.12	Electric Emergency Response Time	Average: 29 min Median: 27 min	Average: 44 min Median: 43 min	Average: 44 min Median: 43 min

TABLE 1-1
SUMMARY OF 2024 METRIC PERFORMANCE AND TARGETS (CONTINUED)

#	Metric	2024 Performance	2024 Target	2025 Target
Ignitions and Wildfire				
3.13	Number of CPUC-Reportable Ignitions in HFTD Areas (Distribution)	89 ignitions	Range: 72 – 84	Range: 70 – 128
3.14	Percentage of CPUC-Reportable Ignitions in HFTD Areas (Distribution)	3.58/1,000 circuit miles	Range: 2.89 – 3.38	Range: 2.83 – 5.18
3.15	Number of CPUC-Reportable Ignitions in HFTD Areas (Transmission)	9 ignitions	Range: 0 – 10	Range: 4 – 12
3.16	Percentage of CPUC-Reportable Ignitions in HFTD Areas (Transmission)	1.67/1,000 circuit miles	0 – 1.85	0.73 – 2.21
Gas				
4.1	Number of Gas Dig-Ins per 1,000 USA tickets on Transmission and Distribution pipelines	1.30	≤1.93	≤1.94
4.2	Number of Overpressure Events	4	≤10	≤10
4.3	Time to Respond On-Site to Emergency Notification	Average (mins): 19.6 Median (mins): 18.1	Average (mins): ≤21.4 Median (mins): ≤19.7	Average (mins): ≤21.3 Median (mins): ≤19.6
4.4	Gas Shut-In Times, Mains	83.6 mins	≤84.9 mins	≤87.4 mins
4.5	Gas Shut-In Times, Services	34.2 mins	≤40.2 mins	≤39.8 mins
4.6	Uncontrolled Release of Gas on Transmission Pipelines	1639	≤3,474	≤3440
4.7	Time to Resolve Hazardous Conditions	132.9 mins	≤182.5 mins	≤173.9 mins
Clean Energy				
5.1	Clean Energy Goals Compliance Metric	2332.8 MW	≥2366.1 MW	≥2666.1 MW
Quality of Service				
6.1	Quality of Service Metric	12 sec	≤15 sec	≤15 sec

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 1.1
RATE OF SIF ACTUAL
(EMPLOYEE)

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PACIFIC GAS AND ELECTRIC COMPANY SAFETY AND OPERATIONAL METRICS REPORT: CHAPTER 1.1 RATE OF SIF ACTUAL (EMPLOYEE)

The material updates to this chapter, since the September 30, 2024 report, are identified in blue font.

A. (1.1) Overview

1. Metric Definition

Safety and Operational Metric (SOM) 1.1 – Rate of Serious Injury and Fatality (SIF) Actual (Employee) is defined as:

Rate of SIF Actual (Employee) is calculated using the formula: Number of SIF-Actual cases among employees x 200,000/employee hours worked, where SIF Actual is counted using the methodology developed by the Edison Electric Institute's (EEI) Occupational Safety and Health Committee (OS&HC).

2. Introduction of Metric

Pacific Gas and Electric Company's (PG&E or the Company) safety stand is, "Everyone and Everything Is Always Safe." This includes our employee and contractor workforce, as well as the public. We remain committed to building an organization where every work activity is designed to facilitate safe working conditions and every member of our workforce is encouraged to speak up if they see an unsafe or risky condition with the confidence that their concerns and ideas will be heard and addressed. As part of this stand, PG&E is committed to employee safety.

As defined by Decision (D.) 21-11-009, the SIF Actual (Employee) SOM calculation is relatively new in application to PG&E's existing injury and SIF dataset. The data were analyzed and reported under this definition beginning with the first report which was submitted in March of 2022.

The EEI OS&HC serious injury criteria are updated annually based on additional learnings from injury classification to provide further clarification or criteria for the following year. In 2024, PG&E used the 2023 OS&HC

serious injury criteria found in Appendix 7 of the EEI Safety Classification and Learning Model guidance.[1] The criteria include:

1) Fatalities;
2) Amputations (involving bone);
3) Concussions and/or cerebral hemorrhages;
4) Injury or trauma to internal organs;
5) Bone fractures (certain types);
6) Complete tendon, ligament, and cartilage tears of the major joints (e.g., shoulder, elbow, wrist, hip, knee, and ankle).
7) Herniated disks (neck or back);
8) Lacerations resulting in severed tendons and/or a deep wound requiring internal stitches;
9) Second (10 percent body surface) or third-degree burns;
10) Eye injuries resulting in eye damage or loss of vision;
11) Injections of foreign materials (e.g., hydraulic fluid);
12) Severe heat exhaustion and all heat stroke cases;
13) Dislocation of a major joint (shoulder, elbow, wrist, hip, knee, and ankle);
    a) Count only cases that required the manipulation or repositioning of the joint back into place under the direction of a treating doctor.
14) “Other Injuries” category should only be selected for reporting injuries not identified in the existing categories.

PG&E’s SIF Program was deployed at the end of 2016 to establish a cause evaluation process for coworker serious safety incidents. This program was established to create consistency and guidance in classifying and evaluating serious safety incidents for all employees and contractors. The goal of PG&E’s SIF Program is to reduce the number and severity of safety incidents that result in a SIF. The program objective is to learn from prior safety incidents by performing cause evaluations on each SIF Actual and SIF Potential incident, implementing corrective actions, and sharing key findings across the enterprise.

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[1] EEI Safety Classification and Learning (SCL) model guidance. Serious Injury criteria are located in Appendix 7. SCL model guidance.

From 2017 to 2020, PG&E classified SIF-A incidents based on the job task and whether a life altering or life-threatening injury, or fatality occurred. In August of 2020, PG&E adopted Edison Electric International's SCL[2] model to classify its SIF incidents. The EEI SCL model classifies incidents into categories: High-Energy SIF (HSIF),[3] Low-Energy SIF (LSIF),[4] Potential SIF (PSIF),[5] Capacity,[6] Exposure,[7] Success,[8] and Low Severity.[9] In 2020, the HSIF terminology was new to the industry; however, it is equivalent to a SIF-A with regard to how serious life threatening or life-altering injuries, or fatalities are determined, per PG&E definition. Adopting the EEI SCL model has improved the SIF Program by bringing a consistent and objective approach to reviewing and classifying SIF incidents across the Company and industry. The SCL model allows the Company to focus its safety and risk mitigation efforts on the most serious outcomes and highest risk work where a high energy incident occurred. The EEI SCL model is also used for the Employee SIF-A Safety Performance Metric (SPM) and is aligned with other California utilities.

The rate of SIF-A (Employee) SOM definition is based on the EEI OS&HC serious injury criteria,[10] which is different than the EEI SCL Model. It is suggested by EEI to use the OS&HC criteria in conjunction with the EEI SCL model. Therefore, using only the OS&HC serious injury criteria creates

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2 EEI, SCL Model available here: https://www.safetyfunction.com/scl-model.

3 *Id.* at p. 17, HSIF is defined as: "Incident with a release of high energy in the absence of a direct control where a serious injury is sustained."

4 *Id.* at p. 17, LSIF is defined as: "Incident with a release of low energy in the absence of a direct control where a serious injury is sustained."

5 *Id.* at p. 17, PSIF is defined as: "Incident with a release of high energy in the absence of a direct control where a serious injury is not sustained."

6 *Id.* at p. 17, Capacity is defined as: "Incident with a release of high energy in the presence of a direct control where a serious injury is not sustained."

7 *Id.* at p. 17, Exposure is defined as: "Condition where high energy is present in the absence of a direct control."

8 *Id.* at p. 17, Success is defined as: "Condition where a high energy incident does not occur because of the presence of a direct control."

9 *Id.* at p. 17, Low Severity is defined as: "Incident with a release of low energy where no serious injury is sustained."

10 EEI Safety Serious Injury criteria effective January 1, 2025. https://www.eei.org/-/media/Project/EEI/Documents/Issues-and-Policy/Power-to-Prevent-SIF/EEISIF.pdf.

a different result in SIF-A classification from the expectation of using the EEI SCL model that includes high energy incidents.

Beginning this year, PG&E will use the updated EEI OS&HC serious injury criteria that were effective January 1, 2025.[11]

B. (1.1) Metric Performance

1. Historical Data (2017 – 2024)

PG&E is including historical data for the years 2017 through 2024[12] in this report. This timeframe is consistent with the implementation of PG&E's SIF Program. The dataset includes injury type, incident date, location, and EEI OS&HC injury classification. See corresponding Employee SIF SOM data file for a list of incidents.

Figure 1.1-1 illustrates the rate of employee serious injuries and fatalities by year from 2017 through 2024. From 2017 through 2024 there are a total of 85 employee SIF Actuals that met the EEI OS&HC serious injury criteria as described in Section A.2. above. Fifty-six percent of the serious injury incidents (48 of 85) met the criteria of bone fracture, including of the hands and feet. Six were fatalities, of those, one involved a violent act of a third party, three involved operations of motor vehicles, one involved a pipeline drying (pigging) line of fire incident, and one involved a tire changing incident. There were no fatalities in 2024.

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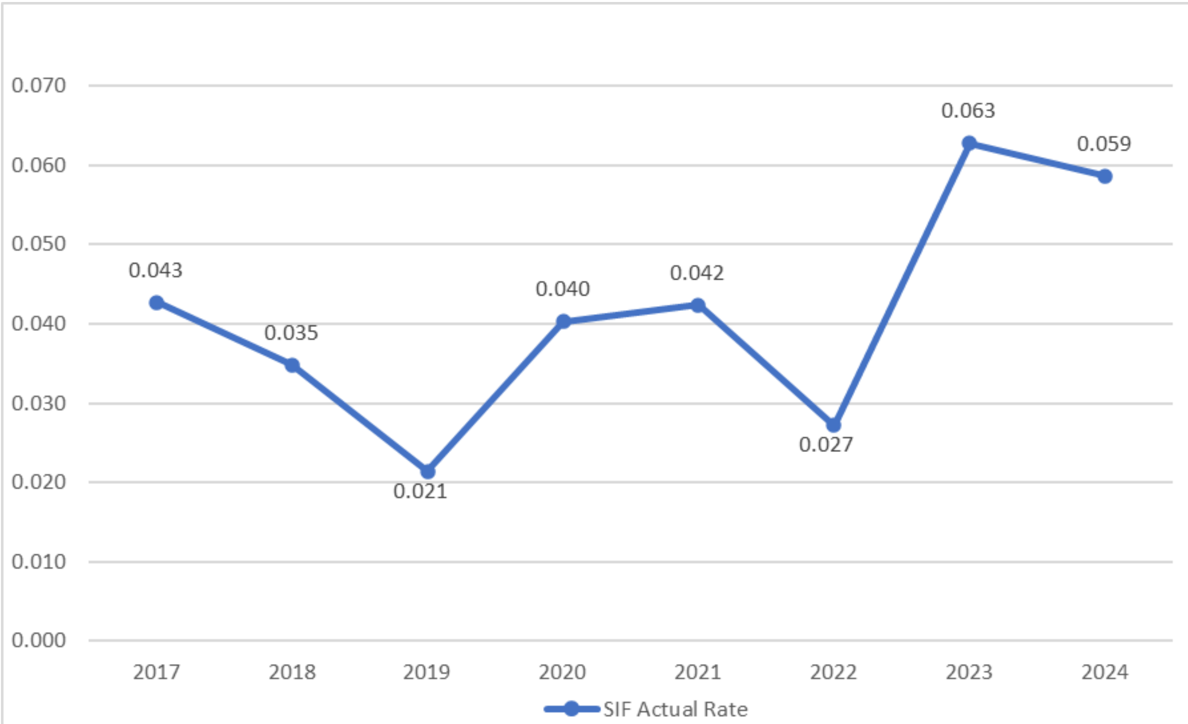
11 https://www.eei.org/-/media/Project/EEI/Documents/Issues-and-Policy/Power-to-Prevent-SIF/EEISIF.pdf.

12 Historical data through 2021 was provided in PG&E's first SOM report provided on April 1, 2022.

FIGURE 1.1-1
RATE OF SIF ACTUAL (EMPLOYEE)
HISTORICAL PERFORMANCE



2. Data Collection Methodology

Injury data are collected by the Nurse Care Line (NCL). The NCL is an enhanced injury reporting process for improving the employee experience when reporting major and minor work-related injuries. The NCL allows employees to speak up, without fear, when faced with a work-related health challenge, strengthening the message that employee health is essential. Employees receive medical advice, self-care information, and clinic referrals. For this review, injury data was pulled from PG&E's Safety and Environmental Management System (SEMS) database, which houses all employee injury data.

As mentioned above, the SIF-A (Employee) SOM as defined in D.21-11-009 is relatively new in application to PG&E's existing injury and SIF dataset, and 2022 was the first year in which the data were analyzed and reported under this definition. To evaluate and establish historical performance for the SOM SIF-A (Employee) metric, PG&E reviewed all employee injury data from 2017 through 2024 to determine if any met one of the 14 EEI OS&HC serious injury criteria as summarized in Section A.2.

above. To establish historical performance for the first SOMs report submittal, PG&E reviewed approximately 18,000-line items of injury data. A substantial portion of those were not Occupational Safety and Health Administration (OSHA)-recordable (i.e., first aid, non-OSHA recordable) and were removed from the population. The remaining population that met the OSHA definition (i.e., work-related injury) was reviewed against the EEI OS&HC serious injury criteria for this report.

3. Metric Performance for the Reporting Period

For 2024, there were 17 employee serious injuries. 59 percent of the employee serious injuries were due to bone fractures (10 of 17). These included bone fractures of the ankle, foot, fingers, and arm.

The 2024 SIF rate of 0.059 is a slight decrease from the year end 2023 rate of 0.063. PG&E's current and planned work activities for improving the long-term performance of this metric are discussed in Section E below.

C. (1.1) 1-Year Target and 5-Year Target

1. Updates to 1- and 5-Year Targets Since Last Report

There have been no changes to the 1-year and 5-year targets since the last SOMs report filing. The 2024 target for rate of SIF-A (Employee) was to remain below the third quartile threshold rate of 0.060 (see Figure 1.1-2 below). The 2025 and 2029 target thresholds of 0.06 considered EEI benchmarking data using previously approved EEI OS&HC criteria.

It should be noted that although the 2024 EEI third quartile threshold value has shifted slightly upward from 0.070 to 0.090, PG&E's 2024 target threshold for the employee SIF Actual remained as 0.060 through 2024. Targets will be re-established once benchmarking data are available that use the new EEI criteria (effective January 1, 2025). As such, we continue to monitor this target and changes in EEI benchmarking data.

2. Target Methodology

To establish the 1-year and 5-year target thresholds, PG&E considered the following factors:

- Historical Data and Trends: PG&E pulled OSHA recorded injuries from 2017 to 2021 to review each injury against the EEI OS&HC serious injury criteria. This injury dataset was used because it aligns with the beginning of the PG&E SIF Program (est. in 2017). Over that historical data period, performance showed a consistent trend at or around 0.040 injury rate, with a dip in 2019 and trend back up in 2020 and 2021; A similar pattern occurred for the years 2022 and 2023 with a dip in rate and then an increase, but still below the 2023 threshold target rate of 0.070. For 2024, PG&E's 2024 target threshold for the employee SIF Actual is 0.060 which represents 0.010 target decrease comparable with PG&E internal benchmarking practices. Given the 2024 EEI third quartile threshold value has shifted slightly upward from 0.070 to 0.090 and the introduction of the new EEI serious injury criteria that became effective at the beginning of this year, we are continuing to monitor the appropriateness of this target. (See Figure 1-1.2 below).

- Benchmarking: In July 2022, PG&E met with EEI leadership and confirmed that OS&HC serious injury criteria benchmarking is available for the metric going back to 2017. Since then PG&E has used benchmarking data from EEI for comparison with PG&E's performance. PG&E's performance for 2024 was below the second quartile threshold.
- Regulatory Requirements: None;
- Attainable Within Known Resources/Work Plan: Yes. We are focusing on high energy hazard identification and implementation of essential controls on the job.
- Appropriate/Sustainable Indicators: While the performance at or below the target threshold is sustainable, the more appropriate metric is to focus on injuries resulting from a high energy incident, which is consistent with both industry SIF-A monitoring and the SPM.
- Other Qualitative Considerations: This target threshold approach was established to account for all job-related tasks with the potential to cause injury as defined by the EEI OS&HC criteria.

3. 2025 and 2029 Target

The initial 2022 and 2026 target thresholds were to maintain at a rate of less 0.080 which allowed for no more than an increase of 0.038, as compared to highest employee SIF Actual rate from 2017 to 2021. The target threshold for 2023 incorporated available EEI employee SIF benchmarking data and the use of the second to third quartile threshold value of 0.070. The 2024 and 2028 target thresholds considered EEI benchmarking data with a 0.010 target decrease in 2024 comparable with PG&E internal benchmarking practices.

Although the 2024 EEI second to third quartile value has shifted slightly upward from 0.070 to 0.090, PG&E's 2025 and 2029 target thresholds for the employee SIF Actual remains as 0.06 and we are continuing to monitor this target as appropriate based on changes in EEI benchmarking data.

As discussed in C.1. above, PG&E's 2025 and 2029 target thresholds are in line with available EEI benchmarking data and PG&E target setting practices.

D. (1.1) Performance Against Target

1. Progress Towards the 1-Year Target

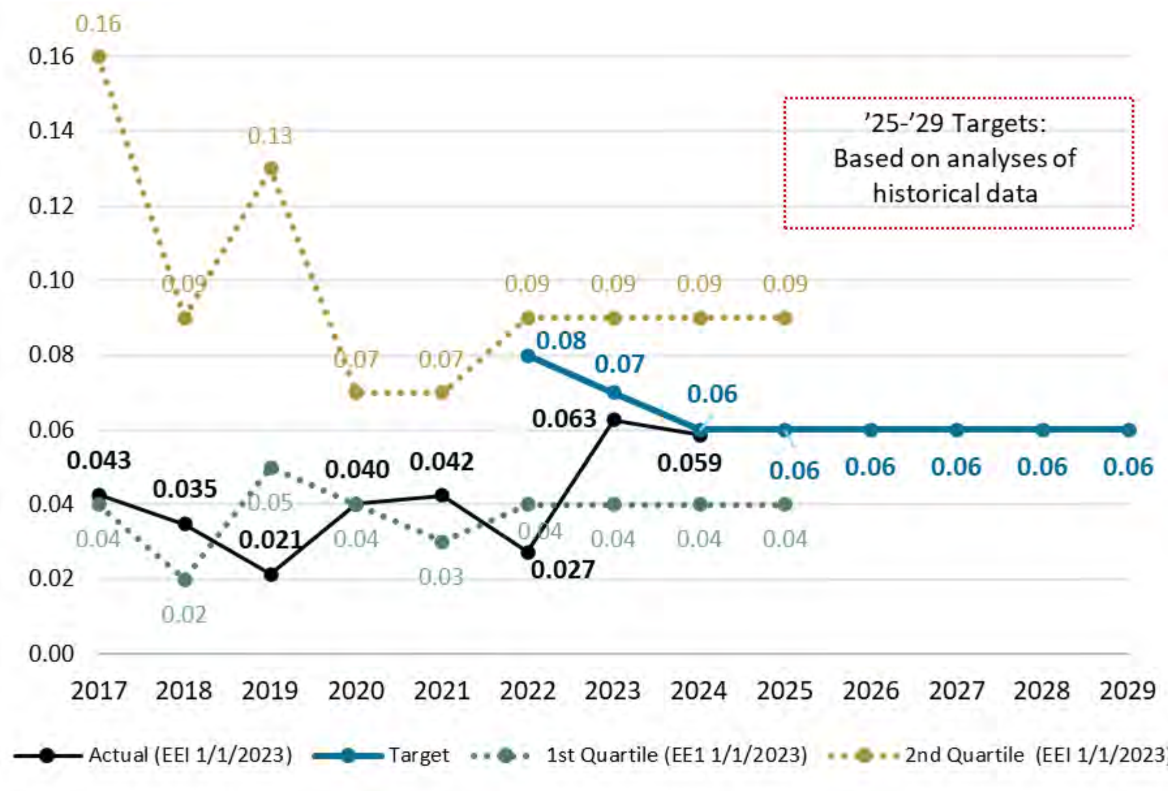
As demonstrated in Figure 1.1-2 below, PG&E saw an increase in the Employee SIF Actual rate from 0.027 in 2022 to 0.063 by the end of 2023. For 2024 there has been a slight decrease in the Employee SIF Actual rate. SOMs SIFs contributing to this rate continue to be primarily due to being in the direct path of a moving object or force (i.e., line of fire, including caught between, and dropped object incidents), and falls, slips, and trips incidents.

SIF investigations have been completed or are underway for the incidents including any needed corrective actions and we are continuing to monitor this trend. In addition, PG&E is implementing the SIF Capacity & Learning model as described in Section E below.

2. Progress Towards the 5-Year Target

As discussed in Section E below, and in consideration of the metric's trend, PG&E is continuing to deploy a number of programs to maintain or improve the long-term performance of this metric and to meet the Company's 5-year performance target.

FIGURE 1.1-2
RATE OF SIF ACTUAL (EMPLOYEE)
HISTORICAL PERFORMANCE AND TARGETS



E. (1.1) Current and Planned Work Activities

<u>SIF Capacity & Learning Model</u>: PG&E is implementing the SIF Capacity & Learning model which redefines safety as measured by the presence of essential controls and the capacity to experience failures safely. Worksite essential controls directly target the stuff that can kill or seriously injure a co-worker or contract partner. When the controls are installed, verified, and used properly, they are not vulnerable to human error. Looking at safety differently with the SIF Capacity and Learning Model advances how we understand, manage, and prevent serious injuries and fatalities. Instead of measuring our success by the number of incidents, we are defining safety by the presence of controls that give coworkers the ability to fail safely. In 2024, over 13,000 frontline workers were trained on the Energy Wheel, Stuff That Kills You and Essential Controls. Also in 2024, PG&E ended the year at 77 percent presence of controls for high energy hazards (using post-incident analysis).

Human Performance (HU) Tools: PG&E has implemented the 10 HU Tools which include: Questioning Attitude, Tailboards and Pre-Job Brief, Situational Awareness, Self-Checking (STAR), Two-Minute Rule, Three-Way Communication, Stop When Unsure, Procedure Use and Adherence, Phonetic Alphabet, and Placekeeping (i.e., physically marking steps in a procedure or other guiding document that have been completed). The HU Tools are deeply connected to the SIF Prevention Program and allow coworkers to slow things down and reduce the chances of human errors caused by internal and external factors. When used effectively, these tools can also help ensure essential controls effectively remain in place and do not break down.

PG&E Safety Excellence Management System (PSEMS): PSEMS is the systematic management of our processes, assets, and occupational health and safety programs to prevent injury and illness. It provides the framework to effectively and safely manage our assets and the integrity of our operating systems and processes. PSEMS attributes of a strong independent assurance program and a training program that encourages a positive attitude toward safety are part of a safety conscience work environment and reinforce performance in Asset Management, Occupational Health & Safety and Process Safety. PSEMS is also part of PG&E's Performance Playbook along with Breakthrough Thinking and the Lean Operating Model.

PSEMS follows the Plan, Do, Check, Act cycle of continuous improvement, ensuring processes are evaluated, coursed, and measured annually. In 2023, A Lloyd's Register Quality Assurance pre-assessment was conducted on the PSEMS implementation, non-conformities were found in Management of Change, Operational Control, Performance Evaluation & Improvement and Assurance. Gap Closure Plan completion is in progress. In 2024, desktop self-assessments were conducted determining baseline maturity scores and a management review was conducted in January 2025 to evaluate the progress and effectiveness of the management system to date and review the strategy moving forward.

Regional Safety Directors: PG&E's team includes a field safety organization led by five Regional Safety Directors who partner with the functional areas (FA) to advise on and facilitate health and safety program implementation and sustainability through the application of best safety practices in each region, and ensure consistency across PG&E.

Safety organization responsibilities for each region include delivering safety programs for safety culture improvements, field observations and hazards identification, and the evaluation of essential control systems for providing co-workers with the ability or “capacity” to safely recover from a high-energy incident without life-threatening or life altering injury if an error or mistake is made. Additional efforts include supporting incident investigations, training, safety tailboards, and emergency response.

PG&E’s SIF Prevention Program: All injuries and reported near hits are evaluated to determine the hazards classification and if the situation is a SIF-actual (work-related high-energy incident from work at or for PG&E that results in a fatality, life-threatening, or life-altering injury) or a SIF-potential (high-energy incident where a fatality or life threatening or altering injury is not sustained) event. The SIF Cause Evaluation team conducts or coordinates in-depth cause evaluations for all incidents classified as SIF-potential or SIF-actual. The results of these investigations and the identified corrective actions are monitored through the corrective action program to ensure timely completion and effectiveness including the elimination of recurrence. The SIF Prevention program is continuously improved through the annual review of existing program processes for enhancement and optimization. This ensures alignment with all FA[13] for enterprise-wide consistency and continuity.

Injury Management: The SIF-A (Employee) SOM definition includes injuries that can occur during any work activity (including low or no energy tasks such as lifting, walking, managing tools like knives), which is broader than the high energy incidents that a mature SIF Program focuses on. Therefore, a significant driver for improvement is within our occupational health organization where our OSHA and DART cases are managed. DART cases are employee OSHA-recordable injuries that involve Days Away from work and/or days on Restricted duty or a job Transfer because the employee is no longer able to perform his or her regular job. From 2019 through 2024 year end, there was an approximate 66 percent decrease in the employee DART rate (number of DART

13 PG&E changed its title for lines of business to FAs in 2022.

cases per 100 fulltime employees divided by number of hours worked). The efforts supporting this reduction include the expansion of PG&E's ergonomic programs and increased Industrial Athlete Specialists for job site evaluations. A primary goal of the efforts is reduced injury severity through injury prevention and early intervention care for employees. In alignment with this, we have strengthened the identification of the highest risk work groups and tasks for field and vehicle ergonomic injuries. We identify high-risk computer users through predictive modeling and provide targeted interventions. Additional efforts also include enhanced injury management containment for injuries at risk for escalation to DART and providing our people leaders with additional injury management training.

Safety Leadership Development: PG&E is continuing to improve Safety Leadership Development and supervisor coaching by continuing to update an impactful, practical training course for front line leaders. The Safety Leadership development program provides training for crew leaders (i.e., those individuals who lead teams of front-line employees doing field operations and maintenance work) so they have the necessary safety skills to create trust, set expectations, remove barriers to safety and identify and mitigate at risk behaviors.

Safety Observation Program: Safety Observations Program plays a critical role in helping to reduce employee and contractor injuries and fatalities by increasing awareness of hazards and exposures in the field, reinforcing positive work practices, and driving PG&E's Speak-Up culture. The Program includes the use of the SafetyNet observation analysis and reporting tool, and the Safety Observations dashboard to communicate safety successes and improvement opportunities to leadership. For 2024, approximately 180,000 co-worker (i.e., employee) and contractor safety engagement observations were conducted across PG&E with at-risk findings communicated to the respective FAs.

For 2024, PG&E continued High Energy Control Assessments (HECA) as part of the Field Safety Engagement program. HECA defines safety through the presence of controls for high energy hazards to assess whether front-line employees are adequately protected against life-threatening hazards. HECA is computed as the percentage of high-energy hazards that have corresponding direct controls.

Transportation Safety: PG&E Transportation Safety programs are designed to protect our employees and the public by establishing requirements and processes to help mitigate risks that can lead to motor vehicle incidents, improve safety performance, and increase awareness of all PG&E employees related to the operation of our motor vehicles. This comprehensive program was established to reduce the number of motor vehicle incidents that have the potential for serious injury, including fatal injury, to PG&E's employees, staff augmentation employees operating vehicles on Company business, and the public. Driver performance data is used to identify specific risk drivers for targeted intervention, including driver training, driver action plans and implementing vehicle safety technology. In addition, PG&E's Transportation Safety Department also ensures compliance with both the Federal Department of Transportation and California state regulations. Additional Motor Vehicle Safety (MVS) Incident risk reduction programs including cell phone blocking and in-cab camera technologies were discussed in the PG&E 2020 Risk Assessment and Mitigation Phase (RAMP) Report.[14] The cellular phone blocking program is currently in use with approximately 2,000 active users.

The program has effectively suppressed over 693,000 texts, over 1.5 million app notifications, and over 173,000 calls since the start of the program through December of 2024.

A Safe Driving Behavior policy and Driver Scorecard enhancement launched in August of 2023. Since then, 580 Action Plans have been initiated and 558 Action Plans have been completed through December 2024. In addition, Smith Driving courses are initiated for apprentice and new hires including behind the wheel and close quarter maneuvering courses.

The retrofit of 744 trouble trucks with Brigade Backeye 360 Camera System technology with an audible backing sensor and rear distance display. The four high-mounted external cameras eliminate blind spots with an in-cab HD display of front, back and both vehicle sides providing the driver improved visibility to see everything in the vehicle's path.

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[14] PG&E 2020 RAMP Report, Chapter 18, Risk Mitigation Plan: MVS Incident.

The retrofit of 410 gas service and electric meter trucks with backup sensor technology with in cab audible alerts and rear distance display. The backup sensors alert the driver of objects in the vehicles blind spot while backing.

PACIFIC GAS AND ELECTRIC COMPANY

SAFETY AND OPERATIONAL METRICS REPORT:

CHAPTER 1.2

RATE OF SIF ACTUAL

(CONTRACTOR)

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
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PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 1.2
RATE OF SIF ACTUAL
(CONTRACTOR)

The material updates to this chapter, since the September 30, 2024 report, are identified in blue font.

A. (1.2) Overview

1. Metric Definition

Safety and Operational Metric (SOM) 1.2 – Rate of Serious Injury and/or Fatality (SIF) Actual (Contractor) is defined as:

Rate of SIF Actual (Contractor) is calculated using the formula: Number of SIF-Actual cases among contractors x 200,000/contractor hours worked, where SIF-Actual is counted using the methodology developed by the Edison Electrical Institute's (EEI) Occupational Safety and Health Committee (OS&HC).

2. Introduction of Metric

Pacific Gas and Electric Company's (PG&E or the Company) safety stand is "Everyone and Everything is Always Safe." Nothing is more important than our goal of continued risk reduction to keep our customers, and the communities we serve as well as our workforce (employees and contractors) safe. PG&E employees and contractors must understand that their actions reflect this priority. Our safety culture begins with each of us individually and extends to our coworkers and our communities. As part of this stand, PG&E is committed to contractor safety.

As defined in Decision (D.) 21-11-009, the SIF Actual (Contractor) SOM calculation is relatively new in application to PG&E's existing injury and SIF dataset. The data were analyzed and reported under this definition beginning with the first report which was submitted in March of 2022.

The EEI OS&HC serious injury criteria are updated annually based on additional learnings from injury classification to provide further clarification or criteria for the following year. In 2024, PG&E used the 2023 OS&HC

serious injury criteria found in Appendix 7 in EEI Safety Classification and Learning Model guidance.[1] The criteria include:

1) Fatalities;
2) Amputations (involving bone);
3) Concussions and/or cerebral hemorrhages;
4) Injury or trauma to internal organs;
5) Bone fractures (certain types);
6) Complete tendon, ligament and cartilage tears of the major joints (e.g., shoulder, elbow, wrist, hip, knee, and ankle);
7) Herniated disks (neck or back);
8) Lacerations resulting in severed tendons and/or a deep wound requiring internal stitches;
9) Second (10 percent body surface) or third degree burns;
10) Eye injuries resulting in eye damage or loss of vision;
11) Injections of foreign materials (e.g., hydraulic fluid);
12) Severe heat exhaustion and all heat stroke cases;
13) Dislocation of a major joint (shoulder, elbow, wrist, hip, knee, and ankle):
    a) Count only cases that required the manipulation or repositioning of the joint back into place under the direction of a treating doctor; and
14) "Other Injuries" category should only be selected for reporting injuries not identified in the existing categories.

PG&E's SIF Program was deployed at the end of 2016 to establish a cause evaluation process for coworker serious safety incidents. When it was deployed only contractor incidents that resulted in a SIF Actual (fatality or serious injury that was defined as life threatening or life altering) were investigated by PG&E and entered into the Corrective Action Program (CAP). The contractor was responsible for investigating all other incidents and reporting back to PG&E, but those incidents were not entered into CAP.

From 2017 to 2020, PG&E classified SIF Actual (SIF-A) incidents based on the job task and whether a life altering or life-threatening injury, or fatality occurred. In August of 2020, PG&E adopted EEI Safety Classification

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1 EEI Safety Classification and Learning (SCL) model guidance. Serious Injury criteria are in Appendix 7. SCL model guidance.

Learning (SCL)[2] model to classify its SIF incidents. The EEI SCL model classifies incidents into categories: High-Energy SIF (HSIF),[3] Low-Energy SIF (LSIF),[4] Potential SIF (PSIF),[5] Capacity,[6] Exposure,[7] Success[8] and Low Severity.[9] In 2020, the HSIF terminology was new to the industry; however, it is equivalent to a SIF-A with regard to how serious life threatening or life-altering injuries, or fatalities are determined, per PG&E definition. Adopting the EEI SCL model has improved the SIF Program by bringing a consistent and objective approach to reviewing and classifying SIF incidents across the Company and industry. The SCL model allows the Company to focus its safety and risk mitigation efforts on the most serious outcomes and highest risk work where a high energy incident occurred. In addition, in June of 2020 PG&E modified the SIF Program to include internal classification and investigation of contractor SIF Potential (SIF-P) incidents.[10] This expanded requirement led to an increase in contractor injury data.

The rate of SIF-A (Contractor) SOM definition is based on the EEI OS&HC serious injury criteria[11] which is different than the EEI SCL Model. It is suggested by EEI to use the OS&HC criteria in conjunction with the EEI

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2 EEI, SCL Model available here: https://www.safetyfunction.com/scl-model.

3 *Id.* at p. 17, HSIF is defined as: "Incident with a release of high energy in the absence of a direct control where a serious injury is sustained."

4 *Id.* at p. 17, LSIF is defined as: "Incident with a release of low energy in the absence of a direct control where a serious injury is sustained."

5 *Id.* at p. 17, PSIF is defined as: "Incident with a release of high energy in the absence of a direct control where a serious injury is not sustained."

6 *Id*. at p. 17, Capacity is defined as: "Incident with a release of high energy in the presence of a direct control where a serious injury is not sustained."

7 *Id.* at p. 17, Exposure is defined as: "Condition where high energy is present in the absence of a direct control."

8 *Id.* at p. 17, Success is defined as: "Condition where a high energy incident does not occur because of the presence of a direct control."

9 *Id.* at p. 17, Low Severity is defined as: "Incident with a release of low energy where no serious injury is sustained."

10 SAFE-1100S-B001: Contractor SIF-P Incidents: Requiring SIF-P Incidents and Cause Evaluations Published 6/2020.

11 EEI Safety Serious Injury criteria effective January 1, 2025. https://www.eei.org/-/media/Project/EEI/Documents/Issues-and-Policy/Power-to-Prevent-SIF/EEISIF.pdf.

SCL model. Therefore, using only the OS&HC serious injury criteria creates a different result in SIF-A classification from the expectation of using the EEI SCL model that includes high energy incidents.

Beginning this year, PG&E will use the updated EEI OS&HC serious injury criteria that were effective January 1, 2025.[12]

B. (1.2) Metric Performance

1. Historical Data (2017 – 2024)

PG&E is including the years 2017 through 2024 in this report. The dataset includes injury type, incident date, location, and EEI OS&HC injury classification. See the corresponding Contractor SIF-A SOM data file for a list of incidents. Following the Kern Order Instituting Investigation (OII) Settlement Agreement,[13] PG&E deployed the SIF Program to investigate employee and contractor incidents resulting in life altering, life threatening, or fatal injuries. Beginning in 2017, PG&E only tracked contractor incidents that were classified through the SIF Program[14] meeting those criteria. Prior to the implementation of the Kern OII requirements, contractors were not required to report SIF incidents. In June 2020, PG&E expanded the SIF Program to include investigating contractor incidents rising to SIF-P classification (focusing on incidents that meet the EEI SCL methodology as described above). This increased the number and types of injuries and incidents that contractors are required to report[15] compared to prior years.[16]

Figure 1.2-1 illustrates the rate of contractor serious injuries and fatalities by year from 2017 through 2024 based on historical data availability as discussed above. For 2020 through 2024, the dataset reflects

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[12] https://www.eei.org/-/media/Project/EEI/Documents/Issues-and-Policy/Power-to-Prevent-SIF/EEISIF.pdf.

[13] Investigation (I.) 14-08-022, Kern OII (Aug. 28, 2014) Settlement Agreement with California Public Utilities Commission (CPUC) see D.15-07-014.

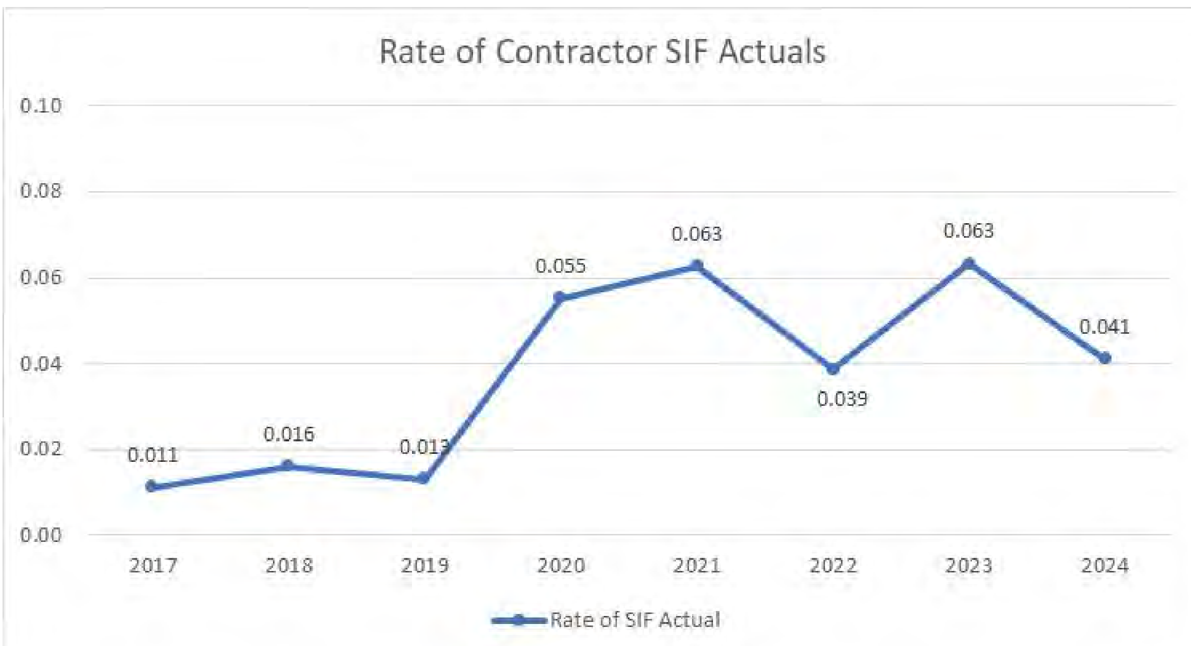
[14] SAFE-1100S Rev. 00 (2017): SIF Program.

[15] SAFE-1100S-B001.

[16] Note, the expanded incident reporting requirement implemented in 2020 does not include the broader SOM SIF-A (Contractor) EEI OS&HC serious injury criteria metric definition.

the expanded SIF-P incident reporting requirements for contractors implemented in June of 2020.[17] The 2017 through 2024 dataset includes a total of 82 contractor SIF Actuals that met the EEI OS&HC serious injury criteria as described in Section A.2. above. Sixty-five percent of the serious injury incidents (44 of 68 serious injuries) met the criteria of bone fracture, including of the hands and feet. Fourteen were fatalities, where one helicopter crash in 2020 claimed the lives of three individuals; the other fatalities involved an act of a third party, falls from trees, electrical pole gas pipe placement, and operations of motor and powered vehicles. There were no contractor fatalities in 2024.

FIGURE 1.2-1
RATE OF SIF ACTUAL (CONTRACTOR)
HISTORICAL PERFORMANCE



2. Data Collection Methodology

Contractor related Serious Safety Incidents[18] or any SIF-A or SIF-P incidents are reported to the Safety Helpline at Company number

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[17] SAFE-1100S-B001: Contractor SIF-P Incidents: Requiring SIF-P Incidents and Cause Evaluations Published 6/2020.

[18] As defined by SAFE-1004S: Safety Incident Notification and Response Management.

1-415-973-8700, Option 1 and then entered into the Enterprise CAP program for SIF review and classification.[19] PG&E's SIF Program[20] is managed through the CAP.

As mentioned above, the SIF-A (Contractor) SOM as defined in D.21-11-009 SOM calculation is relatively new in application to PG&E's existing injury and SIF dataset, and 2022 was the first year in which the data were analyzed and reported under this definition. To evaluate and establish historical performance for the SOM SIF-A (Contractor) metric, PG&E pulled data from the CAP system and reviewed 472 issues with the Issue Type of Contractor Safety. The list included both incidents or injuries reported to PG&E or entered in CAP from 2017 through 2021. Twenty-seven percent, or 128 incidents were related to gas dig-in by a third-party where no injuries occurred. The remaining issues were reviewed to determine if any met the 14 EEI OS&HC serious injury criteria as summarized in Section A.2. above. For the years 2022 through 2024, the same process was used to review Contractor Safety related CAPs entered on a monthly basis. A total of 368 contractor related CAPs were reviewed in 2022, 343 were reviewed for 2023, and 742 were reviewed during 2024.

3. Metric Performance for the Reporting Period

The 2024 SIF rate of 0.041 is a decrease from the end of year 2023 rate of 0.063. PG&E's current and planned work activities for improving the long-term performance of this metric are discussed in Section E below.

All the incidents involved a high-energy event and were classified as either SIF-A (HSIF) or SIF-P per the EEI SCL model and PG&E's SIF Standard.

Performance through 2024 against target is further discussed in Section D.1 below.

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[19] Per SAFE-1100S-B001, PG&E contractors are required to submit any Serious Safety Incidents or PSIF incidents to PG&E within 5-business days of becoming aware of the incident.

[20] SAFE-1100S: SIF Standard determined SIF classification and management.

C. (1.2) 1-Year Target and 5-Year Target

1. Updates to 1- and 5-Year Targets Since Last Report

There have been no changes to the 1- and 5-year targets since the last SOMs report filing. As mentioned above, the rate of Contractor SIF-A dataset includes the expanded SIF-P incident reporting requirements for contractors implemented in June of 2020. We will continue to monitor Contractor SIF-A trends and adjust the targets once the dataset has matured.

2. Target Methodology

To establish the 1-year and 5-year target thresholds, PG&E considered the following factors:

- Historical Data and Trends: The target threshold takes into consideration the historical increase (from 0.013 to 0.063) between 2019, 2020 and 2021, after expanding the contractor reporting requirements in 2020. This increased the amount and rate of contractor serious injuries (as defined by the EEI OS&HC serious injury criteria) by over 466-percent. It also takes into consideration that in 2022 PG&E expanded contractor injury reporting requirements to meet the SOM SIF-A OS&HC criteria;
- Benchmarking: Not available for EEI serious injury criteria effective January 1, 2025. PG&E confirmed that EEI is collecting these data among its utility members and hopes to increase benchmarking capability as more utilities begin to track contractor incident data. For establishing the SOM 1.2: SIF-A (Contractor) target threshold PG&E used the industry data that were available as a proxy to establish approximate calculations. PG&E will continue to refine its targets as benchmark data comes available;
- Regulatory Requirements: None;
- Attainable Within Known Resources/Work Plan: Yes. The main focus for driving down injuries is noted below in planned/future work related to Contractor Safety initiatives;
- Appropriate/Sustainable Indicators: While the performance at or below the target may be sustainable, the more appropriate metric is to focus

on injuries resulting from a high energy incident, which is consistent with both industry SIF-A monitoring and the SPM; and

- Other Qualitative Considerations: This target approach was established to account for all job-related tasks with the potential to cause injury as defined by the EEI OS&HC criteria.

3. 2025 and 2029 Target

Consistent with the 2024 (1-year) and 2028 (5-year) targets, the 2025 (1-year) and 2029 (5-year) target thresholds are to maintain a rate of less than 0.10. This target rate takes into consideration the historical increase (from 0.013 to 0.063) from 2019 through 2021 after expanding the contractor reporting requirements in 2020. It also considers that in 2022 PG&E expanded contractor injury reporting requirements to meet the SOM SIF-A (Contractor) defined EEI OS&HC criteria and that the rates are subject to change depending on number of contractors hours worked.

The target thresholds are set at the highest serious injury occurrence in one year that would be concerning if the rate was surpassed. Since this metric calculation is relatively new to PG&E and 2022 was the first year it was reported, the threshold takes into consideration historical data from 2020 and 2021 with an allowance for understanding this calculation and its consequences. The threshold allows for a 50-percent rate increase over 2021, which allows PG&E to refine expectations as this new metric is refined further.

D. (1.2) Performance Against Target

1. Progress on Sustaining the 1-Year Target

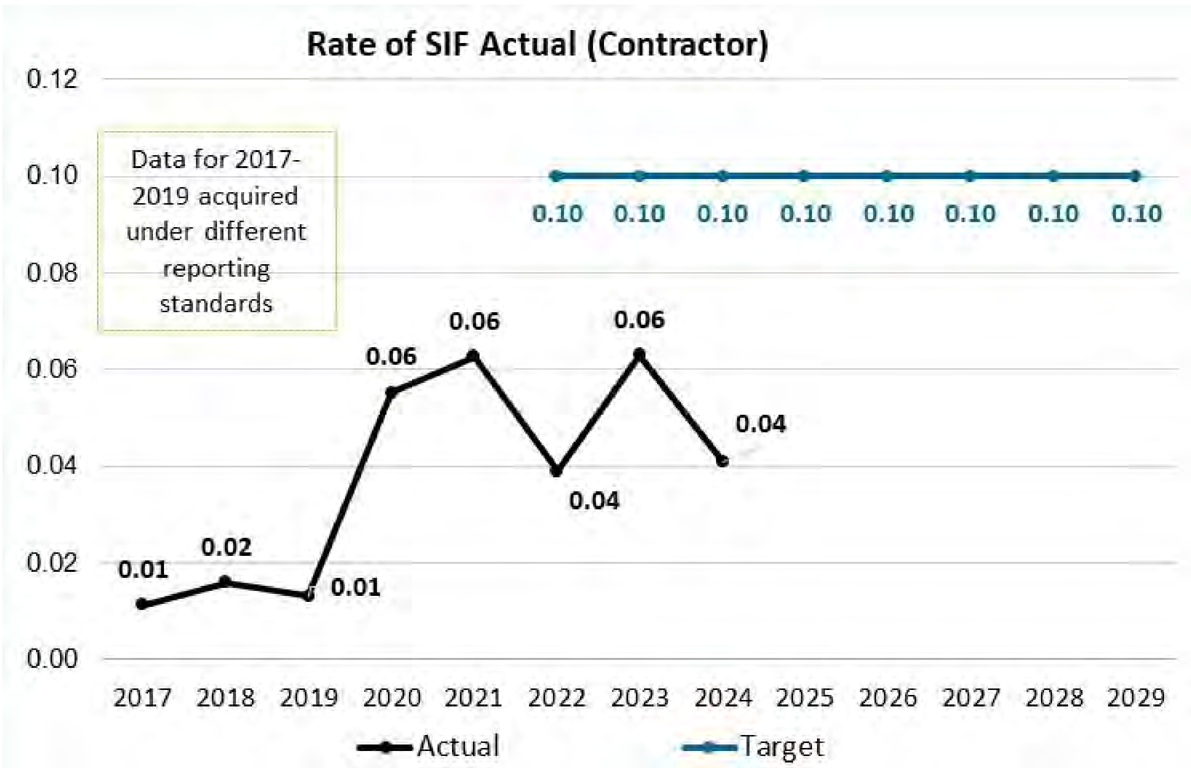
As demonstrated in Figure 1.1-2 below, PG&E experienced an increase in the Contractor SIF Actual rate in 2023, with a downward trend in 2024.

SIF investigations have been completed or are underway for the incidents including corrective actions and we are continuing to monitor this trend. In addition, PG&E is implementing the SIF Capacity & Learning model as described in section E below.

2. Progress on Sustaining the 5-Year Target

As discussed in Section E below, PG&E is continuing to deploy a number of programs to maintain or improve long-term performance of this metric to meet the Company's 5-year performance target and will continue to monitor Contractor SIF-A trends and adjust the targets as appropriate.

FIGURE 1.2-2
RATE OF SIF-A (CONTRACTOR)
HISTORICAL PERFORMANCE AND TARGETS



E. (1.2) Current and Planned Work Activities

- <u>SIF Capacity & Learning Model</u>: PG&E has implemented the SIF Capacity & Learning model which redefines safety as measured by the presence of essential controls and the capacity to experience failures safely. Worksite essential controls directly target the stuff that can kill or seriously injure a co-worker or contract partner. When the controls are installed, verified, and used properly, they are not vulnerable to human error. Looking at safety differently with the SIF Capacity and Learning Model increases our understanding of the management and thus prevention of serious injuries and fatalities. Instead of measuring our success by the number of incidents, we are defining safety by the presence of controls that give coworkers and contractors the ability to fail safely.

- Human Performance (HU) Tools: PG&E has implemented the 10 Human Performance (HU) Tools which include: Questioning Attitude, Tailboards and Pre-Job Brief, Situational Awareness, Self-Checking (STAR), Two-Minute Rule, Three-Way Communication, Stop When Unsure, Procedure Use and Adherence, Phonetic Alphabet, and Placekeeping (i.e., physically marking steps in a procedure or other guiding document that have been completed). The HU Tools are deeply connected to the SIF Prevention Program and allow coworkers to slow things down and reduce the chances of human errors caused by internal and external factors. When used effectively, these tools can also help ensure essential controls effectively remain in place and do not break down.
- Contractor Safety Quality Assurance Reviews (CSQAR): CSQARS are conducted with selected Contractors with adverse trends in safety performance and who are at risk of experiencing a Serious Injury or Fatality, as well as for all new contractors when they begin performing work on behalf of PG&E. This includes contractors new in business, as well as contractors new to PG&E. PG&E utilizes our third-party administrator (TPA), ISNetWorld (ISN), to facilitate these CSQARs. The purpose is to partner directly with our contract partners, perform a comprehensive review of their safety programs and culture, and implement controls to eliminate serious injuries and fatalities. The contractors participate in a six-week examination of their safety culture within their company. Opportunities are identified, they undergo a barrier analysis, and corrective actions are designed and implemented. Following the successful completion of the initial six weeks, PG&E checks in with contractors every 30 days for a minimum of three months to conduct an effectiveness review to ensure the corrective actions were implemented as designed, were effective and self-sustaining, and do not expose employees to unforeseen hazards. As of 2024, 774 CSQARs had been completed with only one contractor experiencing a SIF Potential after having completed the process.
- In addition to contractors with adverse safety trends, in Q3 2024 PG&E began partnering with ISN, PG&Es third-party administrator, to facilitate CSQARs for all new contractors (prime and subcontractors) when they

begin performing work on behalf of PG&E. This includes contractors new in business, as well as contractors new to PG&E.

- Contractor Motor Vehicle Programs: Contractor Motor Vehicle Programs: In March of 2023, PG&E implemented the Slow Your Roll campaign focusing on preventing motor vehicle rollovers with a breakthrough goal of 100 Consecutive Days of Rollover Free Driving. At the time, PG&E was averaging 16 days between rollovers. Later that same year, 100 consecutive days rollover free was reached. In 2024, PG&E observed a reduction in success, averaging approximately one rollover per month with only 64 consecutive days rollover free, therefore, utility standard SAFE-3002S, "PG&E's Contractor Motor Vehicle Safety Standard" was developed and implemented. This standard includes phone-free requirements, including hands-free devices, as well as requiring criterion adopted from American National Standards Institute (ANSI)/American Society of Safety Engineers (ASSE) Z15.1 – 2017: Safe Practices for Motor Vehicle Operations. The intent is to assist contract partners in defining and developing effective driving safety and risk management programs. To support these efforts, FAs are required to define and track specific Key Risk Indicators within their contractor management procedures. FAs are required to take actions to improve KPI performance, where applicable.
- PG&E's Contractor Safety Program: Programs that support this metric include PG&E's Enterprise Health and Safety organization and the Contractor Safety Program. Beginning in 2016, PG&E implemented a formal Contractor Safety Program to help our contractor partners reduce illness and injuries when working with PG&E. The program was implemented as required by the CPUC, Kern OII Settlement Agreement. PG&E's Contractor Safety Program includes all contractors and subcontractors (currently over 2,100) performing high and medium-risk work on behalf of PG&E, on either PG&E owned, or customer owned, sites and assets. The Contractor Safety Program consists of the following primary elements:
  - Contractor Company Pre-Qualification: PG&E leverages the capabilities of ISN to collect performance and safety compliance program information from all prime and subcontractors that conduct work

classified as high or medium risk. PG&E is responsible for the performance of its contractors. As part of this effort, ISN a third-party administrator, independently assesses contractors' historical safety data, and safety, drug/alcohol, and written safety programs to evaluate whether contractors meet PG&E's minimum performance standards and have the necessary risk management programs in place to proactively mitigate risk. A variance to work for PG&E is required for contractors who do not meet the prequalification requirements. The variance process includes a review of the contractor's safety performance, an improvement plan and the business need in relation to the proposed scope of work. The decision to award a variance requires Vice President and Chief Safety Officer approval, or Chief Executive Officer designee approval.

– <u>Enhanced Safety Contract Terms</u>: PG&E Contract terms require that, following a serious public or worker safety incident, the contractor will conduct a cause evaluation, share the analysis with PG&E, and cooperate and assist with PG&E's cause evaluation analysis and corrective actions for the incident, and regulatory investigations and inquiries, including but not limited to Safety Enforcement Division's investigations and inquiries. Under the enhanced Safety Contract Terms, PG&E has the right to:

1) Designate safety precautions in addition to those in use or proposed by the contractor;
2) Stop work to ensure compliance with safe work practices and applicable federal, state and local laws, rules and regulations;
3) Require the contractor to provide additional safeguards beyond what the contractor plans to utilize;
4) Terminate the contractor for cause in the event of a serious incident or failure to comply with PG&E's safety precautions;
5) Review and approve criteria for work plans, which include safety plans; and
6) Require the contractor to promptly, thoroughly, and transparently investigate all safety incidents that occur during Contractor's PG&E related work in compliance with PG&E's Enterprise Cause

Standard, including all SIF-A and SIF-P incidents, which shall be investigated jointly with PG&E, taking into account the priority and needs of Occupational Safety and Health Administration and other regulator investigations.

- Contractor Job Safety Planning: Safety must be factored into every job plan from start to finish. Safety considerations include formal training, job site work controls, specialized equipment to reduce hazards, and personal protective equipment. Each of PG&E's functional areas have safety plan requirements unique to its operations. Prior to commencement of work, PG&E is required to review the adequacy of the safety plans, including contractor safety personnel qualifications where applicable, and perform a safety assessment to evaluate whether additional safety mitigations are required, including whether to assign PG&E onsite safety personnel. These reviews must be conducted by PG&E employees that are qualified to perform such work or PG&E engages third-party experts as appropriate to perform this safety analysis.
- Contractor Oversight: Work activities are governed by qualified PG&E oversight personnel to ensure work follows a PG&E reviewed and approved safety plan designed for the job. PG&E conducts field safety observations of the contractor. For 2024, approximately 122,000 contractor observations were conducted. High-risk findings are reviewed daily, and corrective actions are discussed. Observation data collected by all observers (e.g., PG&E and contractors) are analyzed to support continuous improvement.
- Contractor Safety Performance Evaluation: To maximize and capture lessons learned, the results of which are shared across the enterprise, as well as providing a means of determining future contract award, Functional Area Representatives evaluate contractor safety performance. Prime Contractors must also evaluate all Subcontractors performing any active work during the year. Evaluations must be completed at the conclusion of the contracted work or at least once every calendar year. Safety performance evaluations must include the following minimum performance evaluation criteria:

a. Worksite hazard mitigation;
b. Training and qualifications compliance;
c. Work site safety performance (observations);
d. Safety incident and injury prevention and reporting;
e. Development and implementation of a PG&E-approved safety plan;
f. Speak Up and Stop Work Authority; and
g. Wildfire Prevention and Mitigation.

PACIFIC GAS AND ELECTRIC COMPANY

SAFETY AND OPERATIONAL METRICS REPORT:

CHAPTER 1.3

SIF ACTUAL

(PUBLIC)

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SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 1.3
SIF ACTUAL
(PUBLIC)

The material updates to this chapter, since the September 30, 2024 report, are identified in blue font.

A. (1.3) Overview

1. Metric Definition

Safety and Operational Metric (SOM) 1.3 – Serious Injury and Fatality (SIF) Actual (Public) is defined as:

A fatality or personal injury requiring inpatient hospitalization for other than medical observations that an authority having jurisdiction has determined resulted directly from incorrect operation of equipment, failure or malfunction of utility-owned equipment, or failure to comply with any California Public Utilities Commission (CPUC or Commission) rule or standard. Equipment includes utility or contractor vehicles and aircraft used during the course of business.

2. Introduction of Metric

Pacific Gas and Electric Company's (PG&E or the Company) safety stand is "Everyone and Everything is Always Safe." Our goal is zero public safety incidents that result from the failure or malfunction of a PG&E asset or the failure of PG&E to follow rules and/or standards. In support of this, PG&E is continuing to invest in programs to protect the public including electric transmission (ET) and distribution system reliability and the reduction of wildfire risk. PG&E remains committed to building an organization where every work activity is designed to facilitate safe performance, every member of our workforce knows and practices safe behaviors, and every individual is encouraged to speak up if they see an unsafe or risky behavior with the confidence that their concerns and ideas will be heard and followed up on. As part of this stand, the Public SIF Actual metric is integral in ensuring the safety of our communities.

The Public SIF Actual metric definition established in Decision (D.) 21-11-009 is a different way for PG&E to categorize and report public safety incidents resulting in a SIF. There are two primary differences between the SOMs Public SIF Actual metric and the Safety Performance Metric (SPM) Public SIF metric (SPM Metric 20).

- First, the SOM requires a finding by "an authority having jurisdiction"; and
- Second, that finding must determine that the Public SIF Actual "resulted directly from incorrect operation of equipment, failure or malfunction of utility owned equipment, or failure to comply with any California Public Utilities Commission (CPUC or Commission) rule or standard."[1]

As a result, the data in this report are a subset of the data included with the SPM Report for the Public SIFs metric, which is defined as a fatality or personal injury requiring in-patient hospitalization involving utility facilities or equipment. Equipment, in the case of the SPM, includes utility vehicles used during the course of business.

In 2012, PG&E improved its data collection processes and reporting for public serious incidents. These data were used to inform PG&E's Risk Assessment and Mitigation Phase Report, which informs and helps prioritize our investments to address top safety risks. The report outlines our top safety risks and includes descriptions of the controls currently in place, as well as mitigations—both underway and proposed—to reduce each risk.

B. (1.3) Metric Performance

1. Historical Data (2010 – 2024)

In this report, PG&E is providing fifteen years of historical data from 2010 through 2024. The data include a description of the incident, type of injury, and identification of the authority with jurisdiction that has determined or may determine that incorrect operations, malfunction, or failure to meet a standard was the cause of the SIF. As mentioned above, the data collection and internal reporting processes for public safety serious incidents were improved in 2012. Historical data for the Public SIF Actual metric are based

[1] D.21-11-009 – (Rulemaking 20-07-013) Appendix A, p. 2.

on this timeframe and also include available data for the years of 2010 and 2011.

Since the metric definition requires a finding from an authority having jurisdiction, Public SIF Actual incidents in prior years may not appear in the historical data. For the purposes of this report, PG&E is including incidents where PG&E may have disputed the assertion of an authority with jurisdiction that the Public SIF Actual was caused by incorrect operation of utility equipment, a malfunction of utility equipment, or failure to comply a Commission rule or standard, and/or where the incidents are subject to pending investigation or litigation. These incidents are shown as "unknown" in the corresponding metric data file. PG&E will continue to update the historical data in future SOMs reports as appropriate and identify changes based on new information.

2. Data Collection Methodology

PG&E's Public SIF Actual incident data largely come from the Enterprise Health and Safety Serious Incidents Reports, which includes a compilation of Law Department claims from PG&E's Riskmaster database, Electric Incident Reports, and other reportable incidents such as PG&E Federal Energy Regulatory Commission (FERC) license compliance reports. For the SOMs report, the incidents included in the Public SIF Actual metric must be determined by an authority having jurisdiction to have resulted directly from: (1) incorrect operation of equipment, (2) failure or malfunction of utility-owned equipment, or (3) the failure to comply with any Commission rule or standard. PG&E interprets authorities having jurisdiction to include agencies such as the CPUC, California Department of Forestry and Fire Protection, or the National Transportation Safety Board. The term authority having jurisdiction can also include PG&E itself if PG&E concludes that the definition of the SOM is met.

3. Metric Performance for the Reporting Period

The graphs included in Figure 1.3-1 and Figure 1.3-2 below show the total number of incidents and the total number of serious injuries or fatalities for each identified incident. Between 2010 through 2024, there were 30 confirmed incidents where Public SIF Actuals occurred (Figure 1.3-1), which resulted in a total of 176 public SIFs (Figure 1.3-2). There are two incidents related to wildfire where a serious injury or fatality to a member of the public occurred that are shown as “unknown” due to ongoing investigation and/or litigation.

For 2024, there are two confirmed Public SIF (non-fatal) incidents. They include:

- On May 15, 2024, PG&E employee was in reverse while operating a company vehicle and contacted a pedestrian that was in a crosswalk. The pedestrian sustained a head injury and concussion and was transported by ambulance to the hospital; and
- On May 28, 2024, a third-party was making a left turn when a PG&E employee ran a stop sign and struck the third-party vehicle. The driver of the third-party vehicle was transported to the hospital and admitted for treatment.

A claims report received on May 8, 2024, about a slip and trip that occurred on November 18, 2020, at a PG&E job site has also been included in the report.

FIGURE 1.3-1
NUMBER OF PUBLIC SIF ACTUAL INCIDENTS 2010 – 2024
CONFIRMED AND PENDING INVESTIGATION

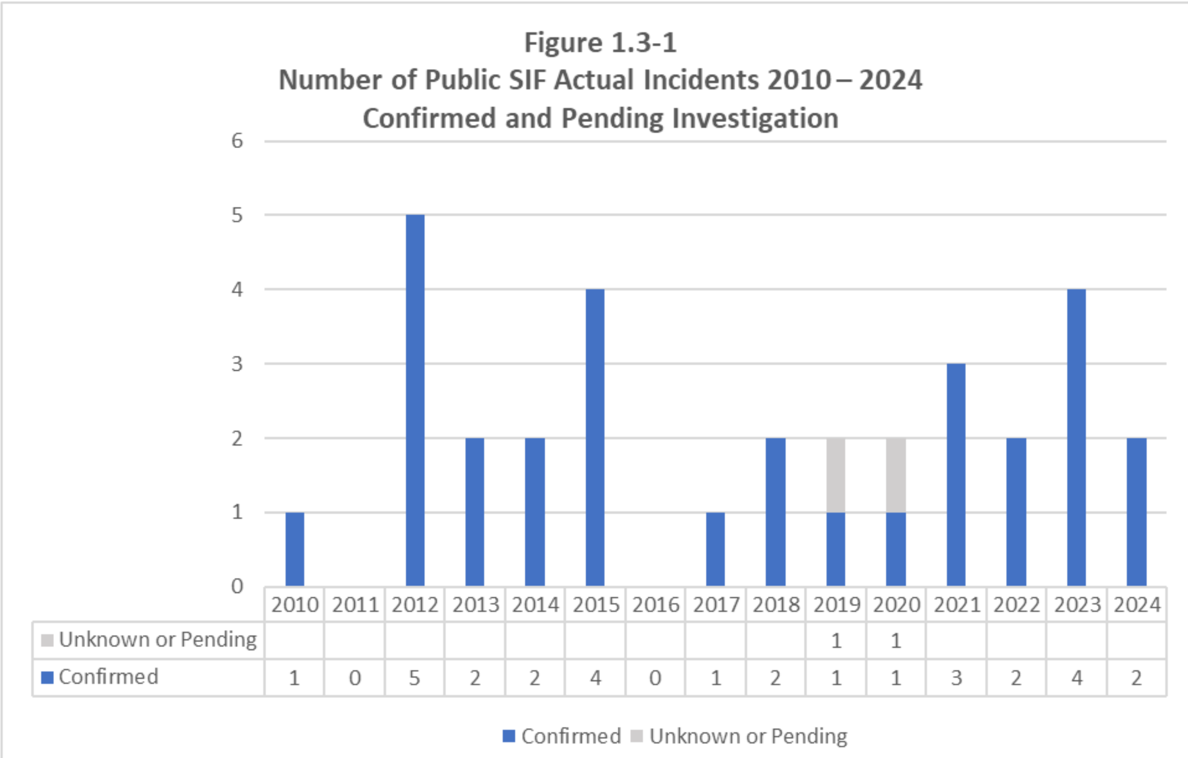
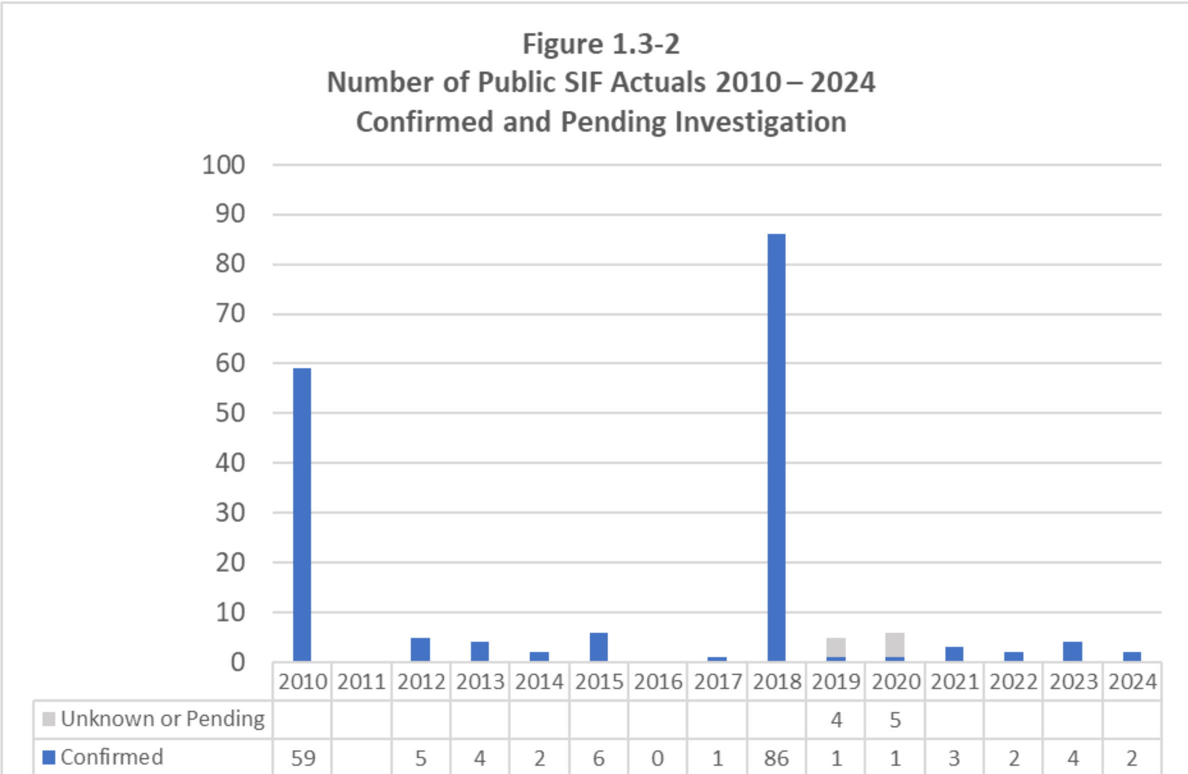


FIGURE 1.3-2
NUMBER OF PUBLIC SIF ACTUALS 2010 – 2024
CONFIRMED AND PENDING INVESTIGATION



PG&E is continuing to evaluate its current and planned Public Safety work activities as described in Section E below and through further maturing its public incident investigation process, including the advancement of Public SIF Actual metric definition requirements and learnings.

C. (1.3) 1-Year Target and 5-Year Target

1. Updates to 1- and 5- Year Targets Since Last Report

There have been no changes to the 1-year and 5-year targets since the last SOMs report filing, for the Public SIF Actual metric, which is to demonstrate progress towards the elimination of serious injuries and fatalities (zero Public SIF Actual incidents).

2. Target Methodology

With our stand of Everyone and Everything is Always Safe, our goal is the elimination of Public SIF Actual incidents resulting directly from incorrect operation of PG&E equipment, failure, or malfunction of PG&E-owned

equipment, or from PG&E's failure to comply with any Commission rule or standard.

