PG&E SAFETY AND OPERATIONAL METRICS

AUDIT REPORT

Prepared for:

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FILSINGER ENERGY PARTNERS

ENERGY • MANUFACTURING • INDUSTRIAL

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Disclaimer

The following report contains Filsinger Energy Partners' ("FEP") assessments, perspectives, analyses, and findings based on information provided to FEP by Pacific Gas and Electric Company ("PG&E"), as well as information obtained from limited field observations and third-party sources.

This report (including any enclosures and attachments) has been prepared for the exclusive use and benefit of PG&E and the California Public Utilities Commission ("CPUC"), and solely for the purpose for which it is provided. FEP does not accept any liability if this report is used for an alternative purpose from which it is intended, nor to any third party in respect of this report.

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All decisions made in connection with the implementation or use of the analyses and findings contained in this report are the sole responsibility of the party making such decisions and are made at their own risk.

GLOSSARY

AGA: American Gas Association
AIDI: Average Interruption Duration Index
AIFI: Average Interruption Frequency Index
CAP: Corrective Action Program
CIC: Commitment Information Center
CESO: Customers Experiencing Sustained Outage
CGI: Can't Get In
Company: Pacific Gas & Electric
CMR: Centralized Metrics Repository
CPUC: California Public Utilities Commission
Decision: California Public Utilities Commission Decision 21-11-009
DiRT: Dig-in Reduction Team
EAM: Electric Asset Management
EEI: Edison Electric Institute
EGIS: Electric Geographic Information System
EH&S: Enterprise Health and Safety
EIA: Energy Information Administration
EMT: Event Management Tool
EOE Process: Enforced Oversight and Enforcement Process
EPSS: Enhanced Powerline Safety Settings
ETGIS: Electric Transmission Geographic Information System
FEP: Filsinger Energy Partners
HFTD: High Fire Threat District
GPS: Geospatial Positioning System
GSR: Gas Service Representative
IEEE: Institute of Electrical and Electronics Engineers
ILIS: Integrated Logging Information System
LOC: Loss of Containment
LP: Low Pressure
LVCM: Large Volume Customer Meter
LVCR: Large Volume Customer Regulator
LSP: Leak Survey Process
MAOP: Maximum Allowable Operating Pressure
MED: Major Event Day
Metric: Safety and Operational Metric
MOP: Maximum Operating Pressures
NQC: Net Qualifying Capacity
OEIS: Office of Energy Infrastructure Safety
OP: Over Pressure
OS&HC: Occupational Safety and Health Committee
PG&E: Pacific Gas & Electric
PSPS: Public Safety Power Shutoff
QDR: Quarterly Data Report
RFI: Request for Information
RFW: Red Flag Warning
SAIDI: System Average Interruption Duration Index

SAIFI: System Average Interruption Frequency Index
SAS: Statistical Analysis System
SCL: Safety Classification and Learning
SIF: Serious Injury and Fatality
SOM: Safety and Operational Metric
SPM: Safety Performance Metric
TIP: Tactical Implementation Plan
T&D: Transmission and Distribution
TOTL: Transmission Operations Tracking and Logging
USA: Underground Service Alert
WiRE: Wildfire Intelligence Reporting Engine
WSIP: Wildfire Safety Inspection Program

1 EXECUTIVE SUMMARY

1.1 Background

Filsinger Energy Partners, Inc ("FEP") was engaged to conduct an audit of the Safety and Operational Metrics ("SOM" or "Metric") for Pacific Gas & Electric Company ("PG&E" or "Company") to evaluate the data collection and reporting processes utilized by PG&E to ensure accuracy and compliance with the SOMs reporting requirements as prescribed in accordance with Order 7 of California Public Utilities Commission ("CPUC") Decision 21-11-009 ("Decision") dated November 4, 2021.

The audit includes the SOMs reports for the periods January 2021 through December 2023.

1.2 Scope of Work

FEP's scope of work included reviewing SOMs reports, collecting supporting data, conducting interviews and performing analysis in evaluating the items listed below.

Metric Accuracy:

- Perform trend analysis for each SOM, including accuracy assessment.
- Establish understanding of the process utilized for verifying accuracy of SOM results prior to publishing.
- Determine if PG&E has consistently extracted information for SOMs from an internal database or internal set of databases throughout the collection process or have new protocols been established for collecting the information.
- Establish whether the data collection protocol and data reporting standards for each SOM has been consistent over the past 10 years. If not, identify which Metrics and which years are reported with the current data collection protocol and data reporting standards.
- Determine how to compare SOMs between the years with different reporting standards.

Metric Management:

- Determine which organization or department is responsible for managing and tracking each SOM.
- Determine the utilization of SOMs within specific work groups.
- Establish an understanding of the method utilized for communication of Metric performance updates (daily, weekly, monthly, quarterly, etc.).
- Determine if a formal process exists that requires PG&E management to act on Metrics that are not meeting identified targets.
- Determine the ways in which PG&E management follows up with the specific work groups on potential issues.
- Determine how actions taken impacted Metric performance positively or negatively.

Metric Targets:

- Determine how SOMs are utilized in managing the organizations/departments and determine the methodology for target setting.
- Evaluate any substantial change in direction of Metric performance, including identification of root cause(s) and any known corresponding actions taken by PG&E.
- Determine if comparative benchmarking data is available for each SOM.

1.3 Approach

FEP performed extensive analysis of the supporting data provided with the SOMs reports. In order to gain an understanding of each Metric and the process for gathering supporting data, reporting results, managing and reviewing the Metric performance and setting the Metric targets, FEP conducted 46 interviews with Metric owners and other employees or contractors that were involved in supporting or reviewing Metrics through various levels of the organization, including the Chief Operating Officer who is ultimately responsible for the performance of the Metrics. FEP also performed a site visit to the Rocklin Distribution Control Center to observe the procedures utilized in receiving and recording outage information including interviewing operations personnel to determine the extent of utilization with operational standards. In addition, the FEP team observed the reliability review teams perform their daily analysis of outage data for accuracy. During the site visit FEP conducted follow-up interviews with the reliability organization staff. FEP also observed the February 2025 meeting of PG&E's Commitment Information Center ("CIC"), a key stakeholder in reviewing and achieving the Metric target in order to understand how Metrics that were off track to meet the Metric target were reviewed and remedied. As a result of the analysis and interviews, FEP issued 370 requests for information ("RFI") to supplement further analysis and confirm statements made in interviews.

As part of the audit of Metric accuracy, FEP used a systematic approach to analyze each SOM. The associated workpapers for each Metric were first analyzed for ten dimensions of rigor, then additional steps were added as necessary to confirm PG&E's Metrics' results. The ten dimensions were divided into four categories: dataset, definitions, calculations, and results as described below.

Dataset

- Supported by Data: Documentation is included as necessary to support the data, such as records for each ignition included in the gross ignition count.
- Dataset Completeness: The dataset includes records of instances included and excluded from the SOMs reporting to allow for an assessment of PG&E's accuracy making exclusions as well as inclusions.
- Expected Timeframe: The dataset covers the full-time frame measured by the SOM.

Definitions

- Definitions: Terms used in the workpapers and reports are defined.
- Complies with CPUC Decision Language: Any provided definitions match or comply with the language provided in CPUC decisions related to that topic.

Calculations

- Calculations/Formulas for Combined Values: The workpapers include the formulas to demonstrate how combined values were calculated, ideally tied to the dataset.
- Replicability: The calculations can be replicated by third parties because formulas are documented, and the dataset is accessible.

Results

- Results Match the Report: The results calculated in PG&E's workpapers match the results that PG&E shared in its reports.
- Sensical Results: The results make sense overall, reflect the narrative that PG&E provides in its report, and are reasonable based on industry standards.

Dataset

When reviewing the workpapers, FEP verified that there was data to support any assertions PG&E made about the SOMs. For example, if PG&E reported 57 ignitions in 2023 for Metric 3.13, FEP confirmed there was data describing and supporting each ignition. Additionally, FEP assessed the level of filtering PG&E conducted on any provided dataset. A minimally filtered dataset better allowed FEP to assess PG&E's process for excluding data which was not relevant to the SOMs. To use Metric 3.13 as an example, FEP received a dataset which included both reportable and non-reportable ignitions. This allowed FEP to verify that the exclusions PG&E made were justified. Additionally, FEP examined the data to validate that it covered the expected timeframe. For example, a 2023 full year workpaper which only included data for June through December was likely missing data points.