In consideration of the above, PG&E also reviewed the following factors:

- Historical Data and Trends: From 2010 through 2024, there were a total of 30 confirmed incidents where Public SIF Actuals occurred (Figure 1.3-1), which resulted in a total of 176 public SIFs (Figure 1.3-2). Two wildfire incidents where a serious injury or fatality occurred are pending due to ongoing investigation and/or litigation. Historical data will continue to inform PG&E's plans and actions to achieve its goal of zero public safety incidents.
- Benchmarking: Not available. This is a new metric definition;
- Regulatory Requirements: CPUC, FERC, and Department of Transportation (DOT), public safety reporting requirements;
- Attainable Within Known Resources/Work Plan: Yes. PG&E's work and resource plan prioritizes public safety risk reduction. This includes minimizing the risk of catastrophic wildfires in alignment with the continued execution of the Wildfire Mitigation Plan (WMP) and maturation of key wildfire mitigation strategies. It also includes mitigation of other public safety risks related to the elimination of serious injuries and fatalities (zero Public SIF Actual incidents);
- Appropriate/Sustainable Indicators for Enhanced Oversight Enforcement: A 1-year goal of zero Public SIF Actuals was established in 2022 and has not changed for 2025 through 2029 (5-year). The goal reflects PG&E's intent to immediately and continuously operate without creating risk to the public; and
- Other Qualitative Considerations: PG&E's approach is aligned to and anchored on PG&E's goal and commitment to "always" safe operations.

3. 2025 Target

As discussed above, PG&E's 1-year target for the Public SIF Actual metric is to demonstrate progress towards the elimination of serious injuries and fatalities (zero Public SIF Actual incidents) resulting directly from incorrect operation of PG&E equipment, failure, or malfunction of PG&E-owned equipment, or PG&E's failure to comply with any Commission rule or standard.

4. 2029 Target

PG&E's 5-year target for the Public SIF Actual metric is to demonstrate progress towards the elimination of serious injuries and fatalities (zero Public SIF Actual incidents) resulting directly from incorrect operation of PG&E equipment, failure, or malfunction of PG&E-owned equipment, or PG&E's failure to comply with any Commission rule or standard.

D. (1.3) Performance Against Target

1. Progress Towards the 1-Year Directional Target

For 2024, there were two confirmed Public SIF Actual incidents that meet the SOMs criteria as described in section B.3. above. This was a 50 percent reduction in incidents compared to 2023.

2. Progress Towards the 5-Year Directional Target

As discussed in Section E below, PG&E is continuing to deploy several programs to maintain or improve long-term performance of this metric to meet the Company's 5-year performance target.

E. (1.3) Current and Planned Work Activities

Many of the current and planned activities to eliminate public safety incidents are addressed by meeting key operations risks, which are discussed in other SOMs Chapters.

The current and planned work activities for reducing the risk of gas transmission and distribution system equipment failure or malfunction, are discussed in Chapters 4.1 through 4.7 of this report. The list below touches upon some of these:

- <u>Gas System Damage Prevention team (Chapter 4.1)</u>: PG&E's Damage Prevention team is responsible for the overall management of PG&E's Damage Prevention Program, by managing the risks associated with excavations around PG&E's facilities and conducting investigations. As an additional control to manage the Damage Prevention Program, the Dig-in Reduction team works closely with various local PG&E operations personnel and respond to referrals from those employees when they observe excavations potentially not in compliance with regulatory requirements. DiRT personnel also assist the Ground Patrol team when they respond to immediate threats identified in the air by the Aerial Patrol team and other

PG&E groups, in order to intervene in unsafe digging activities by third parties and follow up to educate excavators as necessary;

- Gas Public Awareness and Damage Prevention Programs (Chapter 4.1): PG&E's Damage Prevention activities include educational outreach activities for professional excavators, local public officials, emergency responders, and the public who lives and works within PG&E's service territory. The program communicates safe excavation practices, required actions prior to excavating near underground pipelines, availability of pipeline location information, and other gas safety information through a variety of methods throughout the year. These efforts are aimed at increasing public awareness about the importance of utilizing the 811 Program before an excavation project is started, understanding the markings that have been placed, and following safe excavation practices after subsurface installations have been marked;
- Gas Field Service and Gas Dispatch (Chapter 4.3): PG&E's Field Service and Gas Dispatch partner together to respond to customer Gas Emergency (odor calls). There is a shared responsibility in the overall performance of this work. Gas Service Representatives are deployed systemwide, 24 hours a day—utilizing an on-call as needed; and
- Gas Leak Management (Chapter 4.6): The Leak Management Program addresses the risk of Loss of Containment by finding and fixing leaks. PG&E performs leak survey of the gas transmission and storage system twice per year, by either ground or aerial methods in accordance with General Order (GO) 112-F. Leak surveys of pipeline and equipment are commonly accomplished on foot or vehicle, by operator-qualified personnel, using a portable methane gas leak detector. Aerial leak surveys, in remote locations and areas difficult to access on the ground, are performed by helicopter using Light Detection and Ranging Infrared technology. Additional activities that complement the Leak Management Program include risk-based leak surveys, mobile leak quantification, and replacing/removing high bleed pneumatic devices at its compressor stations and storage facilities.
- Gas Transmission Integrity Management (Chapter 4.6): The Integrity Management Program provides the tools and processes for risk ranking and

prioritization of remediation efforts. This program enables PG&E to focus on identifying and remediating threats to its system. The Transmission Integrity Management Program (TIMP) assesses the threats on every segment of transmission pipe, evaluates the associated risks, and acts to prevent or mitigate these threats. The TIMP approach for assessing risk is based on methodologies consistent with American Society of Mechanical Engineers B31.8S and is in compliance with 49 CFR Part 192 Subpart O. Many of PG&E's programs that mitigate, and control transmission pipe asset risks are developed and managed within the TIMP program. Examples of assessments or mitigative work that contribute to reducing or preventing significant incidents include strength testing, inline inspection, direct assessment, direct examination, and pipe replacement.

The current and planned work activities for reducing the risk of Electric transmission and distribution system equipment failure or malfunction are discussed in Chapters 2.1 through 2.4, and Chapters 3.1 through 3.16 of this report. The list below touches upon some of these:

- <u>Vegetation Management (Chapter 2.1):</u> Vegetation Management for Operational Mitigations is a new transitional program which began 2023. This program is intended to help reduce outages and potential ignitions using a risk-informed, targeted plan to mitigate potential vegetation contacts based on historic vegetation outages on Enhanced Powerline Safety Setting-enabled circuits. The focus is on mitigating potential vegetation contacts in Circuit Protection Zones that have experienced vegetation caused outages.

  Focused Tree Inspections is another new transitional program that began in 2023 stemming from the conclusion of the Enhanced Vegetation Management Program. PG&E is developed Areas of Concern to better focus Vegetation Management efforts to address high risk areas that have experienced higher volumes of vegetation damage during Public Safety Power Shutoff (PSPS) events, outages, and/or ignitions. These areas are inspected by Vegetation Management Inspectors with a Tree Risk Assessment Qualification which provides a higher level of rigor to the inspection.

- Downed Conductor Detection (DCD) (Chapter 2.1): To further mitigate high impedance faults that can lead to ignitions, PG&E is piloting specific distribution line reclosers utilizing advanced methods to detect and isolate previously undetectable faults. This innovative solution is called DCD and has been implemented on over 1,100 reclosing devices as of January 31, 2024. This technology uses sophisticated algorithms to determine when a line-to-ground arc is present (i.e., electrical current flowing from one conductive point to another) and the recloser will immediately de-energize the line once detected. Although this technology is new, it has already proven successful in detecting faults that would have otherwise been undetectable. PG&E will continue to learn from these installations through the 2024 wildfire season and expects to optimize and adjust this technology to address system risks as needed.
- Overhead (OH) Patrols and Inspections (Chapter 3.1): PG&E monitors the condition of OH conductor through patrols and inspections consistent with GO 165. Tags are created for abnormal conditions, including those that can lead to a wire down. Work is prioritized in a risk-informed manner to address the issues identified in the tags. In addition, PG&E has implemented risk based aerial inspections using drones in targeted areas. Drone inspections significantly improve our ability to assess deteriorated conditions on the conductor.
- Asset Inspection (Chapter 3.3): Detailed inspections of overhead transmission assets seek to proactively identify potential failure modes of asset components which could create future wire down, outage, and/or safety events if left unresolved or allowed to “run to failure.” Detailed inspections for transmission assets involve at least two detailed inspection methods per structure (ground and aerial), though not necessarily in the same calendar year which allows for staggered inspection methods across multiple years. Aerial inspections may be completed either by drone, helicopter, or aerial lift.

  In addition to the ground and aerial inspections, climbing inspections are also required for 500 kilovolt structures or as triggered. All these inspection methods involve detailed, visual examinations of the assets with use of inspection checklists that are in accordance with the ET Preventive Maintenance standards, as well as the Failure Modes and Effects Analysis.

- Public Safety Power Shut Off (PSPS) (Chapter 3.13): PSPS is a wildfire mitigation strategy, first implemented in 2019, to reduce powerline ignitions during severe weather by proactively de-energizing powerlines (remove the risk of those powerlines causing an ignition) prior to forecasted wind events when humidity levels and fuel conditions are conducive to wildfires. PG&E's focus with the PSPS Program is to mitigate the risks associated with a catastrophic wildfire and to prioritize customer safety. In 2021, PG&E continued to make progress to its PSPS Program to mitigate wildfire risk, including updating meteorology models and scoping processes. In 2023, PG&E continued a multi-rear effort to install additional distribution sectionalizing devices, Fixed Power Solutions, and other mitigations targeted at reducing the risk of wildfire. In 2024, we updated our thresholds utilizing new and improved risk models.
- Public Awareness Programs: Electric public awareness programs educate non-PG&E contractors and the public about power line safety and the hazards associated with wire down events and are intended to reduce the number of third-party electrical contacts. Outreach efforts include social media campaigns focused on increasing customer awareness of overhead lines, representation at local fire safe councils and community events and the automated customer notification system. Security improvements can include proactive equipment replacement, security measures and intrusion detection devices.

In addition, PG&E's 2023 – 2025 WMP[2] also includes information regarding grid system hardening and enhancements to reduce the risk of wildfire.

The current and planned work activities for reducing the risk of the power generation hydroelectric system equipment failure or malfunction are below:

- Power Generations Hydroelectric Programs: Hydroelectric programs include procedures for planning for unusual water releases, along with their associated safety warnings;

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2 PG&E's 2023 - 2025 Wildfire Mitigation Plan.

- Power Generation Compliance Programs: Public Safety Plans are published and routinely updated as required by PG&E hydroelectric facility FERC licenses. FERC required Emergency Action Plans exist for all significant and high hazards dams. The Plans are exercised annually with a seminar and phone drill;
- Hydro Facility Unusual Water Releases and Water Safety Warning Standard and accompanying procedure: Hydroelectric facility Unusual Water Releases and Water Safety Warning documentation establishes Hydro facility requirements for planning and making unusual water releases or high flow events and their associated safety warnings;
- In addition, public safety has distributed hydroelectric safety brochures that included dam safety, water safety, and recreational safety information. The brochures notify the recipient that they live near a hydroelectric facility in order to minimize potential reaction time and encourage them to be aware of dangerous spring flows. PG&E mailed brochures to 7,000 recipients for annual FERC compliance;
- PG&E Dam Safety Surveillance and Monitoring Program: This program establishes and defines PG&E's Dam Safety Surveillance and Monitoring Program for the continued long-term safe and reliable operation of PG&E's dams. Dam surveillance involves the collection of data by various means, including inspections and instrumentation, whereas monitoring involves the review of the collected data as obtained and over time for any adverse trends; and
- Canals and Waterways Safety: In 2022, PG&E Power Generation and external public safety representatives successfully tested a new rope system designed to enable members of the public who might accidentally fall into a hydro canal to pull themselves out of danger. Since 2019, an additional 8.3 miles of barrier fencing has been installed along with 139 newly-designed escape ladders. In addition, 327 warning signs have been posted, identifying the canal and specific GPS location.

Power Generation has also distributed safety information to property owners with canals that bisect their property. A canal entry emergency response plan has been published to guide efficient and timely communications between PG&E personnel and local first responders when responding to emergencies resulting from public entry into PG&E-owned water conveyance systems. PG&E mailed brochures to 1,000 recipients in late Spring of 2024. Brochures included information to help people understand the dangers around canals and to help people prepare and plan for what to do in case of a safety emergency.

- Recreation safety posters are posted for recreation sites identified below time sensitive EAP dams. These recreation areas include campgrounds, river access, trails, and boat ramps. Recreation safety posters illustrate what to do in the event of a high flow event or dam safety emergency. Posters provide the public with information on inundation areas, warning signs of a dam safety emergency, safety precautions, and local agency emergency contacts in order to prevent, moderate, or alleviate the effects of an incident. Annually, public safety works with land agents to check all locations and replace signage where needed.
- Drowning hazard safety signs: In response to public safety concerns associated with specific locations, public safety personnel prepared unique drowning hazard safety signs that informed the public of potentially dangerous river currents and changing water levels. PG&E produced multiple signs that were posted at sites for public information. These signs included potential hazards and safety precautions.

The current and planned work activities for reducing the risk enterprise-wide include:

- K through 8th grade safety awareness education. We are continued our long-standing utility public safety awareness education initiative that offers various interactive and educational materials and programs for K-8 educators, their students, and students' families. These resources help educators increase student awareness of utility safety issues, including safety around hydroelectric facilities and waterways. The content of the materials provided to teachers are aligned with STEM (Science, Technology, Engineering, and Math) standards. These classroom materials are offered to districts and educators in all zip codes within PG&E's service territory. Educators are made aware of these resources using a blend of direct mailing, and one-on-one conversations between company representatives and stakeholders. PG&E representatives make direct telephone calls to local school officials and educators to alert them to the availability of materials. PG&E has made additional phone calls to K- through 8th grade schools located within zip codes where PG&E hydroelectric facilities are located. Each of these schools is contacted up to six times to confirm that the schools have received PG&E's offer of educational classroom booklets and encourage stakeholders to use online educational resources that PG&E makes available on its dedicated Safe Kids website. In 2023, PG&E reached approximately 67,000 teachers and delivered educational materials for nearly 300,000 K-8 students and their families. This same outreach occurred in 2024.

- Transportation Safety: PG&E Transportation Safety programs protect our employees and the public by establishing requirements and processes to control risks that can lead to motor vehicle accidents, improve safety performance, and increase awareness of all PG&E employees related to the operation of motor vehicles. This comprehensive program was established to reduce the number of motor vehicle incidents that have the potential for serious injury, including fatal injury, to PG&E's employees, staff augmentation employees operating vehicles on Company business, and the public. Driver performance data is used to identify specific risk drivers for targeted intervention, including driver training and implementing vehicle safety technology including the cellular phone blocking program currently in use with approximately 2,000 active users. The program has effectively suppressed over 693,000 texts, over 1.3 million app notifications, and over 173,000 calls since the start of the program through 2024. Other programs include:
  - A Safe Driving policy and Driver Scorecard enhancement launched in August of 2023. Since then, 580 Action Plans have been initiated. Of those, 558 Action Plans have been completed through the end of 2024.
  - The initiation of Smith Driving courses for apprentice and new hires including behind the wheel and close quarter maneuvering courses.
  - The retrofit of 744 trouble trucks with Brigade Birdseye External 360 Cameras technology. The cameras are designed to eliminate blind spots, where areas around the vehicle that are obscured to the driver by

bodywork or machinery, and provide the driver with the ability to see everything in the vehicle's path.

– Improvements to vehicle roll-over performance through targeted campaigns and by enabling "harsh cornering" monitoring using vehicle telematics.

PG&E's Transportation Safety Department also ensures compliance with federal DOT and California state regulations and requirements which emphasize public and employee safety:

- Contractor Safety Programs: Pre-qualification requirements for the PG&E Contractor Safety Program include a review of the 3-year history of Serious Safety Incidents (Life Altering/Life Threatening) affecting the public. This information must be updated annually. Additional information on the Contractor Safety program can be found in Chapter 1.2 of this report.

PACIFIC GAS AND ELECTRIC COMPANY

SAFETY AND OPERATIONAL METRICS REPORT:

CHAPTER 2.1

SYSTEM AVERAGE INTERRUPTION DURATION INDEX (SAIDI) (UNPLANNED)

PACIFIC GAS AND ELECTRIC COMPANY
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CHAPTER 2.1
SYSTEM AVERAGE INTERRUPTION DURATION INDEX (SAIDI) (UNPLANNED)

The material updates to this chapter, since the September 30, 2024, report are identified in blue font.

A. (2.1) Overview

1. Metric Definition

Safety and Operational Metric (SOM) 2.1 – System Average Interruption Duration Index (SAIDI) (Unplanned) is defined as:

*SAIDI (Unplanned) = average duration of sustained interruptions per metered customer due to all unplanned outages, excluding on Major Event Days (MED), in a calendar year. "Average duration" is defined as: Sum of (duration of interruption * # of customer interruptions)/Total number of customers served. "Duration" is defined as: Customer hours of outages. Includes all transmission and distribution outages.*

2. Introduction of Metric

SAIDI (unplanned) measures the total number of minutes (or hours) of interruption the average Pacific Gas and Electric Company (PG&E) customer experiences from unplanned outages. This is defined as being without power for more than 5 minutes. PG&E calculates system reliability based on the Institute of Electrical and Electronic Engineers (IEEE) 1366-2022: IEEE Guide for Electric Power Distribution Reliability Indices. Consistent with IEEE 1366-2022, the outages exclude MEDs. IEEE 1366-2022 defines an MED as "A Day in which the daily System Average Interruption Duration Index (SAIDI) exceeds a Major Event Day threshold (TMED) value." The TMED is obtained via statistical analysis over five years to normalize reliability performance from impacts of unusual reliability days, such as major storms.

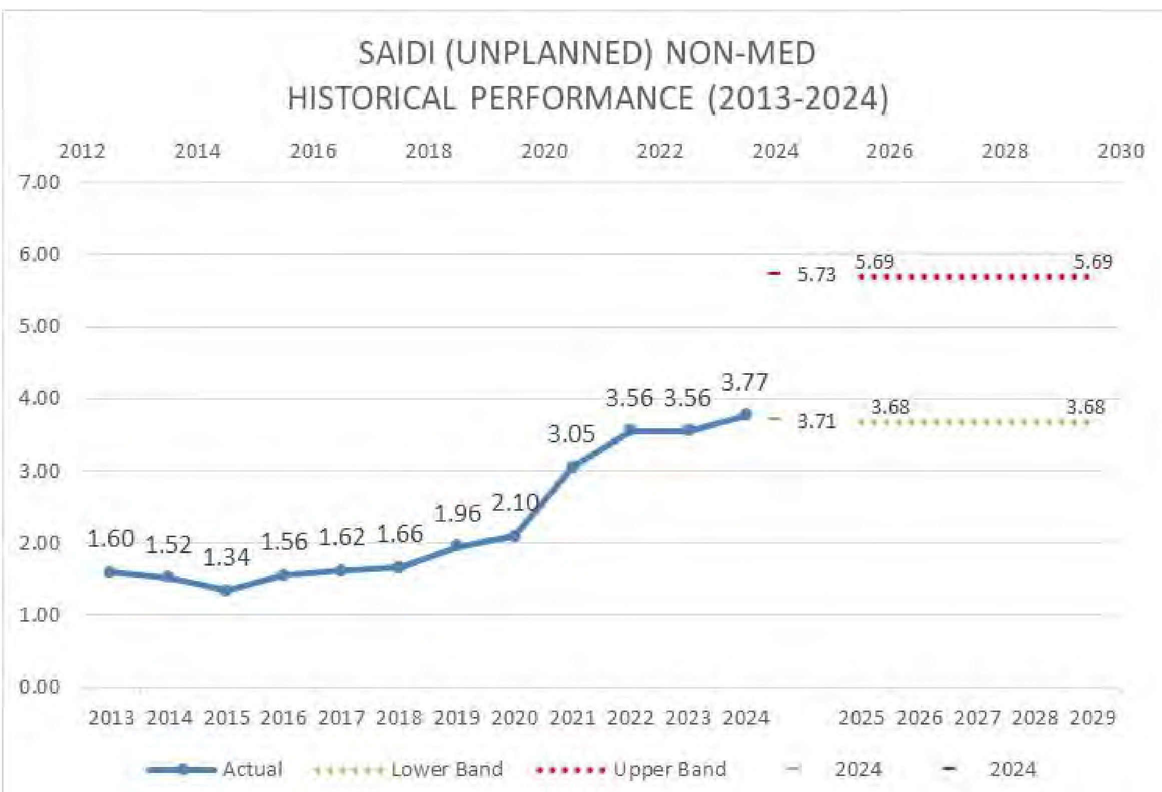
Note: PG&E is working to improve its reliability calculation to align with IEEE 1366-2022. PG&E has consistently utilized Service Point IDs (both *active and inactive) for its reliability calculations and has recently identified underlying data flow issues between different systems. PG&E has continued that approach for reporting the metric results from 2024. For calculation of our 2025 target, the calculation methodology remains the same, but the underlying data will be based upon estimates of customers with active billing accounts. PG&E has a multi-year plan in place to improve its metric reporting to fully align with the prevailing standards and industry best practices.*

B. (2.1) Metric Performance

1. Historical Data (2013 –2024)

Historical performance for this metric covers periods from 2013 through 2024. Reference Figure 2.1-1 for SAIDI unplanned historical performance.

FIGURE 2.1-1
SAIDI (UNPLANNED) NON-MED
HISTORICAL PERFORMANCE (2013-2024)



Note: The data in this figure is subject to change based on continuing review of prior period information.

2. Data Collection Methodology

Data Sources:

- PG&E implemented its current outage reporting system in 2015 that included the data conversion of its legacy database. This new system consists of two main components that are typically referred to as PG&E's Integrated Logging and Information System (ILIS) and its Operations Database (ODB).
- PG&E maintains account specific information for customers affected by outages that are recorded and stored in ODB. This system tracks outages at various levels (generation, transmission, substation, primary distribution, and individual transformers) and the most current outage data were used to compile the information contained in this metric.
- Distribution operators log outage information in ILIS to record the outage start, switching operations, and outage end times.

3. Metric Performance for the Reporting Period

SAIDI unplanned performance for reporting period ending 2024 averaged 225.9 minutes or 3.77 hours. Weather between January and March 2024 saw a high number of storm days causing outages across PG&E's territory and strained restoration resources to bring customers back online. Additionally, Enhanced Powerline Safety Settings (EPSS) and Downed Conductor Detection (DCD) settings installed on the distribution line equipment continued to impact reliability with increased sustained outage frequency and duration.

C. (2.1) 1-Year Target and 5-Year Target

1. Updates to 1- and 5-Year Targets Since Last Report

Targets are updated to reflect 2024 actual performance.

2. Target Methodology

For target baseline, 3-year average of past performance for SAIDI unplanned is utilized to reflect consistent application across the PG&E system. The target band is set with a 50 percent increase from the baseline to form the upper target band, and a 3 percent decrease from the baseline to form the lower target band. This is consistent to the approach utilized for 2024 target setting. It is important to note that for the 1-year and 5-year goal setting, the underlying data is different as described in the first section of the document.

Upper Band: 5.69 $\underline{5.69 = 3.79 \times 1.5}$

Lower Band: 3.68 $\underline{3.68 = 3.79 \times .97}$

- Historical Data and Trends: Considers past performance data, and trends;
- Benchmarking: PG&E is currently in the fourth quartile;
- Regulatory Requirements: CPUC Decision (D.20-05-053);
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: The target range for this metric is suitable for EOE as it accounts for our current work plan and the unknowns of EPSS; and
- Attainable with Known Resources/Work Plan: Yes.
- Other Considerations: None.

3. 2025 Target

The 2025 target range is 3.68 to 5.69 hours. PG&E continues to monitor historical and current performance, year-to-year weather shifts, and outages related to EPSS and DCD, which are key wildfire safety measures. Future targets may account for variability in weather conditions and current uncertainties on future EPSS/DCD impacts.

4. 2029 Target

The 2029 target is the same as the 2025 target range. PG&E continues to monitor historical and current performance, year-over-year weather variables and EPSS- and DCD-related outages. As a result, targets have the potential to be adjusted in each subsequent reporting period.

D. (2.1) Performance Against Target

1. Progress Towards 1-Year Target

Metric performance for this reporting period was 3.77, performing under 2024’s target of 5.73. See Figure 2.1-1 above. Weather and EPSS/DCD settings may impact 2025 performance.

2. Progress Towards 5-Year Target

PG&E considers current and historical performance, current and future planned work activities, and focus on continuous improvement, and expects metric performance to perform under the 5-year target.

E. (2.1) Current and Planned Work Activities

PG&E has existing programs that support SAIDI performance and historical trend data for SAIDI, including but not limited to:

- Vegetation Management: Please see Section 8.2, p. 602, "Vegetation Management, and Inspections" in PG&E's 2023-2025 Wildfire Mitigation Plan R6.[1]
- Asset Replacement (Overhead, Underground): Please see Section 8.1.3.2.5, p. 493, "Overhead Equipment Inspections" in PG&E's 2023-2025 Wildfire Mitigation Plan R6.[1]
- Grid Design and System Hardening: Please see Section 8.1.2, p. 398, "Grid Design and System Hardening" in PG&E's 2023-2025 Wildfire Mitigation Plan R6.[1]
- Downed Conductor Detection: Please see Section 8.1.2.10.1, p. 461, "Downed Conductor Detection Devices" in PG&E's 2023-2025 Wildfire Mitigation Plan R6.[1]
- Animal Abatement: Please see Section 8.1.2.12.2, p. 471, "Other Technologies and Systems" in PG&E's 2023-2025 Wildfire Mitigation Plan R6.[1]
- Overhead/Underground Critical Operating Equipment (COE) Replacement Work: Please see Section 8.1.4, p. 502, "Equipment Maintenance and Repair" in PG&E's 2023-2025 Wildfire Mitigation Plan R6.[1]

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1 2023-2025 Wildfire Mitigation Plan R6.

PACIFIC GAS AND ELECTRIC COMPANY

SAFETY AND OPERATIONAL METRICS REPORT:

CHAPTER 2.2

SYSTEM AVERAGE INTERRUPTION FREQUENCY (SAIFI) (UNPLANNED)

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
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SYSTEM AVERAGE INTERRUPTION FREQUENCY (SAIFI)
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SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 2.2
SYSTEM AVERAGE INTERRUPTION FREQUENCY (SAIFI) (UNPLANNED)

The material updates to this chapter, since the September 30, 2024 report, are identified in blue font.

A. (2.2) Overview

1. Metric Definition

Safety and Operational Metric (SOM) 2.2 – System Average Interruption Frequency (SAIFI)(Unplanned) is defined as:

SAIFI (Unplanned) = average frequency of sustained interruptions due to all unplanned outages per metered customer, except on Major Event Days (MED), in a calendar year. "Average frequency" is defined as: Total # of customer interruptions/Total # of customers served. Includes all transmission and distribution outages.

2. Introduction of Metric

SAIFI (Unplanned) is a measure of the total number of unplanned sustained service interruptions that the average PG&E customer experiences in year. A sustained interruption is defined as an interruption lasting more than 5 minutes.

PG&E calculates system reliability based on the Institute of Electrical and Electronic Engineers (IEEE) 1366-2022: IEEE Guide for Electric Power Distribution Reliability Indices. Consistent with IEEE 1366-2022, reliability indices exclude Major Event Days defined as "Day[s] in which the daily System Average Interruption Duration Index (SAIDI) exceeds a Major Event Day threshold (TMED) value." TMED is calculated using a statistical analysis of the previous five years of daily SAIDI performance to normalize the reliability indices from the impacts of outlier reliability days, such as major storms.

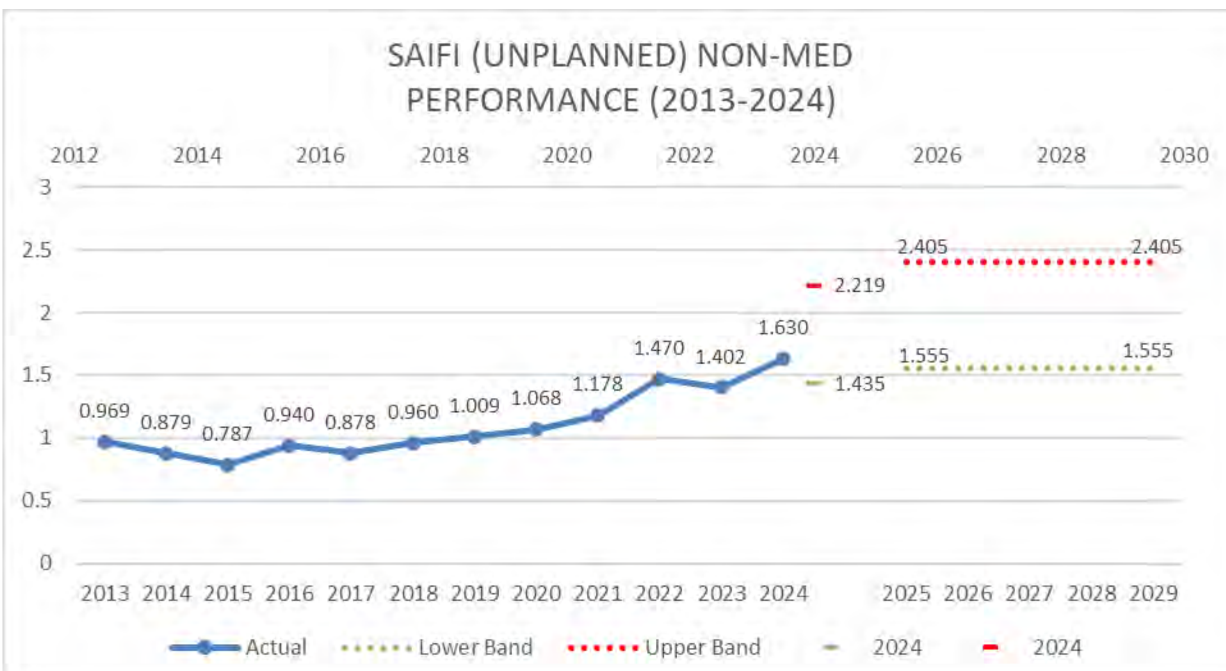
Note: PG&E is working to improve its reliability calculation to align with IEEE 1366-2022. PG&E has consistently utilized Service Point IDs (both *active and inactive) for its reliability calculations and has recently identified underlying data flow issues between different systems. PG&E has continued that approach for reporting the metric results from 2024. For calculation of our 2025 target, the calculation methodology remains the same, but the underlying data will be based upon estimates of customers with active billing accounts. PG&E has a multi-year plan in place to improve its metric reporting to fully align with the prevailing standards and industry best practices.*

B. (2.2) Metric Performance

1. Historical Data (2013 – 2024)

Historical performance for SAIFI covers the period from 2013 through 2024. Refer to Figure 2.1-1 for SAIFI (Unplanned) historical performance.

FIGURE 2.2-1
SAIFI (UNPLANNED)
HISTORICAL PERFORMANCE (2013-2024)



Note: The data in this figure is subject to change based on continuing review of prior period information.

2. Data Collection Methodology

Data Sources:

- PG&E implemented its current outage reporting system in 2015 that included the data conversion of its legacy database. This new system consists of two main components—Integrated Logging and Information System (ILIS) and its Operations Database (ODB);
- PG&E maintains account specific information for customers affected by outages that are recorded and stored in ODB. This system tracks outages at various levels (generation, transmission, substation, primary distribution, and individual transformers); and
- Distribution operators log outage information in ILIS to record the outage start, switching operations, and outage end times.

3. Metric Performance for the Reporting Period

SAIFI (Unplanned) performance for the reporting period ending 2024 was 1.630 outages in 2024. Weather between January and March 2024 saw an unprecedented number of storm days causing outages across PG&E territory and exhausted restoration resources to bring customers back online. Additionally, EPSS and DCD settings installed on the distribution line equipment continued to impact reliability with increased sustained outage frequency and duration.

C. (2.2) 1-Year Target and 5-Year Target

1. Updates to 1- and 5-Year Targets Since Last Report

Targets are updated to reflect 2024 actual performance.

2. Target Methodology

For target baseline, the three-year average of past performance for SAIFI is utilized to reflect consistent Enhanced Powerline Safety Setting (EPSS) application across the PG&E system. The target band is set with a 50 percent increase to form the upper target band and a three percent decrease to form the lower target band. This is consistent with the approach utilized for 2024 target setting. It is important to note that for the one-year and five-year goal setting, the underlying data is different as described in Section 2.2.A.2.

Upper Band: 2.405 2.405 = 1.603 x 1.5

Lower Band: 1.555 1.555 = 1.603 x .97

- Historical Data and Trends: Considers past performance data and trends;
- Benchmarking: PG&E is currently in the fourth quartile;
- Regulatory Requirements: CPUC Decision (D.20-05-053);
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: The target range for this metric is suitable for EOE as it accounts for our current work plan and the unknowns of EPSS;
- Attainable with Known Resources/Work Plan: Yes; and
- Other Considerations: None.

3. 2025 Target

The 2025 target range is 1.555 – 2.405 sustained interruptions per metered customer. PG&E continues to monitor historical and current performance, year-to-year weather shifts, and EPSS and DCD related outages. Future targets may adjust to account for changes due to variability in weather conditions and current uncertainties on future EPSS and DCD impacts.

4. 2029 Target

The 2029 target range is same as the 2025 target. PG&E continues to monitor historical and current performance, and year-over-year weather variables shift, and EPSS and DCD related outages. As a result, targets have the potential to be adjusted in each subsequent reporting period.

D. (2.2) Performance Against Target

1. Progress Towards 1-Year Target

Metric performance for this reporting period was 1.630, performing under 2024’s target of 2.219. See Figure 2.2-1 above. Weather and EPSS/DCD settings may impact 2025 performance.

2. Progress Towards 5- Year Target

PG&E considers current and historical performance, current and future planned work activities, and focus on continuous improvement, and expects metric performance to perform under the 5-year target.

E. (2.2) Current and Planned Work Activities

Existing Programs that SAIFI performance include, but are not limited to, the following:

- Vegetation Management: Please see Section 8.2, p. 602, "Vegetation Management, and Inspections" in PG&E's 2023-2025 Wildfire Mitigation Plan R6;[1]
- Asset Replacement (Overhead, Underground): Please see Section 8.1.3.2.5, p. 493, "Overhead Equipment Inspections" in PG&E's 2023-2025 Wildfire Mitigation Plan R6;[1]
- Grid Design and System Hardening: Please see Section 8.1.2, p. 398, "Grid Design and System Hardening" in PG&E's 2023-2025 Wildfire Mitigation Plan R6;[1]
- Downed Conductor Detection: Please see Section 8.1.2.10.1, p. 461, "Downed Conductor Detection Devices" in PG&E's 2023-2025 Wildfire Mitigation Plan R6;[1]
- Animal Abatement: Please see Section 8.1.2.12.2, p. 471, "Other Technologies and Systems" in PG&E's 2023-2025 Wildfire Mitigation Plan R6;[1] and
- Overhead/Underground Critical Operating Equipment (COE) Replacement Work: Please see Section 8.1.4, p. 502, "Equipment Maintenance and Repair" in PG&E's 2023-2025 Wildfire Mitigation Plan R6.[1]

1 2023-2025 Wildfire Mitigation Plan R6.

PACIFIC GAS AND ELECTRIC COMPANY

SAFETY AND OPERATIONAL METRICS REPORT:

CHAPTER 2.3

SYSTEM AVERAGE OUTAGES DUE TO VEGETATION AND EQUIPMENT DAMAGE IN HFTD AREAS

(MAJOR EVENT DAYS)

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 2.3
SYSTEM AVERAGE OUTAGES DUE TO VEGETATION AND EQUIPMENT DAMAGE IN HFTD AREAS
(MAJOR EVENT DAYS)

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SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 2.3
SYSTEM AVERAGE OUTAGES DUE TO VEGETATION AND EQUIPMENT DAMAGE IN HFTD AREAS (MAJOR EVENT DAYS)

The material updates to this chapter, since the September 30, 2024 report, are identified in blue font.

A. (2.3) Overview

1. Metric Definition

Safety and Operational Metric (SOM) 2.3 – System Average Outages Due to Vegetation and Equipment Damage in High Fire Threat District (HFTD) Areas (Major Event Days (MED)) is defined as:

Average number of sustained outages on MED per 100 circuit miles in HFTD per metered customer, in a calendar year, where each sustained outage is defined as: total number of customers interrupted / total number of customers served.

2. Introduction of Metric

Based on Pacific Gas and Electric Company's (PG&E) understanding, this metric is specific to Customers Experiencing Sustained Outages (CESO) per 100 circuit miles in Tier 2 and Tier 3 HFTD areas, where the basic cause is vegetation or equipment failure during MEDs.

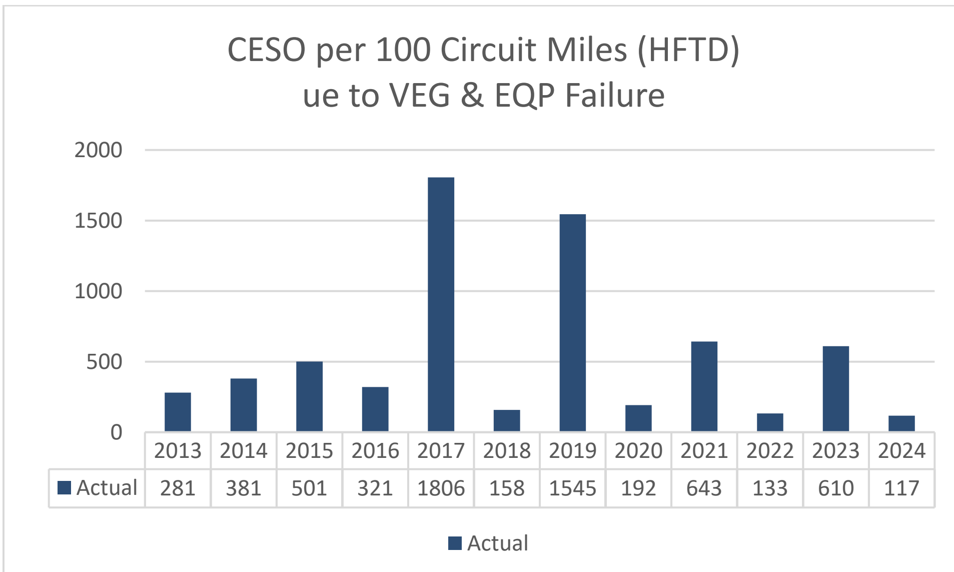
Note: PG&E is working to improve its reliability calculation to align with IEEE 1366-2022. PG&E has consistently utilized Service Point IDs (both active and inactive) for its reliability calculations and has recently identified underlying data flow issues between different systems. PG&E has continued that approach for reporting the metric results from 2024. For calculation of our 2025 target, the calculation methodology remains the same, but the underlying data will be based upon estimates of customers with active billing accounts. PG&E has a multi-year plan in place to improve its metric reporting to fully align with the prevailing standards and industry best practices.

B. (2.3) Metric Performance

1. Historical Data (2013 –2024)

PG&E has measured Customers Experiencing Service Outage (CESO) performance for over 20 years; however, historical performance for this metric covers 2013 through 2024, to align with SOMs “Wires down” metrics.

FIGURE 2.3-1
CESO PER 100 CIRCUIT MILES (HFTD)
VEGETATION AND EQUIPMENT FAILURE



Note: The data in this figure is subject to change based on continuing review of prior period information.

2. Data Collection Methodology

<u>Data Sources:</u>

- PG&E implemented its current outage reporting system in 2015 that included the data conversion of its legacy database. This new system consists of two main components that are typically referred to as PG&E’s Integrated Logging and Information System (ILIS) and its Operations Database (ODB).
- PG&E maintains account-specific information for customers affected by outages that are recorded and stored in ODB. This system tracks outages at various levels (generation, transmission, substation, primary

distribution, and individual transformers) and the most current outage data are used to compile the information contained in this metric.

- Distribution operators log outage information in ILIS to record the outage start, switching operations, and outage end times.

3. Metric Performance for the Reporting Period

The number of vegetation and equipment failure related to CESO per 100 circuit miles during MEDs has varied each year and has been heavily driven not just by the number, but by the severity of the MED experienced in that specific year. There were only five MEDs recorded in 2024, 75 percent less than the 20 MEDs recorded in 2023. In 2024, Vegetation and Equipment failure related outages averaged 117 customers experiencing service sustained outages per 100 circuit miles occurring in HFTD areas on MEDs.

C. (2.3) 1-Year Target and 5-Year Target

1. Updates to 1- and 5-Year Targets Since Last Report

There have been no changes to the directional 1- and 5-Year Targets since the 2021 report filing.

2. Target Methodology

- Directional Only: Maintain (stay within historical range and assumes the response stays the same in events);
- Historical Data and Trends: Considers past performance data and trends;
- Benchmarking: PG&E is currently in the fourth quartile;
- Regulatory Requirements: CPUC Decision (D.20-05-053);
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: The directional target for this metric is suitable for EOE as it states we are to remain within historical performance range while accounting for the randomness of weather patterns and impacts of climate change;
- Attainable with Known Resources/Work Plan: Yes; and
- Other Considerations: None.

D. (2.3) Performance Against Target Progress

1. Progress Towards the 1-Year Target

This is directional-only metric without a specific performance target. PG&E experienced 5 MEDs in 2024, averaging 117 CESO per 100 circuit miles in HFTD areas. Metric performance was below all previous reporting periods (see Figure 2.3-1 above).

2. Progress Towards the 5-Year Target

As mentioned in progress towards the 1 Year target, this is directional-only metric without a specific performance target. Variability in severe weather events and the number of MEDs experienced will impact future reliability performance.

E. (2.3) Current and Planned Work Activities

Existing Programs that support Reliability Metric Performance, include but are not limited to:

- Vegetation Management: Please see Section 8.2, p. 602, "Vegetation Management, and Inspections" in PG&E's 2023-2025 Wildfire Mitigation Plan R6[1].
- Asset Replacement (Overhead, Underground): Please see Section 8.1.3.2.5, pg. 493, "Overhead Equipment Inspections" in PG&E's 2023-2025 Wildfire Mitigation Plan R6.[1]
- Grid Design and System Hardening: Please see Section 8.1.2, p. 398, "Grid Design and System Hardening" in PG&E's 2023-2025 Wildfire Mitigation Plan R6.[1]
- Downed Conductor Detection: Please see Section 8.1.2.10.1, p. 461, "Downed Conductor Detection Devices" in PG&E's 2023-2025 Wildfire Mitigation Plan R6.[1]
- Animal Abatement: Please see Section 8.1.2.12.2, p. 471, "Other Technologies and Systems" in PG&E's 2023-2025 Wildfire Mitigation Plan R6.[1]

1 2023-2025 Wildfire Mitigation Plan R6.

- Overhead/Underground Critical Operating Equipment (COE) Replacement Work: Please see Section 8.1.4, p. 502, “Equipment Maintenance and Repair” in PG&E’s 2023-2025 Wildfire Mitigation Plan R6.[1]

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 2.4
SYSTEM AVERAGE OUTAGES DUE TO VEGETATION AND EQUIPMENT DAMAGE IN HFTD AREAS
(NON-MAJOR EVENT DAYS)

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
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SYSTEM AVERAGE OUTAGES DUE TO VEGETATION AND EQUIPMENT DAMAGE IN HFTD AREAS
(NON-MAJOR EVENT DAYS)

The material updates to this chapter, since the September 30, 2024 report, are identified in blue font.

A. (2.4) Overview

1. Metric Definition

Safety and Operational Metric (SOM) 2.4 – System Average Outages due to Vegetation and Equipment Damage in High Fire Threat District (HFTD) Areas (Non-Major Event Days) is defined as:

Average number of sustained outages on Non-Major Event Days (MED) per 100 circuit miles in High Fire Threat District (HFTD) per metered customer, in a calendar year, where each sustained outage is defined as: total number of customers interrupted/total number of customers served.

2. Introduction of Metric

Based on PG&E's understanding, this metric is specific to Customers Experiencing Sustained Outages (CESO) per 100 circuit miles in Tier 2/3 HFTD areas, where the basic cause is vegetation or equipment failure during non-MEDs.

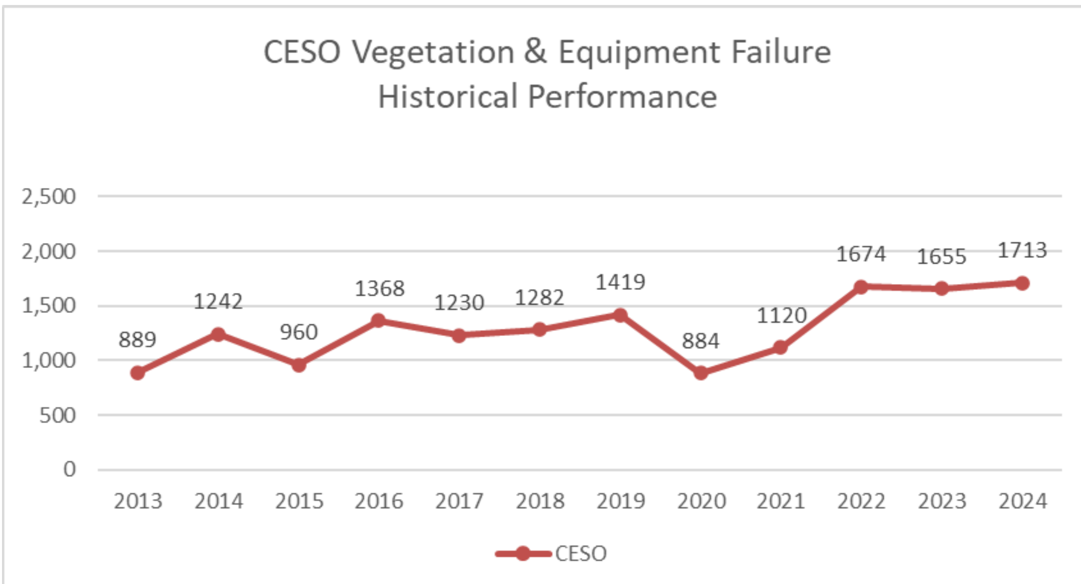
Note: PG&E is working to improve its reliability calculation to align with IEEE 1366-2022. PG&E has consistently utilized Service Point IDs (both active and inactive) for its reliability calculations and has recently identified underlying data flow issues between different systems. PG&E has continued that approach for reporting the metric results from 2024. For calculation of our 2025 target, the calculation methodology remains the same, but the underlying data will be based upon estimates of customers with active billing accounts. PG&E has a multi-year plan in place to improve its metric reporting to fully align with the prevailing standards and industry best practices.

B. (2.4) Metric Performance

1. Historical Data (2013 – 2024)

PG&E has measured CESO performance for over 20 years; however, historical performance for this metric covers 2013 through 2024, to align with SOMs wires down metrics.

FIGURE 2.4-1
CESO VEGETATION & EQUIPMENT FAILURE
HISTORICAL PERFORMANCE



Note: The data in this figure is subject to change based on continuing review of prior period information.

2. Data Collection Methodology

<u>Data Sources:</u>

- PG&E implemented its current outage reporting system in 2015 that included the data conversion of its legacy database. This new system consists of two main components that are typically referred to as PG&E's Integrated Logging and Information System (ILIS) and its Operations Database (ODB).
- PG&E maintains account specific information for customers affected by outages that are recorded and stored in ODB. This system tracks outages at various levels (generation, transmission, substation, primary

distribution, and individual transformers) and the most current outage data were used to compile the information contained in this metric.

- Distribution operators log outage information in ILIS to record the outage start, switching operations, and outage end times.
- Due to data limitations, PG&E uses the Lat/Long of the operating device as a proxy for determining the distribution outage events that occurred in the Tier 2/3 HFTD areas.
- Other Considerations: Transmission and distribution (overhead and underground) circuit miles located in the Tier 2 and Tier 3 HFTD areas.

3. Metric performance for the Reporting Period

Vegetation and Equipment failure related outages totaled 575,226 CESO during this reporting period, averaging 1,713 customers experiencing sustained outages per 100 circuit miles, occurring in HFTD areas, excluding MEDs.

C. (2.4) 1 Year Target and 5-Year Target

1. Updates to 1- and 5-Year Targets Since Last Report

The 1- and 5-year targets remain unchanged since the last reporting period. PG&E continues to assess and monitor historical and current performance, variability in weather conditions, Enhanced Powerline Safety Setting (EPSS) and Downed Conductor Detection (DCD) impacts, and other relevant leading and lagging indicators to set targets.

2. Target Methodology

Target setting Methodology: For target baseline, three-year average of past performance is utilized to reflect consistent EPSS application across the PG&E.

- Historical Data and Trends: Considers past performance data and trends
- Benchmarking: PG&E is currently in the fourth quartile
- Regulatory Requirements: CPUC Decision (D.20-05-053)
- Appropriate/Sustainable Indicators for Enhanced Oversight and
- Enforcement: The target for this metric is suitable for EOE as it aligns with unplanned SAIFI target range and accounts for our current work plan and the unknowns of EPSS;

- Attainable with Known Resources/Work Plan: Yes; and
- Other Considerations: None.

3. 2025 Target

The 2025 target range remains unchanged from reporting period 2022 which is a range of 1523 – 1980 customers experiencing service outages per 100 circuit miles in HFTD areas, excluding MED. PG&E continues to monitor historical and current performance trends, year-to-year weather shifts, and EPSS- and DCD-related outages. As such, targets have the potential to be adjusted in each subsequent reporting period.

4. 2029 Target

The 2029 target is consistent to the 2025 Target set above. PG&E continues to monitor historical and current performance, and year-over-year weather variables shift, and EPSS and DCD related outages. As a result, targets have the potential to be adjusted in each subsequent reporting period.

D. (2.4) Progress Towards 1- and 5-Year Target

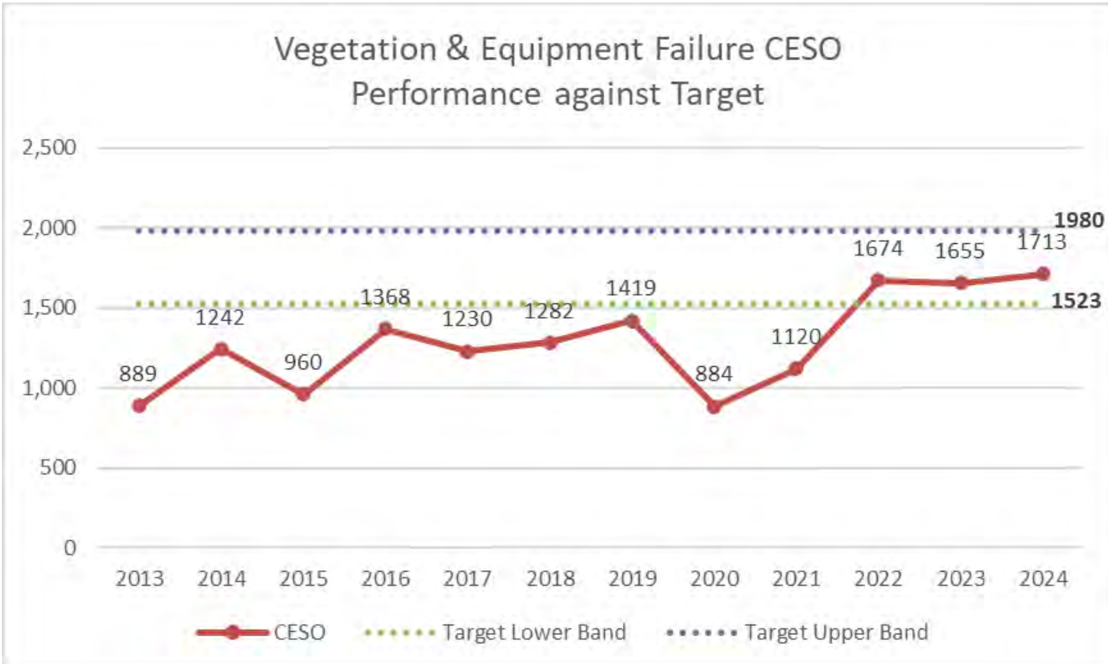
1. Performance Against the 1-Year Target

Metric performance in 2024 measured an average of 1713 CESO per 100 circuit miles, a slight increase above 2023 performance of 1655 and in 2022 performance of 1674.

2. Performance Against the 5-Year Target

As mentioned above, progress toward the 5-year target remains on track. Variability in severe weather events will remain a factor in how reliability metrics perform each year, and trends continue to suggest that EPSS- and DCD-related outages will continue to contribute to declining reliability performance. Despite these challenges, historical performance considerations and continuous improvement, metric performance is expected to maintain the company’s 5-year performance target.

FIGURE 2.4-2
CESO VEGETATION & EQUIPMENT FAILURE (HFTD ONLY)
PERFORMANCE AGAINST TARGET



Note: The data in this figure is subject to change based on continuing review of prior period information.

E. (2.4) Current and Planned Work Activities

Existing Programs that support Reliability Metric Performance, include but are not limited to:

- Vegetation Management: Please see Section 8.2, p. 602, “Vegetation Management, and Inspections” in PG&E’s 2023-2025 Wildfire Mitigation Plan R6.[1]
- Asset Replacement (Overhead, Underground): Please see Section 8.1.3.2.5, p. 493, “Overhead Equipment Inspections” in PG&E’s 2023-2025 Wildfire Mitigation Plan R6.[1]
- Grid Design and System Hardening: Please see Section 8.1.2, p. 398, “Grid Design and System Hardening” in PG&E’s 2023-2025 Wildfire Mitigation Plan R6.[1]

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1 2023-2025 Wildfire Mitigation Plan R6.

- Downed Conductor Detection: Please see Section 8.1.2.10.1, p. 461, "Downed Conductor Detection Devices" in PG&E's 2023-2025 Wildfire Mitigation Plan R6.[1]
- Animal Abatement: Please see Section 8.1.2.12.2, p. 471, "Other Technologies and Systems" in PG&E's 2023-2025 Wildfire Mitigation Plan R6.[1]
- Overhead/Underground Critical Operating Equipment (COE) Replacement Work: Please see Section 8.1.4, p. 502, "Equipment Maintenance and Repair" in PG&E's 2023-2025 Wildfire Mitigation Plan R6.[1]

PACIFIC GAS AND ELECTRIC COMPANY

SAFETY AND OPERATIONAL METRICS REPORT:

CHAPTER 3.1

WIRES DOWN MAJOR EVENT DAYS IN HFTD AREAS

(DISTRIBUTION)

PACIFIC GAS AND ELECTRIC COMPANY
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WIRES DOWN MAJOR EVENT DAYS IN HFTD AREAS
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SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 3.1
WIRES DOWN MAJOR EVENT DAYS IN HFTD AREAS (DISTRIBUTION)

The material updates to this chapter, since the September 30, 2024 report, are identified in blue font.

A. (3.1) Overview

1. Metric Definition

Safety and Operational Metric (SOM) 3.1 – Wires Down Major Event Days (MED) in High Fire Threat District (HFTD) Areas (Distribution) is defined as:

Number of Wires Down events on MED involving overhead (OH) primary or secondary distribution circuits divided by total circuit miles of OH primary distribution lines x 1,000, in HFTD Areas in a calendar year.

2. Introduction of Metric

In 2012, Pacific Gas and Electric Company (PG&E or the Company) initiated the Electric Wires Down Program, including introduction of the electric wires down metric, to advance the Company's focus on public safety by reducing the number of electric wire conductors that fail and result in contact with the ground, a vehicle, or other object.

This metric is associated with our Failure of Electric Distribution OH Asset Risk and our Wildfire Risk, which are part of our 2020 Risk Assessment and Mitigation Phase Report filing.

B. (3.1) Metric Performance

1. Historical Data (2013–2024)

We have 12 years of historical data available from 2013-2024. Although we started measuring distribution wire down incidents in 2012, 2013 marked the first full year distribution wire down incidents were uniformly measured.

During this historical reporting period, external factors such as weather and third-party contact with OH electric facilities continued to influence metric performance Refer to Figure 3.1-1 below for historical performance.

PG&E's OH electric primary distribution system consists of approximately 80,312 circuit miles of OH conductor and associated assets with approximately 24,878 circuit miles traversing through HFTD areas, that pose risk for potential wires down incidents.

Over the last several years, we have completed significant work and launched various initiatives targeted at reducing wires down incidents, including:

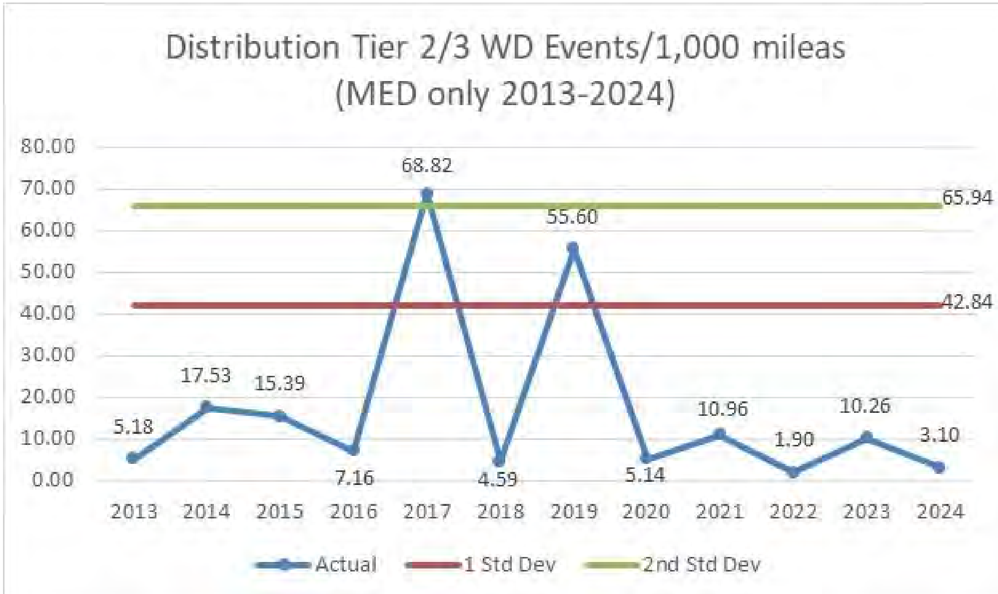
- Performing infrared inspections of OH electric power lines to identify and repair hot spots;
- Clearing of vegetation hazards posing risks to our OH electric facilities; and
- Hardening of OH electric power systems with more resilient equipment.

In addition, our vegetation management (VM) teams conduct site visits of vegetation caused wires down incidents as part of its standard tree-caused service interruption investigation process. The data obtained from site visits supports efforts to reduce future vegetation-caused wires down incidents. The data collected from these investigations also helps identify failure patterns by tree species that are associated with wires down incidents. Additionally, beginning in March of 2024, an extent of condition patrol five spans in all directions from the wire down. The purpose of an extent of condition patrol is to determine subject tree failure mode and identify any additional trees of concern within the extent of condition patrol area. This may include but is not limited to:

- Conditions similar to the failed subject tree;
- Trees damaged from the fire or the failed subject tree;
- Other tree conditions of concern which may lead to another outage or ignition; and
- Non-compliant trees.

Distribution Wire Down Events on MEDs have fluctuate each year and have been heavily driven by not just the number of events, but by the severity of the MED experienced in that specific year (refer to Table 3.1-1 below). Given the randomness of weather patterns, no discernable trends can be learned from historical performance results.

FIGURE 3.1-1
DISTRIBUTION PRIMARY WIRES DOWN INCIDENTS PER 1,000 CIRCUIT MILES TIER 2/3, OCCURRING ON MEDS (2013-2024)



Note: The data in this figure is subject to change based on continuing review of prior period outages.

TABLE 3.1-1
ANNUAL MAJOR EVENT DAYS (2013–2024)

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
4	5	10	3	30	7	31	14	25	5	20	5

Note: The data in this table is subject to change based on continuing review of prior period outages.

2. Data Collection Methodology

PG&E uses the Integrated Logging Information System (ILIS) – Operations Database, to track and count the number of wires down incidents as well as our electric distribution geographical information systems (EDGIS) to determine if the wire down incident was in an HFTD locations. Although our outage database does not specifically identify precise location of the downed wire, we use the Latitude and Longitude (e.g., Lat/Long) of the device used to isolate the involved electric power line Section as a proxy. We also use our EDGIS application to determine if that device (via: Lat/Long information) is in the HFTD (e.g., Tier 2 or Tier 3 location). Outage information is entered into ILIS by our electric distribution operators based on information from field personnel and devices such as Supervisory Control and Data Acquisition alarms and SmartMeter™[1] devices. We last upgraded our outage reporting tools in 2015 and integrated SmartMeter information to identify potential outage reporting errors and to initiate a subsequent review and correction.

PG&E defines the number of wires down events as the number of outages caused by one or more wire down faults. For example, if a single wire down fault causes two protective devices to operate, such as a Line Recloser momentary trip and a downstream fuse burning open, this will be recorded as two separate outages and two wire down events. Alternatively, one protective device operating for a fault caused by multiple spans or phases of wire coming down, will be recorded as one wire down event. This is due to limitations to what can be recorded in the outage logging system. While we are not making any immediate changes to our reporting process, we are evaluating our procedure to determine if our calculation of this metric can be adjusted to address these limitations.

Per Institute of Electrical and Electronics Engineers (IEEE) 1366 Standard, PG&E excludes MEDs to allow major events to be analyzed apart from daily operation and avoid allowing daily trends to be hidden by the large statistical effect of major events. Note: PG&E is working to improve its reliability calculation to align with IEEE 1366-2022. PG&E has consistently utilized Service Point IDs (both active and inactive) for its reliability calculations and has recently identified underlying data flow issues between different systems. PG&E has continued that approach for reporting the metric results from 2024. PG&E has a multi-year plan in place to improve its metric reporting to fully align with the prevailing standards and industry best practices.

3. Metric Performance for the Reporting Period

Distribution Tier 2 and 3 wires down events occurring on MEDs recorded a 70 percent decrease, from 10.26 in 2023 to 3.10 in 2024

[1] SmartMeter is a PG&E registered trademark. All further references to SmartMeters in PG&E's testimony in this proceeding should be assumed to refer to the trademarked name, without continually using the ™ symbol, consistent with legally-acceptable practice.

(Figure 3.1-1). This decrease can be attributed to 5 recorded MEDs in 2024 compared to 20 MEDs in 2023. Historically, since 2013, 10 of the past 12 years, wires down rates have not recorded rates higher than 17.53, apart from two outlying years, 2017 recorded 68.82 and 30 MEDs, and 2019 recorded 55.60 and 31 MEDs. Year-to-year fluctuations in wires down events rates correlates with weather conditions and the number of MEDs experienced in a particular year.

C. (3.1) 1-Year Target and 5-Year Target

1. Updates to 1- and 5-Year Targets Since Last Report

Directional 1- and 5- year targets remain unchanged from the previous reporting period.

2. Target Methodology

- Directional Only: Maintain (stay within historical range, and assumes response stays the same in events).

  Based on the historical performance of this metric, PG&E interprets "Maintain" as staying within 2 standard deviations from the 10-year average. This equates to an upper limit of 65.69 (as shown in Figure 3.1-1);
- Historical Data and Trends: This metric is expected to remain within the historical performance levels, but will vary based on the number of MEDs experienced in a year and the weather conditions;
- Benchmarking: Not available to the best of our knowledge;
- Regulatory Requirements: None;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: The directional target for this metric is suitable for EOE as it states performance will remain within historical range which accounts for unknown factors which may vary, such as the frequency and severity of weather;
- Attainable Within Known Resources/Work Plan: Yes, this metric is attainable within known resources, however, this metric is impacted by variability in conditions outside of PG&E's control, such as the severity of weather on MED; and
- Other Considerations: None.

3. 2025 Target

The 2025 target is a 2-standard deviation of the 10-year average with an upper limit of 65.69.

4. 2029 Target

The 2029 target is the same as the 1-year target, to maintain within historical performance levels, i.e., within the upper limit of 65.69.

D. (3.1) Performance Against Target

1. Progress Towards the 1-Year Target

PG&E's commitment to reduce the number of wires down events continued in 2024, with a performance rate of 3.10 (Figure 3.1-1). Although regions within PG&E's service area have experienced extreme weather events, it resulted in only 5 MEDs. Should weather conditions continue to trend favorably into 2025, this metric should maintain a rate well below the 2025 one-year target set at 65.69.

2. Progress Towards the 5-Year Target

PG&E's commitment to public safety and service reliability drives the initiatives, programs, and work efforts mentioned in Section E below. Data and information collected and analyzed from this metric, continues to inform and influence decision making, improving and maintaining long-term metric performance, which aligns with the 5-year directional performance target.

E. (3.1) Current and Planned Work Activities

PG&E will continue to execute many ongoing activities to reduce wires down, including the following programs:

- <u>OH Conductor Replacement</u>: PG&E's electric distribution system includes approximately 80,312 circuit miles of OH conductor on its distribution system that operates between 4 and 21 kilovolt, including bare and covered conductors. Approximately 54,500 circuit miles of this distribution conductor, including approximately 36,300 circuit miles of small conductor is in non-HFTD areas. PG&E's OH Conductor Replacement Program, recorded in MAT 08J, proactively replaces OH conductor in non-HFTD areas to address elevated rates of wires down and deteriorated/damaged conductors and to improve system safety, reliability, and integrity.

Refer to Exhibit (PG&E-4), Chapter 13, "Overhead and Underground Asset Management" in the 2023 General Rate Case for additional details.

- Patrols and Inspections: PG&E monitors the condition of OH conductor through patrols and inspections consistent with General Order 165. Tags are created for abnormal conditions, including those that can lead to a wire down. Work is prioritized in a risk-informed manner to address the issues identified in the tags. In addition, PG&E has implemented risk based aerial inspections using drones in targeted areas. Drone inspections significantly improve our ability to assess deteriorated conditions on the conductor.
- Grid Design and System Hardening: PG&E's broader grid design program covers a number of significant programs, called out in detail in PG&E's 2023 Wildfire Mitigation Plan (WMP). The largest of these programs is the System Hardening Program which focuses on the mitigation of potential catastrophic wildfire risk caused by distribution OH assets. In 2024, we continued our system hardening efforts by: (i) completing 390 circuit miles of system hardening work which includes OH system hardening, undergrounding and removal of OH lines in HFTD or buffer zone areas; (ii) completing approximately 257 circuit miles of undergrounding work, including Community Rebuild efforts and other distribution system hardening work; and (iii) replacing equipment in HFTD areas that creates ignition risks, such as non-exempt fuses and surge arresters. As we look beyond 2024, PG&E is targeting 310 miles of Undergrounding and 210 miles of OH/removal/remote grid to be completed in 2025 as part of the System Hardening Program. Even though this program will provide wire down mitigation benefit, note that PG&E's approach to wildfire mitigations in the HFTD locations is based on a risk informed prioritization of work in the areas where wildfire risk is evaluated as highest, which combines many asset based composite risk models contributing to the overall probability of failure including conductor failure.

Refer to Section 7.3.3, Grid Design and System Hardening Mitigations in PG&E's WMP for additional details.

- VM: The Enhanced Vegetation Management (EVM) Program targeted OH distribution lines in Tier 2 and 3 HFTD areas and supplemented PG&E's annual routine VM work with California Public Utilities Commission mandated clearances. Our EVM Program went above and beyond regulatory requirements for distribution lines by expanding minimum clearances and removing overhangs in HFTD areas. Due to the emergence of other wildfire mitigation programs (namely Enhanced Powerline Safety Settings (EPSS) and Undergrounding), the program was discontinued in 2023. The trees that were identified as part of the program and previous iterations and scopes will be worked down over the next nine years under a program called Tree Removal Inventory, prioritized by risk rank using our latest wildfire distribution risk model (WDRM). The WMP has a commitment for this program for the mitigation of 25 thousand trees in 2025.

VM for Operational Mitigations is a new transitional program which began 2023 stemming from the conclusion of the EVM program. This program is intended to help reduce outages and potential ignitions using a risk-informed, targeted plan to mitigate potential vegetation contacts based on historic vegetation outages on EPSS-enabled circuits. The focus is on mitigating potential vegetation contacts in Circuit Protection Zones that have experienced vegetation caused outages. Scope of Work is developed by using EPSS and historical outage data and vegetation failure from the current WDRM risk model. Vegetation outage extent of condition inspections conducted on EPSS-enabled devices may generate additional tree work.

Focused Tree Inspections is another new transitional program that began in 2023 stemming from the conclusion of the EVM program. PG&E developed Areas of Concern to better focus VM efforts to address high risk areas that have experienced higher volumes of vegetation damage during Public Safety Power Shutoff events, outages, and/or ignitions. These areas are inspected by VM Inspectors with a Tree Risk Assessment Qualification which provides a higher level of rigor to the inspection.

Refer to Section 8.2, VM and Inspections in PG&E's WMP for additional details.

- <u>Other Advancements:</u> PG&E is applying new technologies in the field to identify and/or prevent conductor to ground faults. This includes:
  - SmartMeter-based methods;
  - Distribution Falling Wire Detection Method;

- Distribution Fault Anticipation;
- Early Fault Detection; and
- Rapid Earth Fault Current Limiter.