In some cases, assumptions were necessary due to data availability or the scope of the review. For example, for Metrics 2.1-2.4 (outage metrics), FEP assumed that the ILIS system was fully complete and accurate. While the scripts used to pull data from various internal databases for those metrics were reviewed, the full contents and integrity of all connected data sources (like ILIS) were not validated. Additionally, in some cases, data was sampled. For example, for Metrics 1.1-1.3 (SIF metrics), FEP validated a selection of injuries in the injury database but did not review every individual record. It was also assumed that all relevant injuries were included in the dataset provided. FEP did not verify whether any injuries may have been omitted from the injury database. Additionally, FEP largely assumed that the data collected in the field was correct. For example, FEP assumed that the documented characteristics of ignitions (Metric 3.13 - 3.16) like cause, size, and location were accurate to PG&E's best knowledge. FEP reviewed available documentation on field events where possible but relied on assumptions of validity where independent verification was impossible.

Definitions

FEP assessed workpapers to ensure that any relevant headings and terminology were sufficiently defined. PG&E defined many concepts relevant to the Metrics in either the SOMs reports or the workpapers. For concepts which were undefined and specific to PG&E processes, FEP verified definitions through RFIs. When applicable, FEP ensured that the definitions complied with CPUC decisions or other relevant statutes. For example, FEP ensured that the definition PG&E used for reportable ignitions matched the CPUC's definition of reportable ignitions.

Calculations

FEP reviewed the data, and the supporting formulas or calculations associated with the Metrics. FEP validated the calculations either by replicating the final values or through RFIs.

FEP replicated the results for all SOMs, to the extent possible. Replicating the results ensured that FEP understood PG&E's processes. In addition to replicating the results, FEP noted areas where the calculations might be different from best industry or mathematical practices.

Results

FEP verified that the results produced in the supporting workbooks matched the results that PG&E shared in SOMs reports. Additionally, FEP considered whether the results made sense based on industry experience, PG&E's description of its processes, and the included data.

FEP's process for validating the results varied based on the nature of the Metric. Some metrics required a review of underlying supporting data, such as Metric 1.1-Employee Serious Injury and Fatality ("SIF") Rates. For Metric 1.1, FEP verified that PG&E accurately produced a SIF rate based on the provided formula. However, verifying the accuracy of Metric 1.1 also required validating how PG&E determined if an injury qualified for inclusion in the Metric as a "serious injury or fatality". FEP reviewed PG&E's process for making this determination and validated a sample of both included and excluded injuries. Other Metrics required a review of underlying scripts used to produce the dataset. For example, Metric 3.5-High Fire Threat District ("HFTD") Wires Down (Red Flag) required identifying Wires Down events which occurred in HFTDs on Red Flag Warning Days. PG&E leveraged a python script for the identification process. To assess the accuracy of Metric 3.5, FEP reviewed both the python script as well as the records of the Wires Down events identified by that script to assess if they should be included in Metric 3.5 and then evaluated PG&E's Metric 3.5 results calculation. FEP also reviewed the data related to all wires down to assess whether all HFTD events appeared to be properly captured.

The analytical approach for each SOM is discussed in Section 2 of the report below.

1.4 Key Findings

1.4.1 Metric Accuracy

Table 1-1 below shows FEP's findings related to accuracy. A finding is classified as significant if it either materially alters the metric results or raises concerns about the accuracy of the underlying data. Even a minimal change to the metric result can qualify as significant if it raises concerns about the integrity of the data used to calculate the metric. As shown, there were a number of significant accuracy issues. It is noted that, except for Metrics 3.7, 3.8, and 3.11, the Metrics with a significant accuracy finding all relate to what appears to be an inaccurate identification of HFTD outages and Wires Down where PG&E has identified events as non-HFTD that appear to be HFTD. PG&E explained that for the outage data prepared for SOMs, the HFTD status for each outage is determined the day following the event. Location information at the initial assignment is sometimes unavailable or incorrect, however the HFTD designation does not get updated following initial assignment. It believes that because of this, some historical outages retained outdated HFTD assignments. This is discussed in more details in the affected Metrics in section 2. FEP also notes that as a result of these findings, PG&E has entered this issue into their Corrective Action Program ("CAP") and is developing a centralized, standardized data repository through the Wildfire Intelligence Reporting Engine ("WiRE"), which aims to improve outage metric reporting. The impact on the individual Metrics is discussed more in Section 2 below.

FEP also identified metrics with minor accuracy findings. A finding is classified as minor if there does not appear to be significant data integrity issues and were not found to recurring. Minor findings could include small typos to manually entered values which did not impact the metric results or issues on the magnitude of a rounding error.

For the most part, FEP was able to replicate the results shared in PG&E's SOMs reports. For most SOMs, PG&E had a consistent approach for extracting and reporting data. For certain Metrics, FEP identified possible areas of improvement where PG&E may be able to increase the rigor of its calculations or improve replicability or transparency. These are generally noted in the Other Findings column and are discussed in more detail for each Metric in Section 2 below.

Table 1-1: Metric Accuracy Findings

Metric	Accuracy Finding	Other Findings
Metric 1.1	Minor	
Metric 1.2	Minor	
Metric 1.3	None	
Metric 2.1	None	
Metric 2.2	None	
Metric 2.3	Significant	Discrepancy between CESO data pulled monthly and annually.
Metric 2.4	Significant	Discrepancy between CESO data pulled monthly and annually.
Metric 3.1	Significant	ILIS as the database of record impacts event counts.
Metric 3.2	Significant	ILIS as the database of record impacts event counts.
Metric 3.3	None	
Metric 3.4	Minor	
Metric 3.5	Significant	ILIS as the database of record impacts event counts.
Metric 3.6	None	
Metric 3.7	Significant	
Metric 3.8	Significant	
Metric 3.9	Minor	
Metric 3.10	Minor	
Metric 3.11	Significant (2021 only)	There is inconsistency around processes for calculating due dates.
Metric 3.12	None	
Metric 3.13	None	Some discrepancy between event coordinates and HFTD designations that did not impact metric results.
Metric 3.14	None	Some discrepancy between event coordinates and HFTD designations that did not impact metric results. Line miles were inconsistent amongst reports and data sources.
Metric 3.15	None	
Metric 3.16	None	Line miles were inconsistent amongst reports and data sources.
Metric 4.1	None	
Metric 4.2	None	Low pressure events are excluded from the calculation.
Metric 4.3	None	Response times for crews who were already onsite included for a small number of events.
Metric 4.4	None	
Metric 4.5	None	
Metric 4.6	None	Data should be pulled after the month closes.
Metric 4.7	None	

Metric 5.1	None	
Metric 6.1	None	

1.4.2 Metric Management

PG&E has Metric owners for each SOM and tracks the performance of each Metric against its target. The organization utilizes LEAN Operating Review meetings along with monthly CIC meetings as an opportunity to review the Metric status with executive and senior management. If a Metric is off track to meet its 1- or 5-year targets, catch back plans are developed by the Metric owner. Catch back plans are intended to try to correct the metric by the end of the current reporting period. Catch back plans are reactive to poor performance of a specific Metric and are often immediate actions that can correct the Metric in the short term, such as allocating more resources, but can be as simple as a change in the data used to calculate the Metric. For example, a catch back plan for Metric 3.11 was to identify and exclude tags that qualified for exemptions.

While PG&E actively monitors the SOMs, FEP notes that the SOMs primarily appear to be a reporting exercise for PG&E, rather than a metric that PG&E actively manages. The communication of the SOM performance tends to be limited to the Metric owner and direct reviewers of the Metric performance, such as the CIC, and is generally not disseminated throughout the organization or to individuals that impact the Metrics' performance, such as line people performing patrols and inspections or contractors who support in daily operations. Much of the data used to calculate SOMs is part of general performance goals within the company and/or overlaps across other metrics required by PG&E, such as the L1 metrics, which are metrics filed with the wildfire safety regulator and are part of incentive compensation plans, or the Safety Performance Metrics ("SPM") which are filed at the CPUC by the major California investor-owned utilities. The SOM definitions usually differ from these metrics but rely on much of the same data. As such, performance data that can impact SOMs is often more broadly communicated throughout the organization, but the performance related to a specific SOM is not. Similarly, work activities that are often cited as impacting the performance of the SOMs are also usually broad Company initiatives meant to proactively improve the performance of a broader dataset which indirectly impacts the SOMs, rather than SOM specific initiatives.