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SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 3.2
WIRES DOWN NON-MAJOR EVENT DAYS IN HFTD AREAS
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SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 3.2
WIRES DOWN NON-MAJOR EVENT DAYS IN HFTD AREAS (DISTRIBUTION)

The material updates to this chapter, since the September 30, 2024 report, are identified in blue font.

A. (3.2) Overview

1. Metric Definition

Safety and Operational Metric (SOM) 3.2 – Wires Down Non-Major Event Days (Non-MED) in High Fire Threat District (HFTD) Areas (Distribution) is defined as:

Number of Wires Down events on Non-MED involving overhead (OH) primary distribution circuits divided by the total circuit miles of OH primary distribution lines x 1,000, in HFTD areas, in a calendar year.

2. Introduction to the Metric

In 2012, Pacific Gas and Electric Company (PG&E or the Company) initiated the Electric Wires Down Program, including introduction of the electric wires down metric, to advance the Company's focus on public safety by reducing the number of electric wire conductors that fail and result in contact with the ground, a vehicle, or other object.

This metric is associated with our Failure of Electric Distribution Overhead (OH) Asset Risk and our Wildfire risk, which are part of our 2020 Risk Assessment and Mitigation Phase Report (RAMP) filing.

B. (3.2) Metric Performance

1. Historical Data (2013 –2024)

We have 12 years of historical data available from 2013-2024. Although we started measuring distribution wire down incidents in 2012, 2013 marked the first full year distribution wire down incidents were uniformly measured.

During this historical reporting period, external factors such as weather and third-party contact with OH electric facilities continued to influence metric performance.. Refer to Figure 3.2-1 below for historical performance.

Our OH electric primary distribution system consists of approximately 80,312 circuit miles of OH conductor and associated assets with approximately 24,878 circuit miles traversing through HFTD areas, that pose risk for potential wires down incidents.

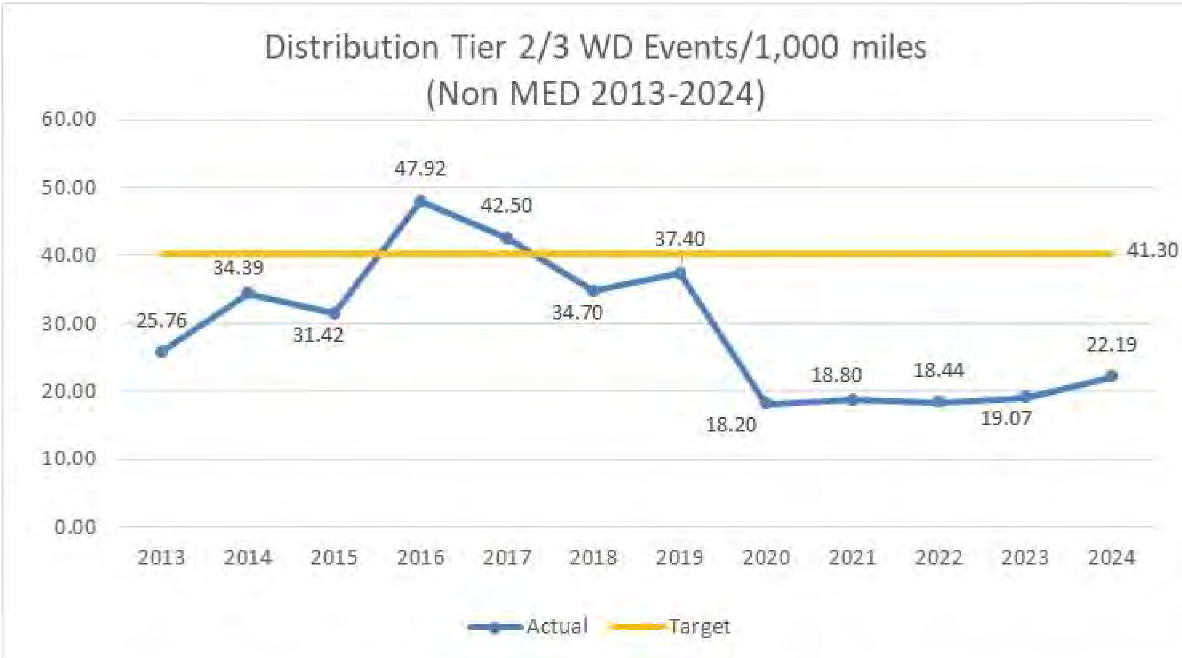
Over the last several years, we have completed significant work and launched various initiatives targeted at reducing wires down incidents, including:

- Performing infrared inspections of OH electric power lines to identify and repair hot spots;
- Clearing of vegetation hazards posing risks to our OH electric facilities; and
- Hardening of OH electric power systems with more resilient equipment.

In addition, our vegetation management (VM) teams conduct site visits of vegetation caused wires down incidents as part of its standard tree-caused service interruption investigation process. The data obtained from site visits supports efforts to reduce future vegetation-caused wires down incidents. The data collected from these investigations also helps identify failure patterns by tree species that are associated with wires down incidents. Additionally, beginning in March of 2024, an extent of condition patrol five spans in all directions from the downed wire. The purpose of an extent of condition patrol is to determine subject tree failure mode and identify any additional trees of concern within the extent of condition patrol area. This may include but is not limited to:

- Conditions similar to the failed subject tree;
- Trees damaged from the fire or the failed subject tree; and
- Other tree conditions of concern which may lead to another outage or ignition.
- Non-compliant trees.

FIGURE 3.2-1
DISTRIBUTION PRIMARY WIRES DOWN INCIDENTS PER 1,000 CIRCUIT MILES TIERS 2/3, OCCURRING ON NON-MEDS (2013- 2024)



Note: The data in this figure is subject to change based on continuing review of prior period outages.

2. Data Collection Methodology

PG&E uses its Integrated Logging Information System (ILIS) – Operations Database to track and count the number of wires down incidents, as well as its electric distribution geographical information systems (EDGIS) to determine if the wire down incident was in an HFTD locations. Although the outage database does not specifically identify precise location of the downed wire, the Latitude and Longitude (e.g., Lat/Long) of the device is used to isolate the involved electric power line Section as a proxy. PG&E also uses its EDGIS application to determine if that device (Lat/Long information) is in the HFTD (e.g., Tier 2 or Tier 3 location). Outage information is entered into ILIS by our electric distribution operators based on information from field personnel and devices such as Supervisory Control and Data Acquisition alarms and SmartMeter™

devices.[1] We last upgraded our outage reporting tools in year 2015 and integrated SmartMeter information to identify potential outage reporting errors and to initiate a subsequent review and correction.

PG&E defines the number of wires down events as the number of outages caused by one or more wire down faults. For example, if a single wire down fault causes two protective devices to operate, such as a Line Recloser momentary trip and a downstream fuse burning open, this will be recorded as two separate outages and two wire down events. Alternatively, one protective device operating for a fault caused by multiple spans or phases of wire coming down, will be recorded as one wire down event. This is due to limitations to what can be recorded in the outage logging system. While we are not making any immediate changes to our reporting process, we are evaluating our procedure to determine if our calculation of this metric can be adjusted to address these limitations. Per Institute of Electrical and Electronics Engineers (IEEE) 1366 Standard, PG&E excludes MEDs to allow major events to be analyzed apart from daily operation and avoid allowing daily trends to be hidden by the large statistical effect of major events. Note: PG&E is working to improve its reliability calculation to align with IEEE 1366-2022. PG&E has consistently utilized Service Point IDs (both active and inactive) for its reliability calculations and has recently identified underlying data flow issues between different systems. PG&E has continued that approach for reporting the metric results from 2024. PG&E has a multi-year plan in place to improve its metric reporting to fully align with the prevailing standards and industry best practices.

3. Metric Performance for the Reporting Period

In 2024, there were 552 distribution wires down events. The number of distribution wires down events occurring on non-MED typically varies each year. Within the past 5 years, 2020-2024, there has been a decrease in the number of events when comparing to years prior to 2020. The variance in this metric is driven by several factors including weather conditions, third

[1] SmartMeter is a PG&E registered trademark. All further references to SmartMeters in PG&E’s testimony in this proceeding should be assumed to refer to the trademarked name, without continually using the ™ symbol, consistent with legally-acceptable practice.

party influence and the number of MED days per year. Furthermore, PG&E's approach to wildfire mitigations in the HFTD locations is based on a risk informed prioritization of work in the areas where wildfire risk is evaluated as highest, as opposed to where wires down incidents have a high likelihood of occurrence if they are in areas where wildfire risk is relatively lower within the HFTD.

In 2024, PG&E had a metric of 22.19.

C. (3.2) 1-Year Target and 5-Year Target

1. Updates to 1- and 5-Year Targets Since Last Report

Directional 1- and 5- year targets remain unchanged from the previous reporting period

2. Target Methodology

- Directional Only: Maintain (stay within historical range, and assumes response stays the same in events).

  Based on the historical performance of this metric, PG&E interprets "Maintain" as staying within 1 standard deviation from the 10-year average. This equates to an upper limit of 41.30 (as shown in Figure 3.2-1);
- Historical Data and Trends: This metric is expected to remain within the historical performance levels, but will vary based on the number of MEDs experienced in a year and the weather conditions;
- Benchmarking: Not available to the best of our knowledge;
- Regulatory Requirements: None;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: The directional target for this metric is suitable for EOE as it states performance will remain within historical range which accounts for unknown factors which may vary such as the frequency and severity of weather;
- Attainable Within Known Resources/Work Plan: Yes, targets are attainable within known resources, however this metric is impacted by the variability in conditions outside of PG&E's control, such as weather conditions that may not be excluded as an MED; and
- Other Considerations: None.

3. 2025 Target

The 2025 target is a 1-standard deviation of the 10-year average with an upper limit of 40.25.

4. 2029 Target

The 2029 target is the same as the 1-year target, to maintain within historical performance levels, i.e., within the upper limit of 40.25.

D. (3.2) Performance Against Target

1. Progress Towards the 1-Year Target

PG&E's commitment to reduce the number of wires down events continued in 2024, with a performance rate of 22.19 (Figure 3.2-1), well within the 2024 target of 41.30. Should weather conditions continue to trend favorably into 2025, this metric should maintain a rate within the 2025 one-year target set at 40.25.

2. Progress Towards the 5-Year Target

PG&E's commitment to public safety and service reliability drives the initiatives, programs, and work efforts mentioned in Section E below. Data and information collected and analyzed from this metric, continues to inform, and influence decision making, improving, and maintaining long-term metric performance, which aligns with the 5-year directional performance target.

E. (3.2) Current and Planned Work Activities

PG&E will continue to execute many ongoing activities to reduce wires down, including the following programs:

- OH Conductor Replacement: PG&E's electric distribution system includes approximately 80,312 circuit miles of OH conductor on its distribution system that operates between 4 and 21 kilovolt, including bare and covered conductors. Approximately 54,500 circuit miles of this distribution conductor, including approximately 36,300 circuit miles of small conductor is in non-HFTD areas. PG&E's OH Conductor Replacement Program, recorded in MAT 08J, proactively replaces OH conductor in non-HFTD areas to address elevated rates of wires down and deteriorated/damaged conductors and to improve system safety, reliability, and integrity.

Please see Exhibit (PG&E-4), Chapter 13, Overhead and Underground Asset Management in the 2023 GRC for additional details.

- Patrols and Inspections: PG&E monitors the condition of OH conductor through patrols and inspections consistent with GO 165. Tags are created for abnormal conditions, including those that can lead to a wire down. Work is prioritized in a risk-informed manner to address the issues identified in the tags. In addition, PG&E has implemented risk based aerial inspections using drones in targeted areas. Drone inspections significantly improve our ability to assess deteriorated conditions on the conductor.
- Grid Design and System Hardening: PG&E's broader grid design program covers a number of significant programs, called out in detail in PG&E's 2023 WMP. The largest of these programs is the System Hardening Program which focuses on the mitigation of potential catastrophic wildfire risk caused by distribution OH assets. In 2024, we continued our system hardening efforts by: (i) completing 390 circuit miles of system hardening work which includes OH system hardening, undergrounding and removal of OH lines in HFTD or buffer zone areas; (ii) completing approximately 257 circuit miles of undergrounding work, including Community Rebuild efforts and other distribution system hardening work; and (iii) replacing equipment in HFTD areas that creates ignition risks, such as non-exempt fuses and surge arresters. As we look beyond 2024, PG&E is targeting 310 miles of Undergrounding and 210 miles of OH/removal/remote grid to be completed in 2025 as part of the System Hardening Program. Even though this program will provide wire down mitigation benefit, note that PG&E's approach to wildfire mitigations in the HFTD locations is based on a risk informed prioritization of work in the areas where wildfire risk is evaluated as highest, which combines many asset based composite risk models contributing to the overall probability of failure including conductor failure.

Please see Section 7.3.3, Grid Design and System Hardening Mitigations in PG&E's WMP for additional details.

- Vegetation Management: The EVM Program targeted OH distribution lines in Tier 2 and 3 HFTD areas and supplemented PG&E's annual routine VM work with California Public Utilities Commission mandated clearances. Our EVM Program went above and beyond regulatory requirements for distribution lines by expanding minimum clearances and removing overhangs in HFTD areas. Due to the emergence of other wildfire mitigation programs (namely EPSS and Undergrounding), the program was discontinued in 2023. The trees that were identified as part of the program and previous iterations and scopes will be worked down over the next nine years under a program called Tree Removal Inventory (TRI), prioritized by risk rank using our latest wildfire distribution risk model. The WMP has a commitment for this program for the mitigation of 25 thousand trees in 2025.VM for Operational Mitigations is a new transitional program which began 2023 stemming from the conclusion of the EVM program. This program is intended to help reduce outages and potential ignitions using a risk-informed, targeted plan to mitigate potential vegetation contacts based on historic vegetation outages on EPSS-enabled circuits. The focus is on mitigating potential vegetation contacts in CPZs that have experienced vegetation caused outages. Scope of Work is developed by using EPSS and historical outage data and vegetation failure from the current WDRM risk model. Vegetation outage extent of condition inspections conducted on EPSS-enabled devices may generate additional tree work.

Focused Tree Inspections (FTI) is another new transitional program that began in 2023 stemming from the conclusion of the EVM program. PG&E developed Areas of Concern (AOC) to better focus VM efforts to address high risk areas that have experienced higher volumes of vegetation damage during PSPS events, outages, and/or ignitions. These areas are inspected by Vegetation Management Inspectors with a Tree Risk Assessment Qualification (TRAQ) which provides a higher level of rigor to the inspection.

Please see Section 8.2, Vegetation Management, and Inspections in PG&E's WMP for additional details.

- Other Advancements: PG&E is applying new technologies in the field to identify and/or prevent conductor to ground faults. This includes:
  - SmartMeter-based methods;
  - Distribution Falling Wire Detection Method;
  - Distribution Fault Anticipation;
  - Early Fault Detection; and
  - Rapid Earth Fault Current Limiter.

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CHAPTER 3.3
WIRES DOWN MAJOR EVENT DAYS IN HFTD AREAS (TRANSMISSION)

The material updates to this chapter, since the September 30, 2024, report are identified in blue font.

A. (3.3) Overview

1. Metric Definition

Safety and Operational Metric (SOM) 3.3 – Wires Down Major Event Days in High Fire Threat District (HFTD) Areas (Transmission) is defined as:

Number of Wires Down events on Major Event Days (MED) involving overhead transmission circuits divided by total circuit miles of overhead transmission lines x 1,000, in HFTD Areas in a calendar year.

2. Introduction of Metric

This metric is a measure of how Pacific Gas and Electric Company (PG&E or the Company) provides safe and reliable electric services to its customers. It is also a measure of how available PG&E's electric transmission (ET) grid is to the market for the buying and selling of electricity as managed by the California Independent System Operator.

This metric is associated with PG&E's Failure of ET Overhead Asset Risk and Wildfire Risk, which are part of the Company's 2020 Risk Assessment and Mitigation Phase Report filing.

B. (3.3) Metric Performance

1. Historical Data (2013 – 2024)

There are 12 years of historical data available from the years 2013- 2024. Although PG&E started measuring wire down incidents in 2012, 2013 was the first full year uniformly measuring the number of transmission wire down events. This metric is normalized by the transmission circuit miles within Tier 2 and Tier 3 HFTDs. The HFTD boundaries are a recent development and were not defined for several years within the historical data timeframe. Hence, for all years prior to and including 2022, PG&E uses 5,525.9 overhead transmission circuit miles in Tier 2/3 HFTD areas and assumes any variances in prior years are negligible. Moving forward, HFTD mileage will be refreshed at the beginning of each year. Table 1 provides the HFTD miles used for each year.

TABLE 3.3-1
HFTD MILES

Line No.	Year	HFTD Miles
1	Prior to 2023	5525.9
2	2023	5437.7
3	2024	5402.3

2. Data Collection Methodology

Unplanned ET outages are documented by PG&E's Transmission Operations Department using its Transmission Operations Tracking and Logging (TOTL) application. If distribution-served customers are affected by a particular transmission wire down event, the data captured in TOTL are merged in a separate data set with respective data from PG&E's distribution outage reporting application Integrated Logging Information System. Follow up is usually required to validate cause of the wire down event, including daily outage review calls with various stakeholder departments to clarify the details of the wire down event. Results are consolidated and regularly communicated internally to keep stakeholders informed of progress.

3. Metric Performance for the Reporting Period

All systems and processes and their outputs exhibit variability. Control charts help monitor variability and can be used to differentiate common causes of variability from special causes. Common, or chance, causes are numerous small causes of variability that are inherent to a system and operate randomly. Special, or assignable, causes can have relatively large effects on the process and may lead to a state that is out of statistical control—i.e., outside control chart limits.

PG&E's control charts are set up using a static time window of 2013-2022. Using the actual data from those years allows us to calculate the following values that are used in the control charts:

- Mean: Average value of the metric.
- Standard Deviation: Amount of variation of the metric calculated by taking the square root of the variance of the dataset.
- Upper Control Limit (UCL): The maximum value that can be attributed to natural fluctuations calculated by mean plus 3 standard deviations.
- Lower Control Limit (LCL): The minimum value that can be attributed to natural fluctuations calculated by mean minus 3 standard deviations.
- Upper Warning Limit (UWL): The warning value that should raise a flag to take a proactive response to prevent the metric from approaching the UCL calculated by mean plus 2 standard deviations.
- Lower Warning Limit (LWL): The warning value that should raise a flag to take a proactive response to prevent the metric from approaching the LCL calculated by mean minus 2 standard deviations.

The probability that a point falls above the UCL which for most control chart designs is an indicator of significant process degradation or below the LCL, an indicator of significant process improvement) if only common causes are operating is approximately 0.00135. It is therefore unlikely to have measures fall beyond the control limits when no special cause is operating. False alarms are possible, but the placement of the control limits at 3 standard deviations (+/-) from the process average is thought to control the number of false alarms adequately in most situations. The simplest rule for detecting presence of a special cause is one or more points that fall beyond upper or lower limits of the chart.

Control charts can further illustrate an expected range of performance based on historical data. They can assist with discrete observations of recent performance improvement or decline or stability.

Figure 3.3-1 below is a control chart showing historical annual performances since 2013 for ET wire down events excluding those that occurred on a declared MED. Similarly, Figure 3.3-2 is a control chart showing all wire down events including MEDs.

FIGURE 3.3-1
ELECTRIC TRANSMISSION WIRES DOWN EVENTS, EXCLUDING MEDS
(2013- 2024)

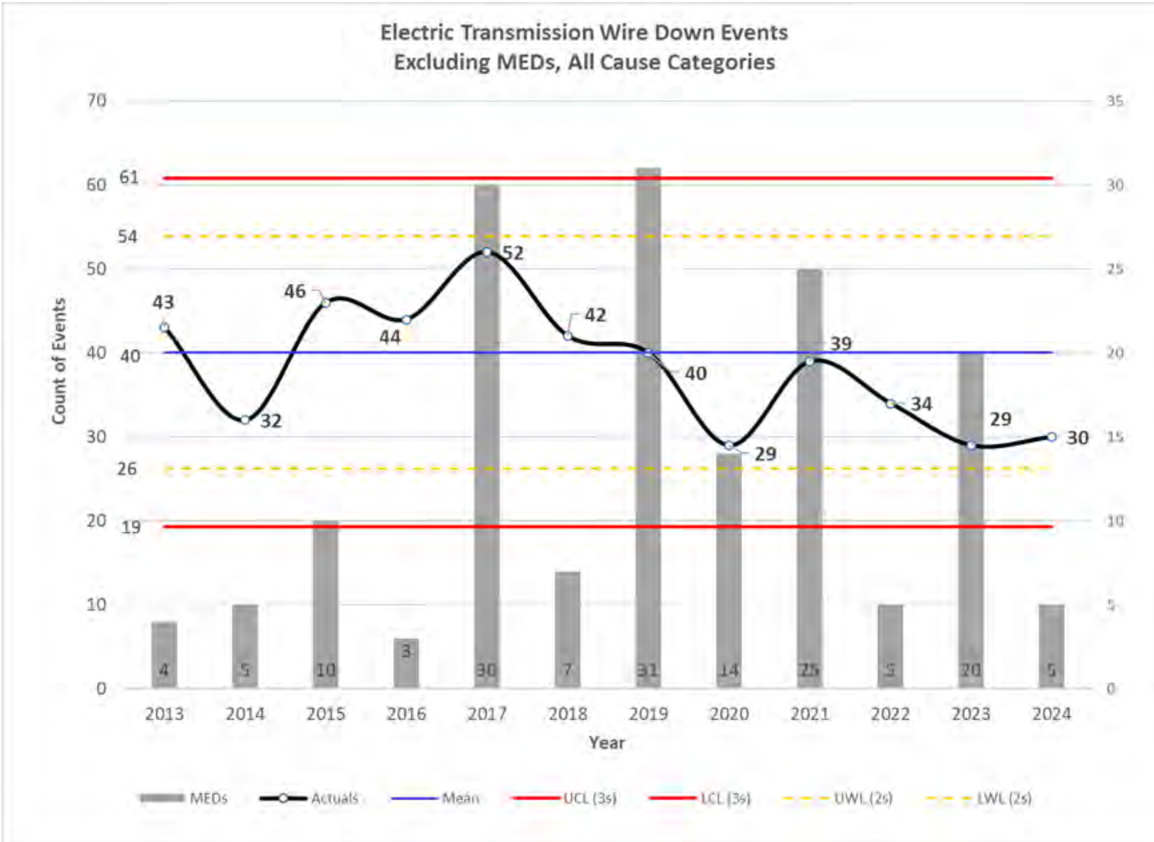
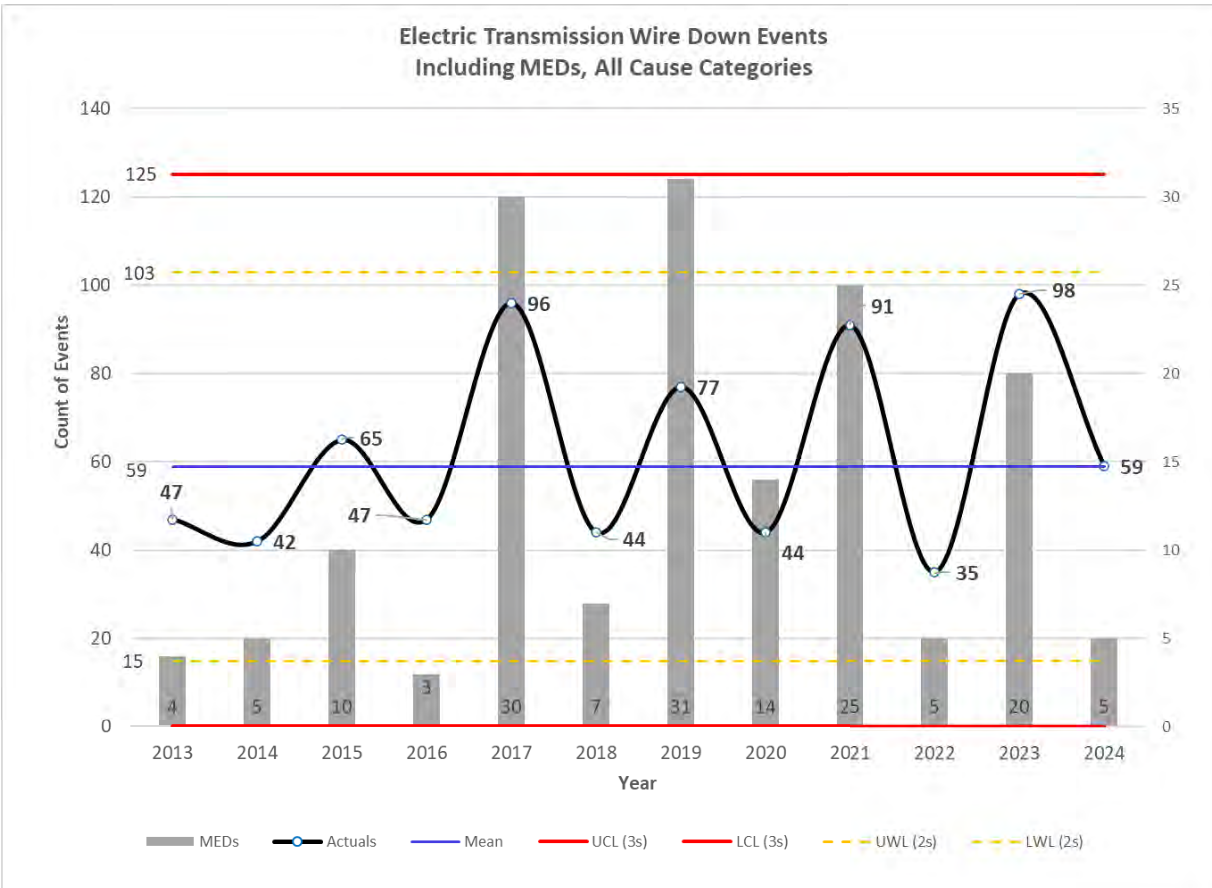


FIGURE 3.3-2
ELECTRIC TRANSMISSION WIRES DOWN EVENTS, INCLUDING MEDS
(2013- 2024)



Comparing the two figures above, one can conclude that on average we can expect more transmission wire down events when MEDs are included. More importantly, there are no instances in either chart where the upper chart limit set at three standard deviations was exceeded. It appears we have a stable performing process in the count of transmission wire down events, whether MEDs are included in the count or not.

Figure 3.3-3 below is analogous to Figure 3.3-2 above but restricts the count of transmission wire down events to those occurring within Tier 2 or Tier 3 HFTDs. All categories related to cause are included. The bars in the chart show congruence between the number of MEDs in a performance year vs. the count of transmission wire down.

FIGURE 3.3-3
ELECTRIC TRANSMISSION WIRES DOWN EVENTS,
INCLUDING MEDS, TIER 2/3 (2013-2024)

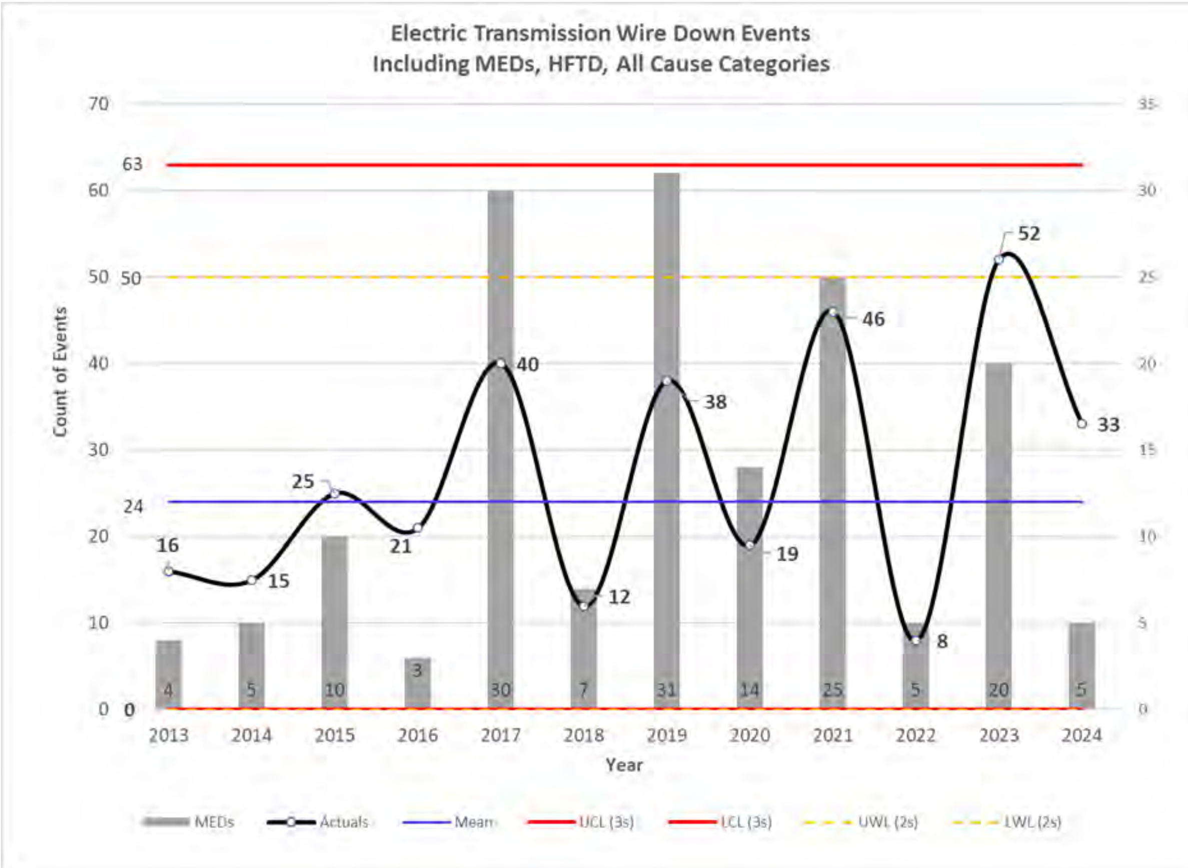
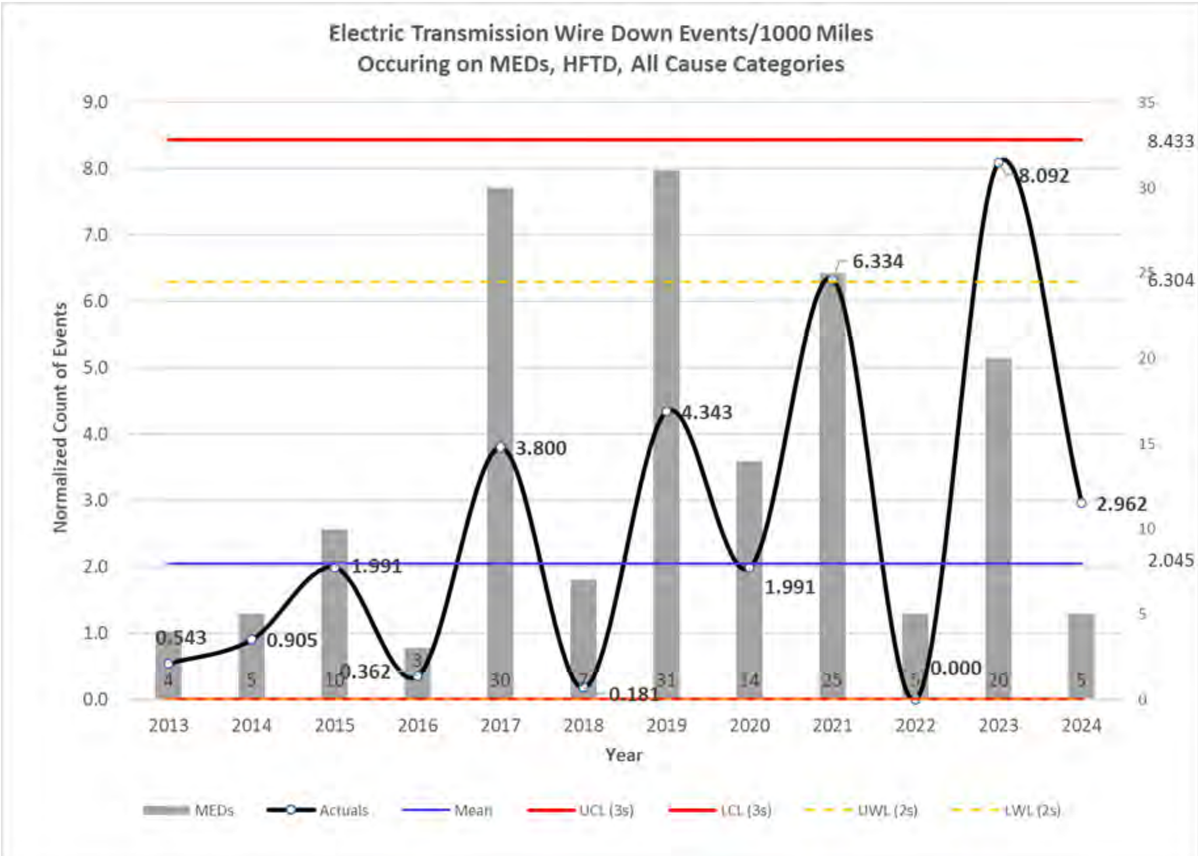


Figure 3.3-4 below is analogous to Figure 3.3-3 above but further restricts the count of transmission wire down events to those that occurred only during a declared MED. These counts are normalized by dividing by the circuit mileage associated circuits located in Tier 2 and Tier 3 boundaries x 1,000. Again, there is congruence between the normalized counts of transmission wire down events and the number of MEDs.

TABLE 3.3-4
ELECTRIC TRANSMISSION WIRES DOWN EVENTS OCCURING ON MEDS, TIER 2/3
(2013- 2024)



C. (3.3) 1-Year Target and 5-Year Target

1. Updates to 1- and 5-Year Targets Since Last Report

There are no updates to the directional 1- and 5-Year Targets since last report, to maintain performance within the historical range, i.e., the target is to stay below the UCL as defined above. The UCL for 2025 (1 Year) and 2029 (5 Year) is 8.433.

2. Target Methodology

- Unplanned Directional Only: Maintain, i.e., stay within historical range as determined by the UCL and the LCL as defined above, and assumes response stays the same in events.

As discussed above in the interpretations of control charts related to this metric—and absent any "special" cause(s) that would result in deviation above the current three standard deviations—it is reasonable to expect that future transmission wire down results would remain within the historical performance levels. Such results will vary based on the number and severity of MEDs experienced in a year; however, end-of-year actuals should remain centered around the mean and below the UCL shown in Figure 3.3-4. It is noted that changes in MED thresholds from year to year can skew the UCL.

- Benchmarking: Not available to best of our knowledge;
- Regulatory Requirements: None;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: The directional target for this metric is suitable for EOE as it states metric performance will remain in historical range;
- Attainable Within Known Resources/Work Plan: Yes, this metric is attainable within known resources, however this metric is impacted by the variability in conditions outside of PG&E's control, such as the severity of inclement weather on MED; and
- Other Considerations: None.

D. (3.3) Performance Against Target

1. Progress Towards the 1-Year Target

PG&E experienced 16 wire down events in HFTDs on 5 MEDs in 2024 resulting in a performance of 2.962. This was below the UCL of 8.433.

2. Progress Towards the 5-Year Target

As discussed in Section E below, PG&E is deploying a number of programs to maintain or improve long-term performance of this metric to meet the Company's 5-year directional performance target.

E. (3.3) Current and Planned Work Activities

Wire down events can be caused by a variety of factors, including, but not limited to asset failure, third-party contact, or vegetation contact. The following work activities may provide future resiliency for certain wire down event causes, though the effectiveness of the work is dependent upon the circumstances of the wire down event (e.g., new assets may still be prone to a wire down event that occur due to extreme weather events outside of standard design guidance).

- Asset Inspection: Detailed inspections of overhead transmission assets seek to proactively identify potential failure modes of asset components which could create future wire down, outage, and/or safety events if left unresolved or allowed to “run to failure.” Detailed inspections for transmission assets involve at least two detailed inspection methods per structure (ground and aerial), though not necessarily in the same calendar year which allows for staggered inspection methods across multiple years. Aerial inspections may be completed either by drone, helicopter, or aerial lift. In addition to the ground and aerial inspections, climbing inspections are also required for 500 kilovolt structures or as triggered. All these inspection methods involve detailed, visual examinations of the assets with use of inspection checklists that are in accordance with the ET Preventive Maintenance standards, as well as the Failure Modes and Effects Analysis.

- Asset Repair and Replacement: Completing repair, replacement, removal or life extension to transmission assets provides the benefit of reduced probability of failure for components that could potentially result in a wire down event. Idle asset de-energization and removal eliminates wires down event risk by removing the energized electrical components.

Many improvements are identified through corrective maintenance notifications. These notifications are typically identified as a result of transmission asset inspections and patrols. Prioritization of maintenance tags are based on severity of the issues found and fire ignition potential (i.e., asset-conditions impacting issues associated with HFTD areas and High Fire Risk Area). Execution of the prioritized work plan would also have to address other factors such as clearance availability, access, work efficiency, etc.

- Vegetation Management (VM): Trees or other vegetation that make contact or cross within flash-over distance of high voltage transmission lines can cause phase to phase or phase to ground electrical arcing, fire ignition or local, regional or cascading, grid-level service interruption. Dense vegetation growing within the right-of-way (ROW) can act as a fuel bed for wildfire ignition. Vegetation growing close to any pole or structure can impede inspection of the structure base and in some cases can damage the structure or conductors and result in wire down events.

  PG&E operates our lines in electric transmission (ET) corridors that are home to vast amounts of vegetation. This vegetation ranges from sparse to extremely dense. Our transmission lines also pass through urban, agricultural, and forested settings. The corridor environment is dynamic and requires focused attention to ensure vegetation stays clear of energized conductors and other equipment. Vegetation inspection is a required operational step in an overall VM Program. Accordingly, PG&E's annual inspection is part of the overall Transmission VM Program responding to the diverse and dynamic environment of our service territory. The Routine North American Electric Reliability Corporation (NERC) and Routine Non-NERC patrols are annually recurring. The Integrated Vegetation Management (IVM) Program maintains cleared ROWs. The frequency and prioritization for each of these programs is described in more detail below.

Routine NERC: The Routine NERC patrol includes Light Detection and Ranging (LiDAR) inspection, visual verification of findings, and mitigation of vegetation encroachments, as well as other vegetation conditions on approximately 6,800 miles of NERC Critical lines. One hundred percent of inspection and work plan completions are required by NERC Standard FAC-003-45. Work is prioritized based on aerial LiDAR detection. This program recurs annually.

- Non-Routine NERC: The Non-Routine NERC Program includes LiDAR inspection, visual verification of findings, and mitigation of vegetation encroachments, as well as other vegetation conditions on approximately 11,400 miles of transmission lines not designated as critical by NERC. Work is prioritized based on aerial LiDAR detection. This program recurs annually.
- Integrated Vegetation Management: The IVM Program is an ongoing maintenance program designed to maintain cleared ROWs in a sustainable and compatible condition by eliminating tall-growing and fire-prone vegetation and promoting low-growing, compatible vegetation. Prioritization is based on aging work cycles and evaluation of vegetation re-growth.

PACIFIC GAS AND ELECTRIC COMPANY

SAFETY AND OPERATIONAL METRICS REPORT:

CHAPTER 3.4

WIRES DOWN NON-MAJOR EVENT DAYS IN HFTD AREAS

(TRANSMISSION)

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 3.4
WIRES DOWN NON-MAJOR EVENT DAYS IN HFTD AREAS
(TRANSMISSION)

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PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 3.4
WIRES DOWN NON-MAJOR EVENT DAYS IN HFTD AREAS (TRANSMISSION)

The material updates to this chapter, since the September 30, 2024 report, are identified in blue font.

A. (3.4) Introduction

1. Metric Definition

Safety and Operational Metric (SOM) 3.4 – Wires Down Non-Major Even Days in HFTD Areas (Transmission) is defined as:

Number of Wires Down events on Non-Major Event Days (MED) involving overhead transmission circuits divided by total circuit miles of overhead transmission lines x 1,000, in High Fire Threat District (HFTD) Areas, in a calendar year.

2. Introduction of Metric

This metric is a measure of how Pacific Gas and Electric Company (PG&E or the Company) provides safe and reliable electric services to its customers. It is also a measure of how available PG&E's Electric Transmission (ET) grid is to the market for the buying and selling of electricity as managed by the California Independent System Operator (CAISO).

This metric is associated with PG&E's Failure of ET Overhead Asset Risk and Wildfire Risk, which are part of the Company's 2020 Risk Assessment and Mitigation Phase Report filing.

B. (3.4) Metric Performance

1. Historical Data (2013 – 2024)

There are 12 years of historical data available from the years 2013- 2024. Although PG&E started measuring wire down events in 2012, 2013 was the first full year uniformly measuring the number of transmission wire down incidents. This metric is normalized by the transmission circuit miles within Tier 2 and Tier 3 HFTDs. The HFTD boundaries are a recent development and were not defined for several years within the historical data timeframe. Hence, for all years prior to and including 2022, PG&E uses 5,525.9 overhead transmission circuit miles in Tier 2/3 HFTD areas and assumes any variances in prior years are negligible. Moving forward, HFTD mileage will be refreshed at the beginning of each year. Table 3.4-1 provides the HFTD miles used for each year.

TABLE 3.4-1
HFTD MILES

Line No.	Year	HFTD Miles
1	Prior to 2023	5525.9
2	2023	5437.7
3	2024	5402.3

2. Data Collection Methodology

Unplanned ET outages are documented by PG&E’s Transmission Operations Department using its Transmission Operations Tracking & Logging (TOTL) application. If distribution-served customers are affected by a particular transmission wire down event, the data captured in TOTL are merged in a separate data set with respective data from PG&E’s distribution outage reporting application (integrated logging information system). Follow up is usually required to validate cause of the wire down event, including daily outage review calls with various stakeholder departments to clarify the details of the wire down event. Results are consolidated and regularly communicated internally to keep stakeholders informed of progress Metric performance.

3. Metric Performance for the Reporting Period

All systems and processes and their outputs exhibit variability. Control charts help monitor variability and can be used to differentiate common causes of variability from special causes. Common, or chance, causes are numerous small causes of variability that are inherent to a system and operate randomly. Special, or assignable, causes can have relatively large effects on the process and may lead to a state that is out of statistical control—i.e., outside control chart limits.

PG&E's control charts are set up using a static time window of 2013-2022. Using the actual data from those years allows us to calculate the following values that are used in the control charts:

- Mean: Average value of the metric.
- Standard Deviation: Amount of variation of the metric calculated by taking the square root of the variance of the dataset.
- Upper Control Limit (UCL): The maximum value that can be attributed to natural fluctuations calculated by mean plus three standard deviations.
- Lower Control Limit (LCL): The minimum value that can be attributed to natural fluctuations calculated by mean minus three standard deviations.
- Upper Warning Limit: The warning value that should raise a flag to take a proactive response to prevent the metric from approaching the UCL calculated by mean plus two standard deviations.
- Lower Warning Limit: The warning value that should raise a flag to take a proactive response to prevent the metric from approaching the LCL calculated by mean minus two standard deviations.

The probability that a point falls above the UCL (for most control chart designs, usually an indicator of significant process degradation) or below the LCL (an indicator, usually, of significant process improvement) if only common causes are operating is approximately 0.00135. It is therefore unlikely to have measures fall beyond the control limits when no special cause is operating. False alarms are possible, but the placement of the control limits at three standard deviations (+/-) from the process average is thought to control the number of false alarms adequately in most situations. The simplest rule for detecting presence of a special cause is one or more points that fall beyond upper or lower limits of the chart.

Control charts can further illustrate an expected range of performance based on historical data. They can assist with discrete observations of recent performance improvement or decline or stability.

Each year since 1998 PG&E and the CAISO or ISO have monitored ET availability using control charts.

Appendix C of the Transmission Control Agreement between PG&E and CAISO states that each participating transmission owner:

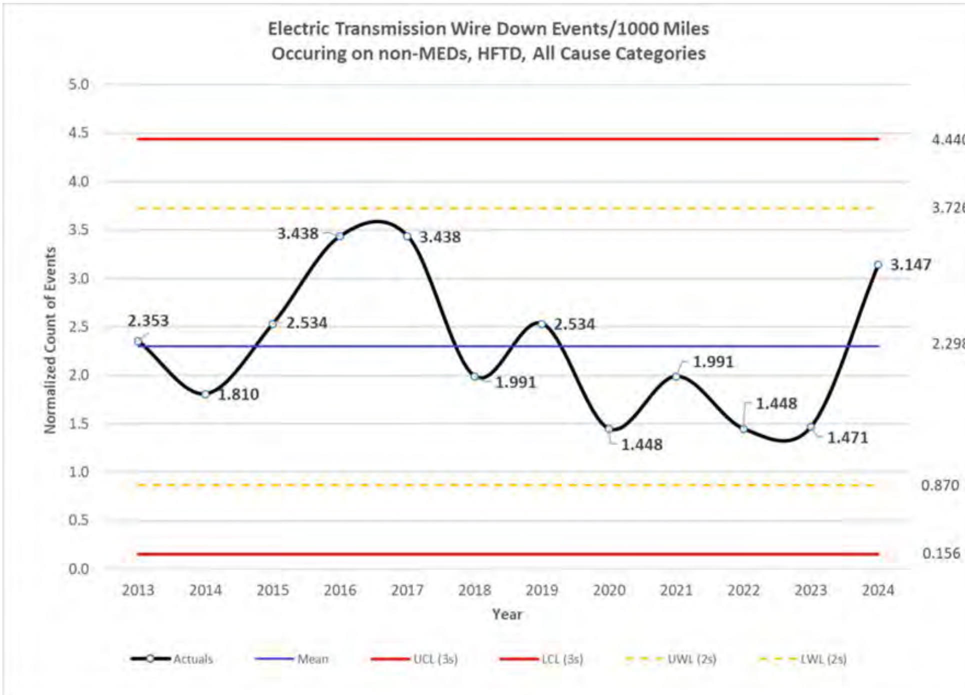
> …shall submit an annual report…describing its Availability Measures performance. This annual report shall be based on Forced Outage records…and shall include the date, start time, end time affected Transmission Facility, and the probable cause(s) if known.

Appendix C goes on to address targets which are defined as "The Availability performance goals established by the ISO," which are based on the control chart limits calculated and shown in the annual report.

As mentioned, ET wire down events have been tracked historically in part as a measure of how available PG&E's ET grid is to the market managed by CAISO. With this proven and statistically robust method of calculating ET availability targets using control charts already established, it is reasonable—and preferable—to adopt this control chart methodology to not only monitor past and present performance but also better predict future performance and facilitate recommendations at a higher confidence level for annual targets related to ET wire down events.

There is precedent internally for using control charts to set targets. Figure 3.4-1 below is a control chart showing historical annual performances through 2024 for ET wire down events excluding those that occurred on a declared MED. The 2024 performance was 3.147 compared to the UCL of 4.440.

FIGURE 3.4-1
ELECTRIC TRANSMISSION WIRES DOWN EVENTS
OCCURRING ON NON-MEDS PER 1,000 CIRCUIT MILES (2013- 2024)



C. (3.4) 1-Year Target and 5-Year Target

1. Updates to 1- and 5-Year Targets Since Last Report

There have been no changes to the 1-year and 5-year targets since the last SOMs report filing. The targets remain at 4.440 which represents the UCL based on three standard deviations as defined above.

2. Target Methodology

To establish the 1-Year and 5-Year targets, the following:

- Historical Data and Trends: 1-Year and 5-Year Targets are set to maintain performance within a 3-standard deviation range using the available historical data. As discussed above in the interpretations of control charts related to this metric—and absent any “special” cause(s) that would result in deviation above the current three standard deviations—it is reasonable to expect that future transmission wire down results would remain within the historical performance levels. Such results will vary based on the number of MEDs experienced in a year; however, end of year actuals should remain centered around the mean and not to exceed the UCL shown in Figure 3.4-1. Changes in MED thresholds from year to year can skew the UCL;

- Benchmarking: Not available to the best of our knowledge;
- Regulatory Requirements: None;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement (EOE): The target for this metric is suitable for EOE as it suggests that future results will remain within the historic performance levels;
- Attainable Within Known Resources/Work Plan: Metric targets are attainable within known resources, however this metric is impacted by the variability in conditions outside of PG&E's control, such as the severity of inclement weather on days that do not register as MEDs; and
- Other Considerations: None.

3. 2025Target

Not to exceed 4.440, which represents maintaining within a 3-standard deviation range. A 3-standard deviation remains consistent with other ET external report filings with the CAISO.

4. 2029 Target

Not to exceed 4.440, which represents maintaining within a 3-standard deviation range. A 3-standard deviation remains consistent with other ET external report filings with the CAISO.

D. (3.4) Performance Against Target

1. Progress Towards the 1-year Target

PG&E experienced 17 wire down events per 1,000 circuit miles on non-MEDs in 2024 resulting in a performance of 3.147. This was below the UCL of 4.440.

2. Progress Towards the 5-year Target

As discussed in Section E below, PG&E is deploying a number of programs to maintain or improve long-term performance of this metric to meet the Company's 5-year performance target.

E. (3.4) Current and Planned Work Activities

Wire down events can be caused by a variety of factors, including but not limited to asset failure, third party contact, or vegetation contact. The following work activities may provide future resiliency for certain wire down event causes, though the effectiveness of the work is dependent upon the circumstances of the wire down event (e.g., new assets may still be prone to a wire down event that occur due to extreme weather events outside of standard design guidance).

- Asset Inspection: Detailed inspections of overhead transmission assets seek to proactively identify potential failure modes of asset components which could create future wire down, outage, and/or safety events if left unresolved or allowed to "run to failure." Detailed inspections for transmission assets involve at least two detailed inspection methods per structure (ground and aerial), though not necessarily in the same calendar year which allows for staggered inspection methods across multiple years. Aerial inspections may be completed either by drone or, helicopter. In addition to the ground and aerial inspections, climbing inspections are also required for 500 kilovolt structures or as triggered. All these inspection methods involve detailed, visual examinations of the assets with use of inspection checklists that are in accordance with the ET Preventive Maintenance (TD-1001M), as well as the Failure Modes and Effects Analysis.
- Asset Repair and Replacement: Completing repair, replacement, removal or life extension to transmission assets provides the benefit of reduced probability of failure for components that could potentially result in a wire down event. Idle asset de-energization and removal eliminates wires-down event risk by removing the energized electrical components. Many improvements are identified through corrective maintenance notifications. These notifications are typically identified as a result of transmission asset inspections and patrols.

  Prioritization of maintenance tags are based on severity of the issues found and fire ignition potential (i.e., asset-conditions impacting issues associated with HFTD areas and High Fire Risk Area). Probability of failure and consequence (such as public safety consequence) may also be considered. Execution of the prioritized work plan would also have to address other factors such as clearance availability, access, work efficiency, etc.

- Vegetation Management (VM): Trees or other vegetation that make contact or cross within flash-over distance of high voltage transmission lines can cause phase to phase or phase to ground electrical arcing, fire ignition or local, regional or cascading, grid-level service interruption. Dense vegetation growing within the right-of-way (ROW) can act as a fuel bed for wildfire ignition. Vegetation growing close to any pole or structure can impede inspection of the structure base and in some cases can damage the structure or conductors and result in wire down events.

PG&E operates our lines in ET corridors that are home to vast amounts of vegetation. This vegetation ranges from sparse to extremely dense. Our transmission lines also pass through urban, agricultural, and forested settings. The corridor environment is dynamic and requires focused attention to ensure vegetation stays clear of energized conductors and other equipment. Vegetation inspection is a required operational step in an overall VM Program. Accordingly, PG&E's annual inspection is part of the overall Transmission VM Program responding to the diverse and dynamic environment of our service territory. The Routine North American Electric Reliability Corporation (NERC) and Routine Non-NERC patrols are annually recurring. The Integrated Vegetation Management (IVM) Program maintains cleared ROWs. The frequency and prioritization for each of these programs is described in more detail below.

- Routine NERC: The Routine NERC patrol includes Light Detection and Ranging (LiDAR) inspection, visual verification of findings, and mitigation of vegetation encroachments, as well as other vegetation conditions on approximately 6,800 miles of NERC Critical lines. One hundred percent inspection and work plan completion are required by NERC Standard FAC-003-45. Work is prioritized based on aerial LiDAR detection. This program recurs annually.
- Non-Routine NERC: The Non-Routine NERC Program includes LiDAR inspection, visual verification of findings, and mitigation of vegetation encroachments, as well as other vegetation conditions on approximately 11,400 miles of transmission lines not designated as critical by NERC.

Work is prioritized based on aerial LiDAR detection. This program recurs annually.

- IVM: The IVM Program is an ongoing maintenance program designed to maintain cleared ROWs in a sustainable and compatible condition by eliminating tall-growing and fire-prone vegetation and promoting low-growing, compatible vegetation. Prioritization is based on aging work cycles and evaluation of vegetation re-growth.

PACIFIC GAS AND ELECTRIC COMPANY

SAFETY AND OPERATIONAL METRICS REPORT:

CHAPTER 3.5

WIRES DOWN RED FLAG WARNING DAYS IN HFTD AREAS

(DISTRIBUTION)

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
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WIRES DOWN RED FLAG WARNING DAYS IN HFTD AREAS
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PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 3.5
WIRES DOWN RED FLAG WARNING DAYS IN HFTD AREAS (DISTRIBUTION)

The material updates to this chapter, since the September 30, 2024 report, are identified in blue font.

A. (3.5) Overview

1. Metric Definition

Safety and Operational Metric (SOM) 3.5 – Wires Down Red Flag Warning (RFW) Days in High Fire Threat District (HFTD) Areas (Distribution) is defined as:

Number of Wires Down events in HFTD Areas on RFW Days involving overhead (OH) primary distribution circuits divided by RFW Distribution Circuit-Mile Days in HFTD Areas, in a calendar year.

2. Introduction of Metric

This metric measures the number of distribution wire down events located in the Tier 2 and Tier 3 HFTD areas that occurred on RFW Days and is divided by sum of days and line miles (of the Tier 2 and Tier 3 HFTD OH distribution line miles involved on each RFW Day).

In 2012, Pacific Gas and Electric Company (PG&E or the Company) initiated the Wires Down Program, including introduction of the wires down metric, to advance the Company's focus on public safety by reducing the number of conductors that fail and result in a contact with the ground, a vehicle, or other object.

This metric is associated with our Failure of Electric Distribution OH Asset Risk and Wildfire risk, which are part of our 2020 Risk Assessment and Mitigation Phase Report (RAMP) filing.

B. (3.5) Metric Performance

1. Historical Data (2013 – 2024)

We have 12 years of historical data available from 2013- 2024.

Although we started measuring distribution wire down incidents in the 2012, 2013 marked the first full distribution wire down incidents were uniformly measured.

During this historical reporting period, external factors such as weather and third-party contact with OH electric facilities continued to influence metric performance. Refer to Figure 3.5-1 below for historical performance.

Our OH electric primary distribution system consists of approximately 80,312circuit miles of OH conductor and associated assets with approximately 24,878 circuit miles traversing through HFTD areas, that pose risk for potential wires down incidents.

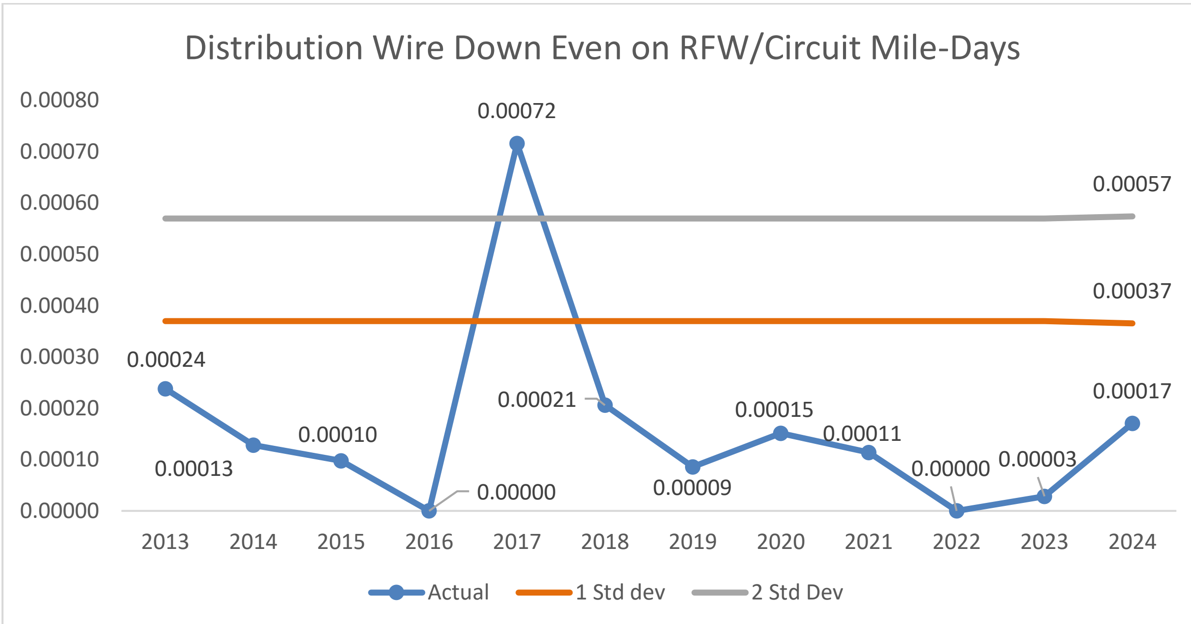
Over the last several years, we have completed significant work and launched various initiatives targeted at reducing wires down incidents, including:

- Performing infrared inspections of OH electric power lines to identify and repair hot spots;
- Clearing of vegetation hazards posing risks to our OH electric facilities; and
- Hardening of OH electric power systems with more resilient equipment.

In addition, our vegetation management (VM) teams conduct site visits of vegetation caused wires down incidents as part of its standard tree caused service interruption investigation process. The data obtained from site visits supports efforts to reduce future vegetation caused wires down incidents. The data collected from these investigations also helps identify failure patterns by tree species that are associated with wires down incidents. Additionally, beginning in March of 2024, an extent of condition patrol five spans in all directions from the downed wire. The purpose of an extent of condition patrol is to determine subject tree failure mode and identify any additional trees of concern within the extent of condition patrol area. This may include but is not limited to:

- Conditions similar to the failed subject tree;
- Trees damaged from the fire or the failed subject tree; and
- Other tree conditions of concern which may lead to another outage or ignition.
- Non-compliant trees.

FIGURE 3.5-1
ELECTRIC DISTRIBUTION
PRIMARY WIRES DOWN INCIDENTS PER RFW/CIRCUIT MILE-DAYS (2013- 2024)



2. Data Collection Methodology

PG&E uses its Integrated Logging Information System (ILIS) – Operations Database to track and count the number of wires down incidents, as well as its electric distribution geographical information systems (EDGIS) to determine if the wire down incident was in an HFTD locations. Although the outage database does not specifically identify precise location of the downed wire, the Latitude and Longitude (e.g., Lat/Long) of the device is used to isolate the involved electric power line Section as a proxy. PG&E also uses its EDGIS application to determine if that device (Lat/Long information) is in the HFTD (e.g., Tier 2 or Tier 3 location). Outage information is entered into ILIS by our electric distribution operators based on information from field personnel and devices such as Supervisory Control and Data Acquisition alarms and SmartMeter™[1] devices. We last upgraded our outage reporting tools in year 2015 and

[1] SmartMeter is a PG&E registered trademark. All further references to SmartMeters in PG&E's testimony in this proceeding should be assumed to refer to the trademarked name, without continually using the ™ symbol, consistent with legally-acceptable practice.

integrated SmartMeter information to identify potential outage reporting errors and to initiate a subsequent review and correction.

PG&E defines the number of wires down events as the number of outages caused by one or more wire down faults. For example, if a single wire down fault causes two protective devices to operate, such as a Line Recloser momentary trip and a downstream fuse burning open, this will be recorded as two separate outages and two wire down events. Alternatively, one protective device operating for a fault caused by multiple spans or phases of wire coming down, will be recorded as one wire down event. This is due to limitations to what can be recorded in the outage logging system. While we are not making any immediate changes to our reporting process, we are evaluating our procedure to determine if our calculation of this metric can be adjusted to address these limitations. PG&E's meteorology group maintains a data base tracking RFW dates, time, and involved areas and determines RFW Circuit Miles Days as follows:

- The National Weather Service (NWS) will issue a RFW and their associated polygons under specific polygon/shapefiles called Fire Zones.
- PG&E's geographic information system team has calculated all OH Distribution and Transmission lines for all the Fire Zone shapefile boundaries that intersect PG&E territory. For each NWS Fire Zone PG&E has the number of OH line miles for Distribution and Transmission and the number of OH line miles for Transmission, which is then also split into the specific HFTD and non HFTD tiers and zones.
- Meteorology then compiles all the archived RFW shapefiles for California, and from all the RFW events, determines which zones there was a RFW under and the duration of time it lasted.
- RFW Circuit Mile Days= RFW days x Circuit line miles.

3. Metric Performance for the Reporting Period

As shown in Figure 3.5-1 above, the distribution wire down events on RFW days per circuit mile day has varied each year but has generally declined since 2017. In 2024 PG&E experienced 15 wire down events on RFWs. In 2023, PG&E experienced one wire down event on RFWs. In 2022, 2021 and 2020 PG&E experienced zero, 13 and 34 wire down events on RFWs. Performance is attributed to ongoing efforts in reducing wires down events, in particular vegetation management and hardening. However, because the number of events is very minimal, and the metric is highly weather dependent in areas that are more susceptible to wire down events, it can be expected to see variance from a year-to-year basis.

C. (3.5) 1-Year Target and 5-Year Target

1. Updates to 1- and 5-Year Targets Since Last Report

Directional 1- and 5- year targets remain unchanged from the previous reporting period.

2. Target Methodology

- Directional Only: Maintain (stay within historical range, and assumes response stays the same in events);

  Based on the historical performance of this metric, PG&E interprets "Maintain" as staying within two standard deviations from the 10-year average. This equates to an upper limit of 0.00057 (as shown in Figure 3.5-1).
- Historical Data and Trends: This metric is expected to remain within the historical performance levels, but will vary based on the number of RFWs and severity of weather experienced in a year;
- Benchmarking: Not available to the best of our knowledge;
- Regulatory Requirements: None;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: The directional target for this metric is suitable for EOE as it suggests performance will remain within the historical range which accounts for unknown factors which may vary such as the frequency and severity of weather;
- Attainable Within Known Resources/Work Plan: The directional target to maintain performance is attainable within known resources, however this metric is impacted by the variability in conditions outside of PG&E's controls, such as the severity of weather on RFWs;
- Other Considerations: None.

3. 2025 Target

The 2025 target is to maintain within historical performance levels, with an upper limit of 0.00057.

4. 2029 Target

The 2029 target is to maintain within historical performance levels, with an upper limit of 0.00057.

D. (3.5) Performance Against Target

1. Progress Towards the 1-year Target

PG&E achieved its 1-year target to reduce the number of wires down events, with a performance rate of 0.00017 (Figure 3.5-1), well within the 2024 target of 0.00057. Should weather conditions continue to trend favorably into 2025, this metric should maintain a rate within the 2025 one-year target set at 0.00057.

2. Progress Towards the 5-year Target

PG&E's commitment to public safety and service reliability drives the initiatives, programs, and work efforts mentioned in Section E below. Data and information collected and analyzed from this metric, continues to inform and influence decision making, improving and maintaining long-term metric performance, which aligns with the 5-year directional performance target.

E. (3.5) Current and Planned Work Activities

PG&E will continue to execute many ongoing activities to reduce wires down, including the following programs:

- <u>OH Conductor Replacement</u>: PG&E's electric distribution system includes approximately 80,312 circuit miles of OH conductor on its distribution system that operates between 4 and 21 kilovolt, including bare and covered conductors. Approximately 54,500 circuit miles of this distribution conductor, including approximately 36,300 circuit miles of small conductor is in non-HFTD areas. PG&E's OH Conductor Replacement Program, recorded in MAT 08J, proactively replaces OH conductor in non-HFTD areas to address elevated rates of wires down and deteriorated/damaged conductors and to improve system safety, reliability, and integrity.

Please see Exhibit (PG&E-4), Chapter 13, Overhead and Underground Asset Management in the 2023 GRC for additional details.

- <u>Patrols and Inspections</u>: PG&E monitors the condition of OH conductor through patrols and inspections consistent with GO 165. Tags are created for abnormal conditions, including those that can lead to a wire down. Work is prioritized in a risk-informed manner to address the issues identified in the tags. In addition, PG&E has implemented risk based aerial inspections using drones in targeted areas. Drone inspections significantly improve our ability to assess deteriorated conditions on the conductor.

- <u>Grid Design and System Hardening</u>: PG&E's broader grid design program covers a number of significant programs, called out in detail in PG&E's 2023 WMP. The largest of these programs is the System Hardening Program which focuses on the mitigation of potential catastrophic wildfire risk caused by distribution OH assets. In 2024, we continued our system hardening efforts by: (i) completing 390 circuit miles of system hardening work which includes OH system hardening, undergrounding and removal of OH lines in HFTD or buffer zone areas; (ii) completing approximately 257 circuit miles of undergrounding work, including Community Rebuild efforts and other distribution system hardening work; and (iii) replacing equipment in HFTD areas that creates ignition risks, such as non-exempt fuses and surge arresters. As we look beyond 2024, PG&E is targeting 310 miles of Undergrounding and 210 miles of OH/removal/remote grid to be completed in 2025 as part of the System Hardening Program. Even though this program will provide wire down mitigation benefit, note that PG&E's approach to wildfire mitigations in the HFTD locations is based on a risk informed prioritization of work in the areas where wildfire risk is evaluated as highest, which combines many asset based composite risk models contributing to the overall probability of failure including conductor failure.

Please see Section 7.3.3, Grid Design and System Hardening Mitigations in PG&E's WMP for additional details.

- <u>Vegetation Management</u>: The EVM Program targeted OH distribution lines in Tier 2 and 3 HFTD areas and supplemented PG&E's annual routine VM work with California Public Utilities Commission mandated clearances. Our EVM Program went above and beyond regulatory requirements for distribution lines by expanding minimum clearances and removing overhangs in HFTD areas. Due to the emergence of other wildfire mitigation programs (namely EPSS and Undergrounding), the program was discontinued in 2023. The trees that were identified as part of the program and previous iterations and scopes will be worked down over the next nine years under a program called Tree Removal Inventory (TRI), prioritized by risk rank using our latest wildfire distribution risk model. The WMP has a commitment for the mitigation of 25K trees in 2025.

VM for Operational Mitigations is a new transitional program which began 2023 stemming from the conclusion of the EVM program. This program is intended to help reduce outages and potential ignitions using a risk-informed, targeted plan to mitigate potential vegetation contacts based on historic vegetation outages on EPSS-enabled circuits. The focus is on mitigating potential vegetation contacts in CPZs that have experienced vegetation caused outages. Scope of Work is developed by using EPSS and historical outage data and vegetation failure from the current WDRM risk model. Vegetation outage extent of condition inspections conducted on EPSS-enabled devices may generate additional tree work.

Focused Tree Inspections (FTI) is another new transitional program that began in 2023 stemming from the conclusion of the EVM program. PG&E developed Areas of Concern (AOC) to better focus VM efforts to address high risk areas that have experienced higher volumes of vegetation damage during PSPS events, outages, and/or ignitions. These areas are inspected by Vegetation Management Inspectors with a Tree Risk Assessment Qualification (TRAQ) which provides a higher level of rigor to the inspection.

Please see Section 8.2, Vegetation Management and Inspections in PG&E's WMP for additional details.

- <u>Other Advancements</u>: PG&E is applying new technologies in the field to identify and/or prevent conductor to ground faults. This includes:
  - SmartMeter-based methods;
  - Distribution Falling Wire Detection Method;
  - Distribution Fault Anticipation;
  - Early Fault Detection; and
  - Rapid Earth Fault Current Limiter.

PACIFIC GAS AND ELECTRIC COMPANY

SAFETY AND OPERATIONAL METRICS REPORT:

CHAPTER 3.6

WIRES DOWN RED FLAG WARNING DAYS IN HFTD AREAS

(TRANSMISSION)

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SAFETY AND OPERATIONAL METRICS REPORT:
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SAFETY AND OPERATIONAL METRICS REPORT: CHAPTER 3.6
WIRES DOWN RED FLAG WARNING DAYS IN HFTD AREAS (TRANSMISSION)

The material updates to this chapter, since the September 30, 2024 report, are identified in blue font.

A. (3.6) Overview

1. Metric Definition

Safety and Operational Metric 3.6 – Wires Down Red Flag Warning Days in High Fire Threat District *(*HFTD) Areas (Transmission) is defined as:

Number of Wires Down events in HFTD Areas on Red Flag Warning (RFW) Days involving overhead (OH) transmission circuits divided by RFW Transmission Circuit-Mile Days in HFTD Areas, in a calendar year.

2. Introduction of Metric

This metric measures the count of Transmission Wire Down events occurring on RFW Days and provides a partial indicator for electric system safety and overall electric service reliability for end-use customers.