For example, Wires Down counts are part of the SPMs and are a significant focus throughout the PG&E organization for continued performance improvement with numerous work activities to support performance improvement. However, PG&E's focus is primarily on system-wide Wires Down rates, considering both transmission and distribution, without making distinctions based on the location of the break. Meanwhile, the Wires Down SOMs (3.1 – 3.6) are very narrowly defined. The six Wires Down Metrics each consider a different slice of the overall picture, making exclusions based on wire type, HFTD tier, red flag warnings, and major event days ("MED"). PG&E has programs to reduce the number of Wires Down events generally and these efforts may positively impact the SOMs' performance. However, PG&E is not directly managing its operations to improve the performance of any one of the Metrics 3.1 through 3.6 specifically. It is FEP's observation that given the very specific definitions of the SOMS, many SOMs would be difficult to actively manage to from an operational standpoint. For example, an aged conductor program or a failed splice replacement program would likely be implemented as system wide program and should generally improve Wires Down events. This would in theory improve SOMs related to Wires Down, but it would likely not be reasonable to design a program that only targets events impacting any one Wires Down Metric, nor would the expected impact on any one of the Wires Down Metrics be fully quantifiable.

1.4.3 Metric Performance and Targets

PG&E has the responsibility of setting a 1- and 5-year target for each SOM. In the SOM reports, PG&E lays out the following four "pillars" for developing targets for each SOM, which appear consistent with the Decision:

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.

4) Targets should be set and evaluated in consideration of a holistic qualitative and quantitative view including additional contextual information and factors.

The method for setting each SOM target is discussed by Metric in Section 2. Generally, most targets are set within the department responsible for tracking the Metric and are based on some reference to historical performance, often with some adjustments. There do not appear to be benchmarks for most of the Metrics, given the SOM specific definitions that do not typically align with industry standard definitions, or even California SPM definitions. For the few Metrics that have regulatory requirements, the target reflects such.

We note that for many metrics the 1-and 5-year targets are set at a level higher than recent performance and often do not include improvement in the target year to year. PG&E notes that this is consistent with targets "set at levels indicating "insufficient progress" or "poor performance" within the context of the Enhanced Oversight and Enforcement Process ("EOE Process")." However, FEP also notes that per the Decision, the "EOE Process is designed to ensure that PG&E is improving its safety and operational performance".

Given the level and trends in many of the Metric targets, particularly compared to actual performance, as well as FEP's industry experience, the targets are generally at levels consistent with guardrails to identify significant concern if a Metric is falling outside of the threshold but do not appear to be driving performance improvement of the SOM. While PG&E has improved performance for many of the SOMs, the targets do not appear to be a contributing factor. In FEP's industry experience, targets are usually set at aspirational levels to drive performance improvement, although it is also noted that aspirational targets are usually tied to incentives, as opposed to oversight such as the EOE. For purposes of this report, FEP has identified targets that are not consistent with performance improvement, but FEP observes that PG&E and the CPUC should better align on the purpose of the targets.

2 METRIC AUDIT

The following has the summary of FEP's audit for each Metric. We note that between similar Metrics (i.e., reliability Metrics), much of the information may be repetitive, but for completeness it was included for each Metric so that each can be read standalone.

2.1 Metric 1.1: Employee Serious Injury and Fatality ("SIF")

The CPUC defines Metric 1.1 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").

Metric 1.1 measures the rate at which PG&E employees experience serious injuries or fatalities in the course of their work. A SIF-Actual case is determined using the methodology developed by EEI's OS&HC that specifies the criteria for what constitutes a serious injury event, ensuring consistency across the industry.

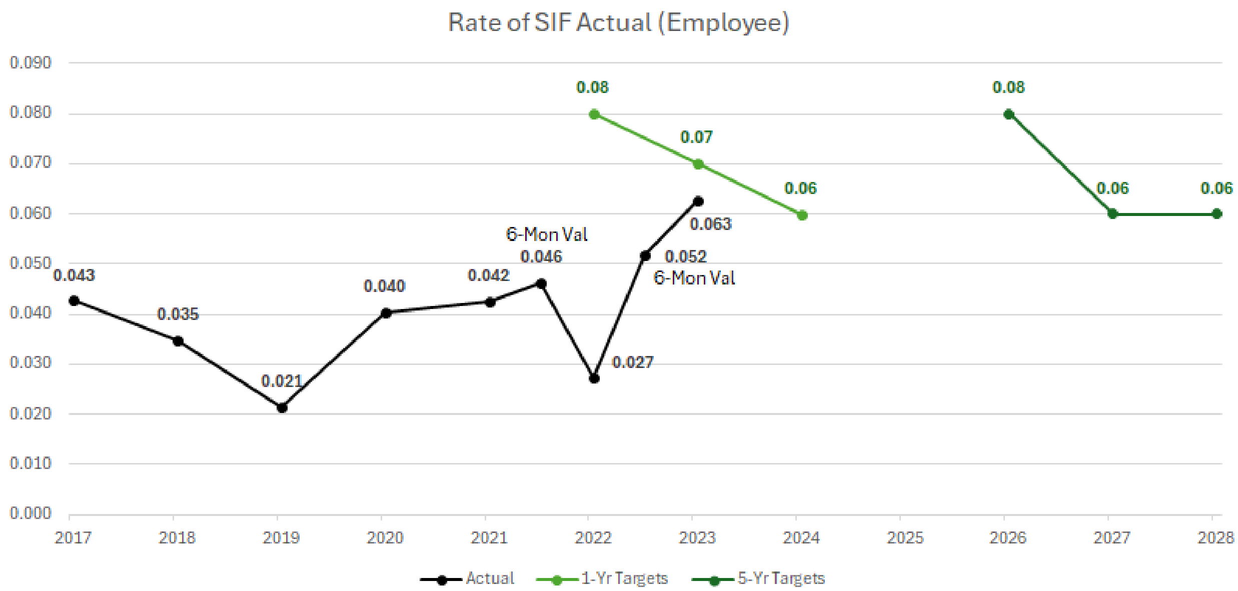
By relating the number of employee SIF-Actual cases to the total employee hours worked and normalizing the result using a factor of 200,000, this metric provides a standardized indicator of workplace safety performance.

The formula for calculating Metric 1.1 is:

$$= \frac{\#\ of\ SIF Actual\ Cases\ Among\ Employees\ X\ 200{,}000}{Employee\ Hours\ Worked}$$

The following chart shows Metric 1.1 results compared to targets for 2017 through 2028, including results from the 2022 and 2023 mid-year reports. All historical values reflect the most recent data available as of the 2023 report and may differ from previously reported figures.

Figure 2-1: Metric 1.1 Summary Chart



2.1.1 Metric 1.1 Accuracy and Consistency

Information utilized for Metric 1.1 is extracted from the organization's Safety and Environmental Management System ("SEMS") database which also provides the foundation for PG&E's CAP. Accordingly, CAP is identified as the formal system of record for injury management. Data enters the SEMS database from a variety of sources, including field injury notifications from functional management or the Nurse Care Line which provides a standard process for reporting and collecting employee injury information. PG&E's SIF Standard provides a detailed description of the tools and processes utilized within the organization to determine if an injury or near miss is classified as a SIF event. The standard introduces the requirement for a SIF Functional Review Team to assess all reported serious injuries in comparison to SIF injury definition criteria to determine appropriate categorization. The SIF Review team is required to utilize SIF EEI OS & HC criteria as a tool for a standard evaluation of all serious injuries for classification purposes. The results of the Review Team's efforts including the required injury data, decisions and justifications made by the team are then inputted into the CAP system.

Additionally, PG&E's Enterprise Health and Safety ("EH&S") SPM and SOMs Process Overview describe the details of managing and certifying SOMs performance along with corporate certification procedures. Upon completion of the Functional Review Team analysis of serious injuries and inclusion of findings into the CAP system, a corporate SOMs SIF Injury Review Team (Senior Director of Safety, Safety Program Manager, and Risk Manager) performs a secondary evaluation to confirm that the injury is categorized accurately for classification with regards to the EEI SIF criteria. This organization is responsible for certifying the serious injury classification and the timely reporting of SOM employee SIF Injuries within the organization.

PG&E identified the inclusion of Review Teams and utilization of the EEI OS & HC SIF criteria as examples of initiatives that have been put in place in the past several years to provide a more streamlined and consistent process for SIF injury reporting.

PG&E began a SIF Program in 2017 as an effort to capture serious injury information and specifically identify those events that can be categorized as significant. At that time PG&E classified SIFs based on job task, life threatening or altering, or fatality. Metric 1.1 requires the company to report on SIF occurrences utilizing the EEI OS&HC criteria which provides a standard approach to classification of events and utilizes a defined list of fourteen categories of injuries that qualify as SIFs. To effectively compare safety injury trends to historical performance the organization reviewed injury reports from 2017 to present to define which met the Metric 1.1 definition in order to utilize the information for yearly performance trending.

Observations on Metric 1.1 Accuracy

To determine the overall accuracy of the employee SIF Actual metric, FEP verified PG&E's reported employee work hours, the count of employee SIF Actual cases (as defined by the EEI OS&HC methodology), and the final metric calculations. FEP found Metric 1.1 results to have minor accuracy issues. The verification process is described in the sections below.

Verification of Employee Hours

Employee hours are defined by PG&E as all productive hours logged into the PG&E time coding system for active employees, including overtime, but excluding overhead items like holidays, vacation, and sick time. Employee hours also include staff augmentation hours, which are provided by the vendor Agile-1.

The Metric 1.1 spreadsheet[1] features two sets of employee hours data: a yearly total and a monthly breakdown for each year. For all report years 2021-2023, the yearly total data is used to calculate the metric result.

FEP reviewed the available hours data on the Metric 1.1 spreadsheet and reviewed PG&E documentation and data to confirm that the hours on the Metric 1.1 spreadsheet were consistent with the hours from the PG&E data source. PG&E provided two documents explaining how hours were totaled, as well as an excel file with monthly data for the 2021-2023 period. The documents explained that the employee labor hours are received via email from the Data Analytics Metrics Team. Hours for the previous month are locked in by the 4th business day of each month. If changes to prior months are made, they are reflected in the month that the changes are made, so the YTD total is trued up without changing prior month entries. The data in the excel file received via data request from PG&E included data for the Year, Date, and Sum of Hours.

FEP discovered a discrepancy between the hours reported in the yearly total for 2021 and the sum of the monthly hours for the year 2021 in the Metric 1.1 spreadsheet. FEP's review of the requested employee hours data showed the same 2021 monthly data as the monthly table in the Metric 1.1 spreadsheet. Further data requests revealed that the hours for December 2021 in the Metric spreadsheet and data request responses were incorrect. PG&E cited that "further adjustments to the hours may have been made after the report was submitted or it could be a data entry error." FEP was given the fixed hours for December 2021, which then matched the 2021 total hours. FEP notes that if original monthly hours were used to calculate this metric, the result for 2021 would have been 0.043 instead of 0.042.

[1] Available as part of the SOMs reports Safety and Operational Metrics, Data Files

Verification of Employee SIF Actual

An employee SIF Actual case is identified based on the criteria developed by the EEI's OS&HC. These criteria are updated annually based on additional learnings from injury classification to provide further clarification or criteria for the following year.

The criteria for 2023 included the following: Fatalities, amputations (involving bone), concussions and/or cerebral hemorrhages, injury or trauma to internal organs, bone fractures (certain types), complete tendon, ligament, and cartilage tears of the major joints (e.g., shoulder, elbow, wrist, hip, knee, and ankle), herniated disks (neck or back), lacerations resulting in severed tendons and/or a deep wound requiring internal stitches, second (10 percent body surface) or third-degree burns, eye injuries resulting in eye damage or loss of vision, injections of foreign materials (e.g., hydraulic fluid), severe heat exhaustion and all heat stroke cases, dislocation of a major joint (shoulder, elbow, wrist, hip, knee, and ankle), and "other injuries" that don't fit in the existing categories. PG&E records incidents that meet or exceed these thresholds.

FEP verified that the table of injuries included in the Metric 1.1 spreadsheet were utilized in the calculations correctly. The total injuries in that table were correctly reflected in the final calculation as well in the reports (e.g. when % of injuries due to bone fractures were reported).

FEP leveraged multiple data sources – including databases containing all OSHA recordable injuries and a database of all DART injuries for the reporting period to verify that the injuries were correctly selected using the relevant EEI criteria. By reviewing and selecting numerous individual cases for in-depth investigation, FEP was able to cross-reference the injury records with those recorded in the SIF spreadsheets. During the review of selected injuries, FEP submitted several RFIs to gather additional information needed to determine whether certain cases met the criteria for SIF classification. After multiple rounds of RFIs, one injury (SEMS ID 10102717) remains in question. PG&E's initial RFI response described the injury as "Right Fibula Fracture; Right ankle Sprain". PG&E further confirmed that surgery was required for the fracture. FEP submitted a final RFI asking why this injury was not classified as a SIF, given that a fracture requiring surgery may meet EEI SIF criteria. The response indicated that "the initial incident report appeared to be an ankle injury only. Nothing further was specified on whether the injury met the EEI criteria for a bone fracture." In addition, PG&E noted "as further process improvement in 2025, we began reviewing incidents that are classified as OSHA recordables with the Worker's Compensation team including Occupational Health leadership to confirm the injury diagnosis and the EEI criteria classification although we are uncertain as to whether this additional review would have resulted in a different determination. We will include any subsequent changes to the SOMs metric 1.1 dataset in our SOMs next report." The EEI criteria for bone fractures mentioned in the 2023 SOMs report indicate only certain types of bone fractures quality as SIFs.

The table below illustrates the categories of employee SIF Actual by year for 2017-2023.

Table 2-1: Categories of Employee SIF Actual

Injury Classification	2017	2018	2019	2020	2021	2022	2023	Total
Bone fracture	5	2	2	5	8	4	9	35
Fatality	1	2	0	1	0	1	1	6
Complete Tendon, ligament or cartilage tears of major joint	1	0	1	0	2	0	1	5
Dislocation of a major joint (that requires manipulation)	2	1	1	0	0	0	0	4
Amputation (involving bone)	0	1	0	0	0	1	1	3
Concussion or cerebral hemorrhages	0	0	1	1	0	0	1	3
2nd (10% body surface) or 3rd degree burns	0	0	0	2	0	0	1	3
Herniated disks (neck or back)	0	2	0	0	0	0	0	2
Other serious injury	0	0	0	1	0	1	0	2
Eye damage or loss of vision	0	0	0	0	1	0	1	2
Injections of foreign materials	1	0	0	0	0	0	0	1
Injury to internal organs	0	0	0	0	0	0	1	1
Severe heat exhaustion or stroke	0	0	0	0	0	0	1	1
Total	10	8	5	10	11	7	17	68

Based on this review, it is reasonable to conclude that the injury data, as reported in the SIF spreadsheets, accurately reflects the true incidence of employee SIF Actual for the periods under review, with the possible exception noted above.

2.1.2 Metric 1.1 Management

The EH&S organization, under the leadership of the Senior Director of Safety, Safety Program Manager, and Risk Manager, is responsible for Metric 1.1 management including data collection, certifying injury classification, and reporting Metric 1.1 performance along with communication of Metric 1.1 performance with functional and executive management. On a monthly basis the team meets to evaluate all incidents, map the events into the EEI SIF criteria, and certify the metric stream (Senior Director of Safety).

The EH&S organization provides advisory services to functional organizations, including the Review Team, with its efforts in the classification and management of Metric 1.1. Daily safety updates are created and shared within PG&E to provide a source for sharing injury prevention communications.

Within the organization all validated SIF events are shared broadly across the organization to educate employees on root causes of injuries and action plans, corrective actions, procedures and controls that are in place to prevent a reoccurrence. Suboptimal performance is subject to operational work activities that are intended to have a positive impact on employee safety. Specific performance status of Metric 1.1 is not shared nor utilized within the operational functional areas as a management tool.

Once Metric 1.1 data is collected, verified, and validated, the EH&S team monitors current performance to those identified as the one and five-year targets. If performance is off track to target the Team will create a Tactical Implementation Plan ("TIP") sheet indicating the actions, including operational work activities, that are in place or initiated that are focused on improved performance.

The organization utilizes the Lean Operating Review and CIC meetings described in Section 1.4 to review the Metric 1.1 status and any catch back work activities.

PG&E has several "work activities" focused on improving safety performance through advanced training and an organizational safety culture transformation. One example of an initiated work activity is the use of the SIF Capacity & Learning Model, which is commonly utilized in industry and inserts proven successful Human Performance tools (situational awareness, three-way communications, phonetic alphabet, etc.) into daily operations. Other activities include the implementation of a Safety Excellence Management System, along with training focused on the development of safety management skills for front line supervisors, and the utilization of Safety Observation program that focuses employees on performing peer observations that identify and eliminate hazards and unsafe work practices. Other work activities are in place and many of these programs are multi-year efforts that are commonly utilized within peer utility organizations. These work activities are Company-wide initiatives focused on SIF generally which impacts the performance of Metric 1.1.