This metric is associated with Pacific Gas and Electric Company's (PG&E or the Company) Failure of Electric Transmission Overhead Asset Risk and Wildfire Risk, which are part of the Company's 2020 Risk Assessment and Mitigation Phase Report filing

B. (3.6) Metric Performance

1. Historical Data (2013 – 2024)

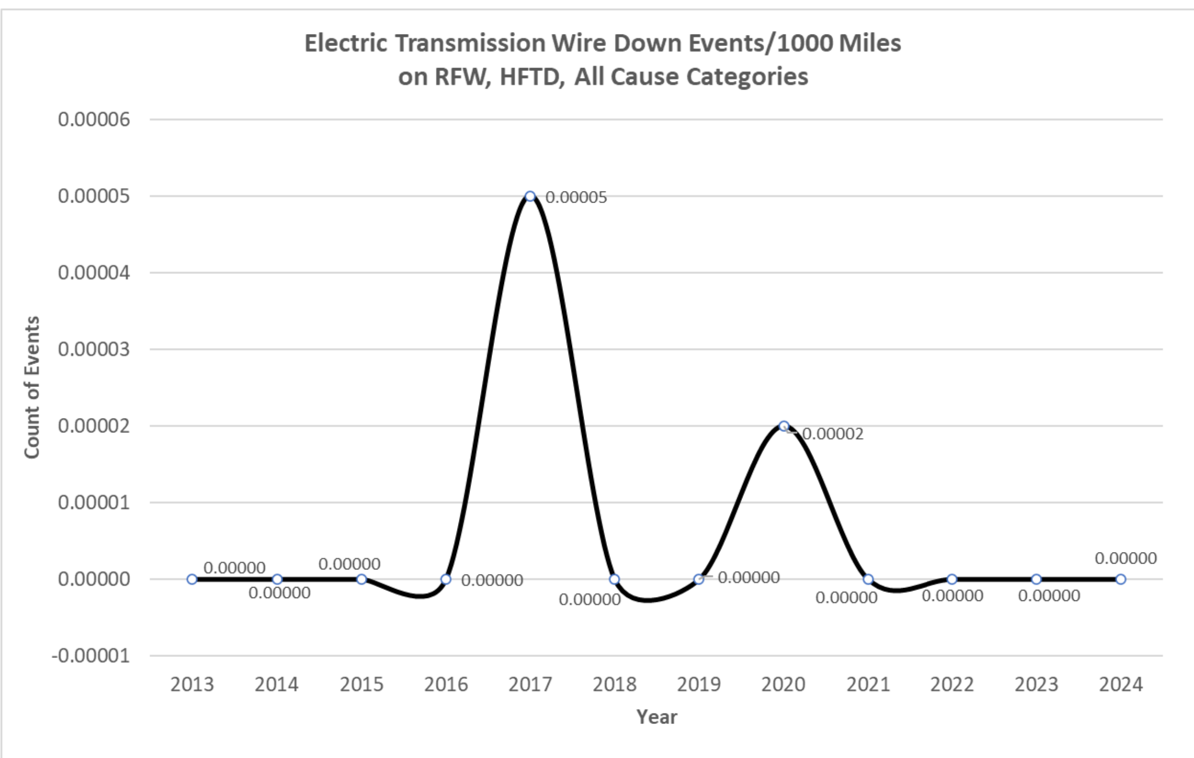
There are 12 years of historical data available from the years 2013-2024. Although PG&E started measuring wire down events in 2012, 2013 was the first full year uniformly measuring the number of transmission wire down incidents. When calculating this metric, both the HFTD OH line miles and number of wires down events are measured based on the area subjected by each specific RFW Day event and summed for each specific year.

The HFTD boundaries are a recent development and were not defined for several years. Hence, for all years prior to and including 2022, PG&E uses 5,525.9 OH transmission circuit miles in Tier 2/3 HFTD areas and assumes any variances in prior years are negligible. Moving forward, HFTD mileage will be refreshed at the beginning of each year. Table 3.6-1 provides the HFTD miles used for each year.

TABLE 3.6-1
HFTD MILES

Line No.	Year	HFTD Miles
1	Prior to 2023	5525.9
2	2023	5437.7
3	2024	5402.3

FIGURE 3.6-1
ELECTRIC TRANSMISSION
WIRES DOWN INCIDENTS PER RFW/CIRCUIT MILE-DAYS (2013-2024)



2. Data Collection Methodology

PG&E used its transmission outage database, typically referred to as Transmission Operations Tracking & Logging to count the number of these events. Although PG&E's outage database does not specifically identify the precise location of the downed wire, PG&E uses the Lat/Long of the device used to operate/isolate the involved line Section as a proxy and then uses its Electric Transmission Geographic Information System application to determine if that point is in a Tier 2 or Tier 3 HFTD area.

The meteorology group maintains a data base with the RFW days/time and involved areas and determines RFW Circuit Miles Days as follows:

- The National Weather Service (NWS) will issue a RFW and their associated polygons under specific polygon/shapefiles called Fire Zones;
- PG&E's geographic information system team has calculated all OH Distribution and Transmission lines for all of the Fire Zone shapefile boundaries that intersect PG&E territory. For each NWS Fire Zone PG&E has the number of OH line miles for Distribution and Transmission and the number of OH line miles for Transmission, which is then also split into the specific HFTD and non HFTD tiers and zones;
- Meteorology then compiles all the archived RFW shapefiles for California, and from all the RFW events, determines which zones there was a RFW under and the duration of time it lasted; and
- RFW Circuit Mile Days= RFW days x Circuit line miles.

3. Metric Performance for the Reporting Period

As shown in Figure 3.6-1, the transmission wire down events on RFW days per circuit mile day is a very small subset of wire down events, making it difficult to identify any trending information. There were no transmission wire down events on RFW days in 2024. Since 2013, only two years have experienced any Transmission Wire Down events on RFWs; 2017 (3) and 2020 (1), respectively.

C. (3.6) 1-Year Target and 5-Year Target

1. Updates to 1- and 5-Year Targets Since Last Report

There are no updates to the directional 1- and 5-Year Targets since last report and are set to maintain performance within the historical range.

2. Target Methodology

- Directional Only: Maintain (stay within historical range, and assumes response stays the same in events);

  Note that there has not been enough historic electric transmission (ET) wire down events on RFW days to establish a target based on prior performance.
- Benchmarking: Not available to best of our knowledge;
- Regulatory Requirements: None;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement (EOE): The directional target for this metric is suitable for EOE as it suggests performance will remain within the historical range;
- Attainable Within Known Resources/Work Plan: Unknown, however this metric is impacted by the variability in conditions outside of PG&E's control, such as the severity of weather on RFWs; and
- Other Considerations: None.

D. (3.6) Performance Against Target

1. Progress Towards the 1-Year Target

As demonstrated in Figure 3.6-1 above, PG&E experienced zero transmission wires down events on RFW Days in which is consistent with Company's 1-year directional target. There were zero transmission wire down events on RFW days in 2024.

2. Progress Towards the 5-Year Target

As discussed in Section E below, PG&E is deploying a number of programs to maintain or improve long-term performance of this metric to align with the Company's 5-year directional performance target.

E. (3.6) Current and Planned Work Activities

Wire down events can be caused by a variety of factors, including but not limited to asset failure, third-party contact, or vegetation contact. The following work activities may provide future resiliency for certain wire down event causes, though the effectiveness of the work is dependent upon the circumstances of the wire down event (e.g., new assets may still be prone to a wire down event that occur due to extreme weather events outside of standard design guidance).

- Asset Inspection: Detailed inspections of OH transmission assets seek to proactively identify potential failure modes of asset components which could create future wire down, outage, and/or safety events if left unresolved or allowed to "run to failure." Detailed inspections for transmission assets involve at least two detailed inspection methods per structure (ground and aerial), though not necessarily in the same calendar year which allows for staggered inspection methods across multiple years. Aerial inspections may be completed either by drone or, helicopter. In addition to the ground and aerial inspections, climbing inspections are also required for 500 kilovolt structures or as triggered. All these inspection methods involve detailed, visual examinations of the assets with use of inspection checklists that are in accordance with the ET Preventive Maintenance (TD-1001M), as well as the Failure Modes and Effects Analysis.
- Asset Repair and Replacement: Completing repair, replacement, removal or life extension to transmission assets provides the benefit of reduced probability of failure for components that could potentially result in a wire down event. For example, by replacing or improving aged, degraded assets and providing more robust, up-to-standard designs. Asset removal eliminates wire-down event risk by removing the energized electrical components. Many improvements are identified through corrective maintenance notifications. These notifications are typically identified as a result of transmission asset inspections and patrols.

  Prioritization of maintenance tags are based on severity of the issues found and fire ignition potential (i.e., asset-conditions impacting issues associated with HFTD areas and High Fire Risk Area). Probability of failure and consequence (such as public safety consequence) may also be considered. Execution of the prioritized work plan would also have to address other factors such as clearance availability, access, work efficiency, etc.

- Vegetation Management (VM): Trees or other vegetation that make contact or cross within flash-over distance of high voltage transmission lines can cause phase to phase or phase to ground electrical arcing, fire ignition or local, regional or cascading, grid-level service interruption. Dense vegetation growing within the right-of-way (ROW) can act as a fuel bed for wildfire ignition. Vegetation growing close to any pole or structure can impede inspection of the structure base and in some cases can damage the structure or conductors and result in wire down events.

  PG&E operates our lines in ET corridors that are home to vast amounts of vegetation. This vegetation ranges from sparse to extremely dense. Our transmission lines also pass through urban, agricultural, and forested settings. The corridor environment is dynamic and requires focused attention to ensure vegetation stays clear of energized conductors and other equipment. Vegetation inspection is a required operational step in an overall VM Program. Accordingly, PG&E's annual inspection is part of our overall Transmission VM Program responding to the diverse and dynamic environment of our service territory. The Routine North American Electric Reliability Corporation (NERC) and Routine Non-NERC patrols are annually recurring. The Integrated Vegetation Management (IVM) Program maintains cleared ROWs. The frequency and prioritization for each of these programs is described in more detail below.

- Routine NERC: The Routine NERC patrol includes Light Detection and Ranging (LiDAR) inspection, visual verification of findings, and mitigation of vegetation encroachments, as well as other vegetation conditions on approximately 6,800 miles of NERC Critical lines. One hundred percent inspection and work plan completion are required by NERC Standard FAC-003-5. Work is prioritized based on aerial LiDAR detection. This program recurs annually.

- Routine Non-NERC: The Non-Routine NERC Program includes LiDAR inspection, visual verification of findings, and mitigation of vegetation encroachments, as well as other vegetation conditions on approximately 11,400 miles of transmission lines not designated as critical by NERC. Work is prioritized based on aerial LiDAR detection. This program recurs annually.

- IVM: The IVM Program is an ongoing maintenance program designed to maintain cleared ROWs in a sustainable and compatible condition by eliminating tall-growing and fire-prone vegetation and promoting low-growing, compatible vegetation. Prioritization is based on aging of work cycles and evaluation of vegetation re-growth.

PACIFIC GAS AND ELECTRIC COMPANY

SAFETY AND OPERATIONAL METRICS REPORT:

CHAPTER 3.7

MISSED OVERHEAD DISTRIBUTION PATROLS IN HFTD AREAS

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MISSED OVERHEAD DISTRIBUTION PATROLS IN HFTD AREAS

The material updates to this chapter, since the September 30, 2024 report, are identified in blue font.

A. (3.7) Overview

1. Metric Definition

Safety and Operational Metric (SOM) 3.7 – Missed Overhead (OH) Distribution Patrols in High Fire Threat District (HFTD) is defined as:

Total number of overhead electric distribution structures that fell below the minimum patrol frequency requirements divided by the total number of overhead electric distribution structures that required patrols, in HFTD area in past calendar year. "Minimum patrol frequency" refers to the frequency of patrols as specified in General Order (GO) 165. "Structures" refer to electric assets such as transformers, switching protective devices, capacitors, lines, poles, etc.

2. Introduction of Metric

Patrols involve simple visual observations to identify obvious structural problems and hazards affecting safety or reliability. Within HFTD, nonconformances identified by patrols can involve conditions that represent a wildfire ignition risk. Performing required patrols on time ensures that nonconformances are identified in a timely manner so that they can be prioritized for repair in accordance with the risk of the condition.

Prior to year 2014, GO 165 required that patrols be completed any time between January 1 and December 31 each year.

Starting in 2015 and through 2019, Pacific Gas and Electric Company (PG&E) implemented the new GO 165 requirement to complete patrols each year within a prescribed timeframe, based on the date of the last patrol or inspection. PG&E's interpretation and implementation of this new language calculated the due date for each patrol each year as follows:

The California Public Utilities Commission (CPUC) Patrol & Inspection requirement defines:

- The due date for each map is based on the date the map was last inspected or patrolled;
- Inspections or patrols may not exceed three additional months past the previous inspection or patrol date (maximum 15 month);
- Inspections or patrols may be performed before the due date;
- Inspections or patrols are performed by the end of the calendar year (12/31/YY); and
- The start of an inspection or a patrol starts a new inspection or patrol interval that must be completed within the prescribed timeframe.

For the years 2020 and 2021, PG&E shifted away from the "12+3" due date for completing patrols, with the intent of wildfire risk reduction by focusing on the High Fire Threat District areas and using new risk models to inform the prioritization of patrols. PG&E completed patrols by static due dates, August 31 for HFTD areas, and December 31st for Non-HFTD areas.

In 2022, PG&E completed OH patrols and inspections in compliance with GO 165. As of 2024, PG&E continues to complete patrols and inspections in compliance with GO 165.

B. (3.7) Metric Performance

1. Historical Data (2015 – 2024)

To be consistent with the implementation of new GO 165 requirements, historical data begins in 2015.[1] The 2015-2019 data includes systemwide results. The 2020-2024, data includes HFTD specific results.

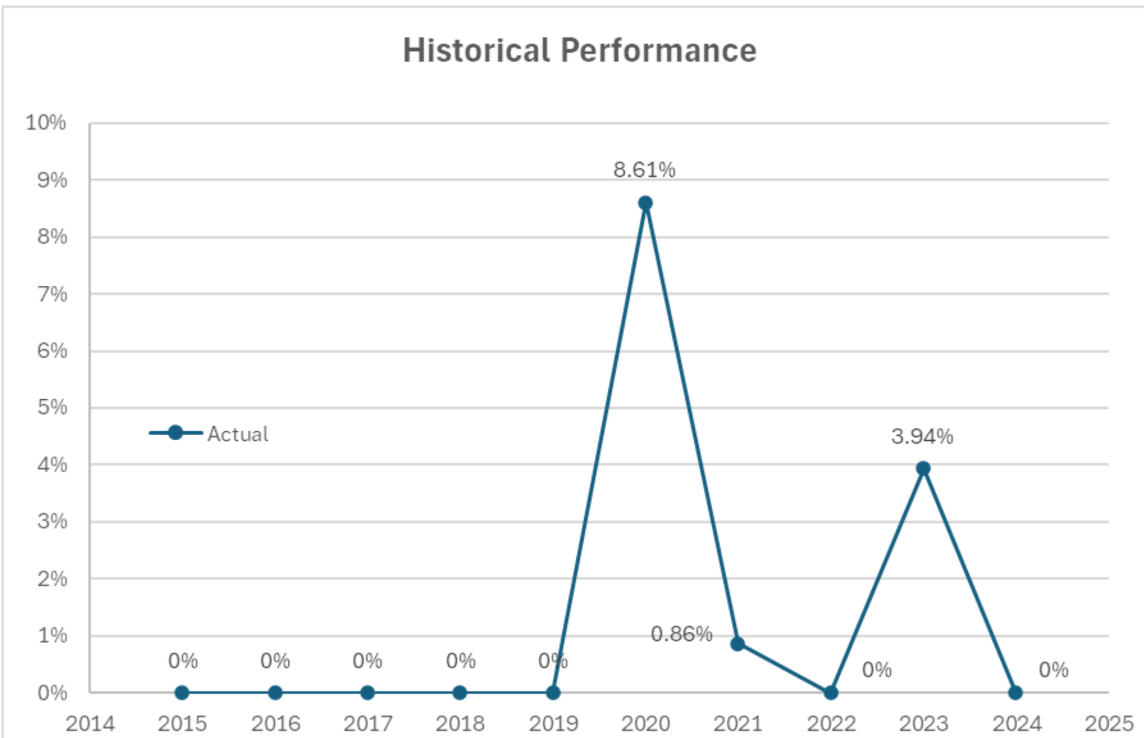
Prior to 2020, PG&E completed patrols on paper by "plat map". Each plat map had a calculated "12+3" due date based on the start date of the last patrol or inspection for that plat map. For the years 2015-2019, PG&E tracked and measured performance of patrols based on the "12+3" calculated due date for each *plat map*. Performance was tracked using detailed excel spreadsheets for each of the 19 Divisions across the system, and SAP data recorded for each plat map, which recorded the actual start and end dates for each plat map, as well as actual units and the PG&E LAN

1 Historical patrol data is at plat map level vs. structure level. We are further validating plat-based results for HFTD vs. NHFTD units, we may see slight changes to volumes completed late vs. on time, or vice-versa.

ID (login ID) of the Inspector who completed the work. PG&E's annual performance for completing patrols in these years was 0.00 percent completed late.

For the years 2020 and 2021, PG&E's performance was impacted by the shift away from completing OH patrols by the "12+3" calculated due dates to the use of a risk--based prioritization approach and focus on HFTD with the intention of wildfire risk reduction.

FIGURE 3.7-1
HISTORICAL PERFORMANCE (2015 –2024)



Note: Actual performance as follows between 2015-2019: 2015: 0.0003 percent, 2016: 0.0003 percent, 2017: 0.0000 percent, 2018: 0.0002 percent, 2019: 0.0015 percent. 2020: 8.61 percent, 2021: 0.86 percent, 2022: 0.00 percent 2023: 3.94 percent, 2024: 0.000009 percent.

2. Data Collection Methodology

The currently used data collection methodology was implemented in 2020. It uses a mobile platform for completing OH inspections, recorded at structure (pole) level using a detailed inspection checklist. PG&E also shifted its maintenance plan structure in SAP from purely plat -map based to circuit/risk based, tracking performance at *structure -level*.

PG&E continues to perform OH patrols on paper, with a goal of shifting to mobile technology over the next few years. OH Patrols are tracked at "maintenance plan" level, using excel spreadsheets and SAP data.

3. Metric Performance for the Reporting Period

Between 2015-2019, PG&E's annual performance for completing patrols by the CPUC "12+3" due date was 0 percent completed late. These results demonstrate our commitment to meet GO 165 CPUC "12+3" due dates.

For the years 2020 and 2021, with the shift to a wildfire risk reduction focused approach and away from completing OH patrols by the "12+3" calculated due date, PG&E's metric performance was 8.61 percent completed late in 2020, 0.86 percent completed late in 2021 and 0 percent were completed late in 2022. For 2023, 3.94 percent were completed late. For 2024, there were three late overhead patrols which equates to a percentage of 0 percent completed late.

C. (3.7) 1-Year and 5-Year Target

1. Updates to 1- and 5-Year Targets Since Last Report

There have been no changes to the 1-year and 5-year targets since the last SOMS filing.

2. Target Methodology

To establish the 1-year and 5-year targets, PG&E considered the following factors:

- Historical Data and Trends: Based on historical performance of 0 percent completed late (2015-2019) and the results of the more recently used wildfire risk reduction approach (2020-2023). In 2024 PG&E intends to improve performance by completing OH patrols to (1) be in compliance with GO 165, with a target range of 0-4 percent completed late, and (2) incorporate Asset Strategy risk models.
- Benchmarking: Not available;
- Regulatory Requirements: GO 165;
- Attainable Within Known Resources/Work Plan: Targeted performance is attainable within PG&E's currently known resource plan;
- Appropriate/Sustainable Indicators for Enhanced Oversight Enforcement: The target range is a suitable indicator for EOE as it

intends to return PG&E to historical levels of near-zero percent noncompliance while also incorporating reasonable impacts resulting from access and other field issues.

- Other Qualitative Considerations: None.

3. 2025 Target

The 2025 target is 0-4 percent to maintain performance compared to 2024.

4. 2029 Target

The 2029 target is 0-1 percent to improve performance compared to 2024, based on the factors described above, and the commitment to continuously improve performance.

D. (3.7) Performance Against Target

1. Progress Towards the 1-Year Target

As demonstrated in Figure 3.7-2 below, PG&E continued to maintain performance within the 0-4% target range set for 2024. For 2024, there were three late overhead patrols which equates to a percentage of 0 percent completed late. The metric performance has shown tremendous improvement from 3.94 percent in 2023. The spike in 2023 was due to incorrect calculation of due dates for Distribution OH Patrols which was identified and corrected.

2. Progress Towards the 5-Year Target

As discussed in Section E below, PG&E has a number of programs to improve the long-term performance of this metric and to meet the company's 5-year performance target.

FIGURE 3.7-2
HISTORICAL PERFORMANCE (2015-2024 AND TARGETS (2025 & 2029)

E. (3.7) Current and Planned Work Activities

- Visibility and Compliance: Currently Supervisors and Inspectors could see the CPUC due dates for each patrol package to ensure understanding as to the due date of the OH patrol.
- Tracking:
  - System Inspections track progress and completion of OH patrols on a continuous basis, using detailed excel tracking spreadsheets + SAP data;
  - System Inspections track and report-out on any “late” OH patrols, including identifying mitigating factors and implementing process improvements or changes to the program; and
  - System Inspections track timeliness of patrols being completed on their weekly scorecard.
- Training: System Inspections conduct refresher training to ensure understanding of the importance of patrols in identifying obvious structural problems and hazards in years where an inspection is not required.
- Maintenance Plan Management Tool: System Inspections Maintenance Planners complete timely review and completion of changes to structures and maintenance plans using the maintenance plan management tool.

PACIFIC GAS AND ELECTRIC COMPANY

SAFETY AND OPERATIONAL METRICS REPORT:

CHAPTER 3.8

MISSED OVERHEAD DISTRIBUTION INSPECTIONS IN HFTD AREAS

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A. (3.8) Overview

1. Metric Definition

Safety and Operational Metric (SOM) 3.8 – Missed Overhead Distribution Detailed Inspections in HFTD Areas is defined as:

Overhead Distribution Detailed Inspections in High Fire Threat District (HFTD): Total number of structures that fell below the minimum inspection frequency requirements divided by the total number of structures that required inspection, in HFTD area in past calendar year. "Minimum inspection frequency" refers to the frequency of scheduled inspections as specified in General Order (GO) 165. "Structures" refers to electric assets such as transformers, switching protective devices, capacitors, lines, poles, etc.

2. Introduction of Metric

Detailed inspections are performed to identify nonconformances affecting safety or reliability. Within HFTD, nonconformances identified by inspections can involve conditions that represent a wildfire ignition risk. Performing required inspections on time ensures that non-conformances are identified in a timely manner so that they can be prioritized for repair in accordance with the risk of the condition.

Prior to year 2014, GO 165 required that inspections be completed any time between January 1 and December 31 each year.

Starting in 2015 and through 2019, PG&E implemented the new GO 165 requirement to complete inspections each year within a prescribed timeframe, based on the date of the last patrol or inspection. Pacific Gas and Electric Company's (PG&E or the Company) interpretation and implementation of this new language calculated the due date for each patrol or inspection each year as follows:

The California Public Utilities Commission (CPUC) Patrol & Inspection requirement defines:

- The due date for each map is based on the date the map was last inspected or patrolled;
- Inspections or patrols may not exceed three additional months past the previous inspection or patrol date (maximum 15 months);
- Inspections or patrols may be performed before the due date;
- Inspections or patrols are performed by the end of the calendar year (12/31/XX); and
- The start of an inspection or a patrol starts a new inspection or patrol interval that must be completed within the prescribed timeframe.

For the years 2020 and 2021, PG&E shifted away from the "12+3" due date for completing inspections with the intent of wildfire risk reduction by focusing on the HFTD areas and using new risk models to inform the prioritization of inspections each year. PG&E completed inspections by the static due dates of, August 31 for HFTD areas, December 31 for Non-HFTD areas.

In 2022, PG&E intends to complete overhead patrols and inspections in compliance with GO 165.

In 2023 and beyond, PG&E will continue to complete patrols and inspections in compliance with GO 165.

B. (3.8) Metric Performance

1. Historical Data (2015 – 2024)

To be consistent with the implementation of new GO 165 requirements, historical data begins in 2015. The 2015-2019 data includes systemwide results. The 2020-2021 data[1] includes HFTD specific results.

Prior to 2020, Pacific Gas and Electric Company (PG&E) completed inspections on paper by plat map. Each plat map had a calculated "12+3"

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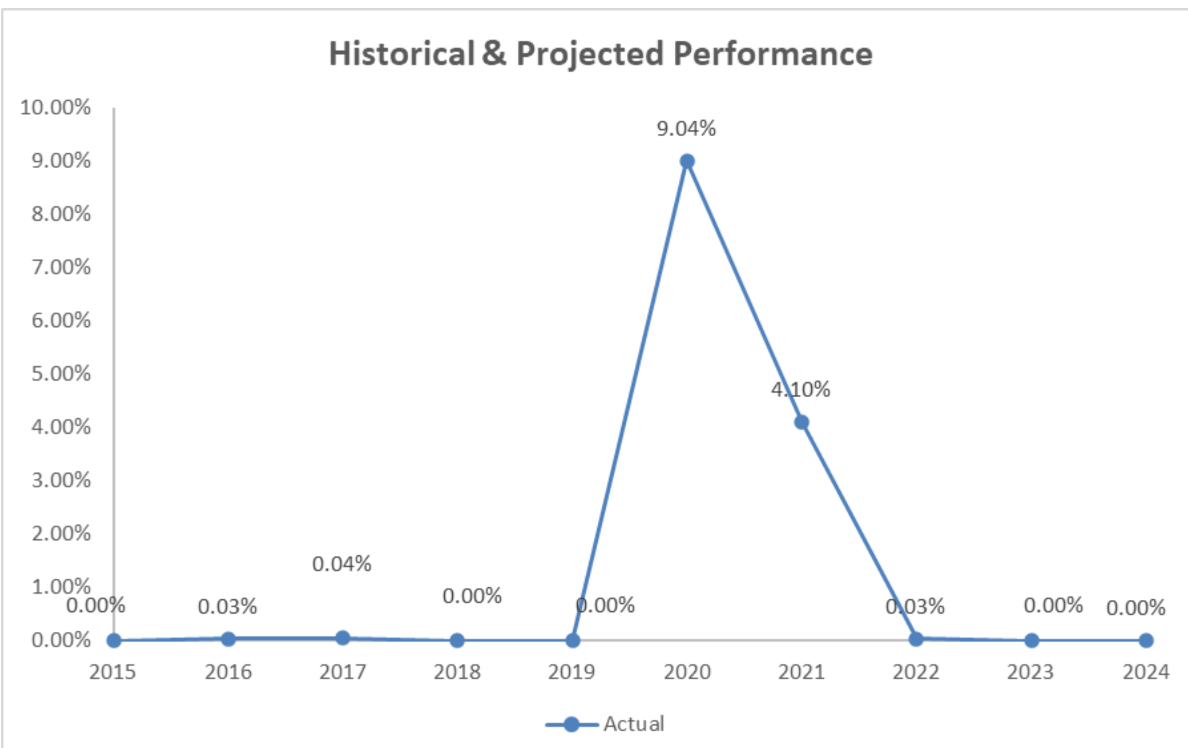
[1] Historical inspection data <2020 is at plat map level vs. structure level. We are further validating plat map-based results for HFTD vs. NHFTD units, we may see slight changes to volumes completed late vs. on time, or vice-versa.

due date based on the start date of the last patrol or inspection for that plat map. For the years 2015-2019, PG&E tracked and measured performance of inspections based on the “12+3” calculated due date for each plat map. Performance was tracked using detailed excel spreadsheets for each of the 19 Divisions across the system, and SAP data recorded for each plat map, which recorded the actual start and end dates for each plat map, as well as actual units and PG&E LAN ID (login ID) of the Inspector who completed the work. PG&E’s annual performance for completion and inspections in these years was 0.01-0.04 percent completed late.

For the years 2020 and 2021, PG&E’s performance was impacted by the shift away from completing overhead inspection by the “12+3” calculated due dates to the use of a risk-based prioritization approach and focus on HFTD with the intention of wildfire risk reduction.

FIGURE 3.8-1
HISTORICAL PERFORMANCE (2015- 2024)



Full year 2020 data has been corrected to 9.04%. Correction was because of an error in calculating late and on-time resulting in an additional 115 late HFTD inspections. This was corrected during Audit_DR_FEP_024_Q001

2. Data Collection Methodology

The currently used data collection methodology was implemented in 2020. It uses a mobile platform for completing Overhead inspections, recorded at structure (pole) level using a detailed inspection checklist. PG&E also shifted its maintenance plan structure in SAP from purely plat-map based to circuit/risk based, tracking performance at *structure -level*.

PG&E now tracks the completion of inspections at structure (pole) level, using the "attainment report," which records actual completion information for each structure from actual inspection data recorded in SAP.

3. Metric Performance for the Reporting Period

Between 2015-2019, PG&E's annual performance for completing inspections by the CPUC "12+3" due date was 0 - 4 percent completed late. These results demonstrate our commitment to meet GO 165 CPUC "12+3" due dates.

For the years 2020 and 2021, with the shift to a wildfire risk reduction focused approach and away from completing overhead inspections by the "12+3" calculated due date, PG&E performance worsened to 9.01 percent completed late in 2020 and 4.10 percent completed late in 2021. In 2022, PG&E's performance improved to 0.03 percent completed late. In 2023, there were 10 late overhead inspections of the 230,491 inspections performed which equates to a percentage of 0 percent. For 2024, there were zero late overhead inspections which equates to a percentage of 0 percent completed late.

C. (3.8) 1-Year and 5-Year Target

1. Updates to 1- and 5-Year Targets Since Last Report

There have been no changes to the 1-year and 5-year targets since the last SOMS filing.

2. Target Methodology

To establish the 1-year and 5-year targets, PG&E considered the following factors:

- Historical Data and Trends: Based on historical performance of 1-4 percent completed late (2015-2019) and the results of the more recently used wildfire risk reduction approach (2020-2023). In 2024 PG&E intends to improve performance by completing overhead inspections to: (1) be in compliance with GO 165, with a target range of 0-2 percent completed late, and (2) incorporate Asset Strategy risk models;

- Benchmarking: Not available;
- Regulatory Requirements: GO 165;
- Attainable Within Known Resources/Work Plan: Targeted performance is attainable within PG&E's currently known resource plan;
- Appropriate/Sustainable Indicators for Enhanced Oversight Enforcement: The target range is a suitable indicator for EOE as it intends to return PG&E to historical levels of near-zero percent non-compliances while also incorporating reasonable impacts resulting from access and other field issues.
- Other Qualitative Considerations: None.

3. 2025 Target

The 2025 target is 0-2 percent to maintain performance compared to 2024.

4. 2029 Target

The 2029 target is 0-1 percent to improve performance compared to 2024, based on the factors described above, and the commitment to continuously improved performance.

D. (3.8) Performance Against Target

1. Progress Towards/Deviation From the 1-Year Target

As demonstrated in Figure 3.8-2 below, PG&E observed a 0 percent missed overhead Distribution inspections in 2024 which was within the Company's 1-year target.

2. Progress Towards/Deviation From the 5-Year Target

As discussed in Section E below, PG&E has several programs to maintain or improve long-term performance of this metric to meet the Company's 5-year performance target.

FIGURE 3.8--2
HISTORICAL PERFORMANCE (2015- 2024) AND
TARGETS (2025 & 2029)

E. (3.8) Current and Planned Work Activities

- Visibility and Compliance: Currently Supervisors and Inspectors can see the CPUC due dates for each inspection, so that they can plan work to be completed on time.
- Tracking:
  - System Inspections tracked progress and completion of overhead inspections on a continuous basis, using detailed SAP data reports and excel tracking spreadsheets.
  - System Inspections tracked and reported-out on any overdue overhead inspections, including identifying mitigating factors and implementing process improvements or changes to address gaps.
  - System Inspections tracked timeliness of inspections being completed on their weekly scorecard.
- Training: System Inspections will conduct annual “Refresher” training on overhead inspections, which includes focus on anything that has changed since the previous year (guidance, standards, procedures), including updates

to the INSPECT application, inspection checklists, and associated Inspector job aids.

- Asset Strategy – Monthly Inspection Validations: Monthly inspection validations will continue to identify required additions to the original plan arising from additions or changes to the asset registry.
- Asset Strategy – Ad Hoc Inspections: Asset Strategy will continue to evaluate the asset registry and may identify additional “ad hoc” structures to be inspected each year, based on analysis related to ignition risk, etc.
- Maintenance Plan Management Tool: System Inspections Maintenance Planners will complete timely review and completion of changes to structures and maintenance plans by way of the “maintenance plan management tool.”
- Desktop Quality Control: System Inspections conducts desktop work verification activities on a valid sample size of completed inspections to evaluate the completeness and quality of inspections.
- Quality Control Field Work Verification: System Inspections conducts “blind” field work verification activities on a valid sample size of completed inspections to evaluate the completeness and quality of inspections.

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 3.9
MISSED OVERHEAD TRANSMISSION PATROLS IN HFTD AREAS

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CHAPTER 3.9
MISSED OVERHEAD TRANSMISSION PATROLS IN HFTD AREAS

The material updates to this chapter, since the September 30, 2024 report, are identified in blue font

A. (3.9) Overview

1. Metric Definition

Safety and Operational Metrics (SOM) 3.9 – Missed Overhead Transmission Patrols in High Fire Threat District (HFTD) Areas is defined as:

Overhead (OH) Transmission Patrols in High Fire Threat District (HFTD): Total number of structures that fell below the minimum patrol frequency requirements divided by the total number of structures that required patrols, in HFTD area in past calendar year where, "Minimum patrol frequency" refers to the frequency of patrols requirements, as applicable. "Structures" refers to electric assets such as transformers, switching protective devices, capacitors, lines, poles, etc.

2. Introduction of Metric

Patrols involve simple visual observations to identify obvious non-conformances affecting safety or reliability. Within HFTD areas, nonconformances identified by patrols can involve conditions that represent a wildfire ignition risk. Performing patrols on time allows non-conformances to be identified in a timely manner so that they can be prioritized for repair in accordance with the risk of the condition.

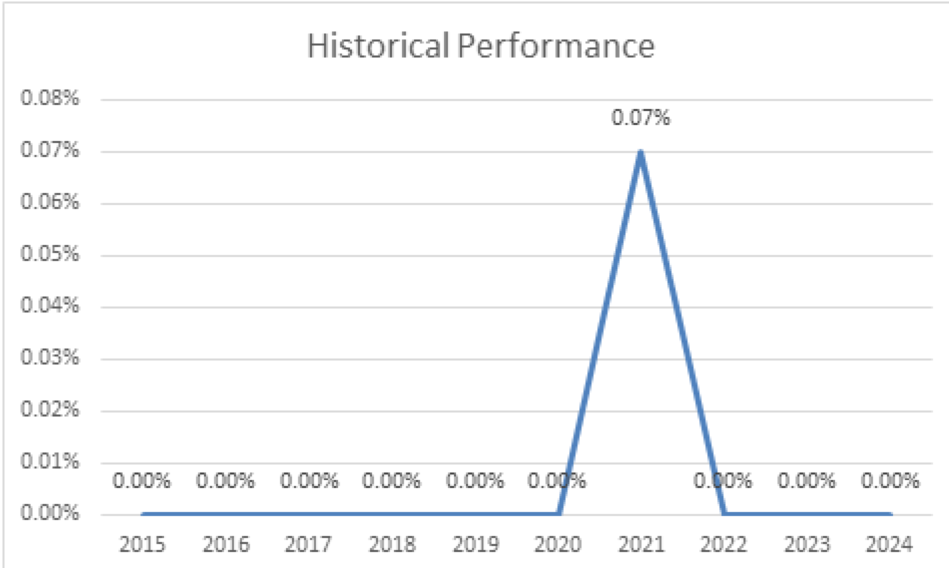
All assets require either a detailed inspection or a patrol each year. While detailed inspections have shifted from circuit-based cycles to an inspection frequency that depends on HFTD and structure-level risk considerations, patrols are performed by circuit. Therefore, any line that does not receive a detailed inspection from end-to-end will require a patrol and it is possible for some structures to receive both an inspection and a patrol in the same year. Patrols may be performed either by air (helicopter) or ground (walking or driving). Compared to transmission detailed inspections, the transmission OH patrol program has not undergone significant changes over the reporting period from 2015-present. Starting in 2021, Pacific Gas and Electric Company (PG&E) imposed an in-year deadline of July 31 for patrols on circuits containing HFTD or High Fire Risk Area structures. Monthly validations of the inspection plan were started in June 2021 to ensure that all assets were either inspected or patrolled each year, including assets that were newly added to the asset registry. The in-year deadline of July 31 introduced in 2021 for inspections and patrols in HFTD will continue to be used in 2022. Beginning in 2022, assets added to the registry after July 31 or whose HFTD changes after July 31 will not be considered late as in 2021, provided that they are inspected or patrolled within 90 days of the addition to the registry or the HFTD change.

B. (3.9) Metric Performance

1. Historical Data (2015-2024)

Historical data is provided from 2015-2024. Data provided for 2015-2019 reflects systemwide performance. HFTD-specific performance is not available prior to 2020. The percentage of missed patrols is calculated as the number of patrols not performed by the required deadline divided by the total number of patrols performed for that year. Through 2020, there was not a specific in-year deadline for patrols, so the deadline was considered December 31. The July 31 deadline for HFTD patrols in 2021 allowed exceptions due to access issues and weather that may have prevented a helicopter to fly, or where access issues may have prevented a ground patrol. In 2021, HFTD structures added to the asset registry after July 31 and inspected after the July 31 deadline were counted as missed inspections, as well as instances where the asset location was corrected from non-HFTD to HFTD after July 31.

FIGURE 3.9-1
HISTORICAL PERFORMANCE (2015-2024)



2. Data Collection Methodology

Overhead patrols are tracked at the "maintenance plan" level, using data sheets to record completion and findings, if applicable, as well as the SAP data.

3. Metric Performance for the Reporting Period

In 2024 there are no missed patrols resulting in a 0.00 percent missed overhead Transmission patrols with a total of 64,862 patrols completed – 40,553 in Tier 2 HFTD areas, 22,667 in Tier 3 HFTD areas, 1,257 in HFRA and 385 in Zone 1 areas.

C. (3.9) 1-Year Target and 5-Year Target

1. Updates to 1- and 5-Year Targets Since Last Report

There have been no changes to the 1-year and 5-year targets since the last SOMS filing.

2. Target Methodology

To establish the 1-Year and 5-Year targets, PG&E considered the following factors:

- Historical Data and Trends: The July 31 deadline for HFTD patrols was first applied in 2021 and is still in practice. Therefore, targets use 2021 performance as a baseline with incremental improvement for the reasons described below;

- Benchmarking: Not available;
- Regulatory Requirements: Relevant items include: (1) General Order 165 requirements to follow internal maintenance procedures, and (2) Wildfire Mitigation Plan targets to perform HFTD inspections and patrols by July 31;
- Attainable Within known Resources/Work Plan: Targets are attainable within currently known resources;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: Targets are suitable indicators for EOE as historical driver of worsening performance (asset registry changes after July 31) will have an allowance to be counted as on time if inspected within 90 days of the addition to the registry or HFTD change at the beginning of 2022. This update ensures that the metric is an appropriate indicator of performance by focusing the measure on timely action to complete inspections as opposed to asset registry completeness; and
- Other Qualitative Considerations: None.

3. 2025 Target

The 2025 target is to maintain performance to 0.00-0.03 percent, based on the 90-day allowance for asset registry changes and consideration of double circuits described in the methodology above.

4. 2029 Target

The 2029 target is to maintain performance to 0.00-0.02 percent, based on the 90-day allowance for asset registry changes and consideration of double circuits described in the methodology above, as well as a reduction over time in the number of asset registry additions from assets being discovered in the field.

D. (3.9) Performance Against Target

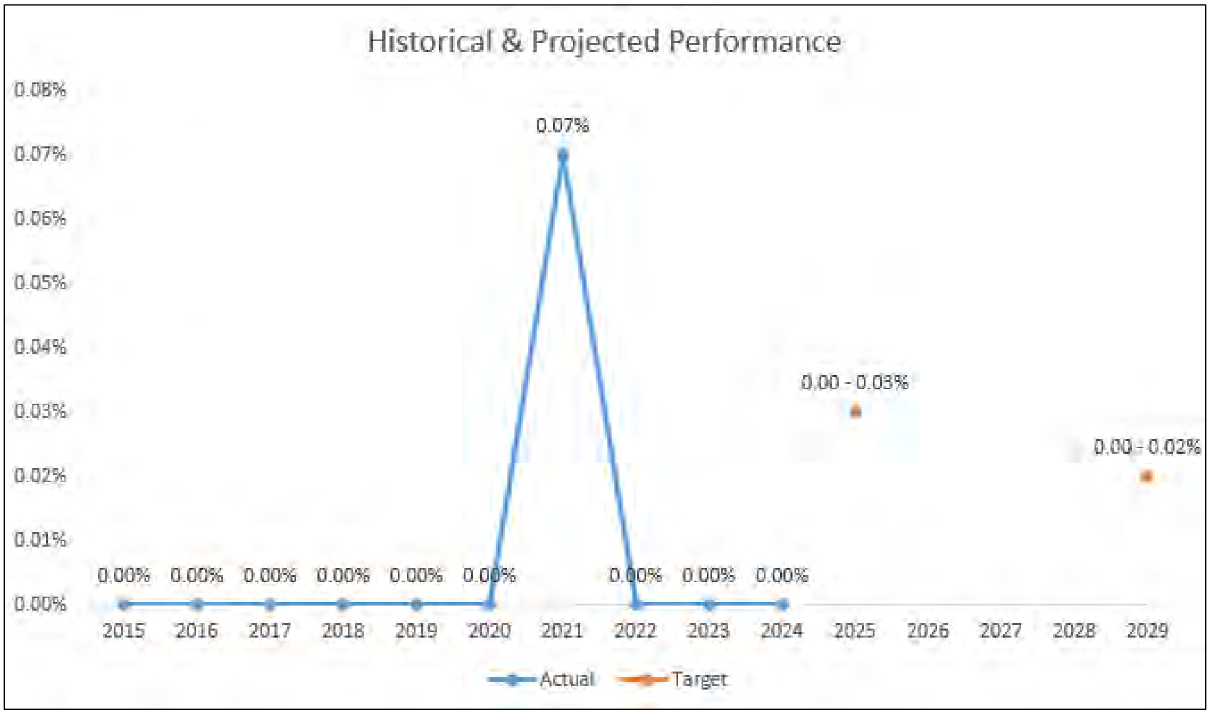
1. Maintaining Performance Against the 1-Year Target

As demonstrated in Figure 3.9-2 below, PG&E observed a 0.00 percent missed overhead Transmission patrols in 2024 which is consistent with company’s 1-year target.

2. Maintaining Performance Against the 5-Year Target

As discussed in Section E below, PG&E is deploying a number of programs to maintain or improve long-term performance of this metric to meet the Company's 5-year performance target.

FIGURE 3.9-2
HISTORICAL PERFORMANCE (2015-2024-) AND TARGET (2025 AND 2029)



E. (3.9) Current and Planned Work Activities

Below is a summary description of the key activities that are tied to performance:

- <u>2024 Inspection and Patrol Plan</u>: The 2024 Inspection and Patrol plan has been created, which defines the initial scope of the HFTD patrols that fall under this metric. The plan contains approximately 170 circuits running through HFTD areas (containing approximately 31,000 HFTD structures) that will be patrolled.
- <u>Monthly Inspection Validations</u>: Monthly inspection validations, which also consider required patrols, will continue to identify required additions to the

original plan arising from additions or changes to the asset registry. Changes in HFTD affect the scope of patrols covered by this metric.

- In-Year Deadline Requirements: The in-year deadline of July 31 introduced in 2021 for patrols in HFTD will continue to be used in 2024, with the same provisions for access issues as in 2021 and the addition of the 90-day requirement described above for additions and changes to the asset registry. The deadline is tracked with the patrol orders so that each HFTD patrol is identified as having the July 31 compliance requirement.

PACIFIC GAS AND ELECTRIC COMPANY

SAFETY AND OPERATIONAL METRICS REPORT:

CHAPTER 3.10

MISSED OVERHEAD TRANSMISSION DETAILED INSPECTIONS IN HFTD AREAS

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MISSED OVERHEAD TRANSMISSION DETAILED INSPECTIONS IN HFTD AREAS

The material updates to this chapter, since the September 30, 2024 report, are identified in blue font.

A. (3.10) Overview

1. Metric Definition

Safety and Operational Metric (SOM) 3.10 – Missed Overhead Transmission Detailed Inspections in HFTD Areas is defined as:

Overhead (OH) Transmission Detailed Inspections in High Fire Threat District (HFTD): Total number of structures that fell below the minimum inspection frequency requirements divided by the total number of structures that required inspection, in HFTD area in past calendar year where, "Minimum inspection frequency" refers to the frequency of scheduled inspections requirements, as applicable. "Structures" refers to electric assets such as transformers, switching protective devices, capacitors, lines, poles, etc.

2. Introduction of Metric

Detailed inspections are performed using several methods (ground, aerial, and climbing) to identify non-conformances affecting safety or reliability. Within HFTD areas, non-conformances identified by inspections can involve conditions that represent a wildfire ignition risk. Performing inspections on time allows non-conformances to be identified in a timely manner so that they can be prioritized for repair in accordance with the risk of the condition.

Due to the importance of detailed inspections in identifying conditions that affect wildfire, other safety, and reliability risks, the OH transmission detailed inspection program has undergone significant evolution over the reporting period for the metric, 2015-present. Prior to 2019, detailed ground inspections were performed by circuit with a frequency depending on the voltage and whether the majority of the structures on the circuit were wood (2-year cycle) or steel (5-year cycle).

The Wildfire Safety Inspection Program (WSIP), which began in late 2018 and extended into 2019, introduced several key improvements to OH transmission inspections including the use of an 'enhanced' inspection methodology with a questionnaire developed from a wildfire-ignition Failure Modes and Effects Analysis and the addition of aerial inspections using high-resolution drone photographs to provide a second vantage point from above to complement the ground inspections performed with the inspector standing at the base of the structure. These improvements from WSIP were incorporated into the regular OH inspection program beginning in 2020.

The 2020 inspections replaced the old wood- or steel-based inspection cycles with cycles that called for more frequent inspections in HFTD areas, annually for Tier 3 and on a 3-year cycle for Tier 2, compared to a 5-year cycle for non-HFTD areas. The 2020 inspections also included non-HFTD structures in High Fire Risk Areas (HFRA), which were treated like Tier 2.

The 2021 inspection program continued using the HFTD-based cycles introduced in 2020 and imposed an in-year deadline for HFTD and HFRA inspections of July 31, consistent with Pacific Gas and Electric Company's (PG&E or the Company) 2021 Wildfire Mitigation Plan (WMP). The intent of this deadline was to allow completion of the inspections and any emergency repairs found from the inspections prior to peak fire season. Monthly validations of the inspection plan were started in June 2021 to ensure that all assets requiring an inspection under their prescribed cycles were included in the plan, including assets that were newly added to the asset registry.

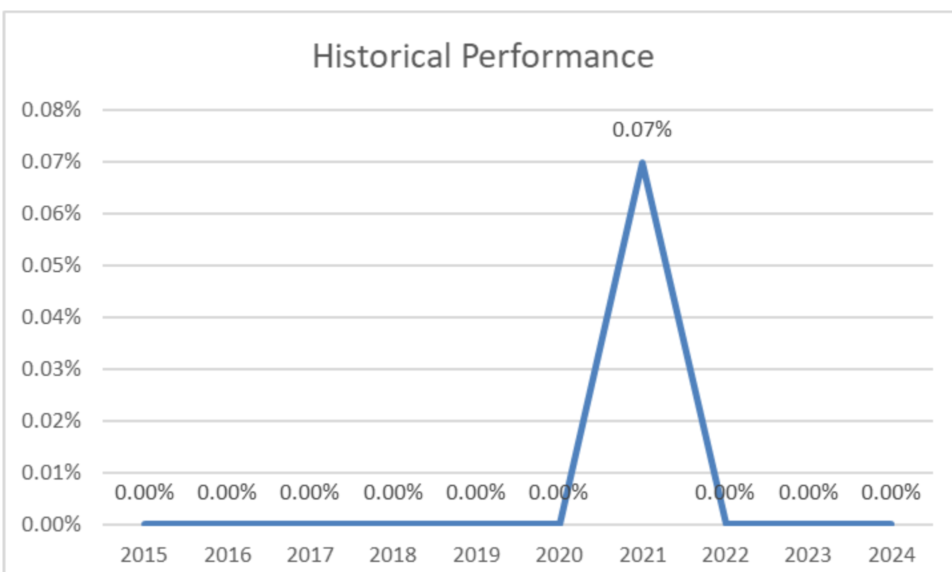
The 2022 inspection scope introduced the use of wildfire risk and consequence scores at the structure level to inform the selection of assets to be inspected. At the beginning of 2022, assets were added to the registry after July 31 or whose HFTD changes after July 31 will not be considered late, provided that they are inspected within 90 days of the addition to the registry or the HFTD change.

B. (3.10) Metric Performance

1. Historical Data (2015 – 2024)

Historical data is provided from 2015 –2024. Data provided for 2015-2019 reflects systemwide performance. HFTD-specific performance is not available prior to 2020. The percentage of missed inspections is calculated as the number of inspections not performed by the required deadline divided by the total number of inspections performed for that year. Through 2020, there was not a specific in-year deadline for inspections, so the deadline was considered December 31. The July 31 deadline for HFTD inspections in 2021 allowed exceptions due to access issues, landowner refusal, or site-specific worker safety situations (i.e., Cannot Get In (CGI)) where an unsuccessful inspection attempt was made prior to the deadline. In 2021, HFTD structures added to the asset registry after July 31 and inspected after the July 31 deadline were counted as missed inspections, as well as instances where the asset location was corrected from non-HFTD to HFTD after July 31.

FIGURE 3.10-1
HISTORICAL PERFORMANCE PERCENT LATE (2015 – 2024)



2. Data Collection Methodology

The currently used data collection methodology was implemented in 2020. It uses a mobile platform for completing overhead inspections, recorded at structure (pole) level using a detailed inspection checklist.

3. Metric Performance for the Reporting Period

In 2024, there were no missed inspections resulting in a 0.00 percent missed overhead Transmission detailed inspections with a total of 45,794 inspections completed – 31,657 in Tier 2 HFTD areas,11,171 in Tier 3 HFTD areas, 2,520 in HFRA and 446 in Zone 1 areas.

C. (3.10) 1-Year Target and 5-Year Target

1. Updates to 1- and 5-Year Targets Since Last Report

There have been no changes to the 1-year and 5-year targets since the last SOMS filing.

2. Target Methodology

To establish the 1-Year and 5-Year targets, PG&E considered the following factors:

- Historical Data and Trends: The July 31 deadline for HFTD patrols was first applied in 2021 and is still in practice. Therefore, targets use 2021 performance as a baseline with incremental improvement for the reasons described below;
- Benchmarking: Not available;
- Regulatory Requirements: Relevant items include: (1) General Order 165 requirements to follow internal maintenance procedures, and (2) Wildfire Mitigation Plan (WMP) targets to perform certain HFTD inspections and patrols by July 31;
- Attainable Within Known Resources/Work Plan: Targets are attainable within currently known resources;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: Targets are suitable indicators for EOE as historical driver of worsening performance (asset registry changes after July 31) will have an allowance to be counted as on time for any assets discovered after January 1 of the given year and due for a baseline frequency

inspection based on installation date (via the created date in SAP), will be inspected within 90 days of when added to the asset registry or by July 31 or the given year, whichever is later. Structures in scope for the given year with HFTD tier changes from Non-HFTD to HFTD after January 1st are also given an allowance for inspection within 90 days of the change or July 31st, whichever is later. This update beginning in 2022 ensures that the metric is an appropriate indicator of performance by focusing the measure on timely action to complete inspections as opposed to asset registry completeness.

- Other Qualitative Considerations: None.

3. 2025 Target

The 2025 target is to maintain performance to 0.00-0.03 percent, based on the 90-day allowance for asset registry changes described in the methodology above.

4. 2029 Target

The 2029 target is to maintain performance to 0.00-0.02 percent, based on the 90-day allowance for asset registry changes described in the methodology above, as well as a reduction over time in the number of asset registry additions from assets being discovered in the field.

D. (3.10) Performance Against Target

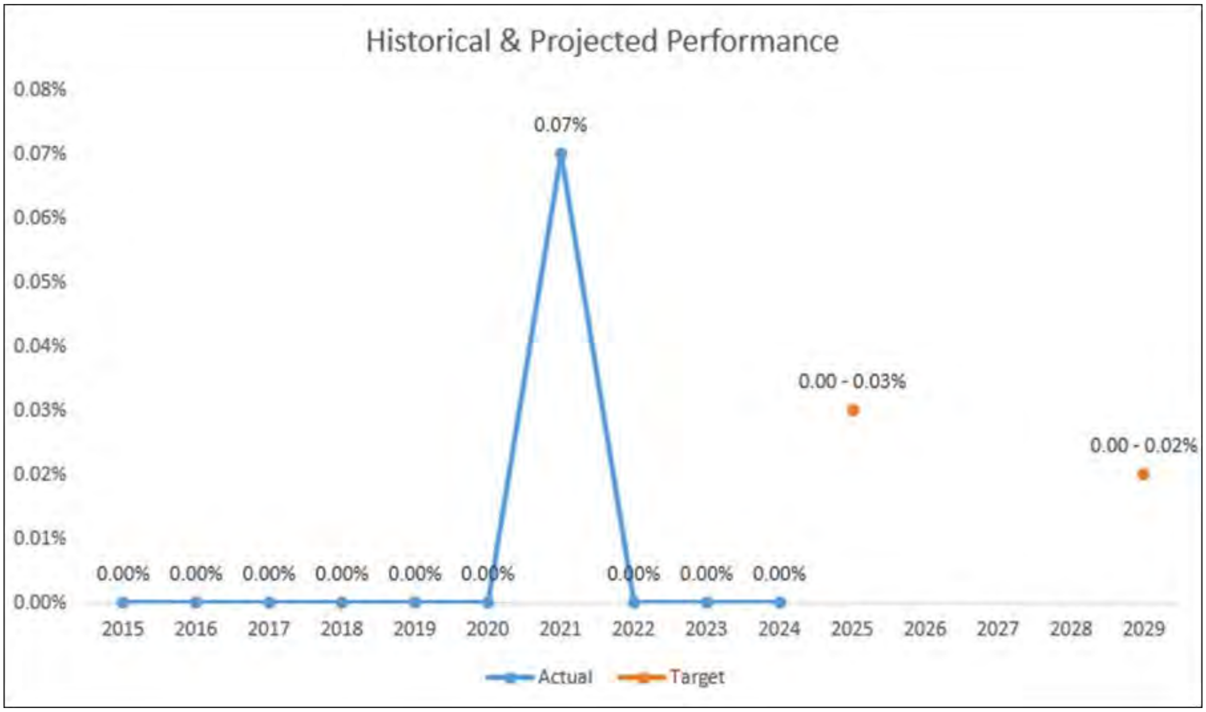
1. Progress Towards the 1-year Target

As demonstrated in Figure 3.10-2 below, PG&E observed a 0.00 percent missed overhead Transmission detailed inspections in 2024 which is consistent with Company’s 1-year target.

2. Progress Towards the 5-year Target

As discussed in Section E below, PG&E has deployed a number of programs to maintain or improve long-term performance of this metric to meet the Company’s 5-year performance target.

FIGURE 3.10-2
HISTORICAL PERFORMANCE (2015-2024) AND TARGETS (2025 AND 2029)



E. (3.10) Current and Planned Work Activities

Below is a summary description of the key activities that are tied to performance.

- 2024 Inspection and Patrol Plan: The 2024 inspection plan has been created and contains Tier 3 and Tier 2 structures totaling approximately 26,000 receiving ground inspection, 24,000 aerial inspections, and approximately 1,700 structures that also will receive a climbing inspection.
- Monthly Inspection Validations: Monthly inspection validations will continue to identify required additions to the original plan arising from additions or changes to the asset registry. Changes in HFTD may affect the scope of inspections covered by this metric
- In-Year Deadline Requirements: The in-year deadline of July 31 introduced in 2021 for inspections in HFTD will continue to be used in 2024, with the same provisions for CGI access issues as in 2021 and the addition of the 90-day requirement described above for additions and changes to the asset registry. The deadline is tracked with the inspection and patrol orders so

that each HFTD inspection is identified as having the July 31 compliance requirement.

PACIFIC GAS AND ELECTRIC COMPANY

SAFETY AND OPERATIONAL METRICS REPORT:

CHAPTER 3.11

GO-95 CORRECTIVE ACTIONS IN HFTDS

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The material updates to this chapter, since the September 30, 2024 report, are identified in blue font.

A. (3.11) Overview

1. Metric Definition

Safety and Operational Metric (SOM) 3.11 – General Order (GO) 95 Corrective Actions in High Fire Threat Districts (HFTD) is defined as:

The number of Priority Level 2 notifications that were completed on time divided by the total number of Priority Level 2 notifications that were due in the calendar year in HFTDs. Consistent with General Order (GO) 95 Rule 18 provisions, the proposed metric should exclude notifications that qualify for extensions under reasonable circumstances.[1]

GO 95, Rule 18, Priority Level 2 has four relevant timeframes for corrective action of which 2 are relevant for HFTD criteria used in SOMs: (1) six months for potential violations that create a fire risk in Tier 3 of HFTD; (2) 12 months for potential violations that create a fire risk in Tier 2 of HFTD.[2]

This metric is also reported as Metric 29 in the annual Safety Performance Metrics Report.

2. Introduction to the Metric

The GO 95 Corrective Actions in HFTD metric measures the number of Priority Level 2 electric corrective notifications (tags) in HFTD that are completed in accordance with the GO 95 Rule 18 timelines. This metric is associated with our Failure of Electric Distribution Overhead Asset Risk and our Wildfire Risk, which are part of our 2020 Risk Assessment and

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1 Correction times may be extended under reasonable circumstances, such as: third-party refusal, customer issue, no access, permits required, system emergencies (e.g., fires, severe weather conditions).

2 GO 95 Rule 18, B1ai-aiii.

Mitigation Phase Report filing. Vegetation Management (VM) work generally follows wildfire risk priorities. Priority notifications are tracked to completion against procedural timelines that are consistent with the underlying risk of the work.

3. Background

This metric consists of two major activities: corrective notification repairs and VM. The section below describes the work, including risk-informed prioritization and associated activities. We also compare Pacific Gas and Electric Company's (PG&E or the Company) priority classifications against GO 95 Rule 18's classification and timelines for completion.

- Corrective Notifications Identified from Inspections: PG&E routinely inspects our electric assets using a variety of methods, including observations when performing work in the area, periodic patrols, and inspections, and targeted condition-based and/or diagnostic testing and monitoring. These inspections of our overhead and underground electric assets are designed to meet GO 165 requirements. Regarding our equipment inspections process, when an inspector identifies a maintenance condition, the inspector may immediately correct the condition (e.g., performs minor repair work) and records the correction or records the uncorrected condition, which is also reviewed by a centralized inspection review team (CIRT). This additional review performed by the CIRT is to drive consistency in inspection results by having a centralized team review all field findings prior to recording the finding as a tag.

If the condition is not immediately corrected, the inspector fills out the initial tag. The centralized review team approves and prioritizes the corrective notification tag in our Work Management system. These tags are prioritized based on the risk posed by the condition and urgency of repairs. We also inspect vegetation in the vicinity of our facilities and apply a similar process, described below.

Regarding Priority Level 2 electric notifications pertaining to our equipment inspections, we have subdivided Priority Level 2 into three categories: Priority "X", Priority "B" and Priority "E". In 2024, PG&E

introduced priority X tags for Level 2 extremely urgent conditions that pose a high potential to safety or reliability but does not pose an immediate risk. These conditions should not wait six months to be addressed similar to other Level 2 conditions and are scheduled to be addressed within seven days.

Priority "B" notifications are scheduled to be addressed within 6 months. Priority "E" are scheduled to be completed within 6 months for Tier 3 and 12 months for Tier 2.

- VM: Regarding our VM Programs, we routinely inspect clearances between our overhead electric assets and adjacent vegetation through a variety of methods, including observations during recurring patrols and targeted program inspections. These inspections are conducted by VM personnel and/or contractors and are designed to identify if tree work is required to meet or, in some cases, exceed GO 95 Rule 35 requirements and fire safety regulations that require a minimum clearance of 4 feet year-round for high-voltage power lines in the California Public Utilities Commission-designated HFTD areas. GO 95 Rule 35 also requires the removal of dead, diseased, defective, and dying trees that could fall into the lines.

  When an inspector identifies a clearance condition or a potential tree hazard, they record an abatement prescription (tree work) within VM's data systems. This tree work is assigned to tree crews and completed in alignment with the timeframes defined in VM standards and procedures, unless there are constraints that require prior resolution before inspection or tree work proceeds (e.g., customer access, city or agency permits, environmental considerations). Unless constrained, tree work completion timing is based on HFTD Tier from the date it was inspected, which is either 180 days for Tier 3 or 365 days for Tier 2. Tree crews document the completion of tree work within VM data systems. VM tree work identified in this way does not follow the Electric Corrective notifications (EC for Distribution) and Line Corrective notifications (LC for Transmission) priority assignments. Our VM timeline to complete this tree work generally aligns with the risk presented by the vegetation and the risk reduction objectives of the VM Program. It is important to note that this data is classified into two categories: (1) Vegetation Dead and Dying and (2) Vegetation Priority 2, where each record reflects work completed on a tree.

- Priority Classifications and Timelines for Completion: We manage our corrective actions in HFTDs with a risk-informed prioritization of our work plans. Our strategy focuses on reducing wildfire risk associated with open corrective notifications. To accomplish this, we address the highest risk Level 2 corrective notifications first. After that, we manage the inventory of Level 2 Priority "E" corrective notifications in a risk-informed manner, where the highest risk Level 2 Priority "E" corrective notifications, within the same clearance point, are targeted first, while deploying safety controls to manage the lower risk Level 2 Priority "E" corrective notifications. This approach allows strategic and targeted wildfire risk reductions, informed by customer impact and risk spend efficiencies, to continue to be our primary focus.

We recognize that our electric Priority "X" and Priority "B" notifications, which we consider having a higher likelihood of creating an equipment failure than other Level 2 Priority notifications, have a more aggressive timeline to address than GO 95 Rule 18 Priority Level 2. However, consistent with the safety and operational metric definitions provided in Decision 21-11-009, we are reporting our performance against the timelines set forth in GO 95 Rule 18 and can provide, upon request, additional information as to how we are performing against our more aggressive internal timelines for our electric Priority "X" and Priority "B" notifications. Furthermore, we are including all EC and LC notifications, as well as all inspection-identified vegetation safety hazards that meet the definition of GO 95 Rule 18 Level 2.

At the end of 2022, Priority "B" was eliminated for newly created transmission (LC) notifications so that priority "E" LC notifications now directly align to Rule 18 Level 2. Priority "E" notifications may have timelines shorter than the maximum allowable Level 2 timelines, so 3-month notifications still can be created as priority "E." The existing population of "B" priority notifications was closed in 2023.

The following table summarizes the priority classifications we use to comply with GO 95 Rule 18. Transmission's priority levels have changed to remove priority “B”, allow reduced durations under priority “E”, and increase the duration for priority “F” to align with the Level 3 duration in GO 95 Rule 18.

TABLE 3.11-1
GO 95 RULE 18 RISK CATEGORIES AND TIMELINES

Line No.	GO 95 Rule 18	PG&E Priority	Description	GO 95 Rule 18 Timeline for Corrective Action	PG&E Internal Timeline for Corrective Action (Electric Notifications)	PG&E Internal Timeline for Corrective Action (Vegetation Tree Work)
1	Level 1	A (Electric) Priority 1 (Vegetation)	An immediate risk of high potential impact to safety or reliability	Take corrective action immediately, either by fully repairing or by temporarily repairing and reclassifying to a lower priority	Consistent with GO 95 Rule 18	Within 24 hrs. after identification
2	Level 2	B (Electric Dx) Priority 2 or Dead & Dying (Vegetation)	Any other risk of at least moderate potential impact to safety or reliability: Take corrective action within specified time period (either by fully repair or by temporarily repairing and reclassifying to Level 3 priority).	Time period for corrective action to be determined at the time of identification by a qualified Company representative, but not to exceed: 1. Six months for potential violations that create a fire risk located in Tier 3 of the HFTD. 2. 12 months for potential violations that create a fire risk located in Tier 2 of the HFTD. 3. 12 months for potential violations that compromise worker safety; and 4. 36 months for all other Level 2 potential violations.	Corrective action within 6 months from date condition identified for electric equipment	1. Within 20 business days from identification Priority 2 Tag. (excluding work that is constrained) 2. Dead & Dying tree(excluding work that is constrained): a. Six months within Tier 3 & Tier 2 of the HFTD; and b. 12 months outside Tier 3 & Tier 2 of the HFTD.
		X (Electric Dx)	High potential impact to safety or reliability but do not pose an immediate risk. (introduced in spring)	Same as above	Corrective action within 7 days from date condition identified for electric equipment	N/A
3		E (Electric)	Any other risk of at least moderate potential impact to safety or reliability: Take corrective action within specified time period (either by fully repair or by temporarily repairing and reclassifying to Level 3 priority).	Same as above	Corrective action within: Six months for conditions that create a fire risk located in HFTD Tier 3 12 months for conditions that create a fire risk located in HFTD Tier 2 Transmission: Corrective action timelines can be reduced below the maximum values listed above.	N/A
4		H (Electric Dx)	These are PG&E Priority "E" Notifications that are planned to be addressed by a planned System Hardening Project	Same as above	Same as above-	N/A

TABLE 3.11-1
GO 95 RULE 18 RISK CATEGORIES AND TIMELINES
(CONTINUED)

Line No.	GO 95 Rule 18	PG&E Priority	Description	GO 95 Rule 18 Timeline for Corrective Action	PG&E Internal Timeline for Corrective Action (Electric Notifications)	PG&E Internal Timeline for Corrective Action (Vegetation Tree Work)
5	Level 3	F (Electric)	Any risk of low potential impact to safety or reliability	Take corrective action within 60 months subject to the specific exceptions.[a]	1. Corrective actions to be addressed within five years from date condition is identified.	N/A

(a) EXCEPTION – Potential violations specified in Appendix J or subsequently approved through Commission processes, including, but not limited to, a Tier 2 Advice Letter under GO 96B, that can be completed at a future time as opportunity-based maintenance. Where an exception has been granted, repair of a potential violation must be completed the next time the Company's crew is at the structure to perform tasks at the same or higher work level (i.e., the public, communications, or electric level). The condition's record in the auditable maintenance program must indicate the relevant exception and the date of the corrective action.

B. (3.11) Metric Performance

1. Historical Data (2020 – Q2 2024)

We are reporting historical data from the years 2020 through 2024.

Our history of available data, which is recorded in our electric work management systems (e.g., SAP) goes back to 2010. However, we are focusing our historical reporting for this metric starting at 2020 due to various changes that occurred prior to 2020, which reshaped GO 95 and GO 165 to include boundaries for HFTD, as well as informed our current inspection methods to be more enhanced towards identifying ignition risks.

Reported timelines generally align with VM adoption of updated internal timeliness for Priority Tag mitigation and additional 'Dead & Dying' tree abatement identified through the implementation of PG&E Enhanced VM (EVM) Program in 2019. The VM Program's work management systems track tree prescriptions and completion of trim / removal through separate databases; the Vegetation Management Database (VMD) and OneVM.

2. Data Collection Methodology

Data collected prior to year 2020 is excluded due to the various GO 165 and GO 95 Rule 18 changes mentioned above.

We are including all EC (Distribution) and LC (Transmission) notifications, as well as all inspection-identified vegetation safety hazards that meet the definition of GO 95 Rule 18 Level 2. Note that due dates must be manually adjusted in our data to align with the GO 95 Rule 18 timelines which vary from our internal timelines as previously mentioned.

3. Metric Performance for the Reporting Period

Metric performance is comprised of an aggregated performance for electric distribution and electric transmission (ET) corrective notifications, as well as vegetation safety hazards.

As described in earlier sections, we are reporting and setting targets against the timeframes identified in GO 95 Rule 18 rather than the timelines articulated in our internal electric Priority "X", Priority "B" and "E" notifications, and internal VM Priority 2 and Dead and Dying Tree abatement corrective notifications.

To address the unprecedented wildfire risk in our service territory, in 2019 we launched our Wildfire Safety Inspection Program (WSIP) as part of our Wildfire Safety Plan. The intent of that program was to expand our focus during inspections to include fire ignition risk posed by failure modes on our electric assets and accelerate the inspections to be complete by the beginning of the 2019 wildfire season. The WSIP generated a volume much greater than what we have typically experienced for our annual electric corrective notification volume, with the majority of electric corrective notifications being of lower risk (e.g., Level 2 Priority "E" & Level 3).