Observations on Metric 1.1 Management

PG&E's utilization of the SIF Standard along with the SPMs and SOM's Process Overview document provides a consistent methodology for collection, analysis, and reporting of SIF Employee injuries. The creation of internal SIF Injury Review Teams to utilize these tools should result in an objective evaluation of the injury to EEI OS&HC criteria and result in consistent classification documentation.

FEP notes that while general employee SIF information is widely shared throughout the organization with a focus on supporting information intended for use in educating employees on specific injury prevention actions, the utilization of Metric 1.1 performance is limited to senior management and those involved in the process of producing Metric 1.1 performance status information.

2.1.3 Metric 1.1 Performance and Targets

The development of the Metric 1.1 target is initiated within the EH&S organization with a historical review of the Metric 1.1 performance coupled with a directive from management for year over year improvement expectations as well as a review of benchmark data. In addition, the EH&S team has the authorization to propose changes to the targets based on its insight into the effectiveness of the work activities in place in preventing SIF injuries. Once the proposed targets are set the metric owner along with functional and executive officers review to gain alignment across the organization and provide approvals.

PG&E reports that it utilizes EEI peer benchmarking for employee SIF Injuries to benchmark its organizational safety performance as well as to help inform Metric 1.1 targets. The EEI database provides a comprehensive assessment of utility industry SIF performance and is an established resource for companies to evaluate their safety records. PG&E reported to the audit team that it participates in several additional industry sponsored benchmarking initiatives that provide insight into Metric 1.1 performance and target setting efforts.

The following table displays PG&E's 2017 through 2023 Metric 1.1 results and the 1-year and 5-year metric targets from the SOM report.

Table 2-1: Metric 1-1 Results and Targets

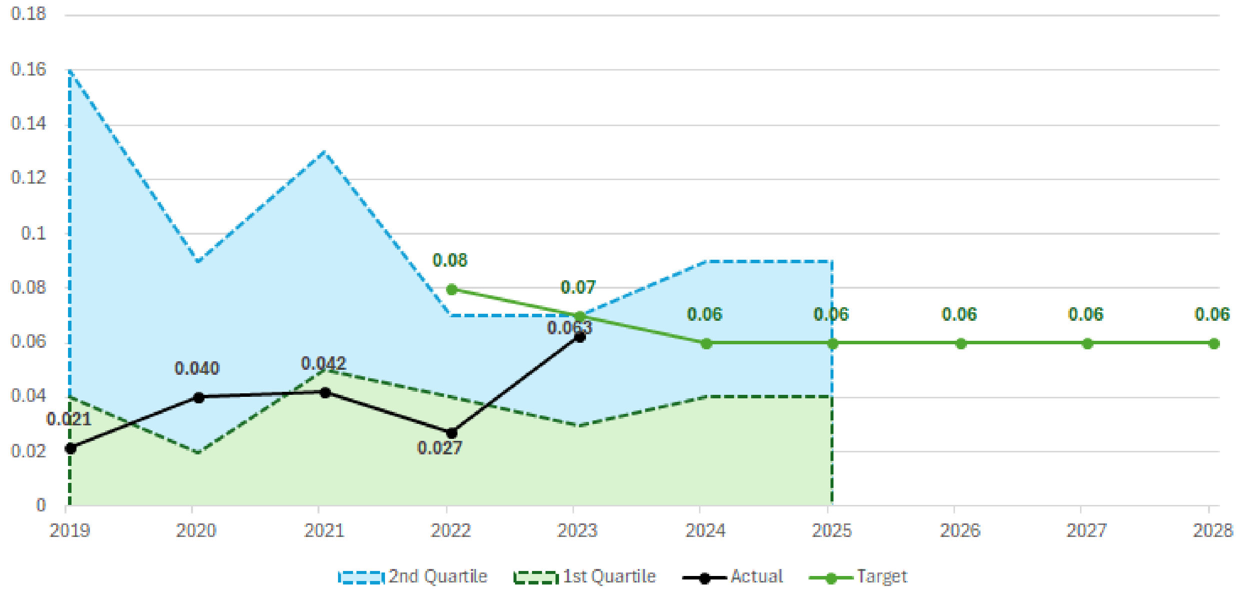
Year	Metric Result	1-Year Target[1]	5-Year Target[1]
2017	0.043		
2018	0.035		
2019	0.021		
2020	0.040		
2021	0.042	0.08	0.08
2022	0.027	0.07	0.06
2023	0.063	0.06	0.06
[1] Targets reflect the target set in that report year (i.e. the 2021 1-year target reflects 2022 target).			

The performance of Metric 1.1 averaged 0.039 for the years 2017 to 2023 and 0.044 for the years 2021-2023. PG&E has lowered the 1-year target by approximately 14% each year. The 5-year target of 0.06 remains unchanged in 2023 from 2022 and includes a buffer gap of approximately 54% when compared to the 2017 to 2023 average performance and 36% compared to 2021-2023 average performance. In 2023 PG&E experienced an increase in the employee SIF rate well above previous year levels. PG&E reported that a trend increase in slips, trips, and falls was the root cause of the degradation in performance. To address the issue the SIF Capacity and Learning Model was put in place, which includes Human Performance tools targeted at reducing risk and injuries.

Observations on Metric 1.1 Performance and Targets

From 2017 to 2023, Metric 1.1 performance, when compared to the EEI benchmarking database, typically drifts between the first and second quartile of industry peers, with the 2023 result of 0.063 firmly in the second quartile. The chart below shows quartile data in the year the corresponding target was set in. In the 2022 report, EEI benchmarking data from 2021 was used to establish the 2023 1-year target. This target of 0.07 was set to match the boundary between the 2nd and 3rd quartiles of the benchmark data. Since the 2023 target was set using 2021 EEI quartile data, that quartile boundary is shown in 2023 on the chart below.

Figure 2-2: Rate of SIF Actual (Employee) Compared to EEI Benchmarking



As reported by PG&E, during the audited period 2021 to 2023, the Metric 1.1 targets were set at lower levels around the second to third quartile threshold. It is FEP's experience that within the utility industry, employee safety performance goals are typically established in the first quartile of peer benchmarking. In most cases these aspirational goals or targets serve as an important motivation and inspiration for the organization to develop, and execute initiatives focused on elimination of SIFs. FEP notes that Metric 1.1 does have declining 1-year targets, which is directionally consistent with targeting for performance improvement.

Given that PG&E has demonstrated sustained performance over an extended period in the first or second quartile, the target thresholds for Metric 1.1 do not appear to drive performance improvement of this metric but other programs within the organization may do so.

FEP was also able to confirm that PG&E has other benchmarking sources (in addition to EEI) that it utilizes in its efforts to secure benchmarking data in evaluating the organization's safety performance relative to employee SIFs. Typically, companies within the utility industry use this benchmarking data to define objective insight as to where their performance compares to peer organizations. In addition, benchmarking efforts can open the organization to opportunities to work within the industry to share "best practice" work activities.

2.2 Metric 1.2: Contractor SIF

The CPUC defines Metric 1.2 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).

Metric 1.2 measures the rate at which PG&E contractors experience serious injuries or fatalities in the course of their work. A SIF-Actual case is determined using the methodology developed by EEI's OS&HC

that specifies the criteria for what constitutes a serious injury event, ensuring consistency across the industry.

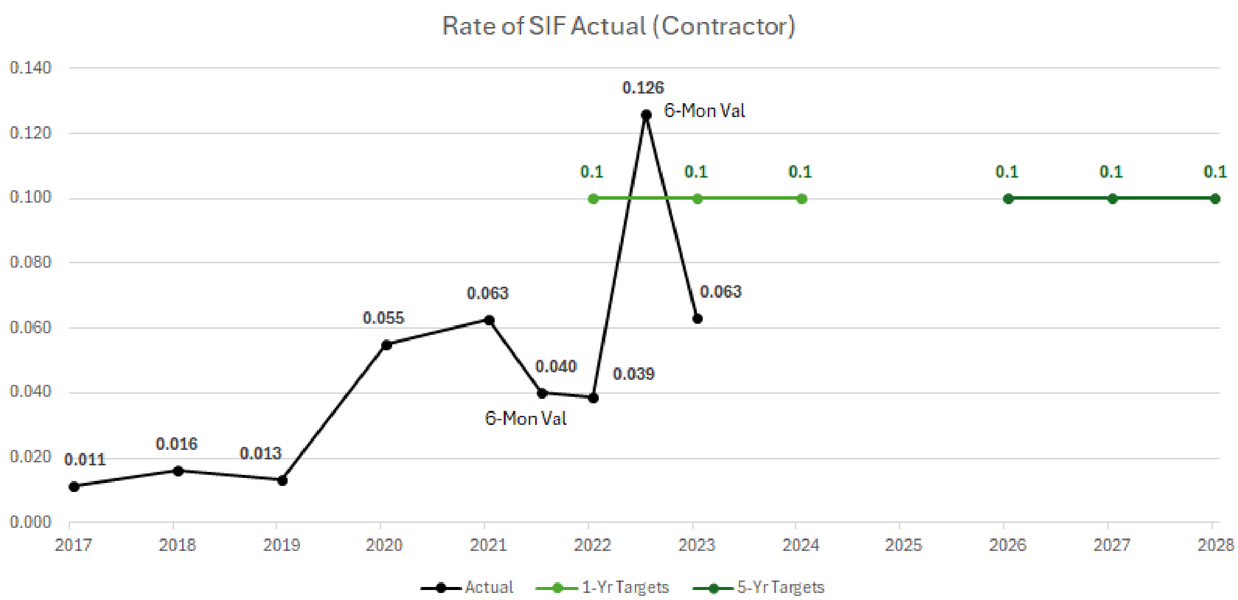
By relating the number of contractor SIF-Actual cases to the total contractor hours worked and normalizing the result using a factor of 200,000, this metric provides a standardized indicator of workplace safety performance.

The formula for calculating Metric 1.2 is:

$$= \frac{\#\ of\ SIF Actual\ Cases\ Among\ Contractors\ X\ 200{,}000}{Contractor\ Hours\ Worked}$$

The following chart shows Metric 1.2 results compared to targets for 2017 through 2028, including results from the 2022 and 2023 mid-year reports. All historical values reflect the most recent data available as of the 2023 report and may differ from previously reported figures.

Figure 2-3: Metric 1.2 Summary Chart



2.2.1 Metric 1.2 Accuracy and Consistency

Information utilized for Metric 1.2 is extracted from the organization's SEMS database which also provides the foundation for PG&E's CAP. Accordingly, CAP is identified as the formal System of Record for injury management. Upon receipt of a contractor injury notification, functional organizations are responsible for coordinating the collection and reporting all pertinent information concerning the event including initial analysis of potential SIF classification.

The audit team conducted several interviews with PG&E contractors and the Director of Contractor Safety to explore the process that the contractor organizations utilize to report injuries. All interviewees described a process where the contractors are required to report a safety incident to their PG&E function coordinator within an hour of an incident. At PG&E's direction and within eight hours of the incident the contract organization must complete a "incident injury report" by utilizing PG&E reporting templates. If the functional organization views the injury as a potential SIF injury it is then incorporated into the CAP system. PG&E will, at its discretion, order the contract organization to perform a “Cause Evaluation” investigation that will provide additional details of root cause of the incident and corrective actions to prevent reoccurrence.

PG&E’s SIF Standard provides a detailed description of the tools and processes utilized within the organization to determine if an injury or near miss is classified as a SIF event. The standard introduces the requirement for a SIF Functional Review Team to assess all reported serious injuries in comparison to SIF injury definition criteria to determine appropriate categorization. The SIF Review team is required to utilize the EEI OS&HC criteria as a tool for a standard evaluation of all serious injuries for classification purposes. The results of the Review Team’s efforts including the required injury data, decisions and justifications made by the team are inputted into the CAP system.

Additionally, PG&E provided the EH&S SPM and SOMs Process Overview that describes the details of managing and certifying SOMs metric performance along with corporate certification procedures. Upon completion of the Functional Review Team analysis of serious injuries and inclusion of findings into CAP, a corporate SOMs SIF Injury Review Team (Senior Director of Safety, Safety Program Manager, and Risk Manager) perform a secondary evaluation to confirm that the injury is categorized accurately for classification with regards to the EEI SIF criteria. This organization is responsible for certifying the serious injury classification and the timely reporting of SOMs Contractor SIF Injuries within the organization.

PG&E has initiated, during the last decade, changes in reporting requirements for contractor safety incidents that have spanned from no requirements for the contractor to provide notification to the current policy of the company to report all SIF Actual and Potential incidents, which began in 2017. Specifically, from 2017 to 2019 contractors were required to classify and report incidents that were defined as a fatality, life threatening, or altering. In mid-year 2020 PG&E elected to establish the EEI Safety Classification and Learning (“SCL”) methodology for injury evaluation that includes SIF Potential incidents and increased the number of incidents reported by broadening the classification criteria. In 2022, PG&E adopted the EEI OS & HC criteria, which provides a standard to classify injuries and utilizes a defined list of fourteen categories of injuries that qualify as SIFs. PG&E extracted information from the contractor CAP database to define historical performance based on Metric 1.2 definition to evaluate performance trends although because of the limitation of injury data from 2017-2020, this period is not comparable to 2021-2023. Specifically, the changes to the reporting requirements have led to a larger population of injuries evaluated for classification as a Metric 1.2 injury. Since June 2022 the reporting requirements have remained consistent.

The addition of incident Review Teams and utilization of the EEI OS&HC Serious Injury criteria has provided a standard process across the organization for classification and reporting of SOMs SIF injuries.

Observations on Metric 1.2 Accuracy

To determine the overall accuracy of Metric 1.2, FEP verified PG&E’s reported contractor work hours, the count of SIF Actual cases (as defined by the EEI OS&HC methodology), and the final metric calculations. FEP found the Metric 1.2 results to have minor accuracy issues. The verification process is described in the sections below.

Verification of Contractor Hours

Contractor hours are defined as all productive hours logged into the PG&E SQL server for active contractors, which includes overtime as hours worked, but excludes overhead items like holidays, vacation, and sick time.

FEP reviewed the available hours data on the Metric 1.2 spreadsheet[2] and reviewed PG&E documentation and data to confirm that the hours on the Metric 1.2 spreadsheet were consistent with the hours from the PG&E data source. PG&E provided the contractor hours data, including all hours logged by contractors from the Data Analytics Metrics Team. When first validating the source of contractor hours to ensure it matched with the hours presented on the Metric 1.2 spreadsheet, FEP was first provided with a contractor hours sheet with approximately half the hours listed in association with this metric. Through a follow-up RFI regarding the discrepancy, PG&E responded that the provided hours were unadjusted, meaning they did not go through the PG&E internal QA/QC process. Further explanation clarified that the unadjusted hours come from the ISNetworld ("ISN") database, but contractor hour data must be pulled from PG&E's server as well to get to the final hours used for Metric 1.2. Originally, contractor hours were categorized under two project types in ISN, Prime and Subcontractor. As the Contractor Safety program evolved, PG&E transitioned to a more detailed classification system based on functional areas (e.g., EO, GO, DCCP). With this change, the Prime category was deactivated and was replaced by the main functional areas (EO, GO, DCPP, etc.). The same happened for the Subcontractor category. When projects areas are deactivated, PG&E is no longer able to pull data from them through the ISN portal. PG&E stores this historical data on a server to ensure data from the deactivated project categories can still be accessed. This resulted in the initial hours being different, since pulling only through ISNetworld only gets you partial contractor hours. The two data sources are combined to come up with one set of hours used in Metric 1.2. PG&E provided the contractor hours that have completed the QA/QC process, and FEP was able to reconcile these, noting a very slight discrepancy in full-year 2022 and 2023 hours between those reported in the Metric 1.2 spreadsheets and provided in the data request (67,356,328 vs 67,356,326 for 2022, and 56,937,720 vs 56,937,718 for 2023). However, FEP noted the contractor hours provided from the Data Analytics Metrics Team for the 2022 and 2023 mid-year report had larger variances to the Metric 1.2 spreadsheet. The 2022 SOMS mid-year report used 34,920,940 hours, whereas the raw data indicated 34,990,456 and the 2023 mid-year report used 25,370,335 hours whereas the raw data indicated 24,184,695. If these provided hours were used, the rounded 2022 mid-year result would remain unchanged, however the 2023 mid-year result would increase from 0.126 to 0.132 (including an additional change mentioned in the Verification of SIF Actual section below).