Given the high volume (e.g., approximately 4x the volume from prior years) of identified electric distribution and transmission corrective notifications in the 2019 WSIP, we pivoted from managing our electric corrective notifications based on due date to focusing our priority through a wildfire risk informed approach. This means we would complete Level 1 and Level 2 Priority "X" and Priority "B" corrective notifications first and manage the inventory of Level 2 Priority "E" and Level 3 corrective notifications.

Our approach for managing the inventory of Level 2 Priority "E" is to: (1) group high concentrations of individual capital intensive rebuild corrective notifications into new, more comprehensive, System Hardening projects, and (2) permanently remove electric lines out of service that have multiple corrective notifications and serve small numbers of customers, where service can be provided via alternate line interconnections or remote grid solutions and (3) bundle and prioritize corrective work execution for those Level 2 Priority "E" notifications that were of high wildfire risk informed priority based on risk spend efficiency as indicated in WMP RN-04. PG&E address its distribution maintenance tag log more quickly through the isolation zone bundling approach described in PG&E's 2023-2025 Wildfire Mitigation Plan (WMP), which was approved by the Office of Energy Infrastructure Safety (Energy Safety) on December 29, 2023. EC notifications are bundled by isolation zone to maximize the number of notifications completed within a single outage and/or planned day of work. Isolation zones are circuit segments located between sectionalizing devices. A bundle consists of all open notifications within a given isolation zone. Bundles are created across all EC types (pole, non-pole capital, non-pole expense). While PG&E's maintenance tag plan described in its 2023-2025 WMP will result in some lower-risk maintenance tags exceeding the current GO 95, Rule 18 timelines, the plan is prudent because it will allow PG&E to reduce the maintenance tag log more quickly and execute more tags with the same amount of resources while reducing the amount of clearances needed per unit executed.

In 2024 PG&E saw a performance of 67.9percent as shown in Figure 3.11-1 below. This performance is below the 2024 one-year target of 69 percent.

We are also currently completing available vegetation priority corrective notifications within our internal timelines, excluding corrective notifications where we are constrained due to external factors, such as customer interferences or permitting. Trees are worked as dependencies and constraints are resolved. This is consistent with our Dead and Dying Tree Abatements.

The following figure plots our historical performance for GO 95 Rule 18 Level 2 HFTD Corrective Notifications.

FIGURE 3.11-1
GO 95 CORRECTIVE ACTIONS IN HFTDS – HISTORICAL PERFORMANCE (2020 – 2024)

TABLE 3.11-2
GO 95 RULE 18 PRIORITY LEVEL 2 ACTUAL 2024
CORRECTIVE ACTIONS PERFORMANCE
(ELECTRIC DISTRIBUTION, ET AND VM)

Line No.	Year 2024	Level 2 Results
1	On Time	169,805
2	Past Due	80,284
3	% On Time	67.9%

TABLE 3.11-3
GO 95 RULE 18 LEVEL 2 ACTUAL 2024
CORRECTIVE ACTIONS PERFORMANCE
(ELECTRIC DISTRIBUTION ONLY)

Line No.	Year 2024	Level 2 Priority "E"	Level 2 Priority "B"	Level 2 Priority "B" From "E"	Level 2 Priority "X"	Level 2 Results
1	On Time	4,102	8,161	(358)	265	12,886
2	Past Due	74,660	589	723	0	75,972
3	% On Time	5.2%	93.3%	33.1%	100%	14.5%

TABLE 3.11-4
GO 95 RULE 18 LEVEL 2 ACTUAL 2024
CORRECTIVE ACTIONS PERFORMANCE
(ET ONLY)

Line No.	Year 2024	Level 2 Results
1	On Time	7,094
2	Past Due	3,305
3	% On Time	68.2%

Note: Per PG&E Utility Procedure TD-8123P-103,effective 1/03/2023, all Level 2 Transmission tags are considered priority "E" which aligns with GO 95, Rule 18 Levels 1, 2, and 3. Tag priority categorization will no longer be provided for Transmission tags.

TABLE 3.11-5
GO 95 RULE 18 LEVEL 2 ACTUAL 2024
CORRECTIVE ACTIONS PERFORMANCE
(VM)

Line No.	Year 2024	EVM Dead and Dying	Vegetation Dead and Dying	Vegetation Priority 2	Level 2 Results
1	On Time	6,177	97,479	46,160	149,816
2	Past Due	40	885	81	1,006
3	% On Time	99.4%	99.1%	99.8%	99.3%

C. (3.11) 1-Year Target and 5-Year Target

1. Updates to 1- and 5-Year Targets Since Last Report

The 1-year and 5-year targets have changed since the last SOMS filing.

2. Target Methodology

To establish the 1-Year and 5-Year targets, we considered the following factors:

- <u>Historical Data and Trends</u>: The targets are based on the projected volume of GO 95 Rule 18 Priority Level 2 notifications, which consider existing open tags and forecasted new tags that are due for each year;
- <u>Benchmarking</u>: Not available;
- <u>Regulatory Requirements</u>: GO 95 Rule 18 requirements;
- <u>Attainable Within Known Resources/Work Plan</u>: Attainability is subject to other emerging higher risk priorities that may influence our ability to meet projected targets. If emerging higher risk priorities emerge throughout the course of the year, we may need to prioritize our available resources to address these higher risk priorities and adjust our work plan accordingly;
- <u>Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement</u>: Yes, performance at projected levels is sustainable, subject to other emerging higher risk priorities may influence ability to meet projected targets. If emerging higher risk priorities emerge throughout the course of the year, we may need to prioritize our available resources to address these higher risk priorities and adjust our work plan accordingly; and

- Other Qualitative Considerations: This target was established with the consideration of our risk informed strategy, as opposed to a corrective notification due date prioritization approach.

3. 2025 Target

Our target for Priority Level 2 corrective maintenance notifications on time completion rates is 73.8 percent for the year 2025.This metric performance is comprised of an aggregated score combining performance of electric distribution, ET and VM.

For year 2025, electric distribution notifications completed on time percentage is projected at approximately 17 percent and ET notifications completed on time percentage is projected at approximately 70 percent. The projected forecast for VM is approximately 98 percent.

Our distribution corrective notifications strategy will continue to focus on reducing wildfire risk associated with our open corrective notifications by working the highest risk spend efficiency bundles for Level 2 corrective notifications first versus managing corrective notification due dates. Using this approach in 2023 through 2024, we reduced the relative wildfire risk associated with backlog[3] open electric distribution corrective maintenance notifications in HFTD Tiers 2 and 3 by as much as 73.4 percent.

Transmission Line expects to have an improved on-time performance on level 2 notifications within 2025. In 2024, Transmission line had conflicting priorities with the remaining open WMP backlog. This conflict does not exist in 2025, and Transmission can focus primarily on completing level 2 notifications prior to the GO 95 due date. Additionally, Transmission Line has created a formal GO 95 rule 18 extension process for documenting due date extensions based on reasonable circumstances, that will improve our on-time performance.

For Vegetation Management, our forecast has been adjusted to account for the expected find rate of trees requiring work, and to reflect the volume of trees that may be constrained due to external factors. The focus of

3 Backlog tags are open ignition EC notifications known as of January 5, 2023, and found prior to Jan 1, 2023, in HFTD/HFRA locations.

Vegetation Management will continue to be placed on execution of the wildfire mitigation programs described in the 2023-2025 WMP.

The following tables summarize PG&E's Year 2024 Target for Priority Level 2 notifications completed on time percentage, as well as a breakdown between the electric distribution, ET and VM Priority Level 2 notifications performance. Since the "B" priority will no longer be assigned to transmission notifications, as described above, transmission projections are not separated by "B" and "E" priority levels. Table 3.11-6 has been updated only to reflect Level 2 results due to the priority level changes in transmission.

TABLE 3.11-6
GO 95 RULE 18 PRIORITY LEVEL 2 PROJECTED 2025
CORRECTIVE ACTIONS PERFORMANCE
(ELECTRIC DISTRIBUTION, ET AND VM)

Line No.	Year 2025	Level 2 Results
1	On Time	162,294
2	Past Due	57,476
3	% On Time	73.8%

TABLE 3.11-7
GO 95 RULE 18 LEVEL 2 PROJECTED 2025
CORRECTIVE ACTIONS PERFORMANCE
(ELECTRIC DISTRIBUTION ONLY)

Line No.	Year 2024	Level 2 Priority "E"	Level 2 Priority "B"	Level 2 Priority "B" From "E"	Level 2 Results
1	On Time	5,130	5,204	233	10,567
2	Past Due	46,169	3,286	2,150	51,605
3	% On Time	10%	61%	10%	17%

TABLE 3.11-8
GO 95 RULE 18 LEVEL 2 PROJECTED 2025
CORRECTIVE ACTIONS PERFORMANCE
(ET ONLY)

Line No.	Year 2024	Level 2 Results
1	On Time	6,820
2	Past Due	2,913
3	% On Time	70%

TABLE 3.11-9
GO 95 RULE 18 LEVEL 2 PROJECTED 2025
CORRECTIVE ACTIONS PERFORMANCE
(VM)

Line No.	Year 2025	Vegetation Dead and Dying	Vegetation Priority 2	EVM Dead and Dying	Level 2 Results
1	On Time	81,202	62,889	816	144,908
2	Past Due	1,657	1,283	17	2,957
3	% On Time	98%	99%	98%	98%

4. 2029 Target

Our 5-year target for Priority Level 2 corrective maintenance notifications on time is 86.1 percent. This target is a 17 percent increase from the 2025 target of 73.8 percent based on our GM-03 commitment to return to compliance in HFTD/HFRA by the end of 2029.

This metric performance is comprised of an aggregated performance where the projected year 2029 volume of on time corrective notifications for electric distribution, ET and vegetation are at 64,677; 8,500; and 144,865, respectively.

For year 2029, we are projecting an on-time percentage of approximately 57 percent, 95 percent, 98 percent for electric distribution, ET, and vegetation notifications performance, respectively.

Our distribution corrective notifications strategy will continue to focus on reducing the most wildfire risk associated with our open corrective notifications per dollar spent by working the highest risk bundles by isolation zone first versus managing corrective notification due dates. Furthermore, we are also revisiting opportunities to further align our distribution electric corrective action Priority levels (e.g., A, B, X, E, F, and H) with that of GO 95

Rule 18 (e.g., Levels 1, 2, and 3), which we expect will improve our performance in the long-term.

The following tables summarize our Year 2029 Target for Priority Level 2 notifications completed on time percentages, as well as a breakdown between the electric distribution, ET and vegetation Priority Level 2 notifications completed on time percentages.

TABLE 3.11-10
GO 95 RULE 18 PRIORITY LEVEL 2 PROJECTED 2029 CORRECTIVE ACTIONS PERFORMANCE
(ELECTRIC DISTRIBUTION, ET AND VM)

Line No.	Year 2029	Level 2 Results
1	On Time	192,934
2	Past Due	31,244
3	% On Time	86%

TABLE 3.11-11
GO 95 RULE 18 LEVEL 2 PROJECTED 2029 CORRECTIVE ACTIONS PERFORMANCE
(ELECTRIC DISTRIBUTION ONLY)

Line No.	Year 2029	Level 2 Priority "E"	Level 2 Priority "B"	Level 2 Priority "B" From "E"	Level 2 Results
1	On Time	27595	7039	1976	36609
2	Past Due	27594	370	104	28069
3	% On Time	50%	95%	95%	57%

TABLE 3.11-12
GO 95 RULE 18 LEVEL 2 PROJECTED 2029 CORRECTIVE ACTIONS PERFORMANCE
(ET ONLY)

Line No.	Year 2029	Level 2 Results
1	On Time	8,075
2	Past Due	425
3	% On Time	95%

TABLE 3.11-13
GO 95 RULE 18 LEVEL 2 PROJECTED 2029 CORRECTIVE ACTIONS PERFORMANCE
(VM)

Line No.	Year 2029	Vegetation Dead and Dying	Vegetation Priority 2	Level 2 Results
1	On Time	121520	26730	148250
2	Past Due	2480	270	2750
3	% On Time	98%	99%	98%

The Figure 3.11-2 plots our aggregated historical and aggregated projected performance for GO 95 Rule 18 Level 2 HFTD Corrective Notifications.

D. (3.11) Performance Against Target

1. Progress Towards 1-Year Target

As demonstrated in Figure 3.11-2 below, PG&E saw a performance of 67.9 percent in all of 2024, which fell below the Company's 1-year target of 69 percent. The root causes of lower performance are: (1) lower than expected on-time completions of Transmission corrective tags due to clearance constraints, emergency activations, and rescheduling conflicts, and (2) lower than expected on-time completions of VM work due to lower than expected find rates.

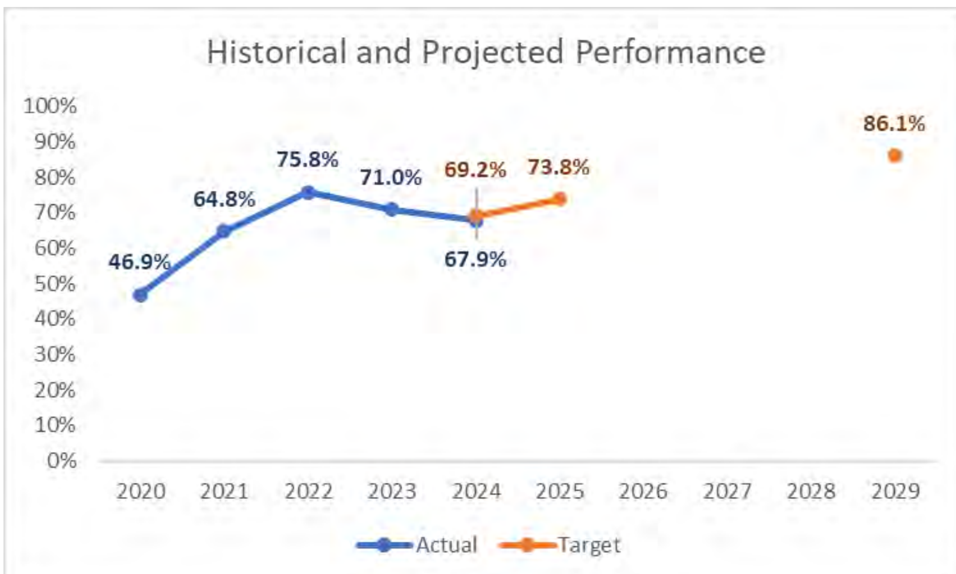
While the consolidated metric fell below target in 2024, Distribution saw an increase in on-time completions from 6k in 2023 to 13k in 2024, resulting in a greater reduction in wildfire risk and in the past due tags. Additionally, PG&E closed ~37 thousand more EC tags in 2024 compared to 2023. Furthermore, we began tracking priority B notifications across the system in greater detail to ensure that these higher risk EC notifications are included in our workplans, this has resulted in increased B tag on-time completion rate from 71 percent in 2023 to 93 percent in 2024.

PG&E also made improvements to the inspection programs to increase effectiveness of identifying maintenance conditions that result in an asset failure. In 2024, PG&E analyzed the population of open tags and based on the engineering studies and a reassessment of failure modes, PG&E developed more objective criteria tied to failure for use during inspections and tag creation. Accordingly, PG&E streamlined its inspection checklists to increase focus on identifying conditions on the five assets that are the most likely to lead to failures. These changes to inspections program in 2024 have allowed PG&E to reduce the creation of in-effective tags that have a lower risk of failure. While VM saw lower than expected completion volumes in 2024, VM exceeded their target of 98.2 percent by achieving an actual on-time rate of 99.3 percent.

2. Progress Towards the 5-Year Target

As discussed in Section E below, PG&E is deploying a number of programs to maintain or improve long-term performance of this metric to meet the Company's 5-year performance target.

FIGURE 3.11-2
GO 95 CORRECTIVE ACTIONS IN HFTDS – HISTORICAL AND PROJECTED PERFORMANCE



E. (3.11) Current and Planned Work Activities

Below is a summary description of the key activities that are tied to performance and their description.

- <u>System Hardening</u>: System Hardening Program focuses on mitigating wildfire risk posed by distribution overhead assets in and near Tier 2 and 3 HFTDs in our service territory. This program targets high wildfire risk miles and applies various mitigation activities, including: (1) line removal, (2) conversion of distribution lines from overhead to underground, (3) application of Remote Grid alternatives, (4) mitigation of exposure through relocation of overhead facilities, and (5) in-place overhead system hardening.

- Overhead Preventative Maintenance and Equipment Repair: Focuses on repair of electric equipment identified with corrective notifications. Our corrective notifications strategy will continue to focus on reducing wildfire risk associated with our open corrective notifications by working the highest risk Level 2 corrective notifications in a risk spend efficiency approach (bundling all open notifications by isolation zone and prioritizing by the most risk reduced per dollar spent starting in 2024) versus managing corrective notification due dates. We plan to accomplish this by continuing to complete Level 1 and Level 2 Priority “B” corrective notifications first and manage the inventory of Level 2 Priority “E” corrective notifications in a risk informed manner, where the highest risk spend efficiency isolation zone of bundled open notifications are targeted first, while deploying safety controls to manage the lower risk Level 2 Priority “E” corrective notifications. The approach allows strategic and targeted wildfire risk reductions, informed by customer impact and risk spend efficiencies, to continue to be our primary focus. PG&E will continue to utilize additional measures to ensure these past due notifications do not turn into realized risk by performing patrols, performing enhanced inspections like aerial and comprehensive pole inspections, and utilizing Enhanced Powerline Safety Settings and Public Safety Power Shutoff during heightened wildfire conditions. Overall, this combination of inspections, engineering containment and bundled execution continues to reduce the risk on PG&E's system thousand.

PACIFIC GAS AND ELECTRIC COMPANY

SAFETY AND OPERATIONAL METRICS REPORT:

CHAPTER 3.12

ELECTRIC EMERGENCY RESPONSE TIME

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SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 3.12
ELECTRIC EMERGENCY RESPONSE TIME

The material updates to this chapter, since the September 30, 2024 report, are identified in blue font.

A. (3.12) Overview

1. Metric Definition

Safety and Operational Metric (SOM) 3.12 – Electric Emergency Response Time is defined as:

Average time and median time in minutes to respond on-site to an electric related emergency notification from the time of notification to the time a representative (or qualified first responder) arrived onsite. Emergency notification includes all notifications originating from 911 calls and calls made directly to the utilities' safety hotline. The data used to determine the average time and median time shall be provided in increments as defined in General Order 112-F 123.2 (c) as supplemental information, not as a metric.

2. Introduction of Metric

This metric measures the average and median time for Pacific Gas and Electric Company (PG&E or the Company) to respond on-site to an electric emergency once a notification is received. Measuring response to calls into PG&E's Emergency line from first responder agencies within 60 minutes has been a long-standing, priority public safety measure for PG&E and within the industry, and this metric, although calculated differently, is similar in its intent for responding quickly to our customers and any potentially unsafe conditions reported.

B. (3.12) Metric Performance

1. Historical Data (2015 – 2024)

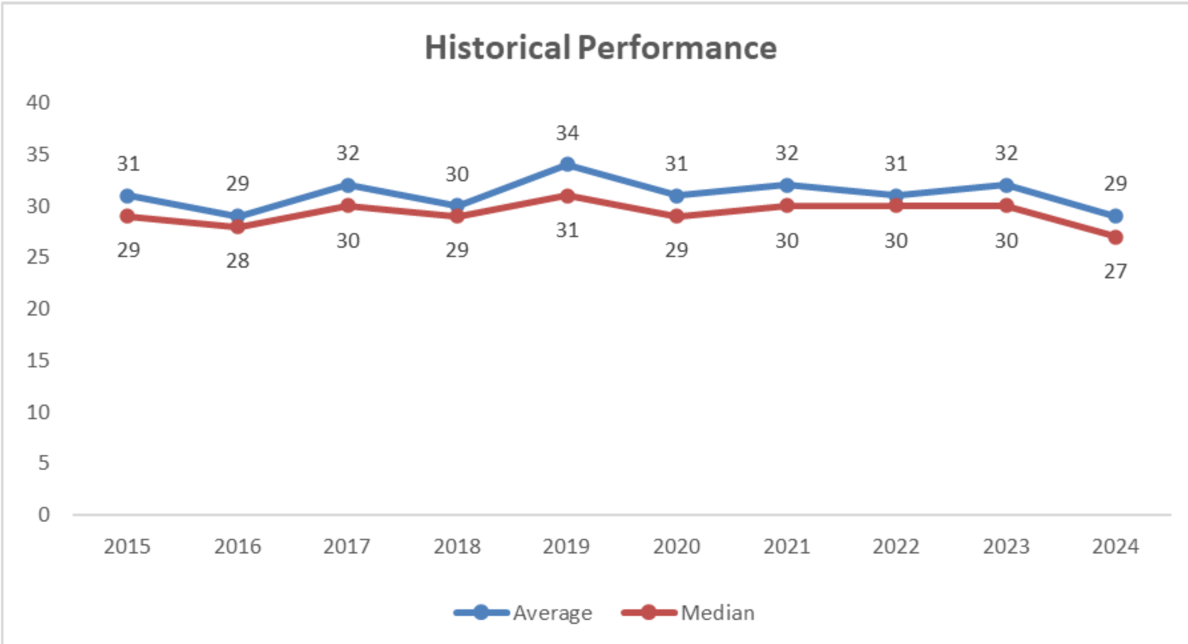
Historical data is provided from 2015 through 2024. Although emergency response data exists prior to 2015 (as mentioned below), current validation practices were not in place until 2015 and therefore only data from 2015 and beyond is reported here for consistency and comparability.

Over the timeframe of 2015 through 2024. There has been a 6 percent reduction in total average response time, from 31 minutes end of year average 2015 to 29 minutes in2024. The median response time also reduced by 7 percent from 29 minutes end of year 2015 to 27 minutes in 2024.

Since 2015, PG&E's historical performance has been within the first quartile and has been in the first decile for several years when measuring percentage of response times within 60 minutes, which is the industry benchmarkable definition.

Metric performance has been driven by accurately predicting when large volumes of calls will occur (based on weather forecasts), proactive scheduling of resources for emergency response, cross functional- coordination across PG&E to train non-traditional stand-by staff, availability of resources for weather days and improved understanding of shifts in storm fronts that impact the system.

FIGURE 3.12-1
ELECTRIC EMERGENCY RESPONSE TIME HISTORICAL DATA (2015 – 2024)



Note: The data in this figure is subject to change based on continuing review of prior period usages. Average and Median values for 2015-2019 have been updated. In 2015-2019 cancelled tags were included in the calculations and are now excluded per our standard for measuring the 60 min response time metric.

2. Data Collection Methodology

The metric performance data is captured and stored in the Outage Information System (OIS) database. Each emergency call has a time stamp. The start time of an electric emergency call involves receipt by utility personnel and entry into the OIS database (creation of a tag). The tag is created in the OIS database when PG&E personnel are on the phone with the first responder dispatch agency (there is a direct PG&E Emergency line into Gas Dispatch, where all emergency calls are routed). This process removes the delay between the time the call is received and entered into the system, and the raw data is then reviewed for duplicate entries, which are cancelled (if found). The timestamp of when PG&E personnel respond on site is primarily when they select the “onsite” button on their mobile data terminals, which marks the completion of the response. If there is a discrepancy or uncertainty, our Electric Dispatch team will validate the exact arrival time by leveraging GPS data from our employee’s vehicles and/or mobile data terminals. The response time in minutes is calculated by the difference between the two timestamps. From each call's response time, the average and median time is calculated for all calls.

3. Metric Performance for the Reporting Period

In 2024 average EO emergency response time was 29 minutes and median response time was 27 minutes. These results exclude the 2024 GO-166 Measured Event period (Feb 4 – Feb 9) and are considered a strong performance as the corresponding benchmarkable calculation, percent response time within 60 minutes, remains at the top of industry performance.

C. (3.12) 1-Year and 5-Year Target

1. Updates to 1- and 5 -Year Targets Since Last Report

There have been no changes to 1- and 5 -Year targets since the last report filing.

2. Target Methodology

To establish the 1 -Year and 5 -Year targets, PG&E considered the following factors:[1]

- <u>Historical Data and Trends</u>: Comparable data is available starting in 2015 although historical benchmarking trends (under alternative definition) are informative back to 2012. This historical data context confirms PG&E's current results are improved, sustained, and reasonably considered strong performance, which has informed the target setting direction to "maintain";
- <u>Benchmarking</u>: Industry benchmarking is available under the emergency response time measure calculated as percent time responding on site within 60 minutes. PG&E is first quartile within this benchmark, and has used this industry data as a key datapoint to inform target setting:
  - To do this, PG&E used available industry benchmark data in 2021 to set its initial electric emergency response targets for this metric.

[1] Targets represent values that serve as appropriate indicator lights to signal a review of potential performance issues. Targets should not be interpreted as intention to worsen performance, as further described below.

Specifically, these estimated values represent the point at which, when exceeded, performance would move out of first quartile and into second quartile;

  - PG&E's intent is to stay in first quartile performance. Given the context that benchmarking provides, PG&E targets are meant to maintain current performance at levels better than the first quartile threshold, and would consider a performance change on the magnitude of exceeding these targets (i.e., moving into a worse estimated quartile, a signal of concern);
  - In other words, target values in this case represent performance levels that PG&E does not want to exceed or move performance towards. Values should not be interpreted as a plan for or expectation of worsening performance;

- Regulatory Requirements: None;
- Attainable With Known Resources/Work Plan: Yes;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: Historical data and trends confirm that maintaining estimated first quartile performance is a sustainable target in both the 1-year and 5-year timeframes. A change in performance on the magnitude of reaching the targets (i.e., performance moving into the estimated second quartile) is an appropriate indicator light to examine potential performance issues as PG&E's intent is to maintain current practices and past improvements and mitigate any future operational impacts that may arise; and
- Other Considerations: None.

3. 2025 Target

The 2025 target is to remain better than 44 minutes for average emergency response time and better than 43 minutes for median emergency response time. Targets are based on maintaining first quartile performance.

4. 2029 Target

The 2029 target is to remain better than 44 minutes for average emergency response time and better than 43 minutes for median emergency response time. Targets are based on maintaining first quartile performance.

D. (3.12) Performance Against Target

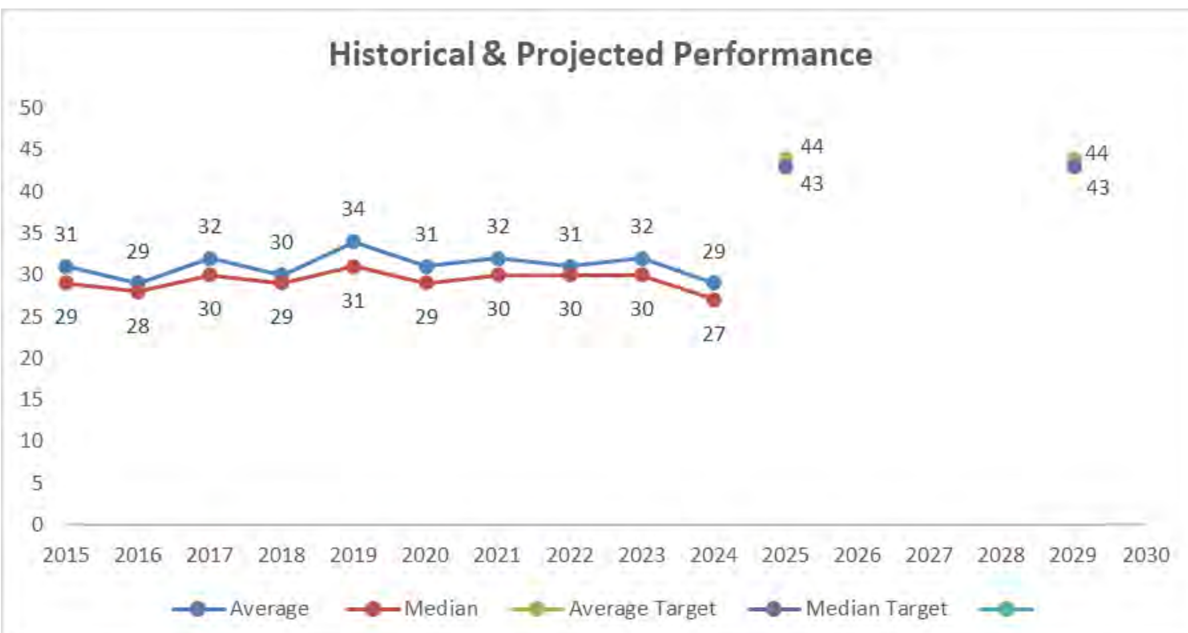
1. Progress Towards the 1-Year Target

As demonstrated in Figure 3.12-2 below, PG&E saw an average of 29 response minutes and a median of 27 response minutes in 2024 which is consistent with the Company's 1-year target.

2. Progress Towards the 5-Year Target

As discussed in Section E below, PG&E has deployed two programs to maintain or improve long term performance of this metric to meet the Company's 5-year performance target.

FIGURE 3.12-2
ELECTRIC EMERGENCY RESPONSE TIME HISTORICAL AND PROJECTED DATA



Average and Median values for 2015-2019 have been updated. In 2015-2019 cancelled tags were included in the calculations and are now excluded per our standard for measuring the 60 min response time metric.

E. (3.12) Current and Planned Work Activities

PG&E continues to refine the following actions in 2025 to maintain its top quartile performance:

- Meteorology, Operations, and Dispatch Support:
  - In 2024, PG&E Meteorology validated and enhanced EO Emergency forecasting by using historical data to train their forecasting model and to provide resource requirement recommendations based on predicted weather. Improved modeling allows for more effective staffing. In 2025, Electric Dispatch will continue to refine its electric emergency stand-by resource scheduling systems and process. The goal is to optimize the number of stand-by resources available in a geographic area to the forecasted system impacts.
  - Meteorology proactively reaches out to Electric Dispatch if a specific geographic area is looking to worsen over the forecast period.
- Blue-Sky Call Out Improvements: In 2025, PG&E is leveraging lean problem solving to identify further actions to incrementally improve upon after-hours electric emergency call out performance.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3.13

NUMBER OF CPUC-REPORTABLE IGNITIONS IN HFTD AREAS

(DISTRIBUTION)

PACIFIC GAS AND ELECTRIC COMPANY
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NUMBER OF CPUC-REPORTABLE IGNITIONS IN HFTD AREAS
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CHAPTER 3.13
NUMBER OF CPUC-REPORTABLE IGNITIONS IN HFTD AREAS (DISTRIBUTION)

The material updates to this chapter, since the September 30, 2024 report, are identified in blue font.

A. (3.13) Overview

1. Metric Definition

Safety and Operational Metrics (SOM) 3.13 – the Number of California Public Utilities Commission (CPUC) Reportable Ignitions in High Fire Threat Districts (HFTD) Areas (Distribution) is defined as:

The number of CPUC-reportable ignitions involving overhead distribution circuits in HFTD Areas.

A CPUC-Reportable Ignition refers to a fire incident where the following three criteria are met: (1) ignition is associated with Pacific Gas and Electric Company (PG&E) electrical assets, (2) something other than PG&E facilities burned, and (3) the resulting fire travelled more than one linear meter from the ignition point.[1]

For this SOM, reporting is specific to Tier 2 and Tier 3 HFTDs.

PG&E provides the CPUC with annual ignition data in the Fire Incident Data Collection Plan, to the Office of Energy Infrastructure and Safety quarterly via quarterly geographic information system, data reporting, in quarterly Wildfire Mitigation Plan updates, and the Safety Performance Metrics Report.

2. Introduction of Metric

The number of CPUC-reportable ignitions in HFTDs provides one way to gauge the level of wildfire risk that customers and communities are exposed to from overhead distribution assets. PG&E's objective is to reduce the number of CPUC reportable ignitions that may trigger a catastrophic wildfire.

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1 Please see CPUC Decision (D.) 14-02-015, issued February 5, 2014 for additional details.

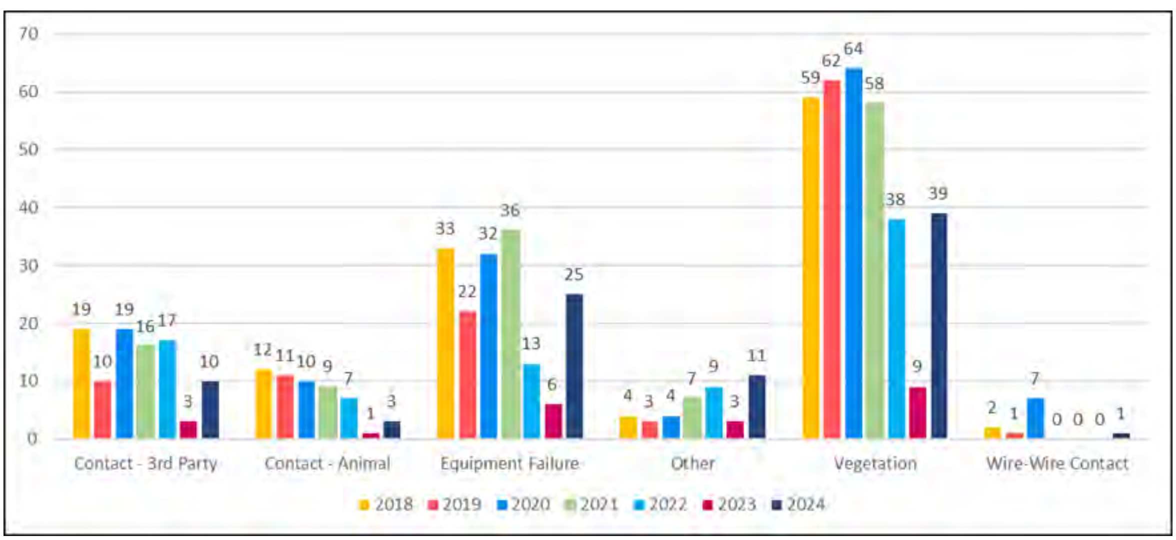
B. (3.13) Metric Performance

1. Historical Data (2015 – 2024)

PG&E implemented the Fire Incident Data Collection Plan in response to D.14-02-015 in June 2014. PG&E's Ignitions Tracker includes all CPUC-reportable ignitions from June 2014 to present. The 2014 data does not represent a complete year and is excluded in this analysis.

PG&E's overhead distribution circuits traverse approximately 25,000 miles of terrain in the HFTD areas where the overhead conductor is primarily bare wire, supported by structures consisting of poles, cross arms, associated insulators, and operating equipment such as transformers, fuses and reclosers. The main causes of CPUC-reportable ignitions have been collected and classified. These fall into six broad categories: vegetation contact, equipment failure, third party contact, animal contact, wire to wire contact, and other causes. The counts for 2018 to 2024, are shown in the graph below, highlighting the degree of variability that occurs from year to year relative to each category.

FIGURE 3.13-1
DISTRIBUTION HISTORIC PERFORMANCE BY SUSPECTED CAUSE



There is also a seasonal pattern to the ignition events as shown in the chart of ignitions by month below for each of the years from 2018 through 2024.

FIGURE 3.13-2
HISTORIC PERFORMANCE BY YEAR/MONTH

Month	2018 Total	2019 Total	2020 Total	2021 Total	2022 Total	2023 Total	2024 Total
January	1	1	0	19	2	0	0
February	4	0	7	2	5	8	1
March	6	2	3	5	4	2	4
April	5	4	3	6	9	6	2
May	4	8	9	17	11	4	10
June	19	14	25	22	14	2	13
July	30	23	23	24	12	8	20
August	25	15	27	17	10	14	10
September	6	16	17	7	9	8	13
October	15	13	17	6	7	2	9
November	14	12	2	0	1	2	5
December	0	1	3	1	0	1	2
Grand Total	129	109	136	126	84	57	89

2. Data Collection Methodology

Data will be collected per PG&E's Fire Incident Data Collection Plan (Utility Standard/Procedure RISK-6306S/P). Results will be inclusive of unique HFTD CPUC-reportable ignitions attributable to the distribution asset class with overhead construction types.

The following ignition events captured by PG&E's Fire Incident Data Collection Plan will be excluded for this metric:

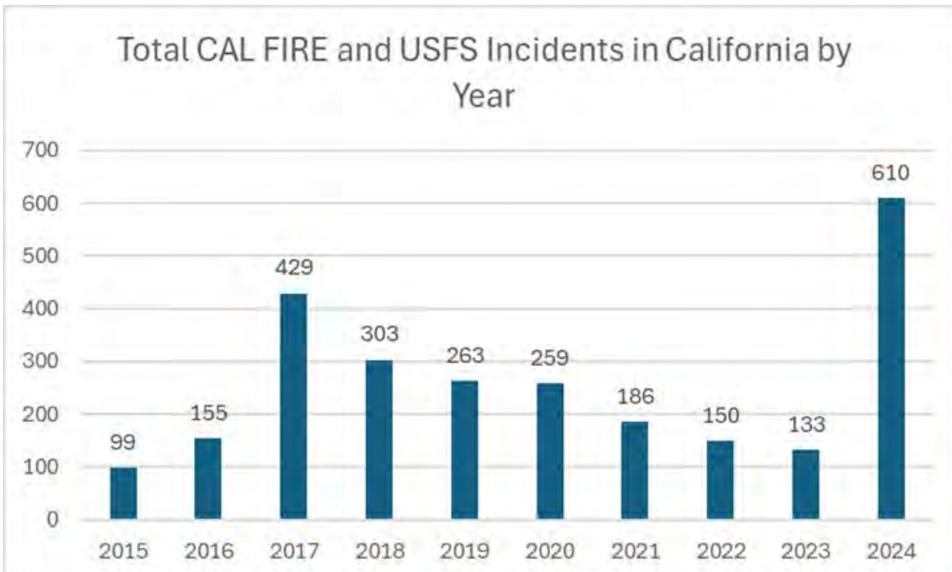
- Duplicate events;
- Ignitions that do not meet CPUC reporting criteria;
- Ignition events outside of Tier 2 and Tier 3 HFTD;
- Transmission ignitions; and
- Ignitions attributable to underground or pad-mounted assets as these are not associated overhead assets. (Ignitions caused by non-overhead assets in HFTD are rare and, as the fires are often contained to the asset, pose less of a wildfire risk.)

3. Metric Performance for the Reporting Period

PG&E finished 2024 with 89 CPUC reportable ignitions in HFTD attributable to overhead distribution assets. While these results were higher than the previous year (2023) (57 ignitions), the 89 ignitions in 2024 are consistent with the average number of ignitions for the previous three years (89 ignitions).

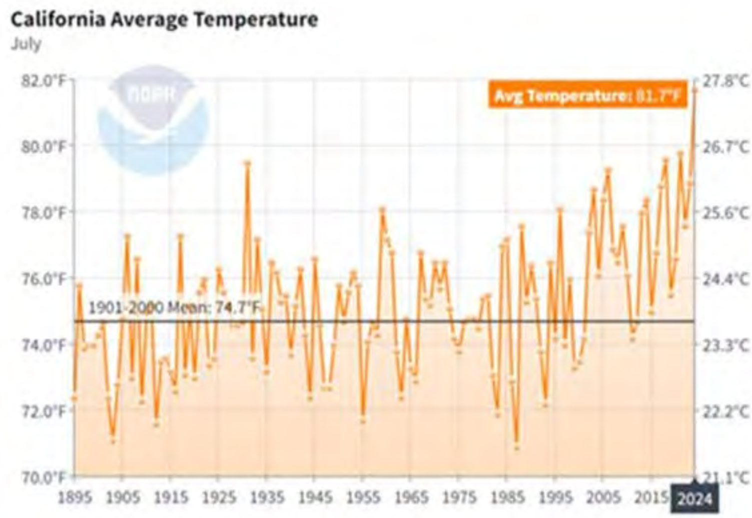
Most importantly, PG&E has observed 49 ignitions where the Fire Potential Index Rating (FPI) was in R3 or greater conditions. This number is higher than the 3-year previous average (44 ignitions). This is driven by a significantly more intense wildfire season in California in 2024; as evidenced by the total number of CAL FIRE and US Forest Service incidents (generally fires over 10 acres in size). These incidents reached 10-year highs in 2024 and represented a 300 percent increase over previous 3-year average (610 fires vs 156 fires). The figure below shows the total count of CAL FIRE and US Forest Service Incidents in California by year since 2015.

FIGURE 3.13-3
TOTAL CAL FIRE AND USFS INCIDENTS IN CALIFORNIA BY YEAR



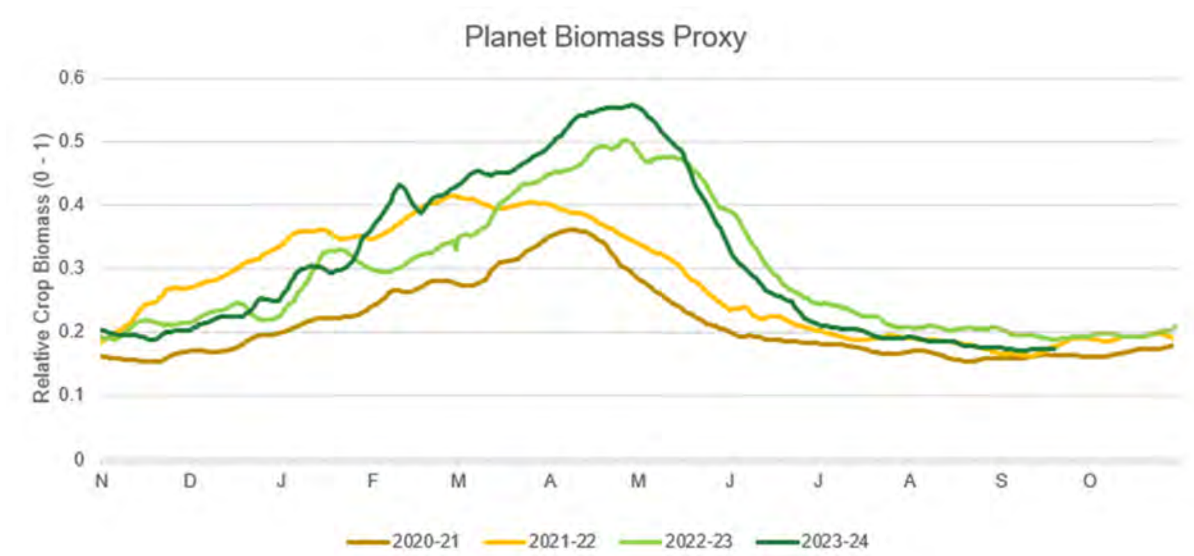
The historic 2024 fire season was driven by severe environmental conditions that were more susceptible to ignitions relative to prior years. In early July 2024, there were historically long-lasting high heat days across PG&E’s territory, leading to a two-week heat wave that has not been seen in the past five years. The average temperature in California in July was the hottest on record as shown in the below figure from National Oceanic and Atmospheric Administration (NOAA).

FIGURE 3.13-4
CALIFORNIA AVERAGE TEMPERATURE – NOAA



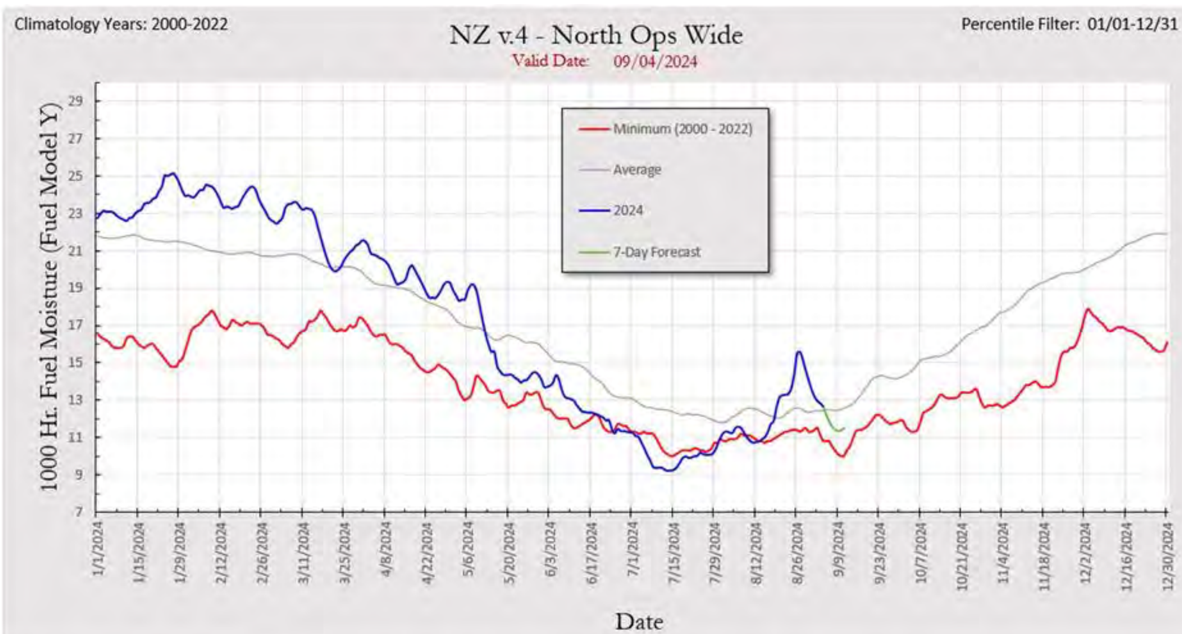
There was significant rainfall in the 2022-2023 and 2023-2024 rainfall seasons, leading to high vegetation growth that dried out during the hot and dry conditions in summer of 2024. The below figure shows greater values of crop biomass from March to May of this past season.

FIGURE 3.13-5
PLANT BIOMASS PROXY



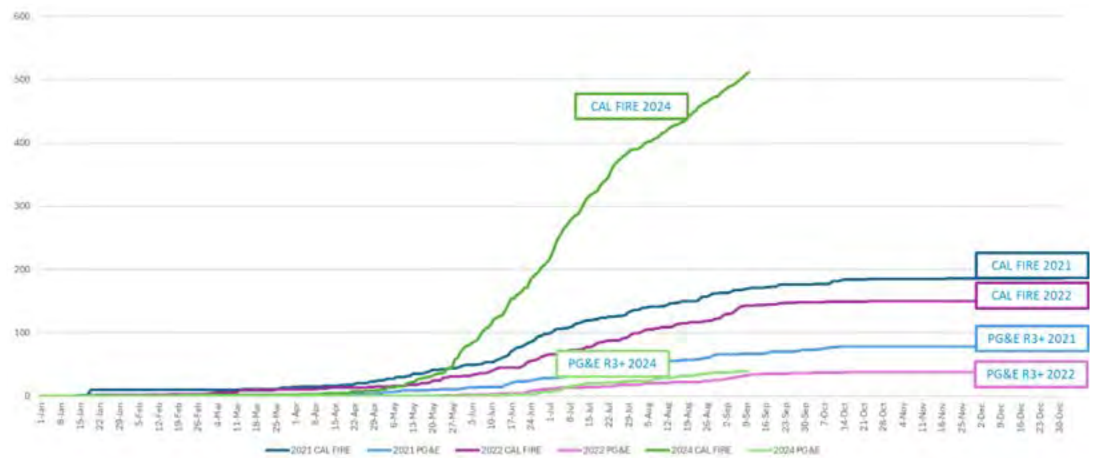
The fuels on the ground in July 2024 were unusually dry. The National Weather Service California North Ops showed a 22 year low for the 1,000-hour dead fuel moisture readings between July 1 and July 15, 2024 (seen below). This rapid increase in the dry fuel moisture within a week is the characteristic of “flash drought” (rapid onset of drought conditions due to combination of intense heat, low RH and lack of precipitation). This phenomenon accelerates the drying out of 1,000-hour dead fuel moisture, turning what would normally take months into just a matter of days.

FIGURE 3.13-6
2024 1,000 HOUR FUEL MOISTURES



While PG&E has seen an uptick in R3+ ignitions compared to 2022 and 2023 (though has seen fewer R3+ ignitions than 2021), California has experienced significantly more fires in 2024 than any prior year recorded by CAL FIRE. The below figure shows CAL FIRE Incident data from 2021, 2022, and 2024 compared to the count of PG&Es R3+ ignitions in HFTA/HFRA. On June 30, before 2024 heat wave, CAL FIRE had 225 percent more incidents than in 2022 and PG&E had 45 percent fewer incidents than in 2022. After the extreme heat wave, on July 15th, CAL FIRE had 309 percent more incidents than in 2022 and PG&E had 43 percent more incidents than in 2022.

FIGURE 3.13-7
CAL FIRE INCIDENTS VS PG&E REPORTABLE IGNITIONS IN R3 AND ABOVE



As a result of the increase in R3+ ignitions in July, PG&E established a task force to develop and execute a suite of mitigations designed to flatten the trend on future ignition events (see Current and Planned Work Activities Section below). Despite the fuel conditions remaining in historically dry conditions and the temperatures hot for the remainder of the fire season, we observed no major fires and believe these mitigations resulted in fewer ignitions for the remainer of the year (and flattened the curve). Please see the figure below with 2024 results in red.

FIGURE 3.13-8
CUMULATIVE REPORTABLE IGNITIONS IN HFTD ASSOCIATED WITH DISTRIBUTION OVERHEAD ASSETS BY YEAR WITH 2024 RESULTS IN RED

Please see the Target Methodology section for an overview of our Fire Potential Index (FPI) model and our strategy to focus operational mitigations, like Enhanced Powerline Safety Settings (EPSS), on reducing ignitions where consequences are more likely.

C. (3.13) 1-Year Target and 5-Year Target

1. Updates to 1- and 5-Year Targets Since Last Report

PG&E proposes to set the 2025 and 2029 upper and lower limit target ranges to account for the previous 5 years of actual results and variability driven by weather and external factors.

This new range will continue to challenge the organization to reduce ignitions of consequence while accounting for variability beyond PG&E's control. Ignition counts, occurring in consequential and non-consequential environmental conditions, are highly variable and subject to a variety of causes such as migratory bird patterns, red flag warning days, and contact from external parties.

PG&E remains focused on reducing those ignitions in R3+ conditions and, as future strategies with direct ignition impact emerge, these targets will be reevaluated.

2. Target Methodology

The two major programs that most directly impact ignition reduction in the near-term are PSPS and EPSS. Other important resiliency programs like undergrounding, system hardening, and vegetation management (VM) will have an impact as multiple years of cumulative work are completed.

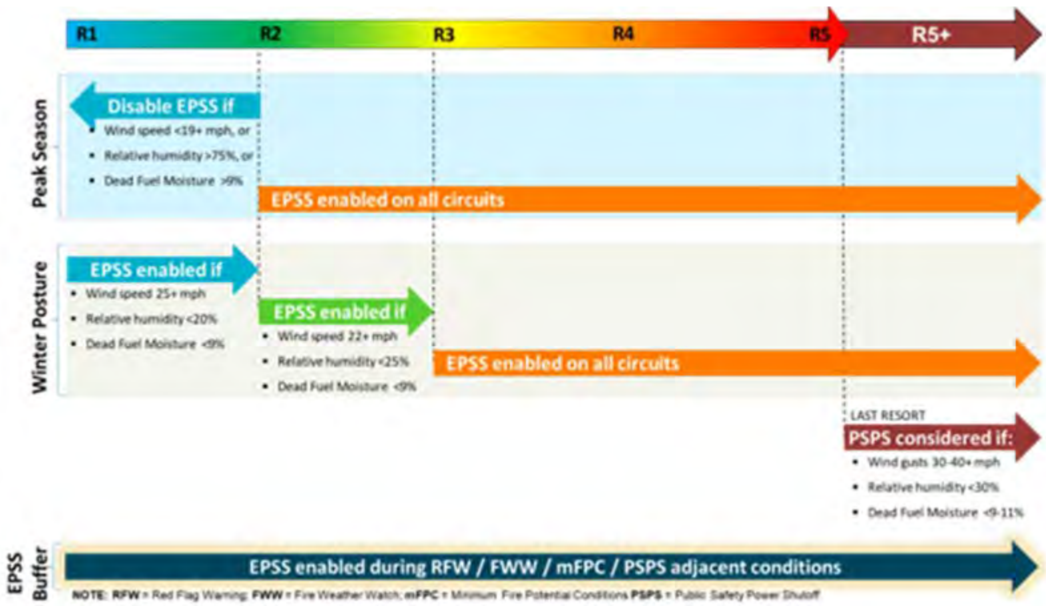
PG&E has observed success with EPSS in terms of mitigating ignitions in R3+ Fire Potential Index (FPI) conditions. These ignitions in R3+ conditions represent all historical reportable ignitions resulting in a fatality, all ignitions over 100 acres in size, and 99 percent of reportable ignitions where a structure was destroyed. See Figure 3.13-4 for fire statistics by FPI rating.

FIGURE 3.13-9
2018-2020 HFTD OVERHEAD REPORTABLE IGNITION STATISTICS BY FPI, ALL ASSET CLASSES

	R2+	R3+
% of Total Reportable Ignitions in HFTD	84%	60%
% of Wildfires >10 Acres	81%	71%
% of Wildfires >100 Acres	100%	100%
% of Total Structures Destroyed	100%	99%
% of Total Fatalities	100%	100%

In 2022, PG&E enabled EPSS technology on over 1,000 circuits, protecting approximately 44,000 overhead distribution miles in our service territory, including all distribution milage within HFTD. We also refined when to enable this tool to mitigate fires of consequence by targeting the right meteorological conditions. When a circuit is forecasted to be in FPI conditions at a specific threshold based on peak season or winter posture, EPSS is enabled on protective devices. See Figure 3.13-5 for details on this enablement criteria.

FIGURE 3.13-10
EPSS ENABLEMENT CRITERIA BASED ON FIRE POTENTIAL INDEX AND SEASON POSTURE



In 2023, PG&E expanded on the capabilities of this program to reduce ignitions where and when they matter by layering additional system protection strategies to complement the capabilities of EPSS, including installing a Downed Conductor Detection (DCD) algorithm on recloser controllers.

In 2024, PG&E established taskforce to identify immediate actions to mitigate in light of the rising exposure (that manifested into increased ignition counts) and perform a cause evaluation to identify the root and contributing causes to an increase in ignitions throughout the year.

PG&E expects continued success with the EPSS program to reduce ignitions of consequence in 2025 and is actively exploring additional layers of protection through technology deployment to further reduce risk (please see Current and Planned Work Activities).

However, ignition counts (in both low and potentially high consequence environments) are dependent on weather conditions and are highly variable. As a result, PG&E forecasts a range of 70 to 128 reportable ignitions to account for variability.

To establish the 1-year and 5-year targets, PG&E considered the following factors:

- Historical Data and Trends: PG&E has layered significant wildfire mitigation strategies over the past 8 years (like EPSS) and, outside of PG&E's own ignition record, there is no comparable historical data to help guide in target setting. PG&E is utilizing the previous 5-years worth of ignition actuals (2020 – 2024) to propose 2025 and 2029 target setting.
- Benchmarking: PG&E benchmarks extensively with other utilities in terms of wildfire risk and ignition reduction. Specifically, PG&E reviews utility ignition trends (where available) and analyzes the risk associated large utility wildfires around the world;
- Regulatory Requirements: D.14-02-015;
- Attainable Within Known Resources/Work Plan: Yes;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: The targets for this metric are suitable for EOE as they consider the potential for an increase in severe weather events due to climate change; and
- Other Qualitative Considerations: The target range takes consideration for some variability in weather.

3. 2025 Target

The 2024 target is 70-128 ignitions. The upper end of this range represents the 5-year previous average (99 ignitions) with an additional full standard deviation (29 ignitions) for those same years to account for variability. The lower end of this range represents a full standard deviation reduction to that same average.

4. 2029 Target

The 2029 target is 70-128 ignitions. The upper end of this range represents the 5-year previous average (99 ignitions) with an additional full standard deviation (29 ignitions) for those same years to account for variability. The lower end of this range represents a full standard deviation reduction to that same average. Additional time and maturity of PG&E's wildfire mitigations strategies will allow PG&E to reduce ignitions in R3+ conditions and forecast the effectiveness of the EPSS program to help inform long-term target ranges.

D. (3.13) Performance Against Target

1. Progress Towards the 1-Year Target

As demonstrated in Figure 3.13-6 below, PG&E ended 2024 with 89 ignitions. This exceeded our 2024 target of 84 ignitions.

2. Progress Towards the 5-Year Target

As discussed above, PG&E proposes different targets for the 2029 5-year goal (see above). Outlined in Section E below, PG&E continues to deploy several programs outside of the EPSS program designed to improve the long-term performance of ignitions in R3+ conditions (where and when they matter) and further our goals of ending catastrophic wildfires associated with utility assets.

FIGURE 3.13-11
HISTORICAL PERFORMANCE (2015-2024) AND TARGETS (2024, 2025, AND 2029)

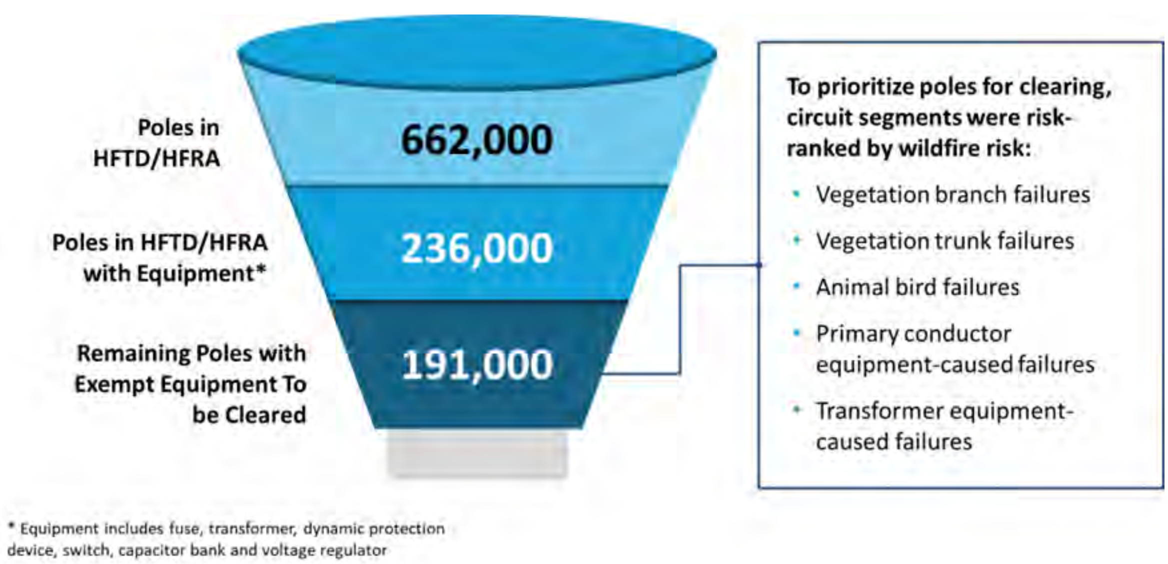
E. (3.13) Current and Planned Work Activities

PG&E can expect to see improved performance on this metric through continual execution of the Wildfire Mitigation Plan (WMP) and maturation of key wildfire mitigation strategies, including:

- <u>R3+ Task Force</u>: On July 11, 2024, we initiated the R3+ Task Force Taskforce to identify immediate actions to mitigate the rising ignition trend seen during an early July heat wave. Mitigations implemented for overhead distribution included pole clearing, expulsion fuse replacement, expedited completion of infrared tags and bird nest clearing tags, installation of Gridscope devices, and addition of AI-enabled wildfire cameras.

  Pole clearing involves identifying and removing flammable material, brush, limbs, and foliage around electric poles and towers. As part of California Public Resources Code § 4292, we clear a 10-foot radius of vegetation around approximately 78,000 poles. As almost half of reportable ignitions in HFTD or HFRA in 2023 and 2024 originated within approximately 10 feet of the base of a pole, pole clearing was identified as a mitigation with significant potential to reduce the risk of ignitions starting at the base of the pole. An additional set of approximately 50,000 distribution poles with overhead equipment were cleared as part of the Task Force, prioritized using the funnel shown in the below figure.

FIGURE 3.13-12
R3+ PROACTIVE POLE CLEARING PRIORITIZATION



  SMU expulsion Fuses (e-Fuses) have been observed to fail catastrophically. In some cases, the failure can cause an ignition. The primary mitigation for these e-Fuses is vegetation clearing at the base of the pole. However, the Task Force recommended replacing roughly 2,500 e-Fuses at 1,000 poles that could not easily be cleared of vegetation at the base of the pole.

Infrared tags result from a test that scans the distribution system looking for bad connections or equipment using infrared imaging. The Task Force recommended expediting the completion of 84 open infrared tags in HFTD and HFRA to resolve any identified faulty equipment prior to the remainder of the wildfire season.

Due to the observed increase in bird contact-related ignitions in July 2024, the Task Force recommended expediting 70 open bird nest tags on the distribution system to clear known bird's nests in HFTD or HFRA.

The Task Force performed a review of EPSS ignition rates over the 2022, 2023, and the partial 2024 wildfire seasons based on delay times. The Task Force observed higher rates of outages becoming ignitions for delay times greater than 60ms and recommended additional investigation into shorter EPSS device delay times during periods of elevated ignition likelihood. Three circuits with devices with delay times greater than 60ms were selected to implement delay times on the circuits that were less than 60ms. This pilot is continuing in 2025 and may be expanded to additional circuits if successful.

Gridscope devices are pole-mounted sensors designed to detect fault conditions such as line breaks, pole tilt, wire-to-wire contact, or arcing. In addition, Gridscope can enable improved fault localization and identification to dispatch troubleshooters to the location of a fault rather than requiring them to patrol an entire circuit. Gridscope was piloted on a variety of EPSS-enabled circuit segments across the service territory prior to the initiation of the Task Force. Subsequently, the Task Force recommended additional Gridscope installations for a second set of circuit segments on four-wire circuits where traditional Downed Conductor Detection is not effective and other circuit segments with elevated wildfire risk based on vegetation contact, conductor failure, and bird contact. To date, we have approximately 10,000 Gridscope devices installed throughout the system. In 2025, we are developing additional processes and procedures to enable integration with other sensors and dispatch tools that we currently use.

AI-enabled wildfire cameras can detect a wildfire and alert local agencies, which leads to quicker response and wildfire containment. The company reviewed the current viewshed across the service territory and developed a list of locations where the viewshed could be improved with the installation of additional wildfire cameras. To date, we have 643 wildfire cameras that cover the viewshed of over 90 percent of our territory. An additional 69 cameras are planned for installation in 2025.

- Maturation of the EPSS Program: In July 2021, to address this dynamic climate challenge, we implemented the EPSS Program on approximately 11,500 miles of distribution circuits, or 45 percent of the circuits in HFTD areas. With EPSS, we engineered changes to our electrical equipment settings so that if an object such as vegetation contacts a distribution line, power is automatically shut off within 1/10th of a second, reducing the potential for an ignition. EPSS enabled settings provide a layer of protection on days when the wind speeds are low. EPSS is especially important during hot dry summer days, when there are low winds. Continued low relative humidity, low fuel moistures levels, and areas where the volume of dry vegetation is in close proximity to the distribution lines, increases the risk of an ignition becoming a large wildfire.

In 2022, we expanded the EPSS scope to all primary distribution conductor in High Fire Risk Area (HFRA) areas in our service territory, as well as select non HFRA areas. In concert with this expansion of the program, PG&E modified enablement criteria (improving risk reduction and reliability).

In 2023, PG&E implemented a DCD algorithm on recloser controllers to mitigate risk of low current fault conditions, also referred to as high-impedance faults.

In 2024, PG&E matured high-impedance fault protection by adjusting Sensitive Ground Fault relay settings and piloting new technology to add DCD-like protection to the small number of circuit miles where we are not capable of implementing DCD.

Please see Section 8.1.8.1.1, Protective Equipment and Device Settings in PG&E's 2023-2025 WMP for additional details.

- Public Safety Power Shut Off (PSPS): PSPS is a wildfire mitigation strategy, first implemented in 2019, to reduce powerline ignitions during severe weather by proactively de-energizing powerlines (remove the risk of those powerlines causing an ignition) prior to forecasted wind events when humidity levels and fuel conditions are conducive to wildfires. PG&E's focus with the PSPS Program is to mitigate the risks associated with a catastrophic wildfire and to prioritize customer safety. In 2021, PG&E continued to make progress to its PSPS Program to mitigate wildfire risk, including updating meteorology models and scoping processes. In 2023, PG&E continued a multi-rear effort to install additional distribution sectionalizing devices, Fixed Power Solutions, and other mitigations targeted at reducing the risk of wildfire. In 2024, we updated our thresholds utilizing new and improved risk models.

  Please see Section 9, PSPS, Including Directional Vision For PSPS in PG&E's 2023-2025 WMP for additional details.

- Grid Design and System Hardening: PG&E's broader grid design program covers several significant programs to reduce ignition risk, called out in detail in PG&E's 2023 WMP. The largest of these programs is the System Hardening Program which focuses on the mitigation of potential catastrophic wildfire risk caused by distribution overhead assets. In 2023, we rapidly expanded our system hardening efforts by:
  - Completing 420 circuit miles of system hardening work which includes overhead system hardening, undergrounding and removal of overhead lines in HFTD or buffer zone areas;
  - Completing at least 350 circuit miles of undergrounding work, including Butte County Rebuild efforts and other distribution system hardening work; and
  - In 2024, PG&E completed ~250 miles of undergrounding.

  As we look to 2025, PG&E is targeting 350 miles of undergrounding to be completed in 2025 as part of the 10,000 Mile Undergrounding Program. This system hardening work done at scale is expected to have a material impact on ignition reduction.

  Please see Section 8.1.2, Grid Design and System Hardening Mitigations in PG&E's 2023-2025 WMP for additional details.

- VM: We restructured our VM Program based on a risk-informed approach. Recent data and analysis demonstrate that the Enhanced Vegetation Management (EVM) Program risk reduction is less than EPSS and additional Operational Mitigations. As a result, we transitioned the EVM Program to three new risk-informed VM programs.
  - Focused Tree Inspections: We developed specific areas of focus (referred to as Areas of Concern), primarily in the HFRA, where we will concentrate our efforts to inspect and address high-risk locations, such as those that have experienced higher volumes of vegetation damage during PSPS events, outages, and/or ignitions.
  - VM for Operational Mitigations: This program is intended to help reduce outages and potential ignitions using a risk informed, targeted plan to mitigate potential vegetation contacts based on historic vegetation caused outages on EPSS-enabled circuits. We will initially focus on mitigating potential vegetation contacts in circuit protection zones that have experienced vegetation caused outages. Scope of work will be developed by using EPSS and historical outage data and vegetation failure from the Wildfire Distribution Risk Model v3 risk model. EPSS-enabled devices vegetation outages extent of condition inspections may generate additional tree work.
  - Tree Removal Inventory: This is a long-term program intended to systematically work down trees that were previously identified through EVM inspections. We will develop annual risk-ranked work plans and mitigate the highest risk-ranked areas first and will continue monitor the condition of these trees through our established inspection programs.

Please see Section 8.2.2, Vegetation Management and Inspections in PG&E’s 2023–2025 WMP for additional details.

PACIFIC GAS AND ELECTRIC COMPANY

SAFETY AND OPERATIONAL METRICS REPORT:

CHAPTER 3.14

PERCENTAGE OF CPUC-REPORTABLE IGNITIONS IN HFTD AREAS

(DISTRIBUTION)

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 3.14
PERCENTAGE OF CPUC-REPORTABLE IGNITIONS IN
HFTD AREAS
(DISTRIBUTION)

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PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 3.14
PERCENTAGE OF CPUC-REPORTABLE IGNITIONS IN HFTD AREAS (DISTRIBUTION)

The material updates to this chapter, since the September 30, 2024 report, are identified in blue font.

A. (3.14) Overview

1. Metric Definition

Safety and Operational Metrics (SOM) 3.14 – The number of California Public Utilities Commission (CPUC) Reportable Ignitions in High Fire Threat Districts (HFTD) areas (Distribution) is defined as:

The number of CPUC-reportable ignitions involving overhead (OH) distribution circuits in HFTD areas divided by circuit miles of OH distribution lines in HFTD multiplied by 1000 miles (ignitions per 1000 HFTD circuit miles).

A CPUC-Reportable Ignition refers to a fire incident where the following three criteria are met: (1) Ignition is associated with PG&E electrical assets, (2) something other than PG&E facilities burned, and (3) the resulting fire travelled more than one linear meter from the ignition point.[1]

For this SOM, reporting is specific to Tier 2 and Tier 3 HFTDs.

PG&E provides the CPUC with annual ignition data in the Fire Incident Data Collection Plan, to the Office of Energy Infrastructure and Safety quarterly via quarterly geographic information system, data reporting, in quarterly Wildfire Mitigation Plan updates, and the Safety Performance Metrics Report.

2. Introduction of Metric

The number of CPUC-reportable Ignitions in HFTDs, normalized by circuit mileage, provides one way to gauge the level of wildfire risk that customers and communities are exposed to from OH distribution assets.

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1 Please CPUC Decision (D.) 14-02-015, issued February 5, 2014, for additional details.

PG&E's objective is to reduce the number of CPUC reportable ignitions that may trigger a catastrophic wildfire.

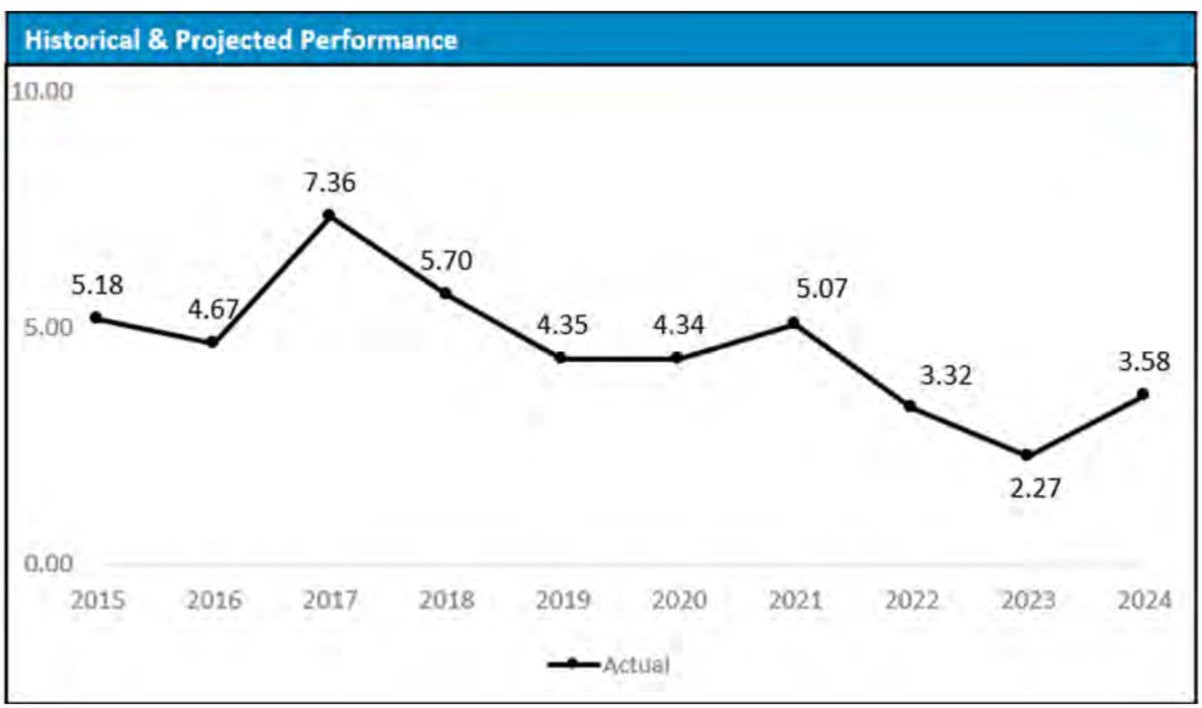
B. (3.14) Metric Performance

1. Historical Data (2015– 2024)

PG&E implemented the Fire Incident Data Collection Plan, in response to D.14-02-015, in June 2014 and our record, the Ignitions Tracker, includes all CPUC-reportable ignitions from June 2014 to present. The 2014 data does not represent a complete year and is excluded in this analysis.

PG&E's OH distribution circuits traverse approximately 25,000 miles of terrain in the HFTD areas where the OH conductor is primarily bare wire, supported by structures consisting of poles, cross arms, associated insulators, and operating equipment such as transformer, fuses and reclosers. Given the volume of equipment within the 25,000 miles of HFTD, the annual number of CPUC-reportable ignitions is too low to detect any statistical pattern.

FIGURE 3.14-1
HISTORICAL PERFORMANCE (2015 – 2024)



2. Data Collection Methodology

Data will be collected per PG&E's Fire Incident Data Collection Plan (Utility Standard/Procedure RISK-6306S/P). Results will be inclusive of unique HFTD CPUC-reportable ignitions attributable to the distribution asset class with OH construction types.

The following ignition events captured by PG&E's Fire Incident Data Collection Plan) will be excluded for this metric:

- Duplicate events;
- Ignitions that do not meet CPUC reporting criteria;
- Ignition events outside of Tier 2 and Tier 3 HFTD;
- Transmission Ignitions; and
- Ignitions attributable to underground or pad mounted assets as these are not associated OH assets. (Ignitions caused by non-OH assets in HFTD are rare and, as the fires are often contained to the asset, pose less of a wildfire risk.)

The circuit mileage utilized to calculate the 2015-2022 performance of this metric originates from PG&E's Electrical Asset Data Reports, refreshed December 2022. The 2023 – 2024 performance and targets are based on an updated sum of overhead circuit mileage, refreshed in 2023.

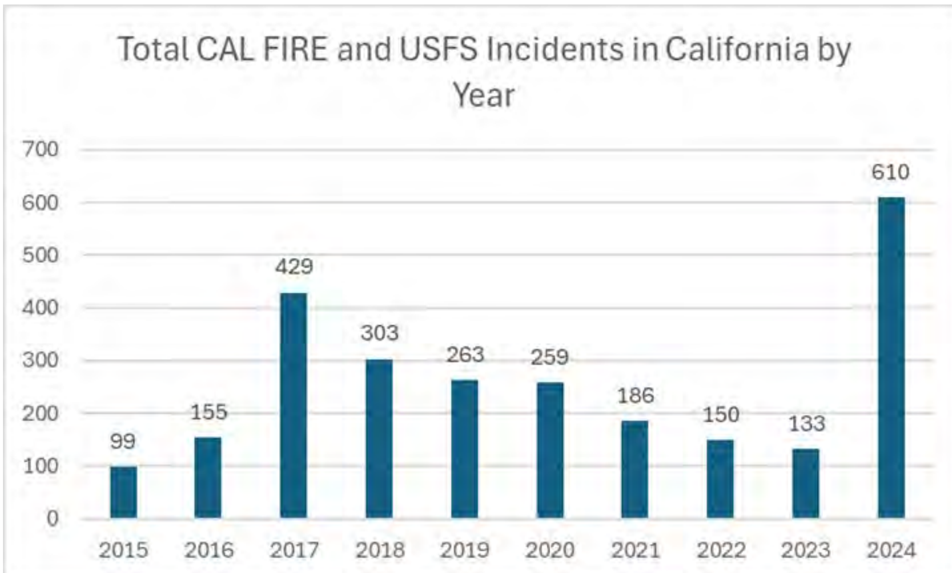
3. Metric Performance for the Reporting Period

PG&E finished 2024 with 89 CPUC reportable ignitions in HFTD attributable to overhead distribution assets (corresponding to a rate of 3.58 ignitions per 1,000 circuit miles). While these results were higher than the previous year (2023) (57 ignitions), the 89 ignitions in 2024 are consistent with the average number of ignitions for the previous three years (89 ignitions).

Most importantly, PG&E has observed 49 ignitions where the Fire Potential Index Rating (FPI) was in R3 or greater conditions. This number is higher than the 3-year previous average (44 ignitions). This is driven by a significantly more intense wildfire season in California in 2024; as evidenced by the total number of CAL FIRE and US Forest Service incidents (generally fires over 10 acres in size). These incidents reached 10-year highs in 2024 and represented a 300 percent increase over previous 3-year averages

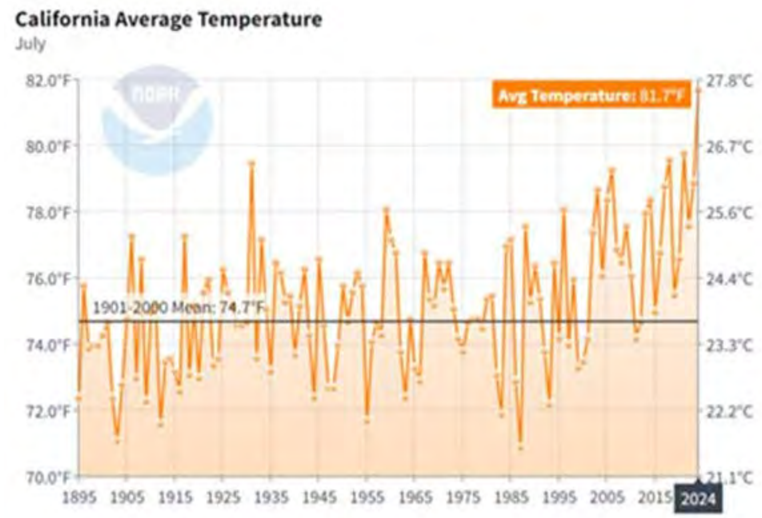
(610 fires vs 156 fires). The figure below shows the total count of CAL FIRE and US Forest Service Incidents in California by year since 2015.

FIGURE 3.14-2
TOTAL CAL FIRE AND USFS INCIDENTS IN CALIFORNIA BY YEAR



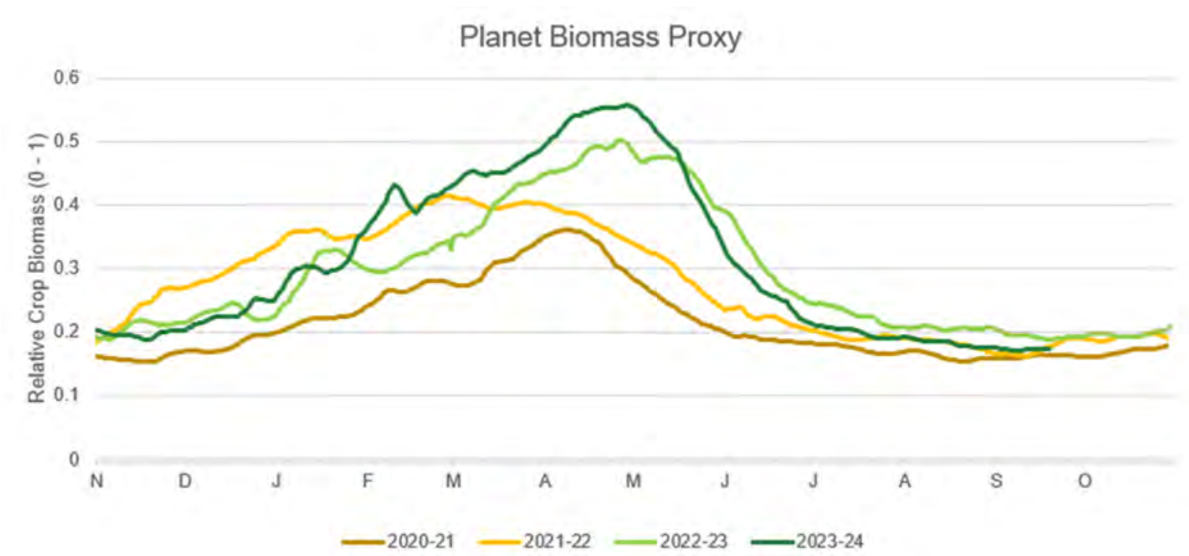
The historic 2024 fire season was driven by severe environmental conditions that were more susceptible to ignitions relative to prior years. In early July 2024, there were historically long-lasting high heat days across PG&E's territory, leading to a two-week heat wave that has not been seen in the past five years. The average temperature in California in July was the hottest on record as shown in the below figure from National Oceanic and Atmospheric Administration (NOAA).

FIGURE 3.14-3
CALIFORNIA AVERAGE TEMPERATURE – NOAA



There was significant rainfall in the 2022-2023 and 2023-2024 rainfall seasons, leading to high vegetation growth that dried out during the hot and dry conditions in summer of 2024. The below figure shows greater values of crop biomass from March to May of this past season.

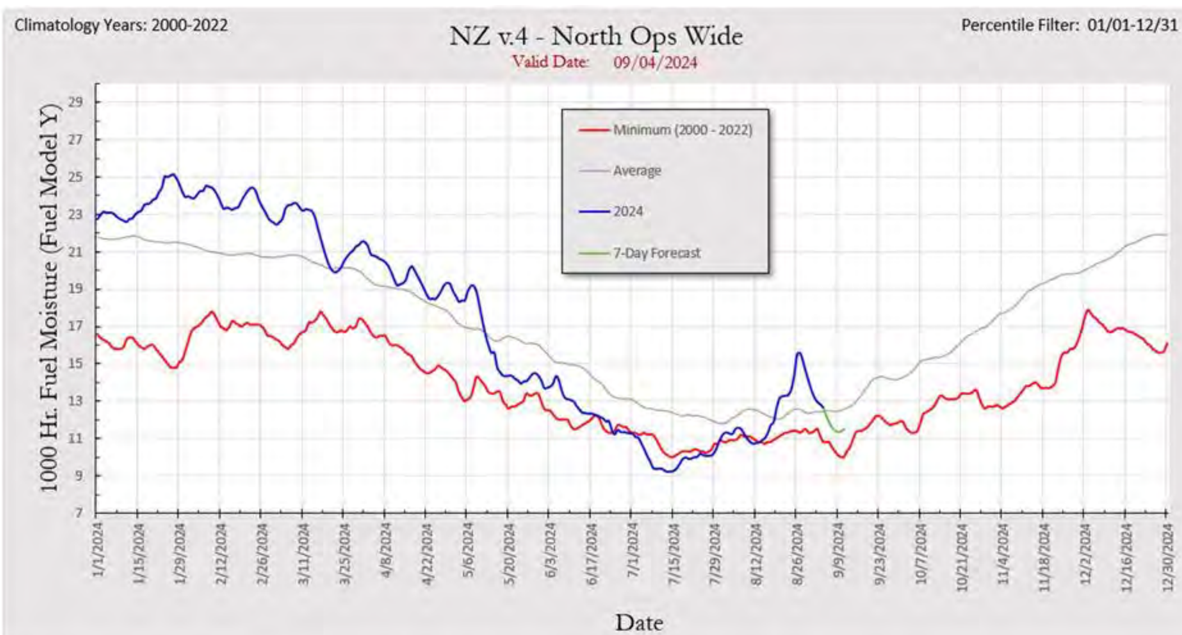
FIGURE 3.14-4
PLANT BIOMASS PROXY



The fuels on the ground in July 2024 were unusually dry. The National Weather Service California North Ops showed a 22 year low for the 1,000-hour dead fuel moisture readings between July 1 and July 15, 2024 (seen below).

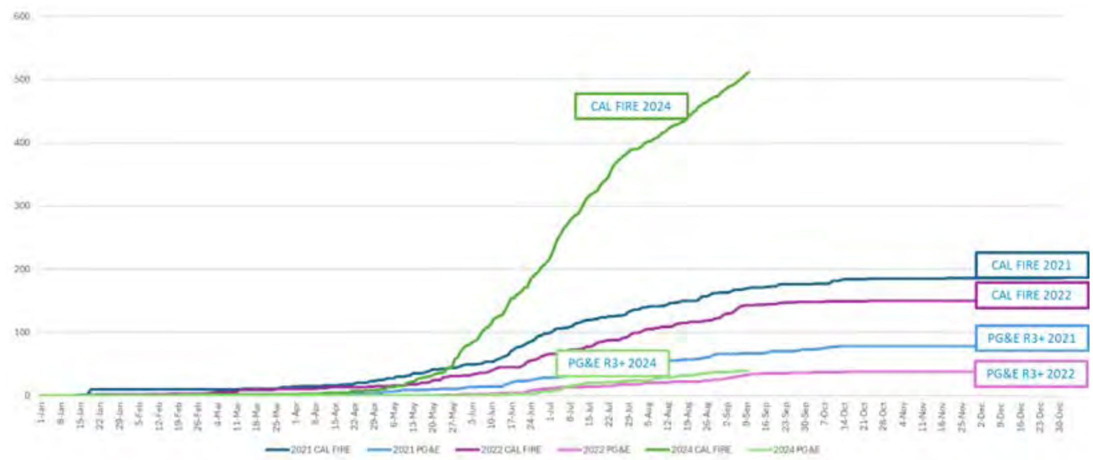
This rapid increase in the dry fuel moisture within a week could is the characteristic of “flash drought” (rapid onset of drought conditions due to combination of intense heat, low RH and lack of precipitation). This phenomenon accelerates the drying out of 1000 –hour dead fuel moisture, turning what would normally take months into just a matter of days.

FIGURE 3.14-5
2024 1,000 HOUR FUEL MOISTURES



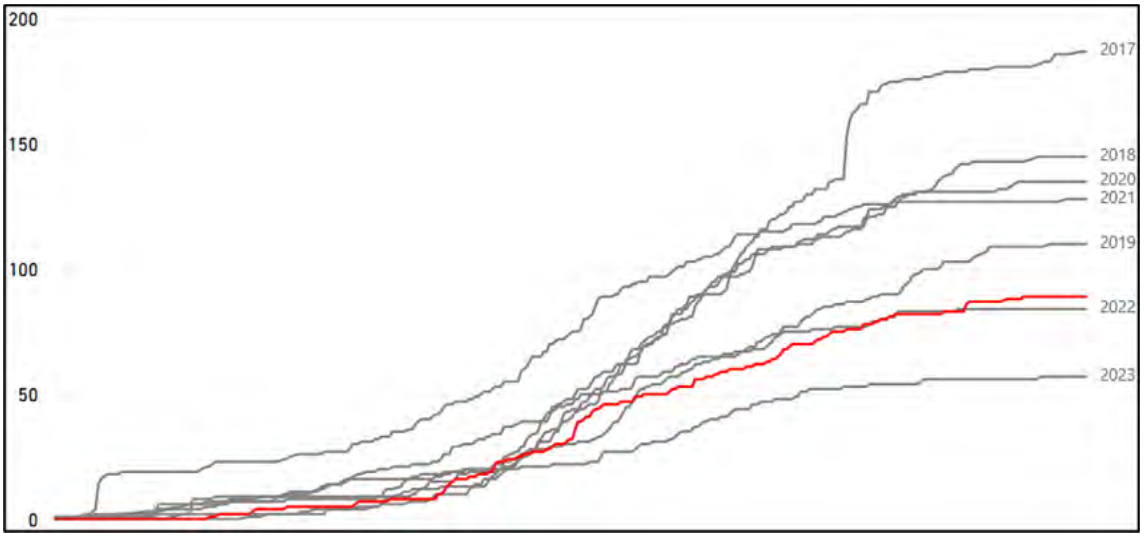
While PG&E has seen an uptick in R3+ ignitions compared to 2022 and 2023 (though has seen fewer R3+ ignitions than 2021), California has experienced significantly more fires of 2024 than any prior year recorded by CAL FIRE. The below figure shows CAL FIRE Incident data from 2021, 2022, and 2024 compared to the count of PG&Es R3+ ignitions in HFTA/HFRA. On June 30th, before 2024 heat wave, CAL FIRE had 225 percent more incidents than in 2022 and PG&E had 45 percent fewer incidents than in 2022. After the extreme heat wave, on July 15th, CAL FIRE had 309 percent more incidents than in 2022 and PG&E had 43% more incidents than in 2022.

FIGURE 3.14-6
CAL FIRE INCIDENTS VS PG&E REPORTABLE IGNITIONS IN R3 AND ABOVE



As a result of the increase in R3+ ignitions in July, PG&E established a task force to develop and execute a suite of mitigations designed to flatten the trend on future ignition events (see Current and Planned Work Activities Section below). Despite the fuel conditions remaining in historically dry conditions and the temperatures hot for the remainder of the fire season, we observed no major fires and believe these mitigations resulted in fewer ignitions for the remainer of the year and (and flattened the curve). Please see the figure below with 2024 results in red.

FIGURE 3.14-7
CUMULATIVE REPORTABLE IGNITIONS IN HFTD ASSOCIATED WITH DISTRIBUTION OVERHEAD ASSETS BY YEAR WITH 2024 RESULTS IN RED



Please see the Target Methodology section for an overview of our FPI model and our strategy to focus operational mitigations, like Enhanced Powerline Safety Settings (EPSS), on reducing ignitions where consequences are more likely.

C. (3.14) 1-Year Target and 5-Year Target

1. Updates to 1- and 5-Year Targets Since Last Report

PG&E proposes to set the 2025 and 2029 upper and lower limit target ranges to account for the previous 5 years of actual results and variability driven by weather and external factors.

This new range will continue to challenge the organization to reduce ignitions of consequence while accounting for variability beyond PG&E's control. Ignition counts, occurring in consequential and non-consequential environmental conditions, are highly variable and subject to a variety of causes such as migratory bird patterns, red flag warning days, and contact from external parties.

PG&E remains focused on reducing those ignitions in R3+ conditions and, as future strategies with direct ignition impact emerge, these targets will be reevaluated.

2. Target Methodology

The two major programs that most directly impact ignition reduction in the near-term are Public Safety Power Shut Off (PSPS) and EPSS. Other important resiliency programs like undergrounding, system hardening, and vegetation management will have an impact as multiple years of cumulative work are completed.

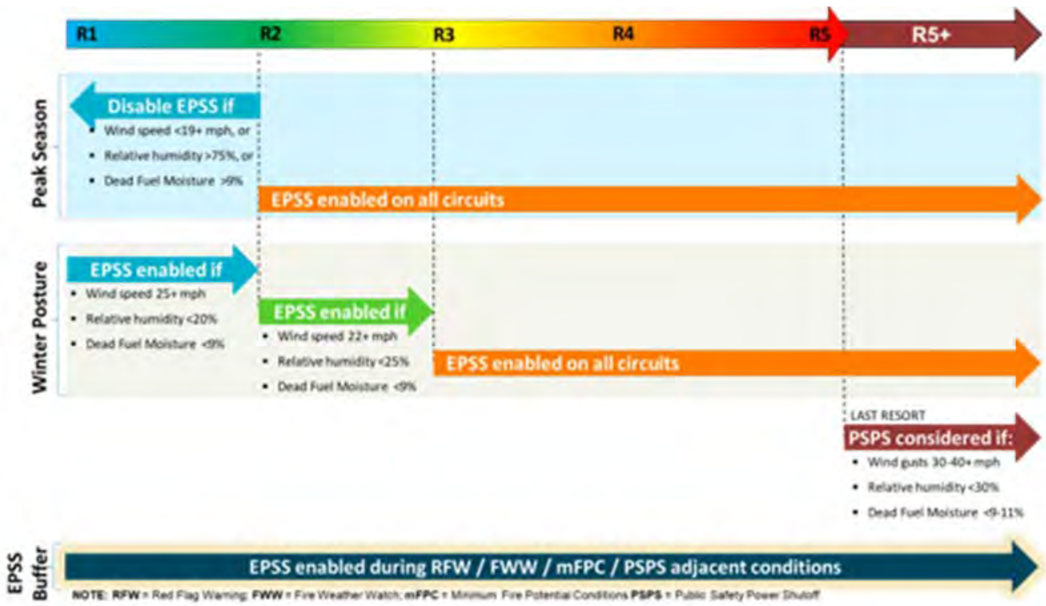
PG&E has observed success with EPSS in terms of mitigating ignitions in R3+ FPI conditions. These ignitions in R3+ conditions represent all historical reportable ignitions resulting in a fatality, all ignitions over 100 acres in size, and 99 percent of reportable ignitions where a structure was destroyed. See Figure 3.14-4 for fire statistics by FPI rating.

FIGURE 3.14-8
2018-2020 HFTD OVERHEAD REPORTABLE IGNITION STATISTICS BY FPI, ALL ASSET CLASSES

	R2+	R3+
% of Total Reportable Ignitions in HFTD	84%	60%
% of Wildfires >10 Acres	81%	71%
% of Wildfires >100 Acres	100%	100%
% of Total Structures Destroyed	100%	99%
% of Total Fatalities	100%	100%

In 2022, PG&E enabled EPSS technology on over 1,000 circuits, protecting approximately 44,000 overhead distribution miles in our service territory, including all distribution milage within HFTD. We also refined when to enable this tool to mitigate fires of consequence by targeting the right meteorological conditions. When a circuit is forecasted to be in FPI conditions at a specific threshold based on peak season or winter posture, EPSS is enabled on protective devices. See Figure 3.13-5 for details on this enablement criteria.

FIGURE 3.14-9
EPSS ENABLEMENT CRITERIA BASED ON FIRE POTENTIAL INDEX AND SEASON POSTURE



In 2023, PG&E expanded on the capabilities of this program to reduce ignitions where and when they matter by layering additional system protection strategies to complement the capabilities of EPSS, including installing a Downed Conductor Detection (DCD) algorithm on recloser controllers.

In 2024, PG&E established taskforce to identify immediate actions to mitigate in light of the rising exposure (that manifested into increased ignition counts) and perform a cause evaluation to identify the root and contributing causes to an increase in ignitions throughout the year.

PG&E expects continued success with the EPSS program to reduce ignitions of consequence in 2025 and is actively exploring additional layers of protection through technology deployment to further reduce risk (please see Current and Planned Work Activities).

However, ignition counts (in both low and potentially high consequence environments) are dependent on weather conditions and are highly variable. As a result, PG&E forecasts a range of 70 to 128 reportable ignitions to account for variability (corresponding to a rate of 2.83 – 5.18 ignitions per 1,000 circuit miles).

To establish the 1-year and 5-year targets, PG&E considered the following factors:

- Historical Data and Trends: PG&E has layered significant wildfire mitigation strategies over the past 8 years (like EPSS) and, outside of PG&E's own ignition record, there is no comparable historical data to help guide in target setting. PG&E is utilizing the previous 5-years worth of ignition actuals (2020 – 2024) to propose 2025 and 2029 target setting.
- Benchmarking: PG&E benchmarks extensively with other utilities in terms of wildfire risk and ignition reduction. Specifically, PG&E reviews utility ignition trends (where available) and analyzes the risk associated large utility wildfires around the world;
- Regulatory Requirements: D.14-02-015;
- Attainable Within Known Resources/Work Plan: Yes;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: The targets for this metric are suitable for EOE as they consider the potential for an increase in severe weather events due to climate change; and
- Other Qualitative Considerations: The target range takes consideration for some variability in weather.

3. 2025 Target

The 2025 target is 70-128 ignitions corresponding to a rate of 2.83 – 5.18 ignitions per 1,000 circuit miles). The upper end of this range represents the 5-year previous average (99 ignitions) with an additional full standard deviation (29 ignitions) for those same years to account for variability. The lower end of this range represents a full standard deviation reduction to that same average.

4. 2029 Target

The 2029 target is 70-128 ignitions corresponding to a rate of 2.83 – 5.18 ignitions per 1,000 circuit miles). The upper end of this range represents the 5-year previous average (99 ignitions) with an additional full standard deviation (29 ignitions) for those same years to account for variability. The lower end of this range represents a full standard deviation reduction to that same average. Additional time and maturity of PG&E's wildfire mitigations strategies will allow PG&E to reduce ignitions in R3+

conditions and forecast the effectiveness of the EPSS program to help inform long-term target ranges.

D. (3.14) Performance Against Target

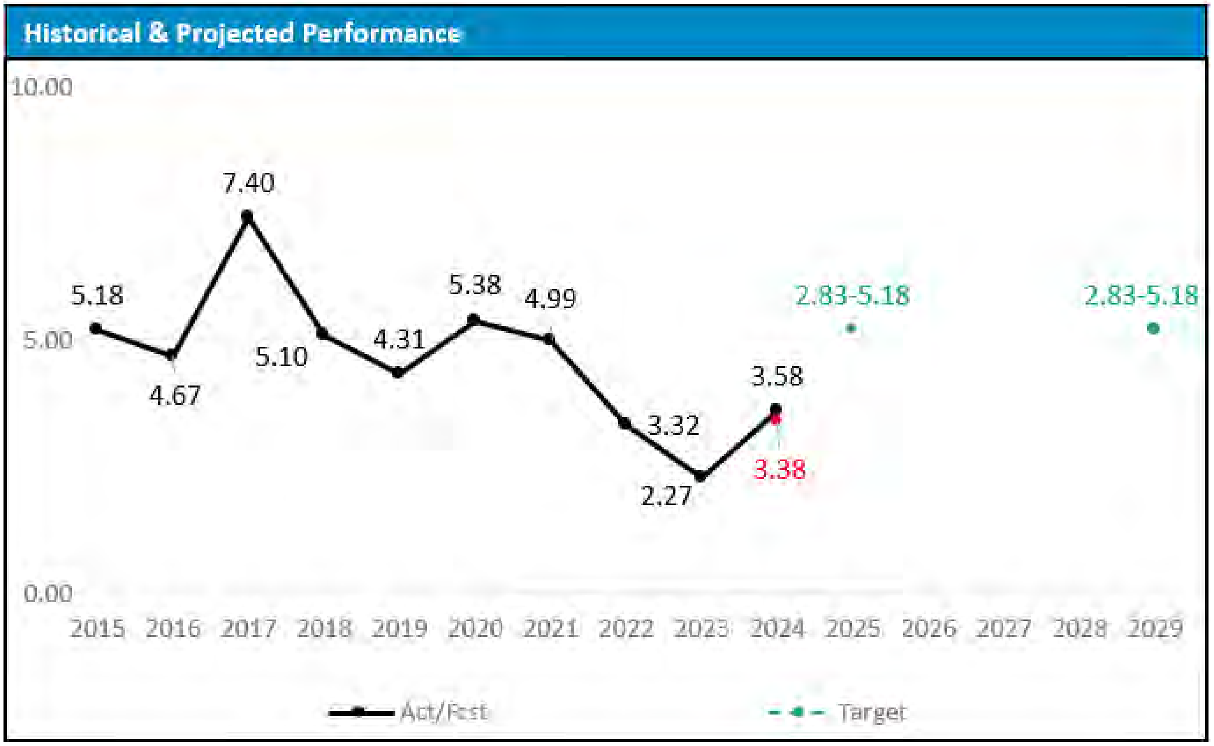
1. Progress Towards the 1-Year Target

As demonstrated in Figure 3.14-6 below, PG&E ended 2024 with 89 ignitions (corresponding to a rate of 3.58 ignitions per 1,000 circuit miles). This exceeded our 2024 target of 84 ignitions (corresponding to a rate of 3.38 ignitions per 1,000 circuit miles).

2. Progress Towards the 5-Year Target

As discussed above, PG&E proposes different targets for the 2029 5-year goal (see above). Outlined in Section E below, PG&E continues to deploy several programs outside of the EPSS program designed to improve the long-term performance of ignitions in R3+ conditions (where and when they matter) and further our goals of ending catastrophic wildfires associated with utility assets.

FIGURE 3.14-10
HISTORICAL PERFORMANCE (2015-2024) AND
TARGETS (2024, 2025 AND 2029)



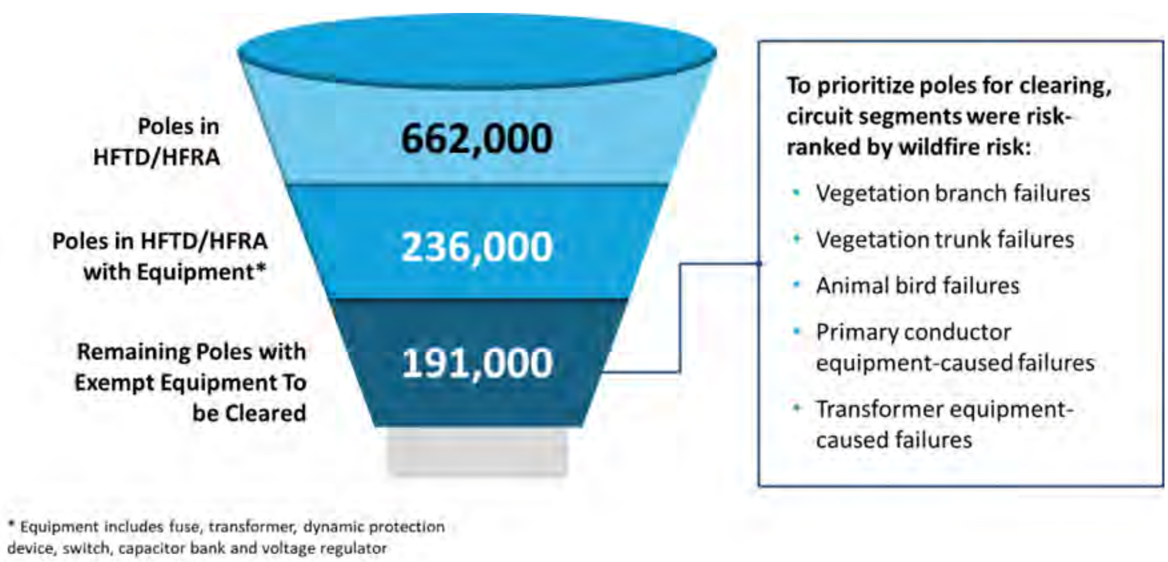
E. (3.14) Current and Planned Work Activities

PG&E can expect to see improved performance on this metric through continual execution of the Wildfire Mitigation Plan (WMP) and maturation of key wildfire mitigation strategies, including:

- R3+ Task Force: On July 11, 2024, we initiated the R3+ Taskforce to identify immediate actions to mitigate the rising ignition trend seen during an early July heat wave. Mitigations implemented for overhead distribution included pole clearing, expulsion fuse replacement, expedited completion of infrared tags and bird nest clearing tags, installation of Gridscope devices, and addition of AI-enabled wildfire cameras.

  Pole clearing involves identifying and removing flammable material, brush, limbs, and foliage around electric poles and towers. As part of California Public Resources Code § 4292, we clear a 10-foot radius of vegetation around approximately 78,000 poles. As almost half of reportable ignitions in HFTD or HFRA in 2023 and 2024 originated within approximately 10 feet of the base of a pole, pole clearing was identified as a mitigation with significant potential to reduce the risk of ignitions starting at the base of the pole. An additional set of approximately 50,000 distribution poles with overhead equipment were cleared as part of the Task Force, prioritized using the funnel shown in the below figure.

FIGURE 3.14-11
R3+ PROACTIVE POLE CLEARING PRIORITIZATION



SMU expulsion Fuses (e-Fuses) have been observed to fail catastrophically. In some cases, the failure can cause an ignition. The primary mitigation for these e-Fuses is vegetation clearing at the base of the pole. However, the Task Force recommended replacing roughly 2,500 e-Fuses at 1,000 poles that could not easily be cleared of vegetation at the base of the pole.

Infrared tags result from a test that scans the distribution system looking for bad connections or equipment using infrared imaging. The Task Force recommended expediting the completion of 84 open infrared tags in HFTD and HFRA to resolve any identified faulty equipment prior to the remainder of the wildfire season.

Due to the observed increase in bird contact-related ignitions in July 2024, the Task Force recommended expediting 70 open bird nest tags on the distribution system to clear known bird's nests in HFTD or HFRA.

The Task Force performed a review of EPSS ignition rates over the 2022, 2023, and the partial 2024 wildfire seasons based on delay times. The Task Force observed higher rates of outages becoming ignitions for delay times greater than 60ms and recommended additional investigation into shorter EPSS device delay times during periods of elevated ignition likelihood. Three circuits with devices with delay times greater than 60ms were selected to implement delay times on the circuits that were less than 60ms. This pilot is continuing in 2025 and may be expanded to additional circuits if successful.

Gridscope devices are pole-mounted sensors designed to detect fault conditions such as line breaks, pole tilt, wire-to-wire contact, or arcing. In addition, Gridscope can enable improved fault localization and identification to dispatch troubleshooters to the location of a fault rather than requiring them to patrol an entire circuit. Gridscope was piloted on a variety of EPSS-enabled circuit segments across the service territory prior to the initiation of the Task Force. Subsequently, the Task Force recommended additional Gridscope installations for a second set of circuit segments on four-wire circuits where traditional Downed Conductor Detection is not effective and other circuit segments with elevated wildfire risk based on vegetation contact, conductor failure, and bird contact. To date, we have approximately 10,000 Gridscope devices installed throughout the system. In 2025, we are developing additional processes and procedures to enable integration with other sensors and dispatch tools that we currently use.

AI-enabled wildfire cameras can detect a wildfire and alert local agencies, which leads to quicker response and wildfire containment. The company reviewed the current viewshed across the service territory and developed a list of locations where the viewshed could be improved with the installation of additional wildfire cameras. To date, we have 643 wildfire cameras that cover the viewshed of over 90 percent of our territory. An additional 69 cameras are planned for installation in 2025.

- <u>Maturation of the EPSS Program</u>: In July 2021, to address this dynamic climate challenge, we implemented the EPSS Program on approximately 11,500 miles of distribution circuits, or 45 percent of the circuits in HFTD areas. With EPSS, we engineered changes to our electrical equipment settings so that if an object such as vegetation contacts a distribution line, power is automatically shut off within 1/10th of a second, reducing the potential for an ignition. EPSS enabled settings provide a layer of protection on days when the wind speeds are low. EPSS is especially important during hot dry summer days when there are low winds. Continued low relative humidity, low fuel moistures levels, and areas where the volume of dry vegetation is in close proximity to the distribution lines, increases the risk of an ignition becoming a large wildfire.

In 2022, we expanded the EPSS scope to all primary distribution conductor in High Fire Risk Area (HFRA) areas in our service territory, as well as select non HFRA areas. In concert with this expansion of the program, PG&E modified enablement criteria (improving risk reduction and reliability).

In 2023, PG&E implemented a DCD algorithm on recloser controllers to mitigate risk of low current fault conditions, also referred to as high-impedance faults.

In 2024, PG&E matured high-impedance fault protection by adjusting Sensitive Ground Fault (SGF) relay settings and piloting new technology to add DCD-like protection to the small number of circuit miles where we are not capable of implementing DCD.

Please see Section 8.1.8.1.1, Protective Equipment and Device Settings in PG&E's 2023-2025 WMP for additional details.

- Public Safety Power Shut Off : PSPS is a wildfire mitigation strategy, first implemented in 2019, to reduce powerline ignitions during severe weather by proactively de-energizing powerlines (remove the risk of those powerlines causing an ignition) prior to forecasted wind events when humidity levels and fuel conditions are conducive to wildfires. PG&E's focus with the PSPS Program is to mitigate the risks associated with a catastrophic wildfire and to prioritize customer safety. In 2021, PG&E continued to make progress to its PSPS Program to mitigate wildfire risk, including updating meteorology models and scoping processes. In 2023, PG&E continued a multi-rear effort to install additional distribution sectionalizing devices, Fixed Power Solutions, and other mitigations targeted at reducing the risk of wildfire. In 2024, we updated our thresholds utilizing new and improved risk models.

Please see Section 9, PSPS, Including Directional Vision For PSPS in PG&E's 2023-2025 WMP for additional details.

- Grid Design and System Hardening: PG&E's broader grid design program covers several significant programs to reduce ignition risk, called out in detail in PG&E's 2023 WMP. The largest of these programs is the System Hardening Program which focuses on the mitigation of potential catastrophic wildfire risk caused by distribution overhead assets. In 2023, we rapidly expanded our system hardening efforts by:
  - Completing 420 circuit miles of system hardening work which includes overhead system hardening, undergrounding and removal of overhead lines in HFTD or buffer zone areas;
  - Completing at least 350 circuit miles of undergrounding work, including Butte County Rebuild efforts and other distribution system hardening work; and

In 2024, PG&E completed ~250 miles of undergrounding.

As we look to 2025, PG&E is targeting 350 miles of undergrounding to be completed in 2025 as part of the 10,000 Mile Undergrounding Program. This system hardening work done at scale is expected to have a material impact on ignition reduction.

Please see Section 8.1.2, Grid Design and System Hardening Mitigations in PG&E's 2023-2025 WMP for additional details.

- VM: We restructured our VM Program based on a risk-informed approach. Recent data and analysis demonstrate that the Enhanced Vegetation Management (EVM) Program risk reduction is less than EPSS and additional Operational Mitigations. As a result, we transitioned the EVM Program to three new risk-informed VM programs.
  - Focused Tree Inspections: We developed specific areas of focus (referred to as Areas of Concern), primarily in the HFRA, where we will concentrate our efforts to inspect and address high-risk locations, such as those that have experienced higher volumes of vegetation damage during PSPS events, outages, and/or ignitions.

- VM for Operational Mitigations: This program is intended to help reduce outages and potential ignitions using a risk informed, targeted plan to mitigate potential vegetation contacts based on historic vegetation caused outages on EPSS-enabled circuits. We will initially focus on mitigating potential vegetation contacts in circuit protection zones that have experienced vegetation caused outages. Scope of work will be developed by using EPSS and historical outage data and vegetation failure from the Wildfire Distribution Risk Model v3 risk model. EPSS-enabled devices vegetation outages extent of condition inspections may generate additional tree work.
- Tree Removal Inventory: This is a long-term program intended to systematically work down trees that were previously identified through EVM inspections. We will develop annual risk-ranked work plans and mitigate the highest risk-ranked areas first and will continue monitor the condition of these trees through our established inspection programs.

Please see Section 8.2.2, Vegetation Management, and Inspections in PG&E’s 2023–2025 WMP for additional details.

PACIFIC GAS AND ELECTRIC COMPANY

SAFETY AND OPERATIONAL METRICS REPORT:

CHAPTER 3.15

NUMBER OF CPUC-REPORTABLE IGNITIONS IN HFTD AREAS

(TRANSMISSION)

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
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NUMBER OF CPUC-REPORTABLE IGNITIONS IN HFTD AREAS (TRANSMISSION)

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NUMBER OF CPUC-REPORTABLE IGNITIONS IN HFTD AREAS (TRANSMISSION)

The material updates to this chapter, since the September 30th 2024 report, are identified in blue font.

A. (3.15) Overview

1. Metric Definition

Safety and Operational Metrics (SOM) 3.15 – Number of California Public Utilities Commission (CPUC)-Reportable Ignitions in High Fire Threat District (HFTD) areas (Transmission) is defined as:

Number of CPUC-reportable ignitions involving overhead transmission circuits in HFTD Areas.

A CPUC-Reportable Ignition refers to a fire incident where the following three criteria are met: (1) Ignition is associated with Pacific Gas and Electric Company (PG&E) electrical assets, (2) something other than PG&E facilities burned, and (3) the resulting fire travelled more than one linear meter from the ignition point.[1]

For this SOM, reporting is specific to Tier 2 and Tier 3 HFTDs.

PG&E provides the CPUC with annual ignition data in the Fire Incident Data Collection Plan, to the Office of Energy Infrastructure and Safety quarterly via quarterly geographic information system, data reporting, in quarterly Wildfire Mitigation Plan updates, and the Safety Performance Metrics Report.

2. Introduction of Metric

The number of CPUC-Reportable Ignitions in HFTDs provides one way to gauge the level of wildfire risk that customers and communities are exposed to from overhead transmission assets. PG&E's objective is to

[1] Please CPUC Decision (D.) 14-02-015, issued February 5, 2014 for additional details.

minimize the number of CPUC-Reportable ignitions in the right locations during the right conditions that may trigger a catastrophic wildfire.

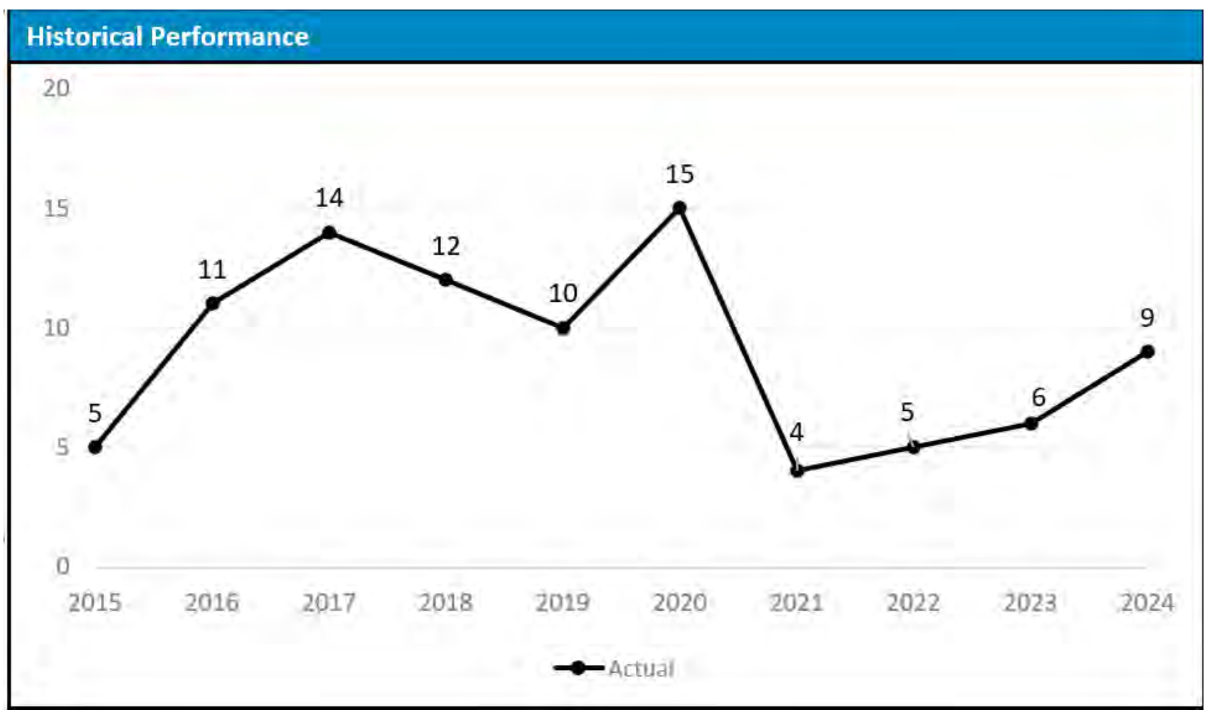
B. (3.15) Metric Performance

1. Historical Data (2015 – 2024)

PG&E implemented the Fire Incident Data Collection Plan, in response to D.14-02-015, in June 2014 and our record, the Ignitions Tracker, includes all CPUC-Reportable ignitions from June 2014 to present. The 2014 data does not represent a complete year and is excluded in this analysis.

PG&E's overhead transmission circuits traverse approximately 5,400 miles of terrain in the HFTD areas where the overhead conductor is primarily bare wire, supported by structures consisting of poles and towers. The annual number of CPUC-Reportable ignitions is too low to detect any statistical pattern.

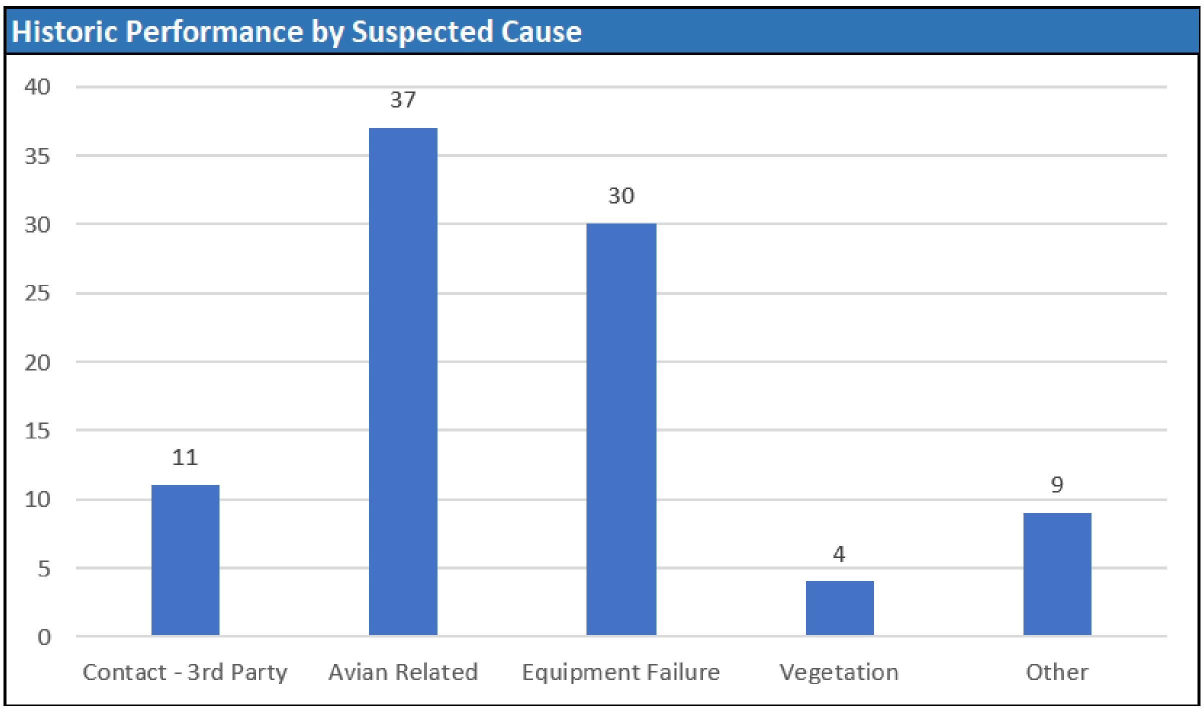
FIGURE 3.15-1
HISTORICAL PERFORMANCE (2015 – 2024)



Note: As part of a Risk Assessment Improvement Plan item in PG&E's 2023 – 2015 WMP, PG&E reviewed historic ignitions data and reattributed certain historical events, resulting in slight changes in the count of ignitions in scope for this metric for historical years (some years increased while others decreased). In general, ignition counts represent a snapshot in time and are subject to change based on new data.

The main causes of CPUC-Reportable ignitions have been collected and classified. These fall into five broad categories: third-party contact, animal contact, equipment failure, vegetation contact, and other causes. The counts for 2015 through 2024 are shown in the graph below (Figure 3.15-2).

FIGURE 3.15-2
HISTORIC (2015 – 2024) PERFORMANCE BY SUSPECTED CAUSE



2. Data Collection Methodology

Data will be collected per PG&E's Fire Incident Data Collection Plan (Utility Standard/Procedure RISK-6306S/P). Results will be inclusive of unique HFTD CPUC-Reportable ignitions attributable to the transmission asset class with overhead construction types.

The following ignition events captured by PG&E's Fire Incident Data Collection Plan (Utility Standard/Procedure RISK-6306S/P) will be excluded for this metric:

Duplicate events;

- Ignitions that do not meet CPUC reporting criteria;
- Ignition events outside of Tier 2 and Tier 3 HFTD;
- Distribution Ignitions; and

- Ignitions attributable to underground or pad mounted assets as these are not overhead assets. Ignitions caused by non-overhead assets in HFTD are rare and, as the fires are often contained to the asset, pose less of a wildfire risk.

3. Metric Performance for the Reporting Period

Historically, reportable transmission ignitions in HFTD are low in volume with variability year-to-year, which complicates the detection of significant trends. PG&E observed nine CPUC-reportable ignitions on overhead transmission assets through 2024; one caused by bird guano on an insulator (contamination), one where the cause is unknown but suspected to have been avian related, five caused by confirmed bird contact, and two equipment failures.

C. (3.15) 1-Year Target and 5-Year Target

1. Updates to 1- and 5-Year Targets Since Last Report

PG&E proposes to set the 2025 and 2029 upper limit of the target range to account for the previous 5 years of actual results and variability driven by weather, and external factors like seasonal bird migration.

2. Target Methodology

To establish the 1-Year and 5-Year targets, PG&E considered the following factors:

- Historical Data and Trends: PG&E has layered significant wildfire mitigation strategies over the past 8 years and, outside of PG&E's own ignition record, to help guide in target setting. PG&E is utilizing the previous 5-years worth of ignition actuals (2020 – 2024) to propose 2025 and 2029 target setting.
- Benchmarking: PG&E benchmarks extensively with other utilities in terms of wildfire risk and ignition reduction. Specifically, PG&E reviews utility ignition trends (where available) and analyzes the risk associated large utility wildfires around the world;
- Regulatory Requirements: CPUC D.14-02-015;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: The targets for this metric are suitable for EOE as they

consider the potential for an increase in severe weather events due to climate change; and

- Other Qualitative Considerations: The target range takes consideration for some variability in weather.

3. 2025 Target

PG&E's target for 2025 is 4-12. The upper and bottom ends of this range represents the 5-year previous average (8 ignitions) subtracting/adding a full standard deviation (4 ignitions) for those same years to account for variability.

4. 2029 Target

PG&E's target for 2029 is 4-12. The upper and bottom ends of this range represents the 5-year previous average (8 ignitions) subtracting/adding a full standard deviation (4 ignitions) for those same years to account for variability. The upper end of the range is 12 in 2025 and 2029 because the volume of transmission ignitions is low, while variability year-to-year remains high.

D. (3.15) Performance Against Target

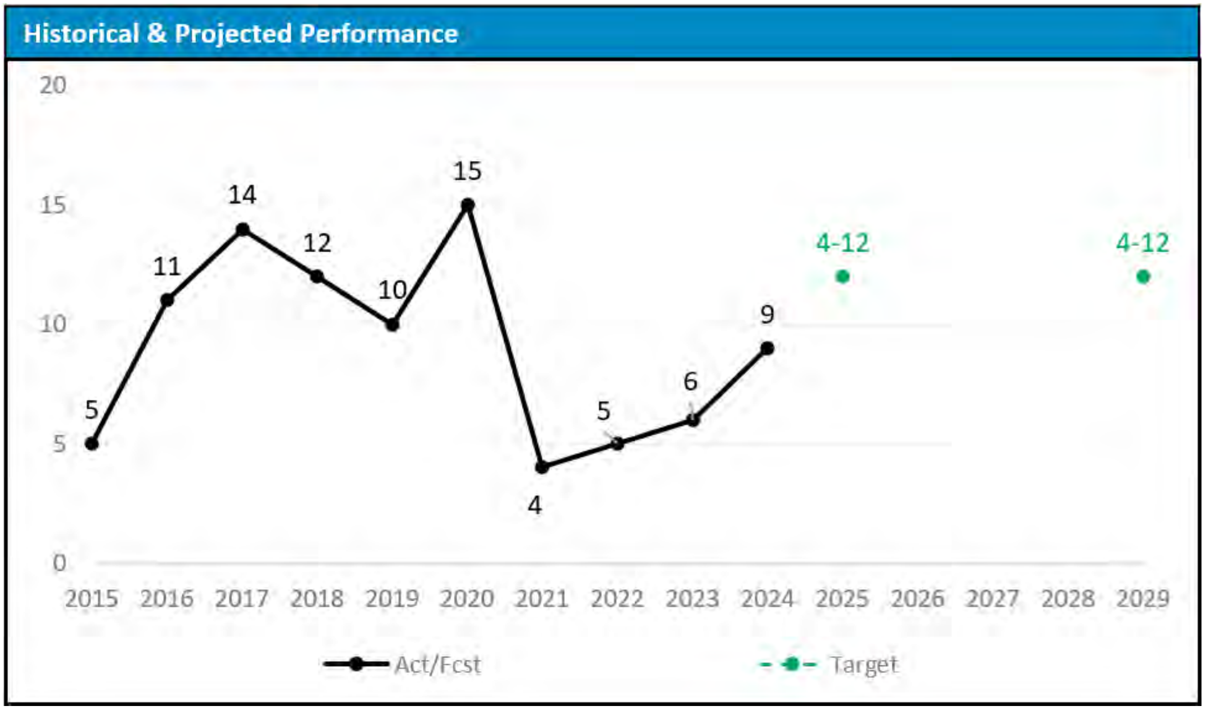
1. Progress Towards the 1-Year Target

As demonstrated in Figure 3.15-3 below, PG&E observed nine CPUC-reportable ignitions on overhead transmission assets in 2024, within our 2024 target range of 0 – 10 ignitions. Most of the ignitions are confirmed or suspected to be avian related.

2. Progress Towards the 5-Year Target

As discussed in Section E below, PG&E is continuing to deploy several programs to keep metric performance within the Company's target range. PG&E expects no deviation from delivering the 2029 goal for this metric.

FIGURE 3.15-3
HISTORICAL PERFORMANCE (2015 – 2024) AND
TARGETS (2025 AND 2029)



Note: As part of a Risk Assessment Improvement Plan item in PG&E's 2023 – 2015 WMP, PG&E reviewed historic ignitions data and reattributed certain historical events, resulting in slight changes in the count of ignitions in scope for this metric for historical years (some years increased while others decreased). In general, ignition counts represent a snapshot in time and are subject to change based on new data.

E. (3.15) Current and Planned Work Activities

Through continual execution of its Wildfire Mitigation Plan (WMP), PG&E has taken action to reduce ignition risk associated with its transmission system, including:

- Utility Defensible Space Program: In 2023, PG&E expanded on Defensible Space Requirements in Public Resources Code Section 4292. Defensible Space is defined by three primary zones of clearance whereas in 2022 there were two zones. Starting in 2023 the first zone (0-5 feet (ft.)) from energized equipment or building is referred to as Zone 0 or the "Ember – Resistant Zone" and is intended to be void of any combustibles. The second zone (5-30 ft.) surrounding energized equipment and building is called the "Clean Zone" and in most cases (with minimal exceptions) is clear of trees and most vegetation. The third and final zone of clearance (30-100 ft.) is the

"Reduced Fuel Zone" where vegetation is permitted if it is reduced or thinned and maintained regularly and within the requirements listed within PG&E's hardening procedures.

  - Approximately 2,700 support structures were completed through this program in 2023 and 2024; and
  - PG&E is targeting an additional 665 support structures in 2024.

Please see Section 8.2.3.5, Substation Defensible Space (Mitigation) in PG&E's 2023-2025 WMP for additional details.

- Conductor Replacement and Removal: In 2021, PG&E completed 93.8 miles of conductor replacements and 10 miles of conductor removals. All this work took place on lines traversing HFTD areas. In 2022, PG&E removed or replaced 32 circuit miles of conductor in HFTD or High Fire Risk Area. In 2023, PG&E removed or replaced 43 circuit miles of conductor in HFTD or High Fire Risk Area. An additional 5 miles are planned through 2025.

Please see Section 8.1.2.5.1, Traditional Overhead Hardening – Transmission Conductor in PG&E's 2023-2025 WMP for additional details.

- Conductor Splice Shunts: A conductor splice is a potential point of failure within a conductor span, due to factors such as corrosion, moisture intrusion, vibration, and workmanship variability. To reduce the risk of failure, PG&E had initiated a program to install a shunt splice on top of the existing splices on This installation eliminates the splice as a single point of failure, as a failure of the original splice would not result in down conductor. Lines prioritized for this program are based on higher risk splice and wildfire consequence. In 2023, 20 transmission lines had splice shunts installed. In 2024, 22 transmission lines had splice shunts installed. An additional 25 lines are planned through 2025.

Please see Section 8.1.2.5.1, Traditional Overhead Hardening – Transmission Conductor in PG&E's 2023-2025 WMP for additional details.

- Conductor Segment Replacements: Another program has been initiated to replace targeted conductor segments within a line. A transmission line may consist of multiple conductor types, including spans of higher-risk segments such as small-sized conductors. This program reduces risk for lines where the conductor segments are may be at higher risk, but the supporting structures are generally in good condition and there is no expected additional electrical capacity need to increase the conductor size. PG&E plans to complete segment replacements on 2 lines in HFTD/High Fire Risk Area in 2025.

Please see Section 8.1.2.5.1, Traditional Overhead Hardening – Transmission Conductor in PG&E's 2023-2025 WMP for additional details.

- Proactive Animal Abatement: Given that avian-caused ignitions are the top driver in recent years, PG&E is exploring two specific mitigations associated with reducing risk of avian related ignitions:
  - PG&E has designed dielectric covers to cover a portion of steel lattice towers where we have observed faults caused by avian contact. PG&E is committing to installing these devices at 22 towers in 2025 and conducting a feasibility study to inform future programs as part of a WMP initiative. Please see Qualitative commitment GH-13 Section 8.2.12 and 8.2.12.2 Other Technologies and Systems not Listed Above – Transmission in PG&E's 2026 2028 WMP for additional details.
  - Executing an annual program to remove bird nests after nesting season. PG&E proactively removed 584 nests from transmission support structures in 2024.

PACIFIC GAS AND ELECTRIC COMPANY

SAFETY AND OPERATIONAL METRICS REPORT:

CHAPTER 3.16

PERCENTAGE OF CPUC-REPORTABLE IGNITIONS IN HFTD AREAS

(TRANSMISSION)

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(TRANSMISSION)

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PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 3.16
PERCENTAGE OF CPUC-REPORTABLE IGNITIONS IN HFTD AREAS (TRANSMISSION)

The material updates to this chapter, since the September 30, 2024 report, are identified in blue font.

A. (3.16) Overview

1. Metric Definition

Safety and Operational Metrics (SOM) 3.16 – percentage of California Public Utilities Commission (CPUC)-Reportable Ignitions in High Fire Threat District (HFTD) Areas (Transmission) is defined as:

The number of CPUC-reportable ignitions involving overhead transmission circuits in HFTD divided by circuit miles of overhead transmission lines in HFTD multiplied by 1,000 miles (ignitions per 1,000 HFTD circuit mile).

A CPUC-reportable ignition refers to a fire incident where the following three criteria are met: (1) Ignition is associated with Pacific Gas and Electric Company (PG&E) electrical assets, (2) something other than PG&E facilities burned, and (3) the resulting fire travelled more than one linear meter from the ignition point.[1]

For this SOM, reporting is specific to Tier 2 and Tier 3 HFTDs.

PG&E provides the CPUC with annual ignition data in the Fire Incident Data Collection Plan, to the Office of Energy Infrastructure and Safety quarterly via quarterly GIS data reporting, in quarterly Wildfire Mitigation Plan (WMP) updates, and the Safety Performance Metrics Report.

2. Introduction of Metric

The number of CPUC-reportable ignitions in HFTDs, normalized by circuit mileage, provides one way to gauge the level of wildfire risk that

1 Please see CPUC Decision (D.) 14-02-015, issued February 5, 2014 for additional details.

customers and communities are exposed to from overhead transmission assets. PG&E's objective is to minimize the number of CPUC-reportable ignitions in the right locations during the right conditions that may trigger a catastrophic wildfire.

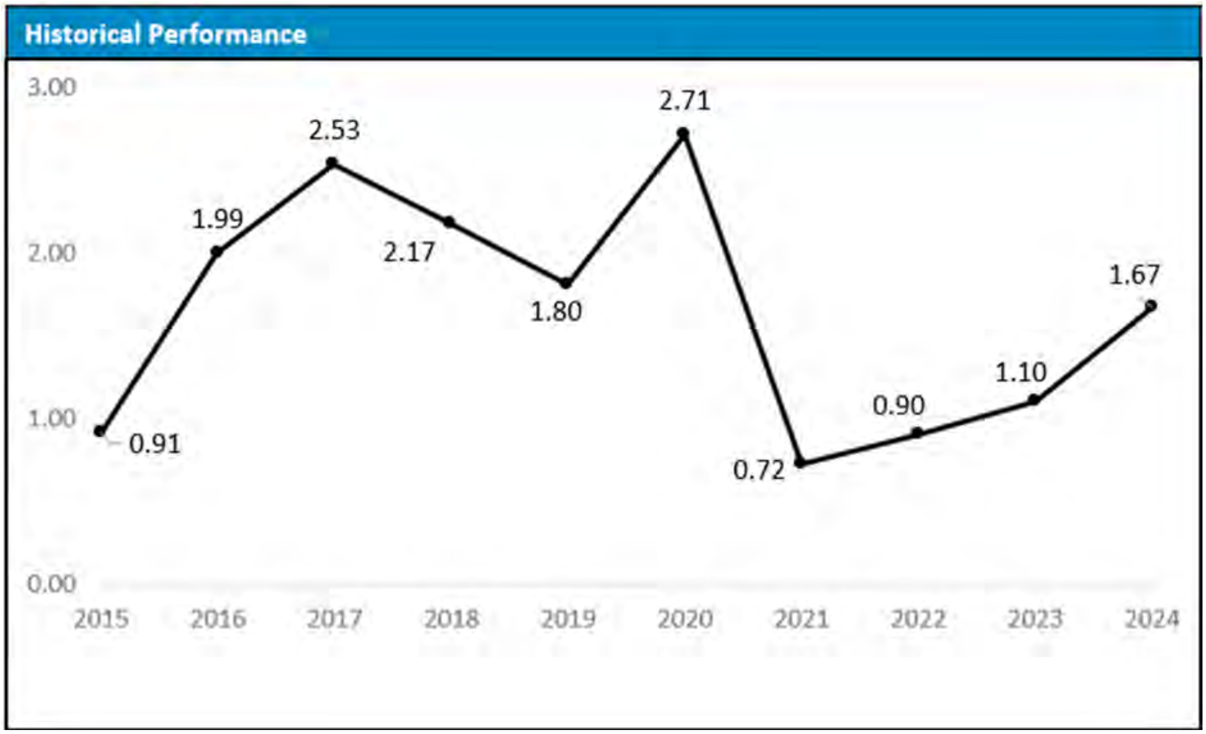
B. (3.16) Metric Performance

1. Historical Data (2015 – 2024)

PG&E implemented the Fire Incident Data Collection Plan, in response to CPUC D.14-02-015, in June 2014 and our record, the Ignitions Tracker, includes all CPUC-reportable ignitions from June 2014 to present. The 2014 data does not represent a complete year and is excluded in this analysis.

PG&E's overhead transmission circuits traverse approximately 5,400 miles of terrain in the HFTD areas where the overhead conductor is primarily bare wire, supported by structures consisting of poles and towers. The annual number of CPUC-reportable ignitions is too low and too variable to detect any statistical pattern.

FIGURE 3.16-1
HISTORICAL PERFORMANCE (2015 – 2024)



Note: As part of a Risk Assessment Improvement Plan item in PG&E's 2023 – 2015 WMP, PG&E reviewed historic ignitions data and reattributed certain historical events, resulting in slight changes in the count of ignitions in scope for this metric for historical years (some years increased while others decreased). In general, ignition counts represent a snapshot in time and are subject to change based on new data.

2. Data Collection Methodology

Data will be collected per PG&E's Fire Incident Data Collection Plan (Utility Standard/Procedure RISK-6306S/P). Results will be inclusive of unique HFTD CPUC-reportable ignitions attributable to the transmission asset class with overhead construction types.

The following ignition events captured by PG&E's Fire Incident Data Collection Plan (Utility Standard/Procedure RISK-6306S/P) will be excluded for this metric:

- Duplicate events;
- Ignitions that do not meet CPUC reporting criteria;
- Ignition events outside of Tier 2 and Tier 3 HFTD;
- Distribution Ignitions; and

- Ignitions attributable to underground or pad mounted assets, as these are not overhead assets. Ignitions caused by non-overhead assets in HFTD are rare and, as the fires are often contained to the asset, pose less of a wildfire risk.

The circuit mileage utilized to calculate the 2015-2022 performance of this metric originates from PG&E's Electrical Asset Data Reports, refreshed December 2022. The 2023-24 performance and targets are based on an updated sum of overhead circuit mileage, refreshed in 2023.

3. Metric Performance for the Reporting Period

Historically, reportable transmission ignitions in HFTD are low in volume with variability year to year, which complicates the detection of significant trends. PG&E observed nine CPUC reportable ignitions on overhead transmission assets through 2024 (corresponding to a rate of 1.67 ignitions per 1,000 circuit miles); one caused by bird guano on an insulator (contamination), one where the cause is unknown but suspected to have been avian related, five caused by confirmed bird contact, and two equipment failures.

C. (3.16) 1-Year Target and 5-Year Target

1. Updates to 1- and 5-Year Targets Since Last Report

PG&E proposes to set the 2025 and 2029 upper limit of the target range to account for the previous 5 years of actual results and variability driven by weather, and external factors like seasonal bird migration.

2. Target Methodology

To establish the 1-Year and 5-Year targets, PG&E considered the following factors:

- Historical Data and Trends: PG&E has layered significant wildfire mitigation strategies over the past 8 years and, outside of PG&E's own ignition record, to help guide in target setting. PG&E is utilizing the previous 5-years worth of ignition actuals (2020-2024) to propose 2025 and 2029 target setting.
- Benchmarking: PG&E benchmarks extensively with other utilities in terms of wildfire risk and ignition reduction. Specifically, PG&E reviews

utility ignition trends (where available) and analyzes the risk associated large utility wildfires around the world;

- Regulatory Requirements: CPUC D.14-02-015;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: The targets for this metric are suitable for EOE as they consider the potential for an increase in severe weather events due to climate change; and
- Other Qualitative Considerations: The target range takes consideration for some variability in weather.

3. 2025 Target

PG&E's target for 2025 is 4-12 (corresponding to a rate of 0.73 – 2.21 ignitions per 1,000 circuit miles). The upper and bottom ends of this range represents the 5-year previous average (8 ignitions) subtracting/adding a full standard deviation (4 ignitions) for those same years to account for variability.[2]

4. 2029 Target

PG&E's target for 2029 is 4-12 (corresponding to a rate of 0.73 – 2.21 ignitions per 1,000 circuit miles). The upper and bottom ends of this range represents the 5-year previous average (8 ignitions) subtracting/adding a full standard deviation (4 ignitions) for those same years to account for variability. The upper end of the range stays at 12 in 2025 and 2029 because the volume of transmission ignitions is low, while variability year to year remains high.