Verification of Contractor SIF Actual

A contractor SIF Actual case is identified based on the criteria developed by EEI OS&HC. These criteria are updated annually based on additional learnings from injury classification to provide further clarification or criteria for the following year.

The criteria for 2023 included the following: Fatalities, amputations (involving bone), concussions and/or cerebral hemorrhages, injury or trauma to internal organs, bone fractures (certain types), complete tendon, ligament, and cartilage tears of the major joints (e.g., shoulder, elbow, wrist, hip, knee, and ankle), herniated disks (neck or back), lacerations resulting in severed tendons and/or a deep wound requiring internal stitches, second (10 percent body surface) or third-degree burns, eye injuries resulting in eye damage or loss of vision, injections of foreign materials (e.g., hydraulic fluid), severe heat exhaustion and all heat stroke cases, dislocation of a major joint (shoulder, elbow, wrist, hip, knee, and ankle), and "other injuries" that don't fit in the existing categories. PG&E records incidents that meet or exceed these thresholds.

[2] Available as part of the SOMs reports Safety and Operational Metrics, Data Files

FEP discovered that the 2023 mid-year report states that there were 15 contractor SIF incidents up through June in 2023, but the database for this period contains 16 injuries. Similarly, the report lists a total of 69 SIF incidents for the 2017-June 2023 time period, whereas the database reflects 70 (due to the additional injury in 2023 that was missed). Additionally, PG&E reported that 52% of injuries met the bone fracture criteria, but the actual percentage in the dataset is 51%. All three discrepancies stem from a single injury missing from the reported dataset, despite its inclusion in the database. As a result, the SIF rate reported by PG&E was 0.118, while incorporating all injuries from the database yields a revised SIF rate of 0.126. PG&E has stated that this discrepancy was corrected in the 2023 year-end report to ensure accurate reporting of the total.

FEP also identified a reporting discrepancy, where the 2023 full-year report indicates that 65% of contractor injuries (38 of 58) were bone fractures, however 38/58 rounds to 66% instead. PG&E agreed this was a rounding error in the report.

PG&E presents the data in the Metric 1.2 spreadsheet in two separate tabs, one contains a database of total contractor SIF injuries, while the other includes a table of labor hours by month and year, and a table of contractor SIF Actual counts, also organized by month and year. Although the final metric calculation is based only on the total hours and total contractor SIF Actuals for the year, the monthly values are provided for reference. FEP identified cases where the dates of injuries listed in the injury database did not align with the monthly contractor SIF counts reported in the summary tables. PG&E attributed this discrepancy to the 2023 mid-year reporting error previously mentioned. However, FEP found that the inconsistencies extend beyond the single additional injury, indicating additional mismatches. Although this finding does not affect the final metric calculation, publicly available data should be consistent and accurate.

FEP leveraged multiple data sources – including databases containing all OSHA recordable injuries and a database of all DART injuries for the reporting period to verify that the SIF incidents were correctly selected using the relevant EEI criteria for employee injuries. Since contractor SIF incidents follow the same process as employee SIF incidents once they are entered into the CAP system, the verification work done for employee SIF incidents contributes directly to this verifying contractor SIF actual quality. The methodology for identifying SIF Actual incidents is identical for both employees and contractors, though this metric only reports on the SIF Actual for contractors.

The table below illustrates the categories of contractor SIF Actual by year for 2017-2023.

Table 2-2: Categories of Contractor SIF Actual

Injury Classification	2017	2018	2019	2020	2021	2022	2023	Total
Bone fracture	0	0	0	7	13	7	11	38
Fatality	2	1	1	4	3	2	1	14
Dislocation of a major joint (that requires manipulation)	0	0	0	1	0	2	2	5
Concussion or cerebral hemorrhages	0	0	0	0	2	0	2	4
Other serious injury	0	1	1	0	0	1	0	3
Eye injuries resulting in eye damage or loss of vision (Excluding corneal abrasion)	0	1	1	0	0	0	0	2
Amputation (involving bone)	0	0	0	1	0	0	1	2
2nd (10% body surface) or 3rd degree burns	0	0	0	1	0	0	0	1
Injections of foreign materials	0	0	0	0	0	0	1	1
Injury or trauma to internal organs	0	0	0	0	1	0	0	1
Lacerations (severed tendons and/or a deep wound)	0	0	0	0	0	1	0	1
Total	2	3	3	14	19	13	18	72

Based on this review, it is reasonable to conclude that the injury data, as reported in the Metric 1.2 spreadsheet (with the exception of the 2023 mid-year result), accurately reflects the true incidence of SIF actual for the periods under review.

2.2.2 Metric 1.2 Management

The EH&S organization, under the leadership of the Senior Director of Safety, Safety Program Manager, and Risk Manager, is responsible for Metric 1.2 management including data collection, certifying injury classification, and reporting Metric 1.2 performance along with communication of metric performance with functional and executive management. On a monthly basis the team meets to evaluate all incidents, map the events into the EEI SIF criteria, and certify the metric stream (Senior Director of Safety).

The EH&S organization provides advisory services to functional organizations, including the Review Teams, with its efforts in the classification and management of Metric 1.2. Daily safety updates are created and shared within PG&E to provide a source for sharing injury prevention communications.

Contractors typically participate in weekly conference calls with their PG&E functional contacts to discuss a variety of issues including safety performance, incident reviews, near misses, and operational efforts to improve safety within its organization. In addition, PG&E sponsors large scale periodic meetings/summits with contractors to review safety performance, discuss changes to safety management processes or requirements, along with other topics focused on SIF injury prevention.

Within the organization all validated contractor SIF events are shared broadly across the organization to educate employees on root causes of injuries and action plans, corrective actions, procedures and controls that are in place to prevent recurrences. Specific status of Metric 1.2 is not shared nor utilized within the operational functional areas as a management tool.

Once SOMs Contractor SIF metric data is collected, verified, and validated, the EH&S team monitors current performance to the one and five-year targets. If performance is off track relative to the target, the Team will create a TIP sheet indicating the actions that will take place to improve performance.

The organization utilizes the Lean Operating Review and CIC meetings described in Section 1.4 above to review the Metric 1.2 status and any catch back work activities.

PG&E notes in the SOM reports that PG&E has created, initiated, and maintain several “work activities” focused on improving overall safety performance of the contractors PG&E utilizes. These programs were referenced in audit interviews where PG&E staff and contractors noted that the initiatives produce a positive influence on improving safety performance. Most notable were the discussions held with contactors who shared that significant focus is placed on the Contractor Pre-Qualification Program, which includes the process utilized to remain qualified to work for PG&E. Contractors shared their requirement to have periodic reviews, provided by third party, of their policies, procedures, performance records and training programs of their organization and any sub-contractors that they employ. Other programs focused on contractor safety include a Contractor Motor Vehicle initiative focused on preventing rollovers along with Contractor Oversight observations focused on confirming that the contractors are following specific job plans approved by PG&E staff.

Observations on Metric 1.2 Management

PG&E’s utilization of the SIF Standard along with the SPMs and SOM’s Process Overview document provides a consistent methodology for collection, analysis, and reporting of SIF Employee injuries. The creation of internal SIF Injury Review Teams to utilize these tools should result in an objective evaluation of the injury to EEI OS&HC criteria and result in consistent classification documentation.

FEP notes that while general SIF Contractor information is widely shared throughout the organization with a focus on supporting information intended for use in educating staff on specific injury prevention actions, the utilization of Metric 1.2 performance is limited to senior management and those involved in the process of producing the SOM’s performance status information.

2.2.3 Metric 1.2 Performance and Targets

The development of the Metric 1.2 target is initiated within the EH&S organization with a historical review of the metric performance coupled with a directive from management for year over year improvement expectations. In addition, the EH&S team has the authorization to propose changes to the targets based on its insight into the effectiveness of the work activities in place in preventing SIF injuries. Once the proposed targets are set, the metric owner along with functional and executive officers review to gain alignment across the organization and provide approvals.

The following table displays PG&E’s 2017 through 2023 Metric 1.2 results and the 1-year and 5-year metric targets.

Table 2-3: Metric 1-2 Results and Targets

Year	Metric Result	1-Year Target[1]	5-Year Target[1]
2017	0.011		
2018	0.016		
2019	0.013		
2020	0.055		
2021	0.063	0.100	0.100
2022	0.039	0.100	0.100
2023	0.063	0.100	0.100
[1] Targets reflect the target set in that report year (i.e. the 2021 1-year target reflects 2022 target).			