D. (3.16) Performance Against Target

1. Progress Towards the 1-Year Target

As demonstrated in Figure 3.15 3 below, PG&E observed nine CPUC reportable ignitions on overhead transmission assets in 2024 (corresponding to a rate of 1.67 ignitions per 1,000 circuit miles), within our 2024 target range of 0 – 10 ignitions (corresponding to a rate of 0 – 1.85 ignitions per

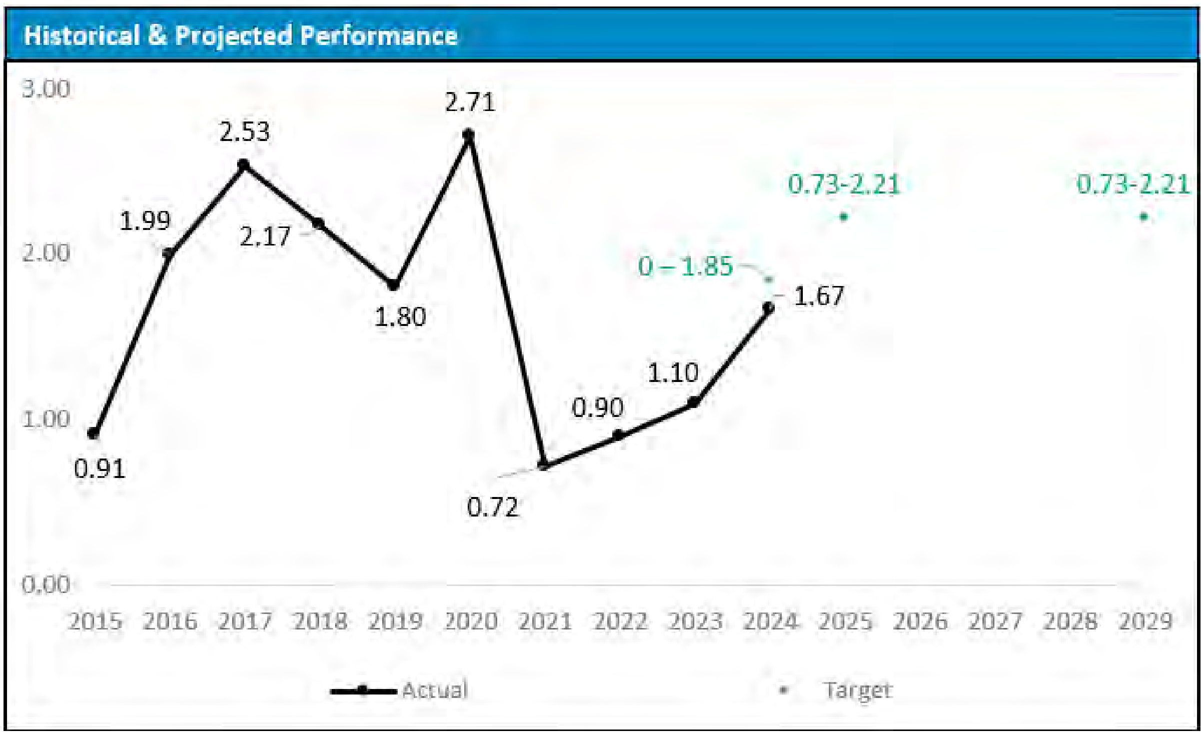
[2] The 2024 target has been corrected to reflect the 2023 mileage data for 2024 performance and target setting. PG&E inadvertently used 2022 mileage for the March report which resulted in a difference of 123 miles.

1,000 circuit miles) . Most of the ignitions are confirmed or suspected to be avian related.

2. Progress Towards the 5-Year Target

As discussed in Section E below, PG&E is continuing to deploy several programs to keep metric performance within the Company's target range. PG&E expects no deviation from delivering the 2029 goal for this metric.

FIGURE 3.16-2
HISTORICAL PERFORMANCE (2015- 2024) AND TARGETS (2024, 2025 AND 2029)



Note: As part of a Risk Assessment Improvement Plan item in PG&E's 2023 – 2015 WMP, PG&E reviewed historic ignitions data and reattributed certain historical events, resulting in slight changes in the count of ignitions in scope for this metric for historical years (some years increased while others decreased). In general, ignition counts represent a snapshot in time and are subject to change based on new data.

E. (3.16) Current and Planned Work Activities

Through continual execution of its WMP, PG&E has taken action to reduce ignition risk associated with its transmission system, including:

- Utility Defensible Space Program: In 2023, PG&E expanded on Defensible Space Requirements in Public Resources Code Section 4292. Defensible

Space is defined by three primary zones of clearance whereas in 2022 there were two zones. Starting in 2023 the first zone (0-5 feet (ft.)) from energized equipment or building is referred to as Zone 0 or the "Ember – Resistant Zone" and is intended to be void of any combustibles. The second zone (5-30 ft.) surrounding energized equipment and building is called the "Clean Zone" and in most cases (with minimal exceptions) is clear of trees and most vegetation. The third and final zone of clearance (30-100 ft.) is the "Reduced Fuel Zone" where vegetation is permitted if it is reduced or thinned and maintained regularly and within the requirements listed within PG&E's hardening procedures.

  - Approximately 2,700 support structures were completed through this program in 2023 and 2024; and
  - PG&E is targeting an additional 665 support structures in 2024

  Please see Section 8.2.3.5, Substation Defensible Space (Mitigation) in PG&E's 2023-2025 WMP for additional details.

- Conductor Replacement and Removal: In 2021, PG&E completed 93.8 miles of conductor replacements and 10 miles of conductor removals. All this work took place on lines traversing HFTD areas. In 2022, PG&E removed or replaced 32 circuit miles of conductor in HFTD or High Fire Risk Area (HFRA). In 2023, PG&E removed or replaced 43 circuit miles of conductor in HFTD or HFRA. An additional 5 miles are planned through 2025.

  Please see Section 8.1.2.5.1, Traditional Overhead Hardening – Transmission Conductor in PG&E's 2023-2025 WMP for additional details.

- Conductor Splice Shunts: A conductor splice is a potential point of failure within a conductor span, due to factors such as corrosion, moisture intrusion, vibration, and workmanship variability. To reduce the risk of failure, PG&E had initiated a program to install a shunt splice on top of the existing splices on This installation eliminates the splice as a single point of failure, as a failure of the original splice would not result in down conductor. Lines prioritized for this program are based on higher risk splice and wildfire consequence. In 2023, 20 transmission lines had splice shunts installed. In 2024, 22 transmission lines had splice shunts installed. An additional 25 lines are planned through 2025.

Please see Section 8.1.2.5.1, Traditional Overhead Hardening – Transmission Conductor in PG&E's 2023-2025 WMP for additional details.

- Conductor Segment Replacements: Another program has been initiated to replace targeted conductor segments within a line. A transmission line may consist of multiple conductor types, including spans of higher-risk segments such as small-sized conductors. This program reduces risk for lines where the conductor segments are may be at higher risk, but the supporting structures are generally in good condition and there is no expected additional electrical capacity need to increase the conductor size. PG&E plans to complete segment replacements on 2 lines in HFTD/HFRA in 2025.

  Please see Section 8.1.2.5.1, Traditional Overhead Hardening – Transmission Conductor in PG&E's 2023-2025 WMP for additional details.

- Proactive Animal Abatement: Given that avian-caused ignitions are the top driver in recent years, PG&E is exploring two specific mitigations associated with reducing risk of avian related ignitions:
  - PG&E has designed dielectric covers to cover a portion of steel lattice towers where we have observed faults caused by avian contact. PG&E is committing to installing these devices at 22 towers in 2025 and conducting a feasibility study to inform future programs as part of a WMP initiative. Please see Qualitative commitment GH-13 Section 8.2.12 and 8.2.12.2 Other Technologies and Systems not Listed Above – Transmission in PG&E's 2026 2028 WMP for additional details; and
  - Executing an annual program to remove bird nests after nesting season. PG&E proactively removed 584 nests from transmission support structures in 2024.

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 4.1
NUMBER OF GAS DIG-INS PER 1,000 UNDERGROUND SERVICE ALERT (USA) TICKETS ON TRANSMISSION AND DISTRIBUTION PIPELINES

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 4.1
NUMBER OF GAS DIG-INS PER 1,000 UNDERGROUND
SERVICE ALERT (USA) TICKETS ON
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SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 4.1
NUMBER OF GAS DIG-INS PER 1,000 UNDERGROUND SERVICE ALERT (USA) TICKETS ON TRANSMISSION AND DISTRIBUTION PIPELINES

The material updates to this chapter, since the September 30, 2024 report, are identified in blue font.

A. (4.1) Overview

1. Metric Definition

Safety and Operational Metric 4.1 – Number of Gas Dig-Ins per 1,000 tickets on Transmission and Distribution Pipelines is defined as:

The number of gas dig-ins per 1,000 Underground Service Alert (USA) tickets received for gas. A gas dig-in refers to damage (impact or exposure) which occurs during excavation activities and results in a repair or replacement of an underground gas facility. Excludes fiber and electric tickets. Also excludes tickets originated by the Utility itself or by utility contractors.

2. Introduction of Metric

Reducing gas dig-ins increases public safety and improves reliability. It is therefore important to take reasonable steps reduce this risk because gas dig-ins represent a potential risk to people, property, and the environment.

If ignited, gas from a dig-in could produce a fire or explosion, either of which, could result property damage, injury or even death. Release of gas from a dig-in also produces a possible health hazard from inhalation of natural gas. Finally, dig-ins typically produce a disruption or loss of service to one or more customers.

For all these reasons, fewer dig-ins reduces risk to public safety and minimizes interruption to the gas business and customers.

B. (4.1) Metric Performance

1. Historical Data (2018 – 2024)

For this metric, Pacific Gas and Electric Company (PG&E or the Company or the Utility) has seven years of historic data available, which includes 2018-2024. The past six years were used for analysis in target setting. Over the historical reporting period, performance improved as demonstrated by both an overall increase in USA tickets and a decrease in gas dig-ins.

FIGURE 4.1-1
THIRD-PARTY TICKETS AND TOTAL DIG-IN COUNTS 2018 – 2024

3rd Party Ticket Counts								Dig-In Count						
2018	2019	2020	2021	2022	2023	2024	Month	2018	2019	2020	2021	2022	2023	2024
66,605	66,900	74,736	69,544	83,536	60,314	76,150	January	100	89	93	118	118	79	77
62,387	58,586	70,016	74,323	80,127	61,733	72,219	February	131	78	119	116	106	79	65
66,538	74,563	69,991	95,177	93,432	68,744	78,603	March	103	103	98	126	143	66	82
71,514	85,215	67,071	93,335	83,657	73,186	86,984	April	147	140	117	147	120	111	110
75,794	86,339	71,786	87,432	87,005	83,866	86,518	May	209	140	128	139	150	123	114
69,824	81,989	80,614	93,008	88,319	80,983	78,908	June	176	176	170	183	149	121	114
68,927	92,787	80,926	84,316	81,346	75,831	87,875	July	190	196	201	170	145	110	141
74,158	89,869	76,521	87,507	94,628	85,879	89,998	August	186	200	182	175	156	135	152
64,678	84,840	79,684	84,126	86,949	79,082	84,797	September	173	167	178	163	124	139	138
77,779	91,022	81,680	82,106	87,461	84,875	93,954	October	179	191	155	135	131	117	129
64,861	72,476	72,089	82,859	79,547	76,765	73,354	November	139	149	131	101	96	119	91
56,219	64,452	73,995	71,744	62,951	63,816	76,550	December	110	87	126	64	45	73	68
819,284	949,038	899,109	1,005,477	1,008,958	895,074	985,910	Total	1,843	1,716	1,698	1,637	1,483	1,272	1,281

Data Collection Methodology

The data used for this metric reporting is maintained in two files. Together, these databases identify the number of dig-ins and the 811 tickets, respectively. To ensure accuracy of the Master Dig-In File data, three data sources are reviewed:

1) The repair data file recorded in SAP- (Obtained using Business Objects GCM058 Quarterly GQI Extract Report);
2) The Event Management (EM) Tool obtained from Gas Dispatch, data file; and
3) The Dig-In Reduction Teams (DiRT) Pronto download file, obtained from the DiRT team data download report.

Events that meet the definition of dig-in are recorded as a ratio of total dig-ins (count) divided by the third-party USA tickets (count) multiplied by 1,000. This metric does not include tickets originated by the Utility itself or by utility contractors.

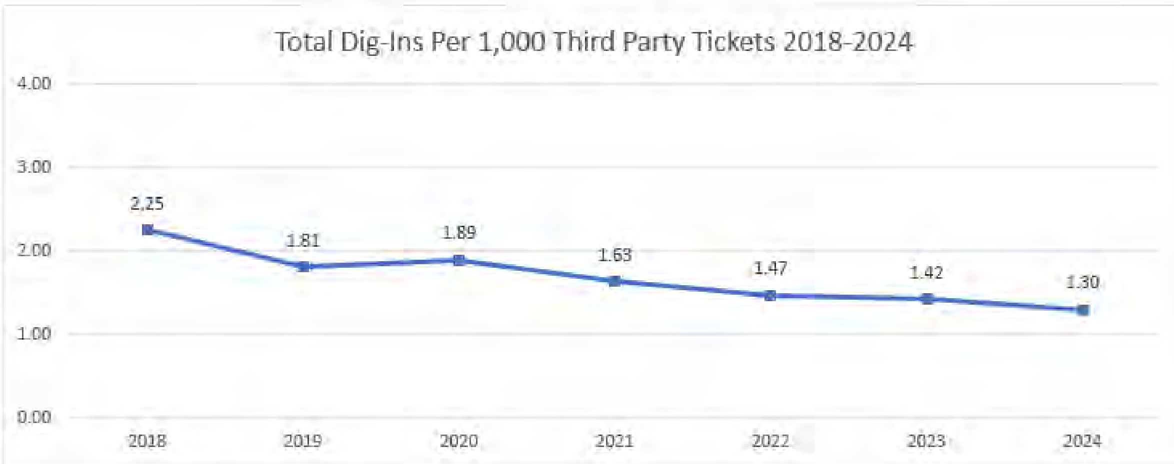
This metric also does not include PG&E dig-ins to third parties (e.g., sewer, water, telecommunications). Dig-ins are reported in real-time, so they should be captured for the reporting period. However, in the event dig-ins are reported after the reporting cycle is closed, the dig-in would be captured in the next reporting cycle (i.e., the next quarter of the current year or the first quarter of the next year). Electric and Fiber dig-ins are also excluded from the dig-in count. Also excluded from the dig-in count are the following (since damages are not from excavation activity):

- Damages to above-ground infrastructure, such as meters and risers, or overbuilds;
- Pre-existing damages (e.g., due to corrosion or old wrap);
- Any intentional damage to a pipeline (e.g., drilling or cutting);
- Damage caused by driving over a covered facility (heavy vehicles damage gas pipe, non-excavation);
- Damage to abandoned facilities;
- Damage due to materials failure (e.g., Aldyl-A pipe);
- Damage caused to gas or electric lines by trench collapse or soldering work; and
- Facility has been fully exposed, and damage is not as a result of excavation activity (as defined by California Government Code 4216 (G)) (e.g., cutting tree roots, object/person contact to exposed gas line.

2. Metric Performance for the Reporting Period

There has been an overall downward trend in the number of dig-ins per 1,000 third-party USA tickets. PG&E attributes the reduction to current and planned Damage Prevention activities. Overall, PG&E has worked to increase knowledge of the requirement to call 811 before digging through Public Awareness Campaigns and by providing training and education to contractors. PG&E continues to show an improvement in its dig-in ratio.

FIGURE 4.1-2
TOTAL DIG-INS PER 1,000 THIRD-PARTY TICKETS 2018 – 2024



C. (4.1) 1-Year Target and 5-Year Target

1. Updates to 1- and 5-Year Targets Since Last Report

Updated targets are provided below.

2. Target Methodology

To establish the 1-year and 5-year targets, PG&E considered the following factors:

- Historical Data and Trends: Comparable data is available starting in 2018. Performance has been consistent with a downward trend from 2018-2024;
- Benchmarking: Although this metric is not benchmarkable as defined (benchmarkable metrics include total tickets rather than only a subset of tickets), benchmark data was used and derived as proxy guideposts to understand PG&E performance for third-party tickets to inform target setting. The target is set at a level consistent with strong performance.
- Regulatory Requirements: None;
- Attainable Within Known Resources/Work Plan: Yes;
- Appropriate/Sustainable Indicators for Enhanced Oversight Enforcement: Yes, performance at or below the set target is a sustainable assumption for maintaining metric performance, plus room for non-significant variability; and
- Other Qualitative Considerations: None.

3. 2025 Target

The 2025 target is to maintain metric performance at or better than a rate of 1.94 based on the factors described above. This improvement is based upon the Damage Prevention Organization's Dig-in Reduction Program. This target represents an appropriate indicator light to signal a review of potential performance issues. Target should not be interpreted as intention to worsen performance.

4. 2029 Target

The 2029 target is to maintain performance better than a rate of 1.90 based on the factors described above. Annual targets should continue to be informed by available benchmarking data.

D. (4.1) Performance Against Target

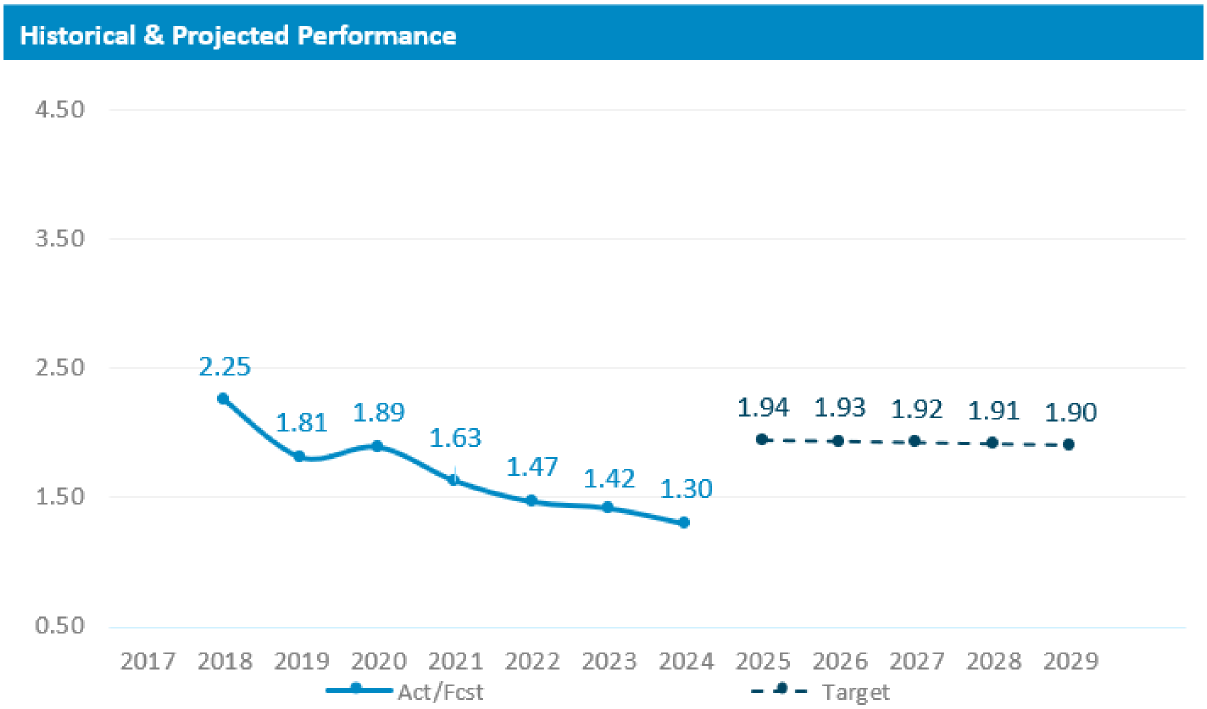
1. Maintaining Performance Against the 1-year Target

As demonstrated in Figure 4.1-3, PG&E saw a 1.30 Gas Dig-In rate in 2024, which is better than the Company's 1-year target of 1.93 and remains consistent with the Company's objective of maintaining first quartile performance. Also, performance of 1.30 Gas Dig-in rate surpassed the 2023 Performance of 1.42.

2. Maintaining Performance against the 5-year Target

As discussed in Section E, PG&E continues to use the Damage Prevention and DiRT programs to maintain performance in its efforts toward the Company's 5-year target.

FIGURE 4.1-3
TOTAL DIG-INS PER 1,000 THIRD-PARTY TICKETS 2018 – 2024
AND TARGETS THROUGH 2029



1yr Target (2025)	5yr Target (2029)
≤ 1.94	≤ 1.90

E. (4.1) Current and Planned Work Activities

PG&E's Damage Prevention team is responsible for the overall management of PG&E's Damage Prevention Program, by managing the risks associated with excavations around PG&E's facilities and conducting investigations. As an additional control to manage the Damage Prevention Program, PG&E has its DiRT). DiRT consists of 23 people (2 Supervisors, 15 PG&E Employees and 6 Contractors) deployed systemwide to investigate dig-ins. Team members work closely with various local PG&E operations personnel and respond to referrals from those employees when they observe excavations potentially not in compliance with the requirements of California Government Code Section 4216. DiRT personnel also assist the Ground Patrol team when they respond to immediate threats identified in the air by the Aerial

Patrol team and other PG&E groups, in order to intervene in unsafe digging activities by third parties and follow-up to educate excavators as necessary.

PG&E's Damage Prevention activities include educational outreach activities for professional excavators, local public officials, emergency responders, and the general public who live and work within PG&E's service territory. The program communicates safe excavation practices, required actions prior to excavating near underground pipelines, availability of pipeline location information, and other gas safety information through a variety of methods throughout the year. These efforts are aimed at increasing public awareness about the importance of utilizing the 811 Program before an excavation project is started, understanding the markings that have been placed, and following safe excavation practices after subsurface installations have been marked. Specific activities aimed at preventing dig-ins include:

- Updating the Locate and Mark Field Guide and procedures to provide clear instruction around critical processes for locating underground assets, including troubleshooting of difficult to locate facilities;
- PG&E participates in the Common Ground Alliance (CGA) – Damage Prevention Institute (DPI). PG&E began this program that is now run by a third-party and available to utilities and excavators across the nation. The program sets safety criteria that PG&E contractors are required to meet to be eligible to do work on behalf of the Utility. The CGA is an internationally-recognized program, with companies in Canada adopting and implementing its certification requirements. The DPI is a way that PG&E is making its own communities safer, and bringing best safety practices to the industry;
- An 811 Ambassador program, which utilizes all PG&E employees to properly identify unsafe excavation activities where employees learn how to identify excavation-related delineations and utility operator markings; and
- In 2023 PG&E re-vamped its Locate and Mark training program to ensure that our locators are receiving the best training available. This training consists of multiple classroom-based modules as well as on the job training with trained peer coaches.

PACIFIC GAS AND ELECTRIC COMPANY

SAFETY AND OPERATIONAL METRICS REPORT:

CHAPTER 4.2

NUMBER OF OVERPRESSURE EVENTS

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SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 4.2
NUMBER OF OVERPRESSURE EVENTS

The material updates to this chapter, since the September 30, 2024 report, are identified in blue font.

A. (4.2) Overview

1. Metric Definition

Safety and Operational Metric 4.2 – Number of Overpressure (OP) events is defined as:

OP events as reportable under General Order (GO) 112-F 122.2(d)(5).

2. Introduction of Metric

An OP event occurs when the gas pressure exceeds the Maximum Allowable Operating Pressure (MAOP) of the pipeline, plus the build ups, set forth in the Code of Federal Regulations (CFR) – 49 CFR 192.201.

This metric tracks the occurrence of OP events, which includes:

1) High pressure Gas Distribution (GD):
   a) (MAOP 1 pound per square inch gauge (psig) to 12 psig) greater than 50 percent above MAOP.
   b) (MAOP 12 psig to 60 psig) greater than 6 psig above MAOP; and
2) Gas Transmission (GT) pipelines greater than 10 percent above MAOP (or the pressure produces a hoop stress of ≥75 percent Specified Minimum Yield Strength, whichever is lower).

OP events on low pressure systems are excluded from this metric because they are not defined in federal code 49 CFR 192.201.

OP events have the potential to overstress pipelines which pose significant safety and operational risks to Pacific Gas and Electric Company's (PG&E) gas system. PG&E has implemented multiple controls and mitigations to reduce OP events.

Following the San Bruno event in 2010, an Overpressure Elimination (OPE) task force was established to identify the root causes of OP events and develop corrective actions.

In 2011, several decisions were made in response to San Bruno incident. One of the most important corrective actions was to lower the normal operating pressure below the MAOP across the system, which resulted in a significant drop-off of OP events from 2011-2012.

Beginning in 2013, causal evaluations were conducted on all OP events. Corrective actions from these evaluations included: equipment and design review, training, fatigue management, improved Gas Event Reporting, and improved work procedures.

In 2015, several benchmarking studies and industry evaluations were conducted to learn OP elimination best practice. The benchmarking studies and analyses helped influence the development and strategies of the OPE Program.

In 2017, after the Folsom OP event,[1] the OPE Program was stood up under one sponsor with dedicated resources. The OPE Program formalized a two-pronged strategy to mitigate the risk of large OP events, while reducing operational risk: (1) Human (HU) Performance Strategy, and (2) Equipment (EQ)-Related Strategy.

In 2020, PG&E retooled an effort to reduce the number of HU Performance-related events. PG&E contracted with Exponent to perform an analysis on the OP and near hit events using the Human Factors Analysis and Classification System to drive focused actions to improve. This effort helped the team to develop the HU Performance tools to: identify and control risk, improve efficiency, avoid delays, reduce errors, prevent events, and promote excellent performance at every facility.

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[1] On January 24, 2017, the Hydraulically Independent System that delivers gas to the Folsom area experienced a large OP event in excess of the system's 60 psig MAOP. The OP event caused damage to the regulator station equipment and resulted in a significant number of leaks on plastic distribution piping. Inspection of the station revealed that the station filter had been clogged with debris and the regulator boot had been eroded by contaminants. Further investigation revealed that an upstream pigging project scraped corrosion scales from internal pipe walls. The scale—along with other debris—traveled downstream, until eventually collecting at Folsom, causing the OP event.

B. (4.2) Metric Performance

1. Historical Data (2011 – 2024)

Historical data of OP events is available since year 2011. Various data points of each OP event including location, Corrective Action Program (CAP) number, date, cause, corrective action, etc. are documented in the OP master list file attachment.

Data source of the metric is commonly from the Supervisory Control and Data Acquisition (SCADA) system, and from direct accounts, including gauge pressure readings, chart recorders, electronic recorders, and metering data.

The availability of data has expanded throughout the years due to the increase in pressure monitoring devices allowing more OP events to be identified and recorded. In 2012, PG&E had 1,409 SCADA pressure points on its pipeline system, and by end of December 2023, that number has grown to 7,042. As of the end of 2024, there are 7,321 SCADA pressure points throughout the PG&E system.

2. Data Collection Methodology

PG&E has both an automated process and field process for logging Gas OP events. For the automated process, the SCADA system monitors EQ pressure and notifies potential issues to Gas Control through alarms. For the field process, field personnel are required to gauge pressure during maintenance and clearances and report to Gas Control if an abnormal operating condition arises. The Gas OP metric reporting process flow is as follows:

1) Control Room Alarm/Third-Party Notification of abnormal pressure reading or Gas Pipeline Operations and Maintenance (GPOM) finds abnormal pressure reading during maintenance.
2) GPOM performs on-site investigation (validates pressure reading and compares onsite pressure with SCADA pressure upon arrival). "As-found" and "as-left" pressures are recorded on maintenance form.
3) Gas Control Room creates Abnormal Incident Report and issues e-page. FIMP reviews the e-page, creates a CAP, and prepares a Quick Hit.

4) OP event is recorded on OP Master List, and Apparent Cause Evaluation is conducted to determine root cause and any corrective actions as applicable.

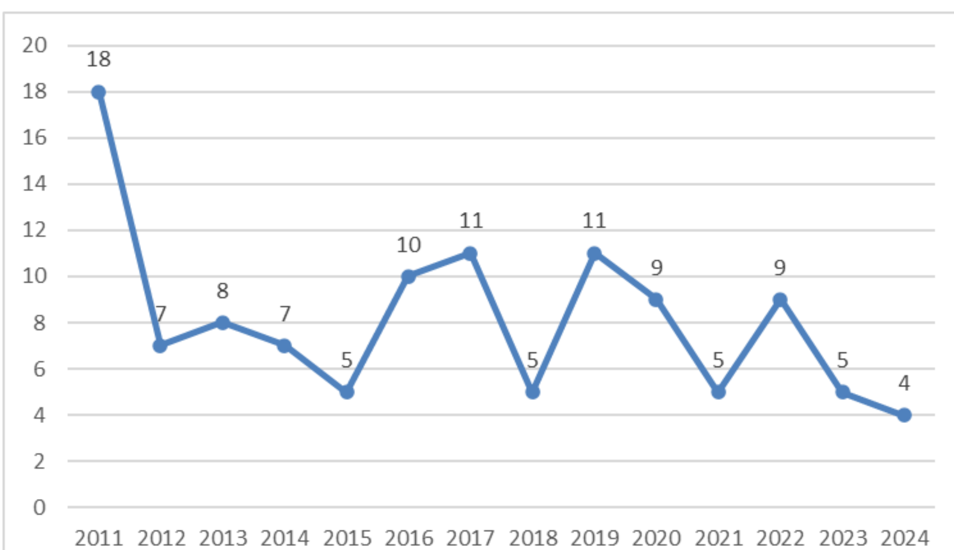
Several controls are in place for this metric:

1) Each OP event is entered into our system of record SAP system CAP to ensure retention of record history.
2) Each OP event's datasets (location, CAP number, date, cause, corrective action etc.) are reviewed by Facility Integrity Management Program team to ensure accuracy and are logged in the OP Master List which is viewable by all PG&E employees; and
3) Each OP event is distributed to stakeholders by an electronic page (e-page) and an e-mail (Quick Hit), reviewed on the next Daily Operations Briefing with leadership.

3. Metric Performance for the Reporting Period

PG&E experienced four overpressure events in 2024. This is the lowest number of overpressure events recorded since PG&E began tracking this metric in 2011, and this number was less than half of the Safety and Operational Metrics target of 10 events as an indicator of poor performance in 2024.

FIGURE 4.2-1
OVERPRESSURE EVENTS 2011 – 2024



C. (4.2) 1-Year Target and 5-Year Target

1. Updates to 1- and 5-Year Targets Since Last Report

The 2025 target is set to be 10 (i.e., same as 2024 target); the 2029 target is set to be 8 (i.e., one less than the 2028 target).

2. Target Methodology

To establish the 1-year and 5-year targets, PG&E considered the following factors:

- Historical Data and Trends: OP events have ranged from 4 to 11 events per year since 2012. We exclude data from 2011, because it was the first year OP data was collected and several anomalies were embedded in the data and is shown for reference purposes only. The upper limit for target-setting is based on the maximum number of events in the past thirteen years.
- Benchmarking: This metric is not traditionally benchmarkable; however, PG&E has contracted with third parties to conduct international and North American industry evaluations. The benchmarking studies indicated that PG&E has demonstrated strong performance in this area.
- Regulatory Requirements: OP events as reportable under California Public Utilities Commission GO No.112-F, 122.2(d)(5).
- Attainable Within Known Resources/Workplan: Yes.
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: Yes, performance at or below the maximum of the past nine years is a sustainable assumption for maintaining metric performance, plus room for non-significant variability; and
- Other Qualitative Considerations: The approach of using the maximum of the past nine years includes the consideration of the expected impact of ongoing SCADA device installations—improved system visibility and monitoring points may result in a higher number of observed OP events. Additionally, as the OP Program has expanded, there has been an increase in pressure monitoring devices throughout the system, which allows more OP events to be identified and recorded.

3. 2025 Target

The upper limit for the 2025 target is based on the maximum of the past thirteen years historical performance. The target is based on the highest number annual events, within 95 percent confidence level (within two standard deviations) of the average number of events, and reflects a trend of continuous improvement. This target represents an appropriate indicator light to signal a review of potential performance issues. Target should not be interpreted as intention to worsen performance.

4. 2029 Target

The 2029 target reflects a 5-year outlook target demonstrating continued focus on improvement year-over-year.   This target demonstrates continued focus on improvement year-over-year. PG&E continues to review operations and look for opportunities to perform work to further reduce OP events and contribute to system safety. However, it should be noted that in D.21-11-069 the Commission denied or reduced funding for a number of the Overpressure Elimination mitigation programs in the 2023 General Rate Case final decision, especially in the GD area.[2] It is unknown what impact this will have on the future trend of OP events, but not adopting these programs is expected to decrease the pace of PG&E's mitigation efforts to reduce OP events in the future. Therefore, despite not receiving authorization from the rate case, PG&E continues to fund the OP elimination efforts - although at a reduced pace.

D. (4.2) Performance Against Target

1. Progress Towards the 1-Year Target

In 2024, four overpressure events occurred in PG&E's gas system, which is lower than the Company's 1-year target of equal to or less than 10.

2. Progress Towards the 5-Year Target

As discussed in Section E below, PG&E is deploying several programs to maintain or improve the long-term performance of the Over Pressure metric to meet the Company's 5-year performance target.

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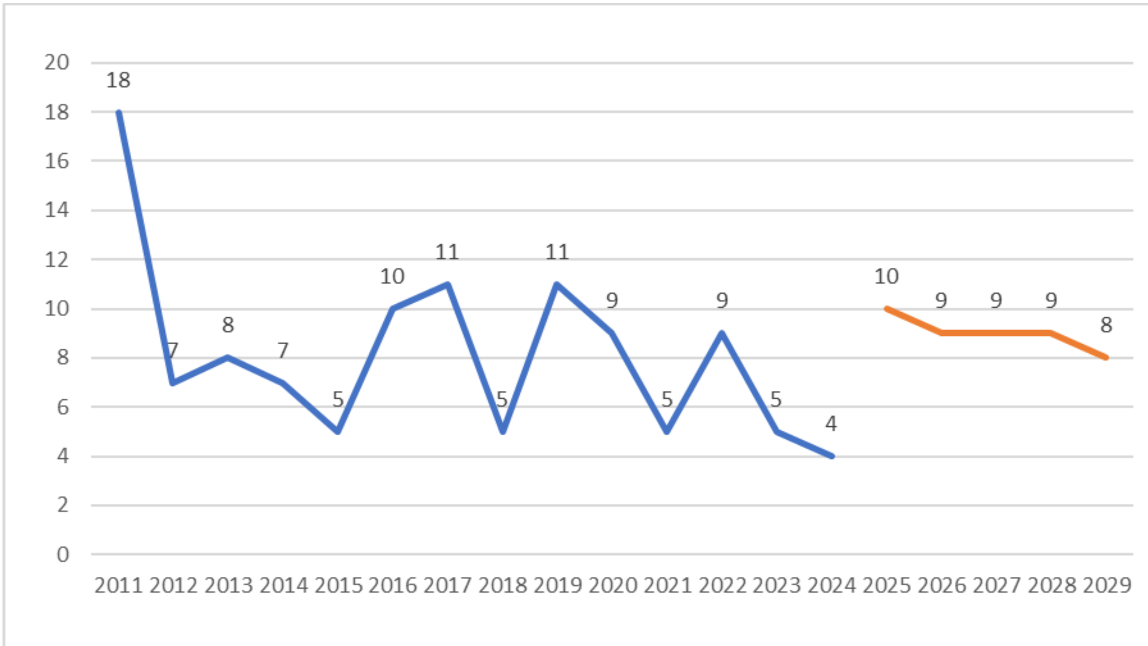
2 The GT and GD Station OPP Enhancement Programs were not adopted by the commission. Similarly, GD SCADA RTU installations were not adopted. All three of these programs are risk mitigations for large OP events.

FIGURE 4.2-2
OVERPRESSURE EVENTS 2011 – 2024 AND TARGETS THROUGH 2029



E. (4.2) Current and Planned Work Activities

PG&E's initial objective included plans to execute the secondary Overpressure Protection Program (OPP) to mitigate common failure mode failure OP events for both GT and GD over a 10-year period (2018-2027). As noted, funding for the following mitigation programs was eliminated in the 2023 GRC decision:

- Gas Distribution: Since the inception of the common failure mode mitigation program through the end of 2024, PG&E has retrofitted approximately 975 GD pilot-operated stations. By end of 2023, PG&E has exceeded the goal of retrofitting 50 percent of GD pilot-operated stations. PG&E will continue the retrofitting of GD pilot-operation stations to mitigate the common failure mode OP events in the Gas Distribution System. These retrofits will be executed at a considerably reduced pace in comparison to what was proposed in the GRC (see footnote 2 on page 4.2-6).
- Gas Transmission: In 2019, PG&E started rebuilding and retrofitting Large Volume Customer Regulators (LVCR) sets specifically to address OP risks and started rebuilding and/or retrofitting Large Volume Customer Meter (LVCM) sets in 2023. Since the inception of the common failure mode mitigation program through the end of 2024, PG&E has rebuilt and/or

retrofitted approximately 115 LVCRs/LVCMs. PG&E will continue modifying GT LVCRs/LVCMs to mitigate the common failure mode OP events in the Gas Transmission System. The modification of this regulation equipment will be executed at a considerably reduced pace in comparison to what was proposed in the 2023 GRC (see footnote 2 on page 4.2-7).

PACIFIC GAS AND ELECTRIC COMPANY

SAFETY AND OPERATIONAL METRICS REPORT:

CHAPTER 4.3

TIME TO RESPOND ON-SITE TO EMERGENCY NOTIFICATION

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TIME TO RESPOND ON-SITE TO EMERGENCY NOTIFICATION

The material updates to this chapter, since the September 30, 2024 report, are identified in blue font.

A. (4.3) Overview

1. Metric Definition

Safety and Operational Metric (SOM) 4.3 – Time to Respond On-Site to Emergency Notification is defined as:

Average time and median time to respond on-site to a gas-related emergency notification from the time of notification to the time a Gas Service Representative (GSR) (or qualified first responder) arrived onsite. Emergency notification includes all notifications originating from 911 calls and calls made directly to the utilities' safety hotlines.

The data used to determine the average time and median time shall be provided in increments as defined in General Order 112-F 123.2 (c) as supplemental information, not as a metric.

2. Introduction of Metric

Gas emergency response measures Pacific Gas and Electric Company's (PG&E) ability to respond with urgency to hazardous or unsafe situations that may be a threat to customer and public safety. In some situations, GSRs respond to emergency situations as first responders. Responding to emergency situations is PG&E's highest priority so that PG&E can prevent or ameliorate hazardous situations. PG&E's goal is to have a GSR on-site as quickly as possible for customer generated gas odor calls. Faster response time to Emergency Notifications reduces the length of emergent situations.

PG&E's GSRs respond to approximately 500,000 gas service customer requests annually. These requests include investigating reports of possible gas leaks; carbon monoxide monitoring; Pilot re-lights; appliance safety checks; and maintenance work, including Atmospheric Corrosion remediation and regulator replacements.

Consistent with current practice, PG&E will continue to treat all customer-reported gas odor calls as Immediate Response (IR) and will attempt to respond to such calls within 60 minutes. To meet this goal, PG&E utilizes industry best practices, such as: mobile data terminals, real-time Global Positioning Systems, backup on-call technicians, and shift coverage of 24 hours a day, seven days a week.

B. (4.3) Metric Performance

1. Historical Data (2011-2024)

Historical data is presented as a value in minutes for response time, indicated as both an average and a median value for all Emergency Notifications for each calendar year.

Data sets prior to 2014 come from historically submitted documentation; data sets from 2014 forward come from the Customer Data Warehouse system (a database for Field Automated Systems (FAS) data) and go through a rigorous, multi-step audit process prior to submission to ensure accuracy and precision.

2. Data Collection Methodology

The response time by PG&E is measured from the time PG&E is notified—defined as the order creation time in Customer Care and Billing by the contact center—to the time a GSR or a PG&E-qualified first responder arrives on-site to the emergency location (including Business Hours and After Hours). PG&E notification time is defined as when a gas emergency order is created and timestamped.

Using PG&E's FAS, the average response time is measured for all IR gas emergency orders generated where a GSR or qualified first responder is required to respond.

The following IR gas emergency jobs are excluded in the total gas emergency orders volume count:

- Level 2 and above emergencies;[1]

[1] Defined in the Gas Emergency Response Plan as a region-wide emergency event that may require 1-2 days for service restoration.

- If the source is a non-planned release of PG&E gas, the original call is included—the gas emergency itself—and all subsequent related orders are excluded;
- If the source is either a planned release of PG&E gas or another non-leak-related event, all related orders from the metric are excluded, including the original call;
  - If technician finds Grade 1 or Class A leak not previously identified by Company personnel, the order will be included in the metric even if the leak was clearly not the source of odor complaint.
- Duplicate orders for assistance;
  - If it's confirmed that internal PG&E personnel made an IR for the wrong address and there are two IRs made for one incident, we will manually adjust the Taken Time of 2nd IR (the correct address) to the actual time the call was created, and then exclude the 1st IR (the incorrect address). For now CDW/BOBJ team will have to manually adjust the Taken Time.
- Cancelled orders;
- For multiple leak calls from the same Multi-Meter Manifold;[2]
- Unknown premise tag with no nearby gas facility; and
- If the FAS system is unavailable—such as during a tech down event—the jobs cannot be created in our system, and are therefore, an exception (not available to be included in the volume).

3. Metric Performance for the Reporting Period

Since 2011, PG&E has improved and maintained strong performance in this metric. In 2024, we have achieved an average response time of 19.6 minutes and a recorded median response time of 18.1 minutes, compared to 19.8 minutes of average response time and 18.2 median response time for the same period in 2023. Our performance in 2024 outperformed target and was our best response time in 8 years as shown in Figure 4.3-1. This was made possible by continued focus by our Field Teams and Gas Dispatch deploying Lean practices, cross collaboration and continued accountability and focus to this metric.

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[2] The first order is included, and all subsequent orders are excluded.

FIGURE 4.3-1
AVERAGE RESPONSE TIME 2017- 2024

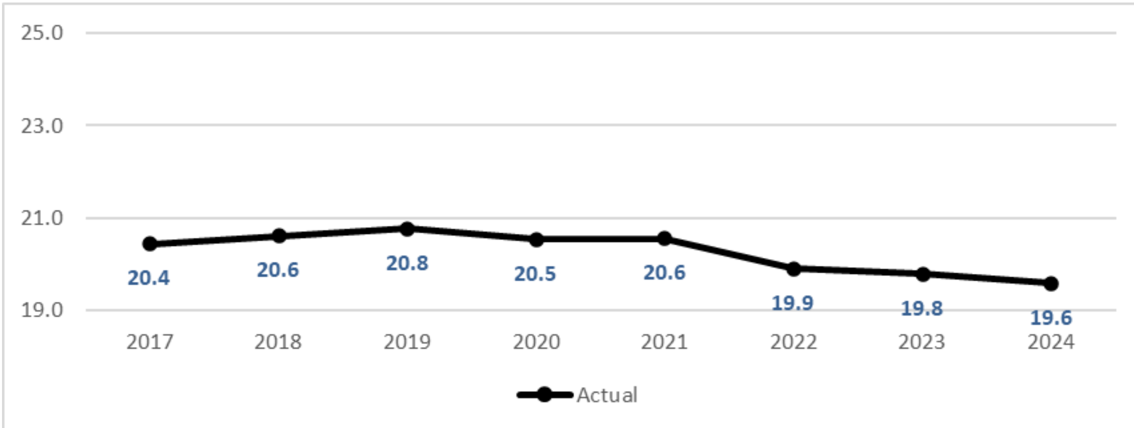
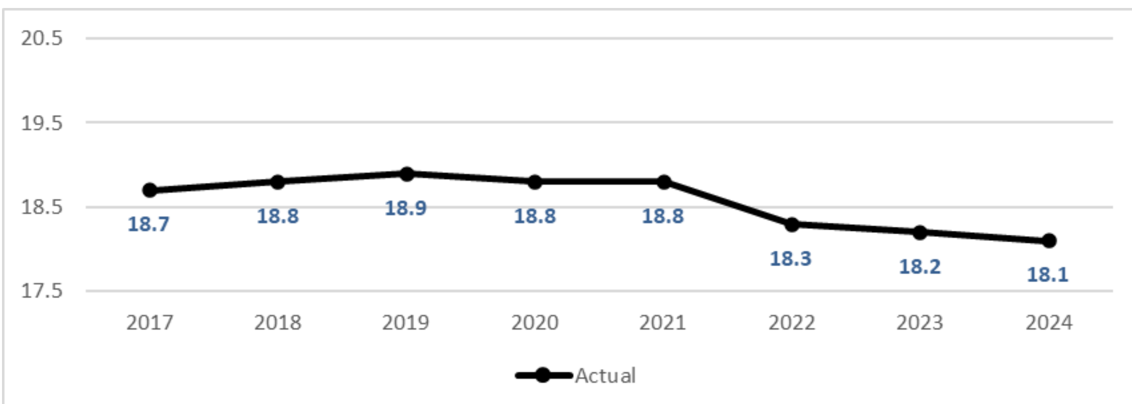


FIGURE 4.3-2
MEDIAN RESPONSE TIME 2017- 2024



C. (4.3) 1-Year Target and 5-Year Target

1. Updates to 1- and 5-Year Targets Since Last Report

Applying the same methodology as in the last SOMs report, there will be a reduction to the 1-year and 5-year targets as described below, reflecting a trend of improved performance.

2. Target Methodology

To establish the 1-year and 5-year targets, PG&E considered the following factors:

- Historical Data and Trends: Comparable data is available starting in 2015. Performance has been consistent from 2015-2024 and maintains top quartile;

- Benchmarking: The targets for average response time and median response time are informed by available benchmarking data and targets are set at a level consistent with strong performance;
- Regulatory Requirements: None;
- Attainable Within Known Resources/Work Plan: Yes;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: Yes, performance at or below the set targets is a sustainable assumption for maintaining average and median response time performance, plus room for non-significant variability; and
- Other Qualitative Considerations: None.

3. 2025 Target

The 2025 target is to maintain performance better than or equal to 21.3 minutes for average response time and 19.6 minutes for median response time, based on the factors described above. These targets represent values that serve as appropriate indicator lights to signal a review of potential performance issues. Targets should not be interpreted as intention to worsen performance.

4. 2029 Target

The 2029 target is to maintain performance better than or equal to 20.9 minutes for average response time and 19.2 minutes for median response time, based on the factors described above. Annual targets should continue to be informed by available benchmarking data.

D. (4.3) Performance Against Target

1. Maintaining Performance Against the 1-Year Target

As demonstrated in Figure 4.3-3 and 4.3-4, PG&E saw an average response time of 19.6 minutes and a median response time of 18.1 minutes in 2024 which exceeded the Company's 2024 target of 21.4 and 19.7 minutes respectively.

2. Maintaining Performance Against the 5-Year Target

As discussed in Section E below, PG&E continues to employ thorough review, auditing, and cross-functional programs to maintain performance in pursuit of the Company's 5-year target.

FIGURE 4.3-3
AVERAGE RESPONSE TIME 2014- 2024 AND TARGETS THROUGH 2029

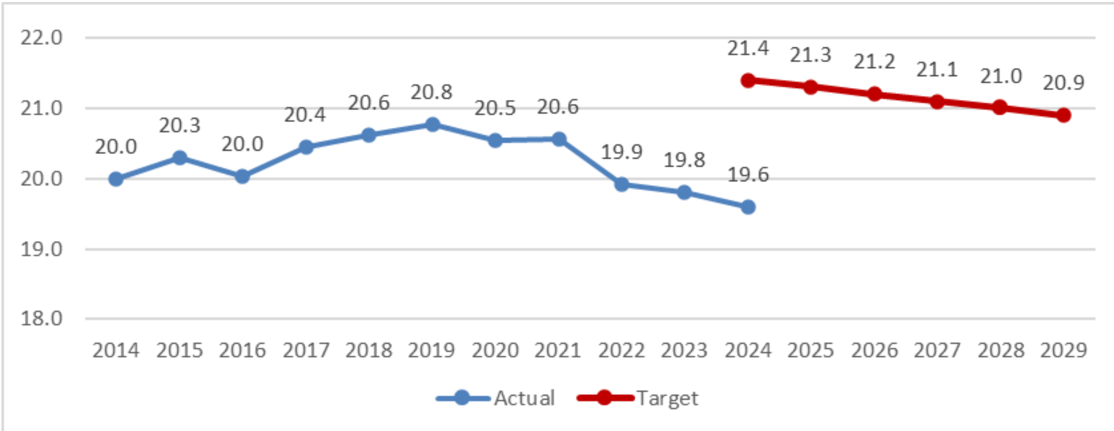
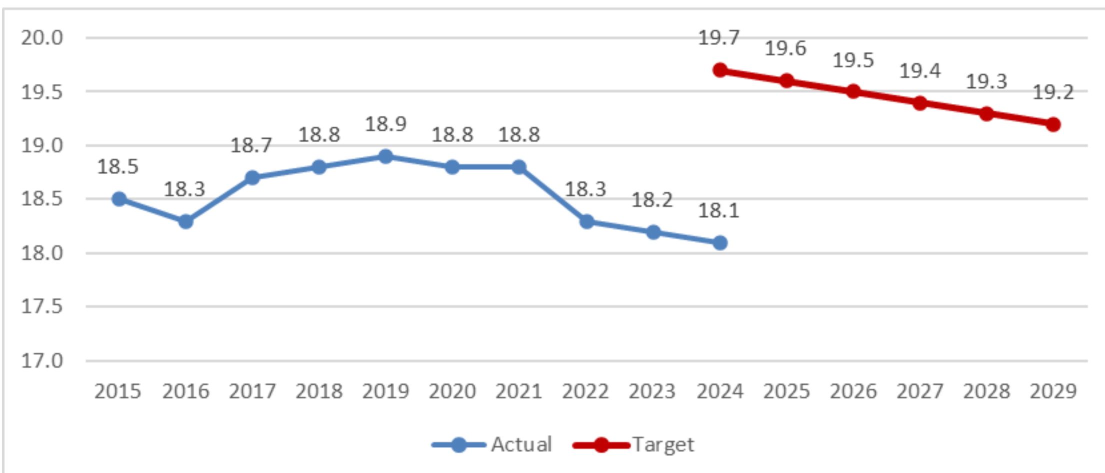


FIGURE 4.3-4
MEDIAN RESPONSE TIME 2015-2024 AND TARGETS THROUGH 2029



E. (4.3) Current and Planned Work Activities

Below is a summary description of the key activities that are tied to performance and their description of that tie.

- Field Service and Gas Dispatch: PG&E's Field Service and Gas Dispatch partner together to respond to customer Gas Emergency (odor calls). There is a shared responsibility in the overall performance of this work. GSRs are deployed systemwide, 24 hours a day—utilizing an on-call as needed;
- Monitoring Controls: Activities which help us to maintain our Gas Emergency Response include continued focus and visibility in our Daily Operating Reviews, Weekly Operating Reviews, and Cross Functional

Reviews. These help to illustrate several key drivers, including Dispatch Handle Time, Drive Time, and Wrap Time; and

- Audits: PG&E performs audits on Emergency calls to identify opportunities.
- Data Analysis: Staffing and historical Gas Emergency Response volume are reviewed to help drive decisions. We utilize Best Practice of Dispatching to the closest resource. In addition, Dispatcher Ride Alongs with GSRs have been implemented to drive cross-functional understanding.

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CHAPTER 4.4

GAS SHUT-IN TIME, MAINS

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A. (4.4) Introduction

1. Metric Definition

Safety and Operational Metric (SOM) 4.4 – Gas Shut-In Time, Mains is defined as:

Median time to shut-in gas when an uncontrolled or unplanned gas release occurs on a main. The data used to determine the median time shall be provided in increments as defined in General Order 112-F 123.2 (c) as supplemental information, not as a metric.

2. Introduction of Metric

The measurement of Gas Shut in Time captures the median duration of time required to respond to and mitigate potentially hazardous gas leak conditions. These leak conditions are associated with the public safety risk of loss of containment on Gas Distribution Main or Service. The term "shut in" refers to the act of stopping the gas flow. It is important for the flow of gas to be stopped to avoid consequences such as overpressure events or explosions and so that work can be safely performed to make repairs in a timely manner. Performance aims for faster response times as a measure of prevention resulting in lower risk of an incident impacting public safety and minimized interruption to the gas business and customers. It is imperative that we promptly and effectively resolve any hazardous conditions on our distribution network while balancing timeliness, customer outages, and employee safety.

The timing for the response starts when the Pacific Gas and Electric Company (PG&E, the Company, or the Utility) first receives the report of a potential gas leak and ends when the Utility's qualified representative determines, per the Utility's emergency standards, that the reported leak is not hazardous, a leak does not exist, or the Utility's representative completes actions to mitigate a hazardous leak and render it as being non-hazardous (i.e., by shutting-off gas supply, eliminating subsurface leak migration, repair, etc.) per the Utility's standards.

This metric measures the median number of minutes required for a qualified PG&E responder to arrive onsite and stop the flow of gas as result of damages impacting gas mains from PG&E distribution network. It does not include instances where a qualified representative determines that the reported leak is not hazardous, or a leak does not exist.

B. (4.4) Metric Performance

1. Historical Data (2014 – 2024)

Historical data for shut-in the gas (SITG) Main metric is available for the period 2014 through 2024. The data captures the median time that a qualified first responder requires to respond and stop gas flow during incidents involving an unplanned and uncontrolled release of gas on distribution mains. This data includes incidents related to distribution main pipelines and regulator stations because of third-party dig-ins, vehicle impacts, explosion, pipe rupture, and material failure.

Before 2014, PG&E used a decentralized emergency process to manage emergencies (i.e., each division used its own resources like mappers, planners, among others to track and manage emergencies). Similarly, support organizations like Dispatch, Mapping and Planning used their own management tools to help schedule and manage emergency information. Dispatch used a management tool called Outage Management that recorded times at various stages of the process (i.e., when the emergency call came in, when the Gas Service Representative (GSR) arrived at the site, when the leak was isolated, etc.). The Distribution Control Room used a tool called Gas Logging System to record incoming information.

In 2014, a centralized process was implemented to allow Distribution, Transmission, Dispatch, Planning and Mapping personnel to be co-located and work together as a team to manage emergencies. This centralized process also allowed the development of the Event Management Tool (EMT) system.

2. Data Collection Methodology

The EMT is currently used as the official system to track gas emergencies from start to finish. It is used by Dispatch and Gas Distribution Control Center (GDCC) teams to create emergency events and collect incident information and allows PG&E to run reports and retrieve historical information. The data captures the time that a qualified first responder requires to respond and stop gas flow during incidents involving an unplanned and uncontrolled release of gas on distribution mains. There are distinct types of incidents recorded in the EMT: explosions, corrosion, cross bore, pipe damage, dig-ins, evacuations, exposed pipe—no gas leak, fires, gas leaks (including Grade 1), high concentration areas, Hi/Lo pressures, material failure, pipe ruptures, vehicle impacts, among others. The EMT provides access to the latest information on an incident. All emergency data is consolidated and stored in one place.

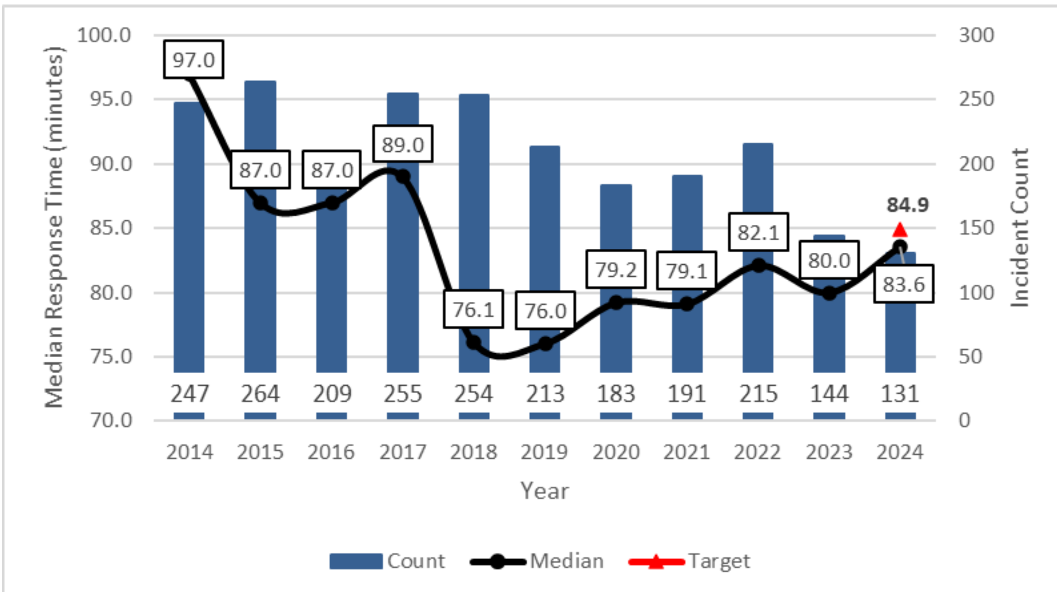
3. Metric Performance for the Reporting Period

The range of data available to calculate the historical shut-in the gas median time for Mains is from 2014 through 2024. Over this reporting period, performance decreased from 97 minutes in 2014 to 83.6 minutes median time in 2024. This long-term improvement is due to strategically prearranging construction crews in locations with high frequency of damages after business hours and weekends, understanding root causes for long shut-in time incidents and sharing best practices system wide during weekly performance review calls.

There is an overall trend in decreased performance from 2019 to 2024. Annual decrease in performance is representative of overall slight fluctuations in performance and is not representative of efforts put forth to improve shut in the gas response time. Delayed response time for mains is under regular evaluation to narrow down root causes. For the 2024 period, the most common reasons for delay included difficult field conditions (i.e., depth of facility), hard soil conditions, traffic, commute, and increased difficulty in isolation.

While there is an upward trend of median response time over the past five years, it is important to note the total count of incidents has decreased significantly in that time. Decreased overall annual volume influences the median response time and impacts the trends we observed. Decreased incident numbers can be attributed to efforts put forth by damage prevention teams within PG&E.

FIGURE 4.4-1
GAS SHUT-IN TIME, MAINS MEDIAN RESPONSE TIME 2014-2024



Year	Count	Median	Target
2014	247	97.0	
2015	264	87.0	
2016	209	87.0	
2017	255	89.0	
2018	254	76.1	
2019	213	76.0	
2020	183	79.2	
2021	191	79.1	
2022	215	82.1	
2023	144	80.0	
2024	131	83.6	84.9

C. (4.4) 1-Year Target and 5-Year Target

1. Updates to 1- and 5-Year Targets Since Last Report

The 2025 target is set as the average of the annual median times the past 7-years (2018-2024) + 10%. The 2029 target will be flat aligned with 2025 target. This target is set to prioritize the safety of our customers, employees, and to minimize service disruptions by allowing PG&E personnel to make informed shut-in gas isolation decisions according to field conditions rather than hastily take actions to shut-in the gas to meet a more stringent target.

2. Target Methodology

To establish the 1-year and 5-year targets, PG&E considered the following factors:

- Historical Data and Trends: As of 2024,the target was based on the average of the 2018 – 2021 median historical data, plus 10 percent. Starting in 2025, the target is based on the average of the 2018-2024 historical data, plus 10 percent. The seven-year period is being used to include recent performance in target setting calculations. Furthermore, the 7-year period is used because 2018 was when the FAS system was first utilized, and this data period is consistent with current operational practices. The use of 10 percent allows for non-significant variability, and accounts for the consideration of risk during shut in events.
- Benchmarking: Not available;
- Regulatory Requirements: None;
- Attainable Within Known Resources/Work Plan: Yes;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: Yes, performance at or below the average of the 2018-2024 annual median response time plus 10 percent is a sustainable assumption for maintaining the improvement from 2018-2024 time frame plus room for non-significant variability; and
- Other Qualitative Considerations: Reducing shut in time to the lowest possible result is not necessarily the best approach from a public safety standpoint, and there is consideration of risk in various situations. In some instances, the safest decision for our employees and the public is to allow the gas to escape before crews shut it off.

3. 2025 Target

The 2025 target is to maintain performance at or lower than 87.4 minutes based on the factors described above. This target was established to account for the consideration of risk in various situations and aligns with our commitment to the safe operations of our assets. This target represents an appropriate indicator light to signal a review of potential performance issues. Target should not be interpreted as intention to worsen performance.

4. 2029 Target

The 2029 target is to maintain performance at or lower than 87.4 minutes, based on the factors described above.

D. (4.4) Performance Against Target

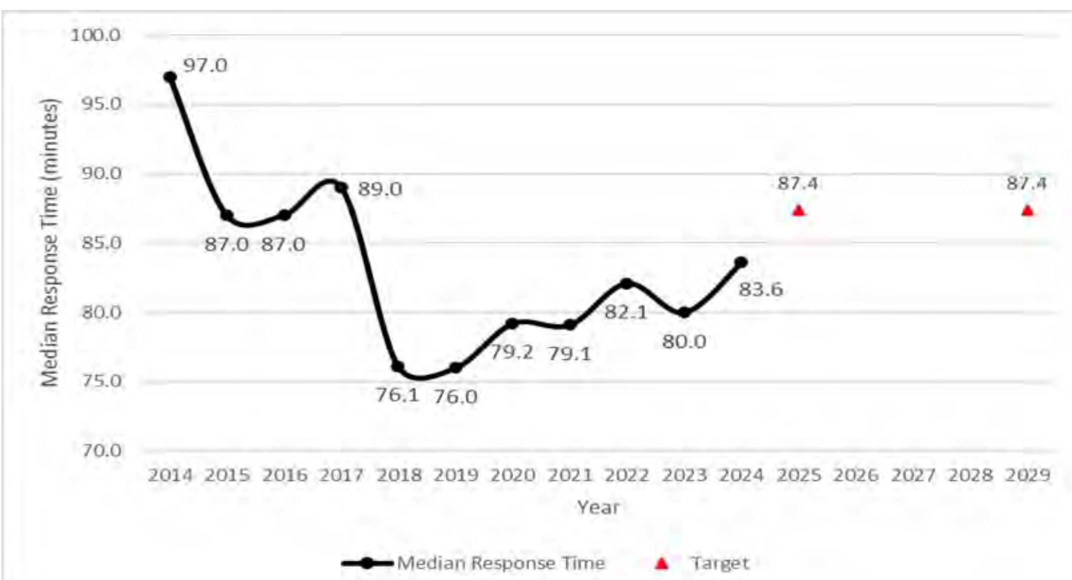
1. Maintaining Performance Against the 1-Year Target

As demonstrated in Figure 4.4-2, PG&E saw a median response time of 83.6 minutes in 2024 which is better than the Company's 1-year target of 84.9 minutes.

2. Maintaining Performance Against the 5-Year Target

As discussed in Section E, PG&E will continue mitigating the risk of loss of containment on Gas Distribution Mains and Services and employing its various programs to maintain performance in its efforts toward its 5-year target.

FIGURE 4.4-2
GAS SHUT IN TIME, MAINS MEDIAN RESPONSE TIME 2014-2024 AND TARGETS THROUGH 2029



E. (4.4) Current and Planned Work Activities

PG&E will continue to drive metric progress through performance management and supervisor-out-in-the-field initiatives. This metric will continue to mitigate the risk of loss of containment on Gas Distribution Main or Service by reducing distribution pipeline rupture with ignition.

The metric is supported by the following programs which focus on improving public safety: Field Services and Gas Maintenance and Construction (M&C).

- Gas Field Service: Field Service responds to gas service requests, which include investigation reports of possible gas leaks, carbon monoxide monitoring, customer requests for starts and stops of gas service, appliance pilot re-lights, appliance safety checks, as well as emergency situations as first responders; and
- Gas Maintenance and Construction: Gas M&C performs routine maintenance of PG&E's gas distribution facilities, which includes emergency response due to dig-ins, as well as leak repairs.

The following process improvement initiatives have been implemented to help achieve metric results:

- Enhanced plastic squeeze capability from approximately 50 percent to all GSRs for < 1.5" plastic pipe;
- Purchased and implemented emergency trailers in every division, allowing for emergency equipment to be accessed quickly and easily;
- Purchased additional steel squeezers for 2-8" steel pipe (housed on emergency trailers);
- Implemented Emergency Management tool (EM tool) to alert maintenance and construction (M&C) of SITG events when notified by third-party emergency organizations;
- Established concurrent response protocol (dispatch M&C and Field Service resources) when notified by emergency agencies. Utility Procedure TD-6100P-03 Major Gas Event Response: Fire, Explosion, and Gas Pipeline Rupture was updated in 2021 to align with PG&E's response and communication protocols; and
- Implemented 30-60-90-120+ minute communication protocols between Gas Distribution Control Center and Incident Commander to ensure consistent communication and issue escalation during events.

The following process improvement initiatives are on-going to help achieve metric results:

- Daily Operating Reviews to identify deviations from the targets for the previous 24 hours and identify countermeasures for continuous improvement;
- Weekly Operating Review meetings weekly to share best practices and review long duration events;
- Provide yearly plastic squeeze training for all Field Service employees as part of Operator Qualification refresher;
- Live action drills to simulate emergency scenarios, practicing isolation procedures and documenting lessons learned;
- Time duration threshold to review incidents during Gas Daily Briefings reduced from >120 to > 90 minutes;
- Dispatching two M&C crews along with an excavation truck to assist in excavation timeliness;
- Dispatching locate and mark representative upon initial discovery to assist in leak location prior to M&C crew arrival;
- Dispatch initiating underground service alerts followed by immediate notification to allow for immediate marking of facilities;
- Increasing number of isolation valves along a pipeline for ease of isolation; and
- Pilot process to have General Construction crews provide emergency support if Division M&C Crews not available due to rest period (pilot program in San Jose, Fresno and Bakersfield).

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SAFETY AND OPERATIONAL METRICS REPORT:

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GAS SHUT IN TIME, SERVICES

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A. (4.5) Overview

1. Metric Definition

Safety and Operational Metric 4.5 – Gas Shut-In Time, Services is defined as:

Median time to shut-in gas when an uncontrolled or unplanned gas release occurs on a service. The data used to determine the median time shall be provided in increments as defined in General Order 112-F 123.2 (c) as supplemental information, not as a metric.

2. Introduction of Metric

The measurement of Gas Shut-In Time captures the median duration of time required to respond to and mitigate potentially hazardous gas leak conditions. These leak conditions are associated with the public safety risk of loss of containment on Gas Distribution Main or Service. The term “shut-in” refers to the act of stopping the gas flow. It is important for the flow of gas to be stopped to avoid consequences such as overpressure events or explosions and so that work can be safely performed to make repairs in a timely manner. Performance aims for faster response times as a measure of prevention resulting in lower risk of an incident impacting public safety and minimized interruption to the gas business and customers. It is imperative that we promptly and effectively resolve any hazardous conditions on our distribution network while balancing timeliness, customer outages, and employee safety.

The timing for the response starts when Pacific Gas and Electric Company (PG&E, the Company, or the Utility) first receives the report of a potential gas leak and ends when the Utility’s qualified representative determines, per the Utility’s emergency standards, that the reported leak is not hazardous, a leak does not exist, or the Utility's representative completes actions to mitigate a hazardous leak and render it as being non-hazardous (e.g., by shutting-off gas supply, eliminating subsurface leak migration, repair, etc.) per the Utility's standards.

This metric measures the median number of minutes required for a qualified PG&E responder to arrive onsite and stop the flow of gas as result of damages impacting gas mains from PG&E distribution network. It does not include instances where a qualified representative determines that the reported leak is not hazardous, or a leak does not exist.

B. (4.5) Metric Performance

1. Historical Data (2014 – 2024)

Historical data for Shut-In the gas (SITG) Services metric is available for the period 2014 – 2024. The data captures the median time that a qualified first responder is required to respond and stop gas flow during incidents involving an unplanned and uncontrolled release of gas on services. This data includes incidents related to distribution services and related components such as service lines, valves, risers, and meters due to third party dig-ins, vehicle impacts, explosion, pipe rupture, and material failure.

Before 2014, PG&E used a decentralized emergency process to manage emergencies, i.e., each division used its own resources like mappers, planners, among others to track and manage emergencies. Similarly, support organizations like Dispatch, Mapping and Planning used their own management tools to help schedule and manage emergency information. Dispatch used a management tool called Outage Management that recorded times at various stages of the process (i.e., when the emergency call came in, when the Gas Service Representative (GSR) arrived at the site, when the leak was isolated, etc.). The Distribution Control Room used a tool called Gas Logging System to record incoming information.

In 2014, a centralized process was implemented to allow Distribution, Transmission, Dispatch, Planning and Mapping personnel to be co-located and work together as a team to manage emergencies. This centralized process also allowed the development of the Event Management Tool (EMT) system.

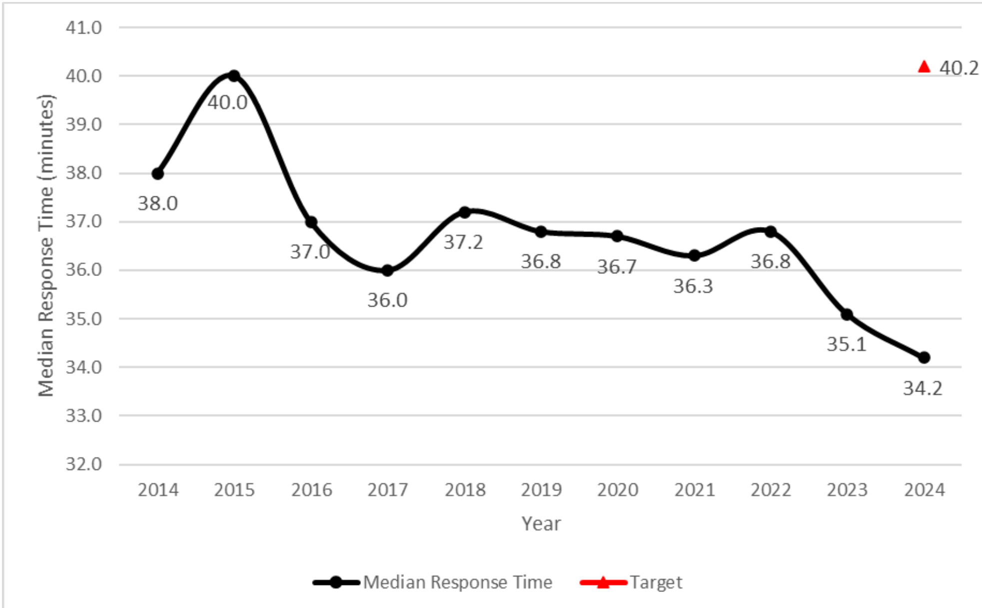
2. Data Collection Methodology

The EMT is currently used as the official system to track gas emergencies from start to finish. The EMT is used by Dispatch and Gas Distribution Control Center (GDCC) teams to create emergency events and collect incident information and allows PG&E to run reports and retrieve historical information. There are distinct types of incidents recorded in the EMT: explosions, corrosion, cross bore, pipe damage, dig-ins, evacuations, exposed pipe—no gas leak, fires, gas leaks (including Grade 1), high concentration areas, Hi/Lo pressures, material failure, pipe ruptures, vehicle impacts, among others. The EMT provides access to the latest information on an incident. All emergency data is consolidated and stored in one place.

3. Metric Performance for the Reporting Period

The range of data available to calculate the historical SITG median time for Services is from 2014 to 2024. Over this reporting period, performance improved by 10 percent, decreasing from 38.0 minutes in 2014 to 34.2 minutes in 2024. This response time represents an improvement of 2.6 percent compared to 2023 end of year results. This improvement is due to strategically prearranging construction crews in locations with high frequency of damages after business hours and weekends, understanding root causes for long shut-in time incidents, sharing best practices system wide during weekly performance review calls, and First Responders personnel squeezing services on arrival when possible.

FIGURE 4.5-1
GAS SHUT IN TIME, SERVICES MEDIAN RESPONSE TIME 2014-2024



C. (4.5) 1-Year Target and 5-Year Target

1. Updates to 1-Year and 5-Year Targets Since Last Report

The 2025 target is set as the average of the annual median times the past 7-years (2018-2024) + 10%. The 2029 target will be flat aligned with 2025 target.

2. Target Methodology

To establish the 1-year and 5-year targets, PG&E considered the following factors:

- Historical Data and Trends: As of 2024, the target was based on the average of the 2018 - 2021 median historical data, plus 10 percent. Starting in 2025, the target is based on the average of the 2018-2024 historical data, plus 10 percent. The seven-year period is being used to include recent performance in target setting calculations. Furthermore, the seven-year period is used because 2018 was when the FAS system was first utilized, and this data period is consistent with current operational practices. The use of 10 percent allows for non-significant variability, and accounts for the consideration of risk during shut in events;
- Benchmarking: Not available;

- Regulatory Requirements: None;
- Attainable Within Known Resources/Work Plan: Yes;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: Yes, performance at or below the average of the 2018-2024 annual median response time plus 10 percent is a sustainable assumption for maintaining the improvement from 2018-2024 time-frame plus room for non-significant variability; and
- Other Qualitative Considerations: Reducing shut in time to the lowest possible result is not necessarily the best approach from a public safety standpoint, and there is consideration of risk in various situations. In some instances, the safest decision for our employees and the public is to allow the gas to escape before crews shut it off.

3. 2025 Target

The 2025 target is to maintain performance at or lower than 39.8 minutes based on the factors described above. This target was established to account for the consideration of risk in various situations and aligns with our commitment to the safe operations of our assets. This target represents an appropriate indicator light to signal a review of potential performance issues. Target should not be interpreted as intention to worsen performance.

4. 2029 Target

The 2029 target is to maintain performance at or lower than 39.8 minutes based on the factors described above.

D. (4.5) Performance Against Target

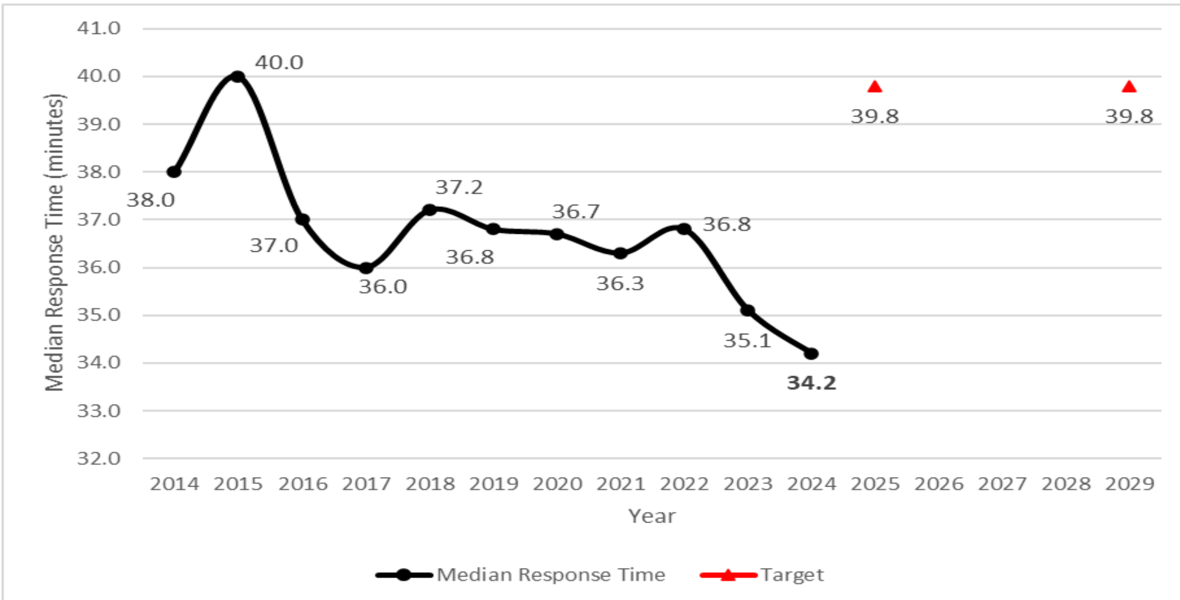
1. Maintain Performance Against the 1-Year Target

As demonstrated in Figure 4.5-2, PG&E saw a median response time of 34.2 minutes in 2024, which is better than the Company's 1-year target of 40.2 minutes.

2. Maintain Performance Against the 5-Year Target

As discussed in Section E, PG&E will continue mitigating the risk of loss of containment on Gas Distribution Mains and Services and employing its various programs to maintain performance in its efforts toward its 5-year target.

FIGURE 4.5-2
GAS SHUT IN TIME, SERVICES MEDIAN RESPONSE TIME 2014-2024 AND TARGETS THROUGH 2029



E. Current and Planned Work Activities

PG&E will continue to drive metric progress through performance management and supervisor-out-in-the-field initiatives. This metric will continue to mitigate the risk of loss of containment on Gas Distribution Main or Service by reducing distribution pipeline rupture with ignition.

The metric is supported by the following programs which focus on improving public safety: Field Services and Gas Maintenance and Construction (M&C).

Gas Field Service: Field Service responds to gas service requests, which include investigation reports of possible gas leaks, carbon monoxide monitoring, customer requests for starts and stops of gas service, appliance pilot re-lights, appliance safety checks, as well as emergency situations as first responders.

Gas M&C: Gas M&C performs routine maintenance of PG&E's gas distribution facilities, which includes emergency response due to dig-ins, as well as leak repairs.

The following process improvement initiatives have been implemented to help achieve metric results:

- Enhanced plastic squeeze capability from approximately 50 percent to all GSRs for < 1.5" plastic pipe.

- Purchased and implemented emergency trailers in every division, allowing for emergency equipment to be accessed quickly and easily.
- Purchased additional steel squeezers for 2-8” steel pipe (housed on emergency trailers).
- Implemented Emergency Management tool (EM tool) to alert M&C of SITG events when notified by third-party emergency organizations.
- Established concurrent response protocol (dispatch M&C and Field Service resources) when notified by emergency agencies. Utility Procedure TD-6100P-03 Major Gas Event Response: Fire, Explosion, and Gas Pipeline Rupture was updated in 2021 to align with PG&E’s response and communication protocols.
- Implemented 30-60-90-120+ minute communication protocols between GDCC and Incident Commander to ensure consistent communication and issue escalation during events.

The following process improvement initiatives are on-going to help achieve metric results:

- Daily Operating Reviews to identify deviations from the targets for the previous 24 hours and identify countermeasures for continuous improvement.
- Weekly Operating Review meetings weekly to share best practices and review long duration events.
- Provide yearly plastic squeeze training for all Field Service employees as part of Operator Qualification refresher.
- Live action drills to simulate emergency scenarios, practicing isolation procedures and documenting lessons learned.
- Time duration threshold to review incidents during Gas Daily Briefings reduced from >120 to > 90 minutes.
- Dispatching locate and mark representative upon initial discovery to assist in leak location prior to M&C crew arrival.
- Dispatch initiating underground service alerts followed by immediate notification to allow for immediate marking of facilities.
- Pilot process to have General Construction crews provide emergency support if Division M&C Crews not available due to rest period (pilot program in San Jose, Fresno and Bakersfield).

PACIFIC GAS AND ELECTRIC COMPANY

SAFETY AND OPERATIONAL METRICS REPORT:

CHAPTER 4.6

UNCONTROLLED RELEASE OF GAS ON

TRANSMISSION PIPELINES

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UNCONTROLLED RELEASE OF GAS ON TRANSMISSION PIPELINES

The material updates to this chapter, since the September 30, 2024 report, are identified in blue font.

A. (4.6) Overview

1. Metric Definition

Safety and Operational Metrics (SOM) 4.6 – Uncontrolled Release of Gas on Transmission Pipelines is defined as:

The number of leaks, ruptures, or other loss of containment on transmission lines for the reporting period, including gas releases reported under Title 49 Code of Federal Regulations (CFR) Part 191.3.

2. Introduction of Metric

This metric tracks the total number of Grade 1, 2, and 3 leaks, as well as ruptures and other losses of containment on gas transmission (GT) pipelines. Leaks are an important indicator because each leak's uncontrolled flow of gas into the surrounding area can increase the consequence of incidents and cause disruption to our customers' gas service. Leaks are also an important indicator in evaluating the likelihood for where other incidents could occur due to similar criteria or conditions.

B. (4.6) Metric Performance

1. Historical Data (2016 – 2021)

Pacific Gas and Electric Company (PG&E) started by reviewing six years of historical data, comprising the years 2016 through 2021. In evaluating the data, PG&E noted changes in detection capabilities and frequency of surveys for the years after 2018. For this reason, the data used to develop these metrics is focused on 2019-2021.

2. Data Collection Methodology

Leak data is managed and pulled by the PG&E Leak Survey Process team. This data is extracted from PG&E's GCM013 report using SAP data.

This report aggregates all leaks found during the reporting period including the location, line type, and grade of leak. Original grade is used for the metric criteria because it is not subject to change even if the leak condition or status changes due to regrade, cancelation, or repair.

In addition, transmission incidents reported to Pipeline and Hazardous Materials Safety Administration (PHMSA) that meet the incident reporting definition in CFR 191.3 are considered for metric inclusion. These events may be leaks, ruptures, or other incidents. For each reporting period, PG&E will review any transmission incidents reported to PHMSA and compare against the GCM013 leaks using available information like incident location (Route/MP, latitude/longitude, or street address) and date/time of incident to remove any duplicates between the two datasets.

3. Metric Performance for the Reporting Period

The annual count of all leaks, ruptures, and loss of containment had been increasing steadily since 2016, with the largest increase seen from 2018 to 2019. This increase is primarily due to a California Air Resources Board (CARB) rule change which requires more frequent leak surveys. The increase has improved visibility and resulted in a larger leak dataset relative to prior years. In March 2017, CARB finalized and approved the Oil and Gas Greenhouse Gas (GHG) Rule codified under California Code of Regulations, Title 17, Division 3, Chapter 1, Subchapter 10, "Climate Change," Article 4. Effective January 1, 2018, the GHG Rule covers emission standards, including, but not limited to, stringent leak detection and repair requirements for facilities in certain Oil and Gas sectors. This rule applies to PG&E's underground natural gas storage facilities and GT compressor stations. As a result, PG&E performs a quarterly leak survey at the impacted facilities and performs leak repairs based on CARB's repair timelines. Overall, the 1801 leaks and 1 PHMSA reportable gas release incident found in 2024 are trending well below the baseline established using the 2019 – 2021 leak history. While there is an uptick in the number of leaks found in 2024, compared to the 1350 leaks found in 2023, the proactive maintenance performed, and replacement of components as required by CARB Oil and Gas Rule have contributed to the overall decline in transmission leaks since the high in 2020.

FIGURE 4.6-1
LEAKS BY GRADE TYPE 2016 – 2024

Note: Figure 4.6-1 does not contain the 1 count of PHMSA gas release reportable incident.

C. (4.6) 1-Year Target and 5-Year Target

1. Updates to 1- and 5-Year Targets Since Last Report

There have been no changes to the 1-year and 5-year target methodology since the last SOMs report filing. Applying this methodology, the targets have been updated as described below.

2. Target Methodology

To establish the 1-Year and 5-Year targets, PG&E considered the following factors:

- Historical Data and Trends: The targets are based on annual 1 percent reduction starting with the average of the three years of historical data between 2019-2021. Those three years were used as the timeframe most representative of current leak survey practices.
- Benchmarking: Not available;
- Regulatory Requirements: None;
- Attainable Within Known Resources/Work Plan: Yes;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: Yes, performance at or below the average of the past three years (2019-2021) is a sustainable assumption and allows for non-significant variability; and

- Other Qualitative Considerations: The target also takes into consideration that the results for this metric may fluctuate based on miles of leak surveys performed and changing CARB requirements. The number of leaks found has a correlative relationship to the miles of leak surveys performed and number of components surveyed. While this is a positive impact for risk visibility and mitigation, it can be a driver of varying trends appearing in the results.

3. 2025 Target

The 2025 target is to maintain performance at or lower than 3,440 leaks, ruptures, or other loss of containment on GT pipelines. This proposed target is based on the average of total leaks found from 2019-2021 (3,545 leaks, ruptures, or other loss of containment on GT pipelines). Then the 1 percent annual reduction is applied to this baseline target which could be impacted by the factors described above, see Figure 4.6.2. This target aligns with our commitment to improved performance from the baseline established from the 2019-2021 results. This target represents an appropriate indicator light to signal a review of potential performance issues. Even though the target is set at a performance level higher than 2024 performance, it should not be interpreted as intention to worsen performance.

4. 2029 Target

The 2029 target is to maintain performance at or lower than 3,304 events, which reflects a continued focus on improvement year over year and is based on the factors described above.

D. (4.6) Performance Against Target

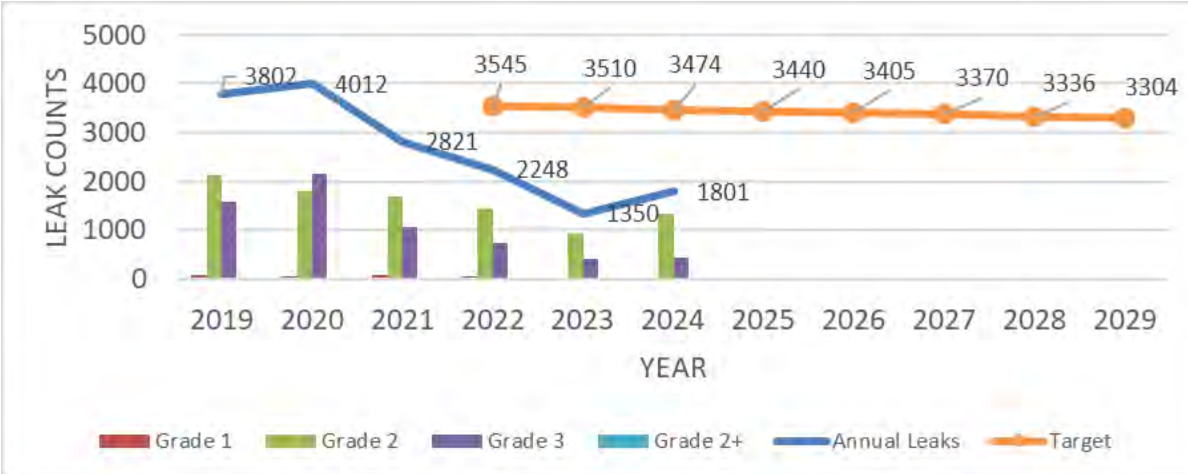
1. Maintaining Performance Against the 1-Year Target

Figure 4.6-3 demonstrates that PG&E identified 1802 unintended gas release events (1801 leaks and 1 PHMSA reportable incident) in 2024, which is 48 percent less than the Company's 1-year target of 3,474 unintended gas release events.

2. Progress Towards/Deviation From the 5-Year Target

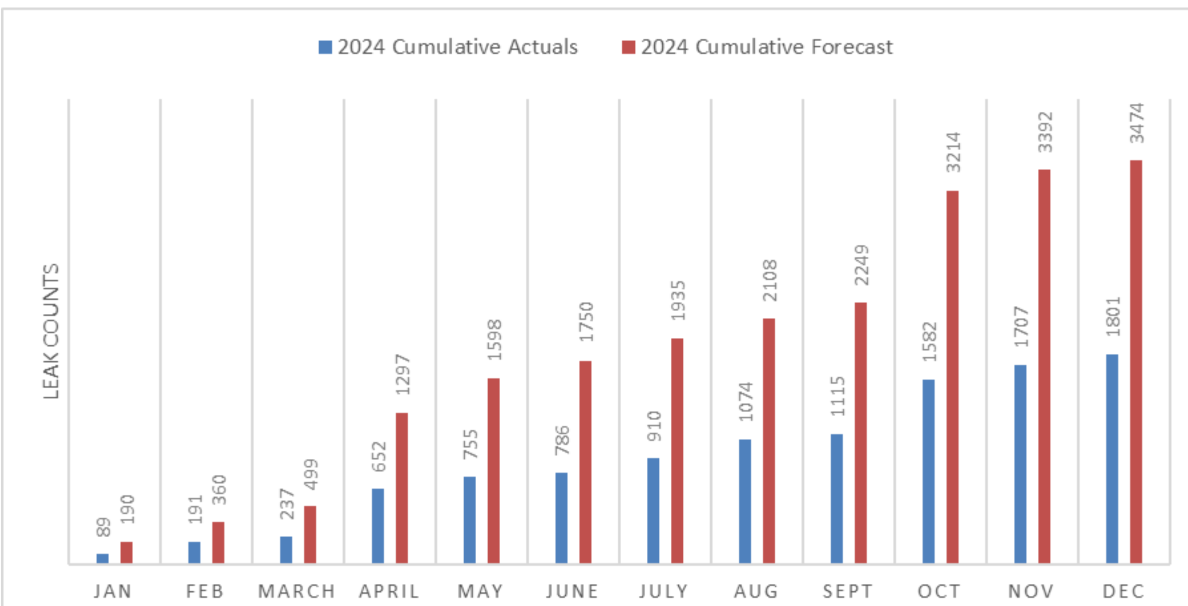
As discussed in Section E, PG&E continues using surveys and assessments, risk mitigation, and its programs to achieve the Company's 5-year performance target.

FIGURE 4.6-2
LEAKS BY GRADE TYPE 2019 – 2024 AND TARGETS THROUGH 2029



Note: Figure 4.6-2 does not contain the 1 count of PHMSA gas release reportable incident.

FIGURE 4.6-3
UNCONTROLLED RELEASE OF GAS INCIDENTS THROUGH 2024



Note: Figure 4.6-3 does not contain the 1 count of PHMSA gas release reportable incident.

E. (4.6) Current and Planned Work Activities

The primary programs that support the risk reduction goals of this metric are Transmission Integrity Management and Leak Management.

- Transmission Integrity Management: The Integrity Management Program provides the tools and processes for risk ranking and prioritization of remediation efforts. This program enables PG&E to focus on identifying and remediating threats to its system. The Transmission Integrity Management Program (TIMP) assesses the threats on every segment of transmission pipe, evaluates the associated risks, and acts to prevent or mitigate these threats. The TIMP approach for assessing risk is based on methodologies consistent with American Society of Mechanical Engineers B31.8S and is in compliance with 49 CFR Part 192 Subpart O. Many of PG&E's programs that mitigate, and control transmission pipe asset risks are developed and managed within the TIMP program. Examples of assessments or mitigative work that contribute to reducing or preventing significant incidents include strength testing, inline inspection, direct assessment, direct examination, and pipe replacement.
- Leak Management: The Leak Management Program addresses the risk of Loss of Containment (LOC) by finding and fixing leaks. PG&E performs leak survey of the GT and storage system twice per year, by either ground or aerial methods in accordance with General Order 112-F. Leak surveys of pipeline and equipment are commonly accomplished on foot or vehicle, by operator-qualified personnel, using a portable methane gas leak detector. Aerial leak surveys, in remote locations and areas difficult to access on the ground, are performed by helicopter using Light Detection and Ranging Infrared technology. Additional activities that complement the TIMP include risk-based leak surveys, mobile leak quantification, and replacing/removing high bleed pneumatic devices at compressor stations and storage facilities.
- In-line Inspection (ILI): In-line inspection is the most effective integrity assessment tool for identifying and repairing pipe anomalies whose continued growth could result in loss of containment. To utilize ILI, a pipeline must be upgraded to allow the passage of the ILI tools. PG&E plans on performing ILI upgrades at a pace of 4 upgrades per year. At the end of 2024, PG&E has 58 percent of the system capable of ILI. Work

during the 2023 rate case period will contribute to PG&E's overall goal of upgrading the system so that 65 percent of PG&E's GT pipeline miles, are capable of ILI by end of 2038.

- External Corrosion Direct Assessment (ECDA): PG&E expects to conduct ECDA indirect inspections on approximately 268 miles of transmission pipeline in HCAs during the rate case period. ECDA indirect inspections assess the cathodic protection and coating condition of pipelines to identify locations for direct examinations of the pipeline. These inspections and direct examinations inform mitigations needed to enhance cathodic protection and ensure external corrosion and the resulting leaks are minimized.
- Close Interval Survey: PG&E also has a Close Interval Survey (CIS) Program targeted at monitoring the effectiveness of the transmission pipelines' cathodic protection (CP) systems by reading the CP levels between the annual monitoring locations. This program annually assesses 3-10 percent of PG&E's gas transmission pipelines. Assessing the levels of CP between test points provides increased confidence that the readings obtained at test stations reflect conditions along the entire system and enable PG&E to make CP adjustments where CIS indicates additional CP is warranted. CIS is recognized as a best practice to assess CP along the entire pipeline, verify electrical isolation, and identify potential interference gradients that may compromise the integrity of the system.
- Strength Testing: Strength tests reduce significant loss of containment incidents like ruptures by confirming the integrity of a pipeline at its Maximum Allowable Operating Pressure (MAOP). They are conducted as a qualifying test for MAOP reconfirmation and for integrity assessments when:
  - Class location changes.
  - A Section of pipe lacks a Traceable, Verifiable, and Complete (TVC) record of a test that supports the MAOP, per 192.624 and PUC 958; or
  - As an integrity assessment to verify pipeline integrity.

Currently, approximately 90 percent of PG&E's GT pipelines have a TVC strength test. For the pipelines lacking TVC records, PG&E is prioritizing the pipelines in HCAs, MCAs, Class 3 and 4 in order to meet the 2028 and 2035 compliance dates specified in 192.624. After these compliance dates are met, PG&E will work to complete the remaining transmission pipelines required by PUC 958.

PACIFIC GAS AND ELECTRIC COMPANY

SAFETY AND OPERATIONAL METRICS REPORT:

CHAPTER 4.7

TIME TO RESOLVE HAZARDOUS CONDITIONS

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The material updates to this chapter, since the September 30, 2024 report, are identified in blue font.

A. (4.7) Overview

1. Metric Definition

Safety and Operational Metric (SOM) 4.7 – Time to Resolve Hazardous Conditions (TRHC) is described as:

Median response time to resolve Grade 1 leaks. Time starts when the utility first receives the report and ends when a utility's qualified representative determines, per the utility's emergency standards, that the reported leak is not hazardous or the utility's representative completes actions to mitigate a hazardous leak and render it as being non-hazardous (i.e., by shutting-off gas supply, eliminating subsurface leak migration, repair, etc.) per the utility's standards.

The data used to determine the Median Time shall be provided in increments as defined in General Order 112-F 123.2 (c) as supplemental information, not as a metric.

2. Introduction of Metric

The measurement of TRHC captures the duration of time required to mitigate hazardous gas leak conditions. These leak conditions are associated with the public safety risk of loss of containment on Gas Distribution Main or Service. Performance aims for faster resolution times as a measure of prevention resulting in lower risk of an incident impacting public safety and minimized interruption to the gas business and customers. It is imperative that we promptly and effectively resolve any hazardous conditions on our distribution network while balancing timeliness, customer outages, and employee safety. Long duration blowing gas events have the potential to negatively impact public safety if an ignition source is present, as well as it poses a risk if migration into sub-surface structures occurs.

B. (4.7) Metric Performance

1. Historical Data (2018 – 2024)

Historical data for TRHC Grade 1 Leaks metric is available for 2018 – 2024. The data captures the time that a qualified first responder requires to respond and stop gas flow due to Grade 1 leaks. This data includes leaks identified in our distribution system and includes all facility types, i.e., customer facilities, service and main pipelines, meters, regulator stations, service risers, valves. It includes leaks identified by Pacific Gas and Electric Company (PG&E) personnel only and with a final resolution of leak repaired.

Before 2014, PG&E used a decentralized emergency process to manage emergencies (i.e., each division used its own resources like mappers, planners, among others to track and manage emergencies). Similarly, support organizations like Dispatch, Mapping and Planning used their own management tools to help schedule and manage emergency information. Dispatch used a management tool called Outage Management that recorded times at various stages of the process (i.e., when the emergency call came in, when the Gas Service Representative arrived at the site, when the leak was isolated, etc.). The Distribution Control Room used a tool called Gas Logging System to record incoming information.

In 2014, a centralized process was implemented to allow Distribution, Transmission, Dispatch, Planning and Mapping personnel to be co located and work together as a team to manage emergencies. This centralized process also allowed the development of the Event Management Tool (EMT) system which was implemented in 2018.

PG&E started tracking gas flow stop times for Grade 1 leaks in 2018 although this has not been a mandatory requirement, except when the incident is California Public Utilities Commission or Department of Transportation reportable.

2. Data Collection Methodology

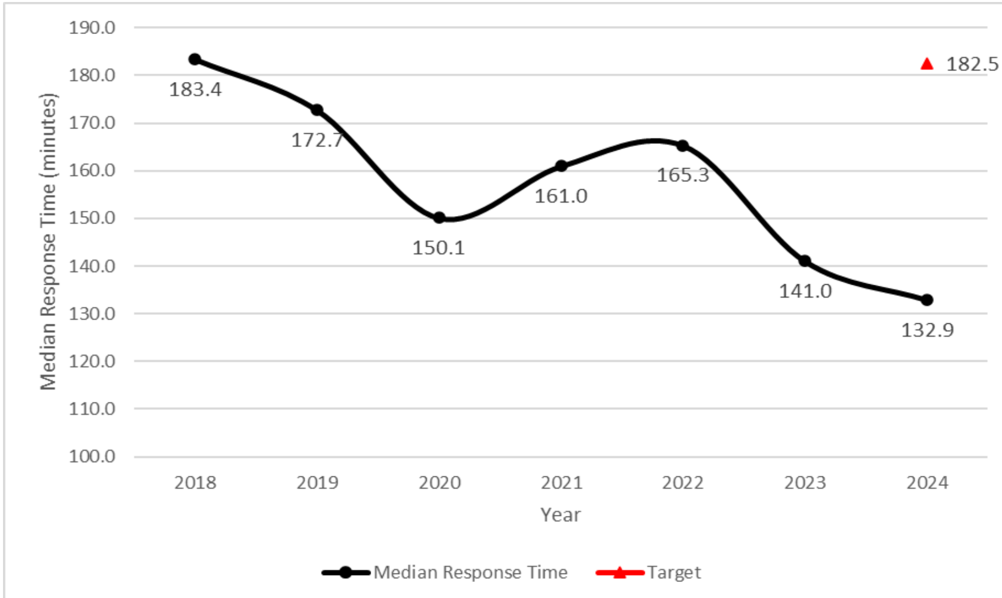
The EMT is currently used as the official system to track gas emergencies from start to finish. The EMT provides access to latest information on an incident. All emergency data is consolidated and stored in one place.

The EMT is used by Dispatch and Gas Distribution Control Center teams to create emergency events and collect incident information. It also allows us to run reports and retrieve historical information. There are distinct types of incidents recorded in the EMT: explosions, corrosion, cross bore, pipe damage, dig-ins, evacuations, exposed pipe—no gas leak, fires, gas leaks (including Grade 1), high concentration areas, Hi/Lo pressures, material failure, pipe ruptures, vehicle impacts, among others. No transmission events are included in the metric.

3. Metric Performance for Reporting Period

The range of data available to calculate the historical TRHC for Grade 1 leaks is from 2018 to 2024. In this timeframe, performance improved significantly, decreasing from 183.4 minutes in 2018 to 132.9 minutes in 2024. The performance in 2024 represents a 5.7 percent improvement over the performance of 141.0 minutes in 2023. This improvement is due to strategically prearranging construction crews in locations with high frequency of Grade 1 leaks after business hours and weekends, understanding root causes for long shut-in time incidents, sharing best practices system wide during weekly performance review calls, and improved partnership between Field Service and Maintenance and Construction (M&C) organizations.

FIGURE 4.7-1
TIME TO RESOLVE HAZARDOUS CONDITIONS MEDIAN RESPONSE TIME 2018-2024



C. (4.7) 1-Year Target and 5-Year Target

1. Updates to 1- and-5-Year Targets Since Last Report

The 2025 target is set as the average of the annual median times the past 7-years (2018-2024) + 10 percent. The 2029 target demonstrates a continued focus on improvement by reducing an additional 0.5 minutes each subsequent year.

2. Target Methodology

To establish the 1-year and 5-year targets, PG&E considered the following factors:

- Historical Data and Trends: As of 2024, the target was based on the average of the 2018-2021 historical data, plus 10 percent. Starting in 2025, the target is based on the average of the 2018-2024 historical data, plus 10 percent. The seven-year period is being used to include recent performance. The seven-year period was used because 2018 is the first year of available historical data. The use of 10 percent allows for non-significant variability, as well as unknown variability given that this is a new metric that has not been well measured and tracked in the past.
- Benchmarking: Not available;

- Regulatory Requirements: None;
- Attainable Within Known Resources/Work Plan: Yes;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: Yes, performance at or below the average of the 2018-2024 period, plus 10 percent, is a sustainable assumption for maintaining the improvement from 2018-2024 time-frame, plus room for non-significant variability and other unknown variables; and
- Other Qualitative Considerations: This is a new metric to PG&E that has not yet been closely tracked or well understood.

3. 2025 Target

The 2025 target is to maintain performance at or lower than 173.9 minutes based on the factors described above. 2025 target is the average of the annual median times the past 7-years (2018-2024) + 10 percent This target aligns with our commitment to the safe operations of our assets. This target represents an appropriate indicator light to signal a review of potential performance issues. Target should not be interpreted as intention to worsen performance.

4. 2029 Target

The 2029 target is to maintain performance at or lower than 171.9 minutes based on the factors described above along with stepped improvement of 0.5 minutes year-over-year.

D. (4.7) Performance Against Target

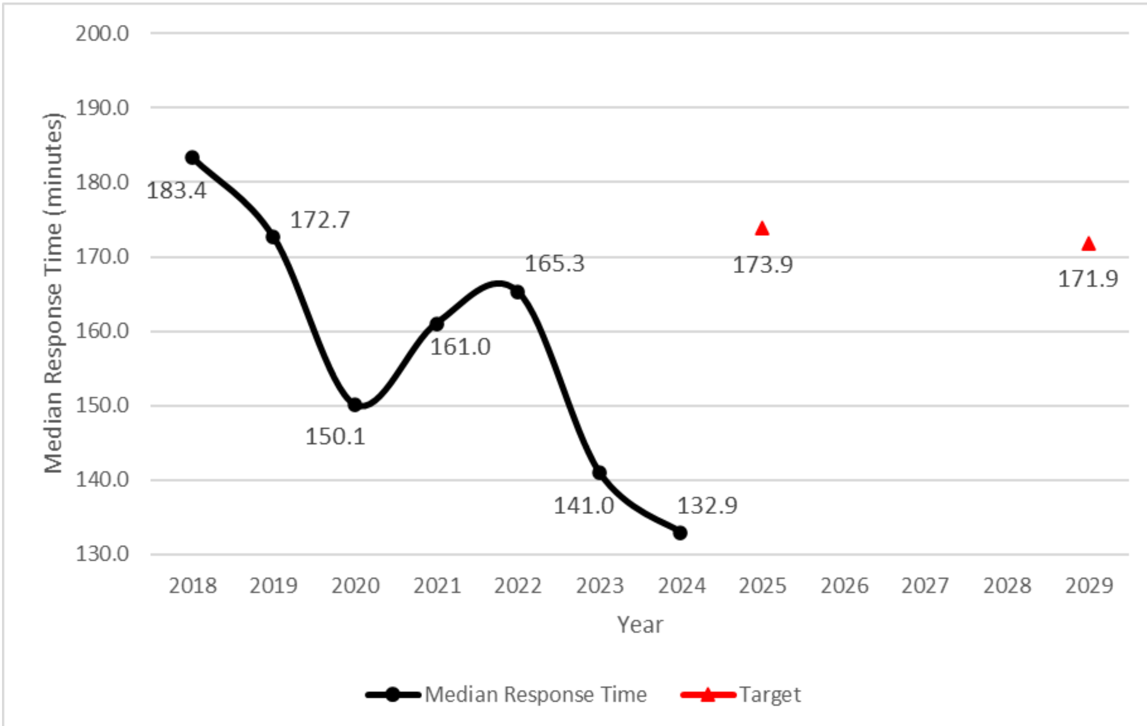
1. Maintaining Performance Against the 1-Year Target

As demonstrated in Figure 4.7-2, PG&E saw a median response time of 132.9 minutes in 2024 which is better than the Company's one-year target.

2. Maintaining Performance Against the 5-Year Target

As discussed in Section E, PG&E will continue mitigating the risk of loss of containment on Gas Distribution Mains and Services and employing its various programs to maintain performance in its efforts toward its five-year target.

FIGURE 4.7-2
TIME TO RESOLVE HAZARDOUS CONDITIONS MEDIAN RESPONSE TIME 2018-2024 AND TARGETS THROUGH 2029



E. (4.7) Current and Planned Work Activities

Starting in 2022, PG&E is applying the definition as stated in Decision 21-11-009 to existing data for further visibility. There are on-going efforts in place to ensure traceable and verifiable data. PG&E plans to implement SAP controls to ensure that Field Service and M&C personnel are capturing this data at each occurrence. This will drive visibility into the metric to allow for performance management. This metric will continue to mitigate the risk of loss of containment on Gas Distribution Main or Service by reducing distribution pipeline rupture with ignition.

The metric is supported by the following programs which focus on improving public safety: Field Services and Gas M&C.

- <u>Gas Field Service</u>: Field Service responds to gas service requests, which include investigation reports of possible gas leaks, carbon monoxide monitoring, customer requests for starts and stops of gas service, appliance pilot re-lights, appliance safety checks, as well as emergency situations as first responders.

- Gas M&C: Gas M&C performs routine maintenance of PG&E's gas distribution facilities, which includes emergency response due to dig-ins, as well as leak repairs.

The following process improvement initiatives are on-going to help achieve metric results:

- Daily Operating Reviews to identify deviations from the targets for the previous 24hrs and identify countermeasures for continuous improvement;
- Weekly Operating Review meetings to share best practices and review long duration events;
- Provide yearly plastic squeeze training for all Field Service employees as part of Operator Qualification refresher;
- Live action drills to simulate emergency scenarios, practicing isolation procedures and documenting lessons learned;
- Piloting process to auto dispatch notification to Gas M&C Superintendent if a grade 1 leak gas flow repair activities extend over 400 minutes; and
- Piloting process for General Construction crews to provide emergency support when Division M&C Crews not available due to rest period (pilot in San Jose, Fresno, and Bakersfield).

PACIFIC GAS AND ELECTRIC COMPANY

SAFETY AND OPERATIONAL METRICS REPORT:

CHAPTER 5.1

CLEAN ENERGY GOALS COMPLIANCE METRIC

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SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 5.1
CLEAN ENERGY GOALS COMPLIANCE METRIC

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PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 5.1
CLEAN ENERGY GOALS COMPLIANCE METRIC

The material updates to this chapter, since the September 30, 2024 report, are identified in blue font.

A. (5.1) Overview

1. Metric Definition

Safety and Operational Metric 5.1 – Clean Energy Goals Compliance Metric is defined as:

Progress towards Pacific Gas and Electric Company's (PG&E) procurement obligations as adopted in Decision (D.) 21-06-035, D.19-11-016 and any subsequent decision(s) in Rulemaking (R.) 20-05-003, or a successor proceeding, updating these requirements.

2. Introduction to the Clean Energy Goals Compliance Metric

The Clean Energy Goals Compliance Metric (CEG Metric) directs PG&E to report on its progress towards meeting the procurement obligations in the following California Public Utilities Commission (Commission) decisions: (1) D.19-11-016, (2) D.21-06-035, and (3) D.23-02-040 (together, the Integrated Resource Planning (IRP) Decisions).[1]

In November 2019, the Commission issued D.19-11-016 in part to address near-term system reliability concerns beginning in 2021. D.19-11-016 requires incremental procurement of system-level Resource Adequacy (RA) capacity of 3,300 megawatts (MW) by all Commission-jurisdictional Load-Serving Entities (LSE).[2] In line with state policy goals, the Commission also expressed a preference that LSEs pursue

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[1] See D.22-02-004 directing PG&E to make progress towards procuring a 95 MW 4-hour energy storage project at the Kern-Lamont substation and a 50 MW 4-hour energy storage project at the Mesa substation, pp. 160-162; Ordering Paragraph (OP) 13 of D.22-02-004 exempts these energy storage projects from the Clean Energy Goals Compliance Metric.

[2] D.19-11-016, p. 34.

"preferred resources" such as new clean electricity capacity.[3] Of the 3,300 MW procurement order, PG&E is directed to procure 716.9 MW of RA capacity on behalf of its bundled service customers with online dates between the years 2021-2023.[4]

D.19-11-016 also allowed each non-investor-owned utility (non-IOU) LSE an opportunity to "opt-out" of its procurement obligation and required notification to the Commission in February 2020 to exercise this option. On April 15, 2020, the Commission issued a ruling increasing PG&E's procurement obligation by 48.2 MW, to an aggregated total of 765.1 MW, to account for LSE opt-outs.[5] PG&E is required to procure the 765.1 MW with the following online dates: 50 percent (382.6 MW) by August 1, 2021, 25 percent (191.3 MW) by August 1, 2022, and 25 percent (191.3 MW) by August 1, 2023.[6]

On July 29, 2022, PG&E filed supplemental Advice Letter (AL) 6654-E-A, discussing the fact that three "opt-out" LSEs ceased serving customers in California. As stated in AL 6654-E-A, PG&E consulted with the Commission's Energy Division, and it was determined that the total opt-out procurement obligation assigned to these three LSEs is 1.2 MW. As set forth in D.22-05-015, in the event of an "LSE bankruptcy, or any other exit from the market," any associated costs attributable to the opt-out procurement shall be allocated to the traditional cost allocation mechanism (CAM). On January 12, 2023, the Commission adopted Resolution (Res. E-5239 and clarified that the 1.2 MW of procurement that PG&E conducted on behalf of opt-out LSEs that subsequently ceased serving customers will continue to count towards PG&E's procurement obligation under D.19-11-016.[7]

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3 D.19-11-016, Conclusion of Law (COL) 22.

4 D.19-11-016, OP 3.

5 See Administrative Law Judge's Ruling Finalizing Load Forecasts and GHG Benchmarks for Individual 2020 IRP Filings and Assigning Procurement Obligations Pursuant to D.19-11-016, issued on April 15, 2020, p. 11.

6 Due to rounding, numbers presented throughout this chapter may not add up precisely to the totals provided.

7 Res.E-5239, p. 11.

In June 2021, the Commission issued D.21-06-035 to address the mid-term (period of 2023-2026) reliability needs of the electric grid and to help achieve the state's greenhouse gas (GHG) emissions reduction targets. In the decision, the Commission ordered 11,500 MW of incremental resource procurement exclusively from zero-emitting resources, unless the resource otherwise qualifies under California's Renewables Portfolio Standard eligibility requirements.[8] Of this total, PG&E is required to procure 2,302 MW with the following online dates: 400 MW by August 1, 2023; 1,201 MW by June 1, 2024; 300 MW by June 1, 2025; and 400 MW by June 1, 2026. In addition, D.21-06-035 also required that 900 MW (of PG&E's 2,302 MW) have specific operational characteristics to spur the development of long-duration energy storage, increase the availability of firm clean energy, and serve as a replacement source of clean energy for the retiring Diablo Canyon Power Plant.[9]

In February 2023, the Commission issued D.23-02-040 which requires incremental procurement of system-level capacity of 4,000 MW by all LSEs to address projected increases in electric demand, increasing impacts of climate change, the likelihood of additional retirements of fossil-fueled generation, and the likelihood that delays beyond 2026 of long-duration energy storage and firm clean energy (collectively, long lead-time resources) required under D.21-06-035 will be necessary. Of this total, PG&E is required to procure 777 MW with the following online dates: 388 MW by June 1, 2026; and 388 MW by June 1, 2027. The decision also revised the online dates of long lead-time resources from June 1, 2026, to June 1, 2028, for all Commission-jurisdictional LSEs.

In aggregate, to date, the total amount of PG&E's procurement ordered under the IRP Decisions is 3,844.1 MW with online dates between 2021-2028. Table 1 outlines PG&E's procurement obligation for each year.

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8 D.21-06-035, OP 1.

9 *Id*., pp. 35-36; See also D.21-06-035, p. 56 requiring PG&E to procure 500 MW of zero-emitting resources by June 1, 2025, and 400 MW of long lead-time resources by June 1, 2026.

TABLE 5.1-1
PG&E'S TOTAL PROCUREMENT OBLIGATION PURSUANT TO THE IRP DECISIONS
(PRESENTED AS MW OF NET QUALIFYING CAPACITY (NQC))

Line No.	Online Date	D.19-11-016	D.21-06-035	D.23-02-040	Total
1	8/1/2021	382.6			382.6
2	8/1/2022	191.3			191.3
3	8/1/2023	191.3	400		591.3
4	6/1/2024		1,201		1,201
5	6/1/2025		300		300
6	6/1/2026			388	388
7	6/1/2027			388	388
8	6/1/2028		400		400
9	Total	765.1	2,302	777	3,844.1

3. Background on Net Qualifying Capacity

For the purpose of assessing whether an LSE's procurement obligation has been met in accordance with the IRP Decisions, the Commission uses capacity counting rules based on the Commission's RA Program and the results of effective load carrying capability (ELCC) modeling by consultants E3 and Astrapé.[10] The counting rules are generally expressed as a percentage that is applied to the nameplate capacity of the procured resource. For example, a 4-hour energy storage resource with a nameplate capacity of 100 MW can count 90.7 MW towards an LSE's 2024 requirement (100 MW * 90.7 percent ELCC = 90.7 MW of NQC). PG&E's procurement progress in this report is presented as MW of NQC based on the applicable counting rules and guidance provided by the Commission.[11]

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10 See D.21-06-035, p. 71 and D.23-02-040, pp. 28-29.

11 See the Incremental ELCC Study for Mid-Term Reliability Procurement (January 2023 Update), p. 10 at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/20230210_irp_e3_astrape_updated_incremental_elcc_study.pdf; See also the Staff Memo on Incremental ELCC to be Used for Mid-Term Reliability Procurement (D.21-06-035) at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-02-irp_mtr_elccs-public_transmittal_memo_v1.pdf.

B. (5.1) Metric Performance

1. Historical Data

Pursuant to the IRP Decisions, resource procurement obligations and compliance milestones began in 2021. The projects pertaining to PG&E's resource procurement obligations and compliance milestone date requirements of August 1, 2021, August 1, 2022, and August 1, 2023 have all achieved commercial operation.

Starting in 2024, the compliance milestone date for resources to be online by was set to June 1 per D.21 06 035. For the procurement milestone of June 1, 2024 PG&E had originally procured 2,685 MW to meet its 2,366.1 MW obligations. However, project development delays resulted in PG&E being unable to meet the June 1 compliance milestone date by 33.3 MW.

TABLE 5.1-2
PG&E'S HISTORICAL METRIC PERFORMANCE (MW OF NQC)

Line No.	Online Date	Total Procurement Obligation	Actual Procured Capacity
1	8/1/2021	382.6	418.2
2	8/1/2022	573.8	585.2
3	8/1/2023	1,165.1	1,165.2
4	6/1/2024	2,366.1	2,332.8

FIGURE 5.1-1
PG&E'S HISTORICAL METRIC PERFORMANCE (MW OF NQC)

PG&E relies upon three main sources of available data to monitor its procurement progress toward the IRP Decisions: (1) the baseline list of resources used to establish the procurement targets, (2) Commission rules and guidance on determining the MW of NQC, and (3) PG&E's internal database containing all of its energy procurement contracts approved by the Commission.

1) Baseline List of Resources: In establishing the procurement targets in the IRP Decisions, the Commission established baseline assumptions of resources available to meet system reliability needs. LSEs must demonstrate that the MW of NQC of the procured resource, new and/or existing, are incremental to the Commission's baseline assumptions.[12]

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[12] See the Commission's baseline assumptions at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/20200103_procurement_baseline_list.xlsx (D.19-11-016) and https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/d2106035_baseline_gen_list_20220902.xlsx (D.21-06-035).

PG&E uses this information to ensure resources are eligible to count towards its procurement obligations.

2) Commission Rules and Guidance on MW of NQC: As described above, the amount of MW of NQC that can be used to count towards an LSE's procurement obligation is based on the Commission's rules and guidance. PG&E uses this information to determine the amount of MW of NQC that is eligible to count towards its procurement obligations.

3) PG&E's Internal Database: This database contains PG&E's energy procurement contracts approved by the Commission, including procurement contracts to meet PG&E's procurement obligations under the IRP Decisions. The data contained in this database is consistent with the procurement contracts and respective ALs filed for Commission approval.

2. Data Collection Methodology

As described above, PG&E uses the baseline list of resources and the Commission's rules and guidance on MW of NQC to monitor its procurement progress.[13]

3. Metric Performance for Reporting Period

PG&E procured sufficient incremental MW of NQC to meet and exceed its procurement obligations for incremental capacity with online dates in 2024 pursuant to D.19-11-016 and D.21-06-035.[14] However, due to project development delays, as further explained in section D.1, PG&E will seek bridge resources to replace delayed resources on a monthly basis beyond the June 1, 2024 online obligation date.

PG&E notes that the Commission stated that procurement:

13 See the information maintained by the Commission at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/more-information-on-authorizing-procurement/irp-procurement-track.

14 PG&E's ALs 5826-E, 6033-E, 6289-E, and 6477-E.

> …amounts [that] are in excess of [an] LSE's obligation under D.19-11-016…may be counted toward the capacity requirements [in D.21-06-035] if they otherwise qualify.[15]

Moreover, D.21-06-035 stated that the Commission:

> …will allow LSEs to show procurement that they have conducted to support the Commission's orders or requirements in the context of the RPS program, as well as for emergency reliability purposes in R.20-11-003, as compliance toward the requirements herein.[16]

Accordingly, PG&E estimates that approximately 262 MW of NQC of its procurement toward the procurement for both D.19-11-016 and R.20-11-003 that have been approved by the Commission, and that are in excess of what is required by each of those decisions, may be applied towards its procurement obligations under D.21-06-035.[17]

On January 21, 2022, PG&E filed AL 6477-E requesting Commission approval of nine agreements resulting from PG&E's Mid-Term Reliability Phase 1 solicitation to meet its procurement obligations under D.21-06-035. These agreements total 1,434 MW of NQC and have been approved by the Commission.[18] Subsequently, unprecedented market upheavals affected the economic and commercial viability of several of the projects comprising of these nine agreements.[19] This unexpected market challenge posed a risk of project failures for all LSEs in the market procuring resources toward the IRP Decisions, including PG&E. As a result, to maintain the commercial viability of the projects, PG&E negotiated amendments for four of the nine projects. Amendments were presented to the Commission for approval on September 23, 2022. The Commission approved these amendments on December 1, 2022.[20]

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15 D.21-06-035, p. 80.

16 *Id*.

17 PG&E's AL 6289-E.

18 On April 21, 2022, the Commission adopted Res.E-5202 approving the nine agreements without modification as filed in PG&E's AL 6477-E.

19 For example, on July 20, 2022, PG&E filed AL 6658-E, requesting approval of contract amendments for the AMCOR and the North Central Valley projects after each developer described external barriers to completing their projects in line with their existing contract obligations.

20 PG&E's AL 6711-E.

On January 13, 2023, PG&E filed AL 6825-E, on February 14, 2023, PG&E filed AL 6861-E, and on September 13, 2023, PG&E filed AL 7022-E, requesting Commission approval of four additional agreements resulting from PG&E's Mid-Term Reliability Phase 2 solicitation to further meet its procurement obligations under D.21-06-035. These agreements have been approved by the Commission.[21]

Despite the significant unprecedented market challenges PG&E has made steady progress towards achieving its procurement obligations under D.21-06-035.

As stated above, D.21-06-035 requires that 900 MW of NQC (of PG&E's 2,302 MW of NQC) have specific operational characteristics. Specifically, PG&E is directed to procure 500 MW of NQC of firm zero-emitting resources with online dates by June 1, 2025, and 400 MW of NQC of long lead-time resources with online dates by June 1, 2028.[22] PG&E issued its Mid-Term Reliability Phase 3 solicitation on February 7, 2023 to solicit additional resources toward fulfilling all of its procurement obligations under D.21-06-035, including, the 900 MW of NQC with specific operational characteristics.

On February 27, 2024, PG&E filed AL 7177-E, and on September 9, 2024, PG&E filed AL 7356-E, requesting Commission approval of five agreements resulting from PG&E's Mid-Term Reliability Phase 3 solicitation. These agreements have been approved by the Commission[23]. Additionally, on June 18, 2024, PG&E filed AL 7299-E and on November 4, 2024, PG&E filed AL 7420-E requesting approval of four agreements from the Mid-Term Reliability Phase 3 solicitation. These agreements are currently pending at the Commission. PG&E issued a Long Lead Time

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21 On April 27, 2023, the Commission adopted Res.E-5262 and Res.E-5263 approving PG&E's AL 6825-E and AL 6861-E. On January 11, 2024, the Commission adopted Res.E-5297 approving AL 7022-E.

22 The long lead-time (LLT) resources are comprised of: (1) firm zero-emitting generation with a capacity factor of at least 80 percent and (2) long-duration storage resources defined as having at least eight hours of duration.

23 On June 4, 2024, the Commission adopted Res. E-5325 approving PG&E's AL 7177-E and on February 20, 2025, the Commission adopted Res. E-5370 approving PG&E's AL 7356-E.

solicitation on October 15, 2024 to purchase 200 MW of Long Duration Energy Storage projects and 200 MW of Firm Zero-Emitting projects as directed by D.21-06-035. Projects have been shortlisted and contracts are being negotiated.

C. (5.1) 1-Year Target and 5-Year Target

1. Updates to 1-Year Target and 5-Year Target Since Last Report

The 1-year target has been updated to reflect PG&E's required procurement for 2025 under the IRP Decisions which is to procure 2,666.1 MW of cumulative NQC by June 1, 2025, as outlined in Table 5.1-1. The 5-year target has also been updated to reflect PG&E's additional procurement requirements, as outlined in Commission decision—D.23-02-040—issued in February 2023.[24] As summarized in Table 5.1-1, the 5-year target for 2029 remains the same as the 2028 target, which is to procure 3,844.1 MW of cumulative NQC by June 1, 2028. However, later this year, PG&E may request an extension to the online date requirement for the LLT resources, through a CPUC-authorized process. If granted, the extension would require the procurement of bridge resources to meet the target from June 1, 2028 until the approved extended online date.

2. Target Methodology

To establish the 1-year and 5-year targets, PG&E considered the following factors:

- Historical Data and Trends: Not Applicable
- Benchmarking: Not applicable.
- Regulatory Requirements: The targets are set to match the cumulative procurement obligations set forth in the IRP Decisions.
- Attainable Within Known Resources/Work Plan: Yes.
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: Yes.
- Other Considerations:
  - The target approach was established to meet the Commission's current procurement obligations. PG&E's procurement obligation

[24] D.23-02-040, p. 31.

may increase if other LSEs fail to meet their procurement obligations and PG&E is ordered by the Commission to make back-stop procurement on their behalf;[25] and

- The ability for procured capacity to actually come online by established contractual online dates can be impacted by external factors, as has occurred recently due to impacts of the COVID-19 pandemic, significant and unprecedent market challenges, supply chain disruptions and the Department of Commerce's investigation into potential solar module tariff circumvention.[26]

3. 2025 Target

The 1-year target for the CEG Metric is to procure 2,666.1 MW of cumulative NQC with an online date by June 1, 2025, which is equal to the cumulative procurement obligations for 2021, 2022, 2023, 2024, and 2025 as outlined in Table 5.1-1.

4. 2029 Target

The Integrated Resource Plan Decisions does not have a 2029 obligation to align with a new 5-year target for the CEG Metric. Therefore, the current target remains to procure 3,844.1 MW of cumulative NQC with an online date by June 1, 2028, which is equal to the cumulative procurement obligations for 2021-2028 as outlined in Table 5.1-1. However, given market and development challenges to procuring capacity from resources qualified to meet the 2028 obligations as the IRP Decisions require, PG&E may request an extension through a CPUC authorized process later this year. If granted, the extension would allow up to 400 MW of Long Lead Time resources to be procured with a 2031 online date, instead of a 2028 online date, as long as bridge resources are procured for the interim period. In this case, the 2029 target would remain at 3,844.1 MW, but some bridge resources may be used to meet the target, as permitted.

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[25] D.19-11-016, p. 67.

[26] Erne, David, Mark Kootstra. 2023. Final Draft Diablo Canyon Nuclear Power Plant Extension – CEC Analysis of Need to Support Reliability. California Energy Commission. Publication Number: CEC-200-2023-004.

D. (5.1) Performance Against Target

1. Progress Towards the 1-Year Target

PG&E executed contracts for sufficient incremental capacity with online dates on or before June 1, 2025 to meet the 1-tear target. However, counterparties have cited ongoing supply chain disruptions, interconnection delays, and permitting delays as impacting project development schedules and their ability to meet contractual online dates. As impacts to project online dates are identified, PG&E will look to procure bridge resources, as permitted in D.21-06-035 and D.23-02-040 to mitigate against project online date delays.

2. Progress Towards the 5-Year Target

PG&E continues to make progress towards meeting the 5-year target. Within this overall procurement target, PG&E has a requirement to procure 900 MW of NQC with specific operational characteristics and the Commission decision for supplemental mid-term procurement as outlined above. In September 2023, PG&E filed for approval of one contract that is expected to count towards the operational characteristics as a Zero-Emitting Resource. Additionally, in June 2024, PG&E filed for approval of two renewable generation contracts which are expected to be contractually paired with an energy storage resource to count towards the operational characteristics as a Zero-Emitting Resource.

PG&E reiterates, and as outlined above, that developers and LSEs have experienced significant and unprecedented market challenges, increases in component prices, continued supply chain constraints, and industry-wide inflation on total project costs that have hindered the ability for developers to bring projects online by their contractual online dates.[27] In recognition of these challenges, the Commission has provided mitigation tools in D.23-02-040,D.24-02-047, and D.24-09-006 for LSEs to continue making progress towards their procurement obligations to ensure system reliability in the mid-term. These mitigation tools include extending the online date of

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27 Erne, David, Mark Kootstra. 2023. Final Draft Diablo Canyon Nuclear Power Plant Extension – CEC Analysis of Need to Support Reliability. California Energy Commission. Publication Number: CEC-200-2023-004.

long lead-time resources from 2026 to 2028, allowing LSEs to request for a further extension for long lead-time resources until 2031 for cost considerations or projects with later online dates, allowing the use of bridge resources and, in some cases, re-contracting with resources that are retiring or have expiring or expired contracts.[28] PG&E will continue to work with developers and the Commission to address the challenges noted above in order to meet the current 5-year target, and any additional procurement requirements in support of the state's reliability needs.

FIGURE 5.1-2
PG&E'S CLEAN ENERGY GOAL HISTORICAL PERFORMANCE AND TARGETS (MW OF NQC)

E. (5.1) Current and Planned Work Activities

Below is a summary description of the key activities that are tied to performance and their description of that tie.

- Solicitations: As noted above, PG&E launched its Mid-Term Reliability Phase 2 and Phase 3 solicitations in April 2022 and February 2023, respectively, seeking to satisfy its remaining procurement obligations under

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28 D.23-02-040, COLs 7 and 12. D.24-02-047, OPs 16 and 19. D.24-09-006, OP 1.

the IRP Decisions, specifically to procure 500 MW of NQC of zero-emitting resources by June 1, 2025, and 400 MW of NQC of long lead time resources by June 1, 2028. PG&E issued an additional Long Lead Time solicitation on October 15, 2024.

- Supplemental Procurement Order: As described earlier, on February 23, 2023, the Commission issued D.23-02-040 increasing PG&E's procurement requirements through 2028. Accordingly, PG&E has incorporated the supplemental procurements order by this decision into its current and planned work activities.
- Bridge Procurement to Mitigate Delayed Resources: PG&E will pursue permitted bridge resources to bridge procurement gaps where resources are delayed, as authorized by the IRP.

PACIFIC GAS AND ELECTRIC COMPANY

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CHAPTER 6.1

QUALITY OF SERVICE

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QUALITY OF SERVICE

The material updates to this chapter, since the September 30, 2024 report, are identified in blue font.

A. (6.1) Overview

Safety and Operational Metric (SOM) 6.1 – The Quality of Service Metric which is defined as:

The Average Speed of Answer (ASA) for Emergencies metric is a safety measure related to multiple risks, as well as quality of service and management measure, and is defined as follows: ASA in seconds for Emergency calls handled in Contact Center Operations (CCO).[1]

1. Introduction of Metric

A call is classified as an emergency when a caller selects the option of an emergency or hazard situation through the Interactive Voice Response (IVR) system. Once this option is selected the call is routed to an agent to receive the highest priority attention possible.

Not only is Emergency ASA a quality measurement of how efficiently we are able to answer customers calling us to report an emergency, but it is also a safety measurement. Answering the call is the first step ensuring the customer is safe.

The metric is calculated by determining the average amount of time it took to connect customers to a service representative for calls where the customer identifies via IVR that they are calling to report a hazardous or emergency situation, such as a suspected natural gas leak or downed power line.

2. Background

On an annual basis, Pacific Gas and Electric Company (PG&E) handles between 5 to 6 million customer calls. Between 2017 and 2021, emergency-related calls averaged nine percent of total call volume;

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1 D.21-11-019, Appendix A, p. 12.

however, in the 2020 and 2021 years, emergencies calls have increased due to weather-related storms events, rotating outages, Public Safety Shutoffs (PSPS), and Enhanced Power Safety Settings (EPSS). In 2020 and 2021 emergency calls handled were 10 percent and 11 percent of total call volume, respectively.

Historically, PG&E has been able to successfully manage staffing needs to ensure emergency calls are answered quickly. The metric and associated targets are designed to maintain our performance.

B. (6.1) Metric Performance

1. Historical Data (2015 – 2024)

PG&E has ten years of historical data representing 2015 –2024 to include the total emergency calls handled and ASA by month.

The historical data for this metric provided with this report provides total emergency calls handled and the ASA performance by month and year.

2. Data Collection Methodology

The performance data is gathered from PG&E's telephony system, Cisco Unified Contact Center Enterprise (UCCE). The data includes the number of emergency calls handled and the total wait times (in seconds). Data is compiled each day for daily, weekly, monthly, and yearly reporting.

Historical data is collected using Microsoft's Management Studio application via a Structured Query Language (SQL) server owned by the Workforce Management Reporting team.

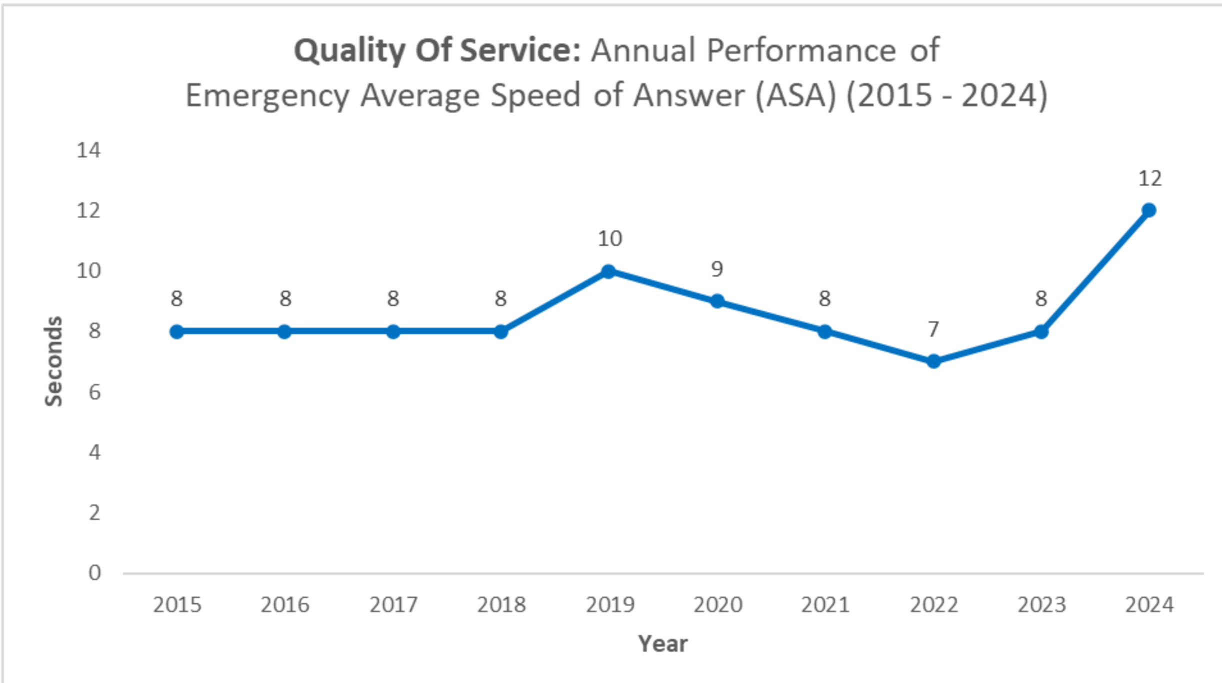
The data is gathered by extracting summarized data for emergency specific call types. The call types are created by the Workforce Management Routing Team, to categorize the types of calls that are entering the phone system, Cisco UCCE.

PG&E began archiving historical call data in 2015 once it was identified that Cisco UCCE system was truncating historical data as it was running out of storage.

3. Metric Performance for Reporting Period

Between 2015 and 2024, the performance of Emergency ASA ranged between seven and twelve seconds, with a median performance of eight seconds (see Figure 6.1-1). In 2024, PG&E's call wait time was highest (12 seconds) due to an atmospheric river in February 2024.

FIGURE 6.1-1
ANNUAL PERFORMANCE OF EMERGENCY ASA BETWEEN 2015 2024

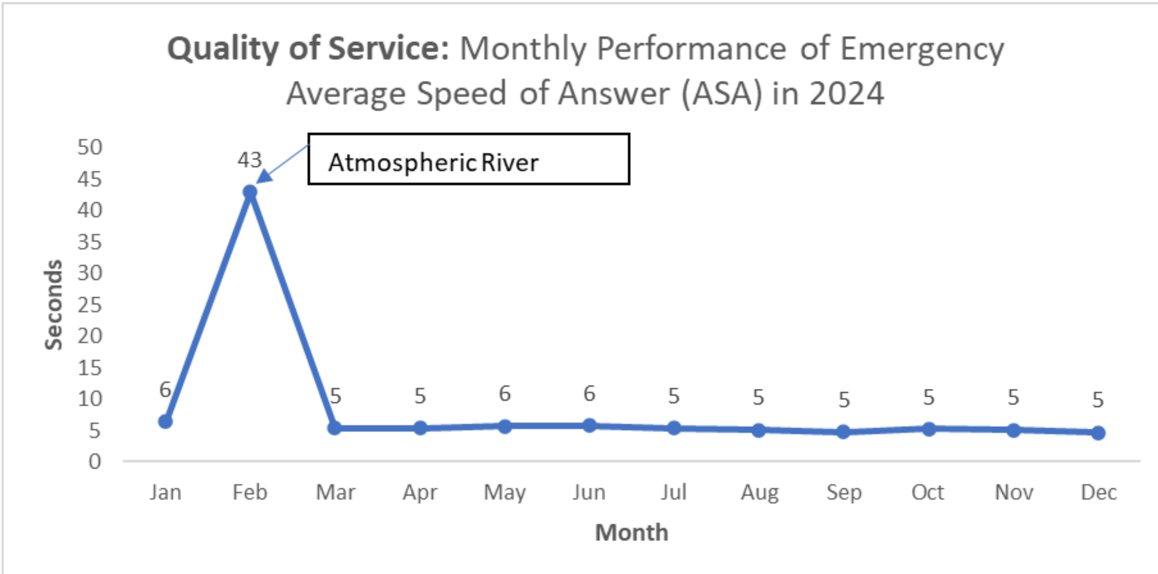


In 2024, the Emergency ASA performance was 12 seconds. Over the course of the year, monthly performance metrics fluctuated between five seconds and 43 seconds, as illustrated in Figure 6.1-2.

On February 2, 2024, the state of California endured a storm of unprecedented magnitude, which resulted in significant power outages within PG&E's service area. During the hours of 2:00 PM to 6:00 PM on February 2nd, the contact center experienced an overwhelming volume of calls. This surge in call volume directly contributed to the observed decline in Emergency ASA performance.

Additional primary drivers to the performance were based on unanticipated incidents (e.g., weather incidents impacting power outages, unplanned power outages) and call center representative staffing availability.

FIGURE 6.1-2
MONTHLY PERFORMANCE OF EMERGENCY ASA IN 2024



C. (6.1) 1 Year Target and 5 Year Target

1. Updates to 1- and 5-Year Targets Since Last Report

There have been no changes to the 1-year and 5-year targets since the last SOMs report filing. The 2025 1-year target is to be at or below 15 seconds and the 2029 5-year target is to be at or below 15 seconds.

2. Target Methodology

To establish the 1-year and 5-year targets, PG&E considered the following factors:

- Historical Data and Trends: The target is based on the average of years 2015 to 2019 historical data. These years were utilized as they are most consistent with current operational practices, including the expansion of PSPS, EPSS, and Rotating outage programs. The average of this period is used as a reasonable indicator for sustaining and maintaining the performance going forward;
- Benchmarking: Not available;
- Regulatory Requirements: None;
- Attainable Within Known Resources/Work Plan: Yes, performance at or below the set target is sustainable; and

- Other Qualitative Considerations: None.

3. 2025 Target

The 2025 target is to be at or below15 seconds for the year to maintain performance based on the factors described above.

4. 2029 Target

The 2029 target is to be at or below 15 seconds for the year to maintain performance based on the factors described above.

D. (6.1) Performance Against Target

1. Progress Towards the 1-Year Target

As demonstrated in figure 6.1-1 above, PG&E’s 2024 performance was 12 seconds, within the Company’s 1-year target.

2. Progress Towards the 5-Year Target

As discussed in Section E below, PG&E has implemented a number of processes to maintain longer-term performance of this metric to meet the Company’s 5-year target.

E. (6.1) Current and Planned Work Activities

The performance of this metric is significantly driven by Contact Center Representative resourcing. The CCO are staffed to handle forecasted volume based on historical trends. As staffing needs change due to upcoming events (e.g., PSPS, weather impacts, storm, or heat-related outages) overtime is offered and planned in advance to increase staffing needs. Mandatory overtime (employees are required to stay on shift) and Emergency overtime (PG&E's Workforce Management team will send out notifications to offer Emergency overtime to employees currently not on shift) are available options during same-day operations to support additional staffing needs. PG&E is forecasting to maintain the current level of staffing for 2025-2029.

Additionally, providing customers upfront messages of extended wait times via IVR can be used to set expectations and advise customers to call back unless there is an emergency.