The average rate from 2017-2023 was 0.037 and 0.055 for 2021-2023. The 1- and 5 – year targets of 0.1 are 82% higher than the 2021-2023 average and 59% higher than its worst years of 0.063 in 2021 and 2023. As shown, Metric 1.2 has a step change in performance in 2020. PG&E maintains that the historical performance contractor SIF events rates from 2017 to 2019 are lower based on the reporting classification requirements of that period. In addition to a narrow injury database for 2017 to 2019, the introduction of the EEI OS & HC criteria for SOMs SIF incidents created a level of uncertainty in the impact of Contractor SIF qualifying events. PG&E set the target at 0.1 to account for this uncertainty. However, FEP notes that the 5-year target is also set at this level and there has been no change to the targets since the inception of the SOMs.

PG&E notes that the modifications and adjustment to the Contractor SIF reporting guidelines has created an uncertain view of the significance of historical perspective of past performance to properly inform threshold target setting. PG&E staff have shared the vision that recent efforts to remain consistent with reporting requirements will provide a more accurate database for modeling future threshold targets.

Observations on Metric 1.2 Performance and Targets

PG&E reports that it is currently unable to secure reliable benchmarking from peer organizations for Metric 1.2. The FEP Audit team was able to identify a potential option, ISNetworld, who is currently providing services to PG&E, for providing this type of benchmarking information. In addition, monitoring other key safety metrics like PG&E Employee Safety Benchmarking information, Contractor Safety SPM's, DART, and Recordable injuries may provide a reasonable assessment of the trend of contractor's safety performance to better inform a target.

Given that PG&E has demonstrated sustained performance over an extended period well below the established threshold target, the target thresholds for the SOMs do not appear set to drive performance improvement of this metric but other programs within the organization may do so. It is FEP's experience that within the utility industry, organizational safety goals are set at aspirational levels that promote staff motivation and execution of initiatives to improve overall corporate safety performance. FEP would also expect that the targets would decline with subsequent years (i.e. 2023 1-year target may be lower than the 2022 1-year target) and the 5-year target would be lower than 1-year targets if performance improvement was the goal of the targets.

2.3 Metric 1.3: Public SIF

The California Public Utilities Commission (CPUC) defines Metric 1.3 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 20 during the course of business.

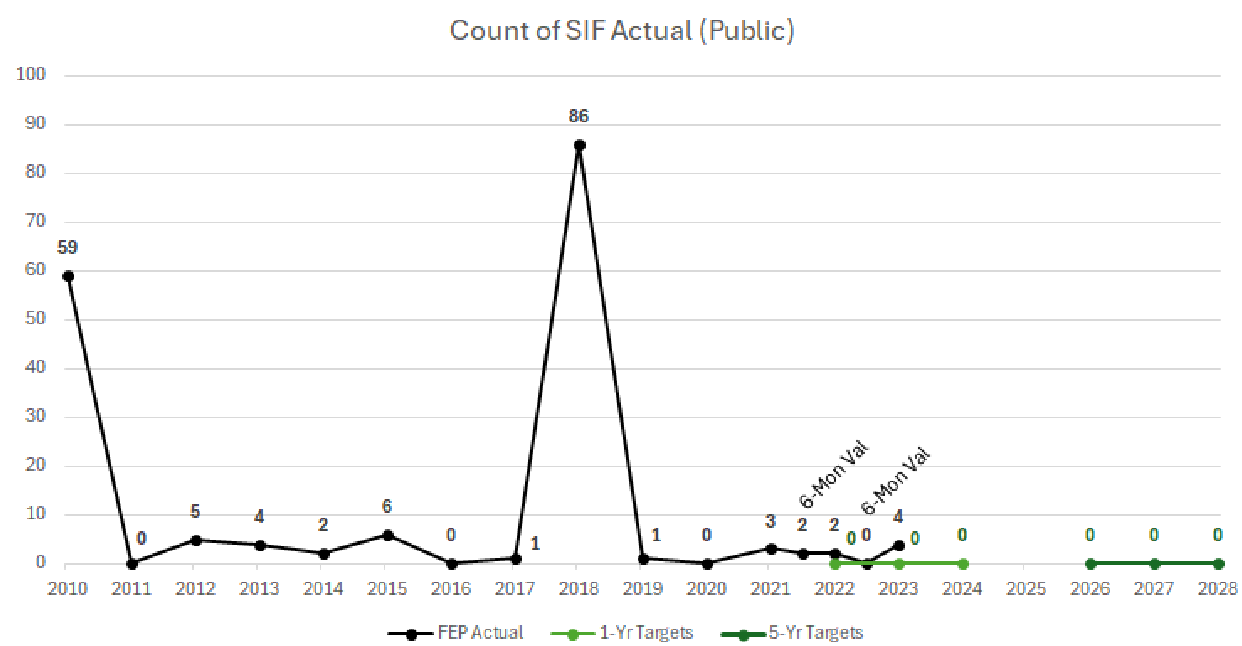
Metric 1.3 tracks the number of SIF Actual incidents impacting the public that are caused by PG&E. This metric provides a clear measure of severe safety incidents directly linked to utility operations.

The formula for calculating Metric 1.3 is:

$$= \# \ of \ SIF \ cases \ among \ the \ public \ caused \ by \ PG\&E \ activities \ or \ equipment$$

The following chart shows Metric 1.3 results compared to targets for 2010 through 2028, including results from the 2022 and 2023 mid-year reports. All historical values reflect the most recent data available as of the 2023 report and may differ from previously reported figures.

Figure 2-4: Metric 1.3 Summary Chart



2.3.1 Metric 1.3 Accuracy and Consistency

Information utilized for Metric 1.3 is extracted from the EH&S Serious Incidents Reports, which also provides the foundation for PG&E's CAP. Accordingly, CAP is identified as the formal System of record for injury management. Notification of public injuries can be reported through functional organizations, claims departments of the internal legal organization or regulatory authorities. Functional organization management is responsible for injury data submission into the CAP system.

PG&E's SIF Standard along with the Public Safety Incident Standard provides detailed descriptions of the tools, processes, and function responsibilities utilized in managing and classifying public injuries for SIF designation. Review of the standards along with interviews with PG&E staff revealed that the standards introduce the requirement for a SIF Functional Review Team to assess all reported serious injuries by utilizing the Public Safety Incident Flowchart as a tool for a standard evaluation. The results of the Review Team's efforts including the required injury data, decisions and justifications made by the team are then inputted into the CAP system.

Additionally, PG&E's SPM and SOM Process Overview describe the details of managing and certifying SOMs metric performance along with corporate certification procedures. Upon completion of the Functional Review Team analysis of serious injuries and inclusion of findings into CAP, a corporate EH&S SOMs Public-only SIF Injury Review Team perform a secondary evaluation to confirm that the injury is categorized accurately for classification regarding the SOMs SIF criteria. This organization is responsible for certifying the serious injury classification and the timely reporting of SOMs Public SIF Injuries within the organization.

In situations where the incident and subsequent SIF impact is under investigation by a third party or in active litigation, PG&E maintains a pending status for the SOMs report. Upon the completion of the investigation or conclusion of litigation, the status of the incident is finalized.

The Metric 1.3 definition for Public SIF requires all incidents to be reviewed for jurisdictional determination along with PG&Es incorrect operation of equipment, failure or malfunction of equipment, or failure to comply with a CPUC standard or rule for classification. To provide a historical perspective of performance, PG&E applied the Metric 1.3 definition to its 2010 to 2020 database of public incidents and determined what injuries qualify for SOMs reporting and utilization in trend analysis. This initiative along with the utilization of Incident Review Teams and the Public Safety Flow Chart provides the opportunity for consistent metric reporting.

Observations on Metric 1.3 Accuracy

Public SIF investigations seek to determine if the incident resulted directly from one or more of the following: an incorrect operation of equipment, failure or malfunction of utility-owned equipment, failure to comply with any CPUC Rules or Standards.

FEP reviewed the public SIF incidents listed in the database included in each Metric 1.3 spreadsheet[3] considering this criterion. In addition, FEP was provided with a list of all Public SIFs that were not classified as meeting the Metric 1.3 criteria from 2010 to 2023. For example, two incidents related to the Kincade and Zogg wildfires involved public SIFs that remain listed as "unknown" due to ongoing investigations and litigation. These cases are currently marked as pending.

FEP also conducted independent internet research to identify any additional incidents where PG&E was implicated with injuries or fatalities, including cases under litigation, to ensure that no major events were overlooked.

FEP verified that all injuries listed in the Metric 1.3 spreadsheet were utilized in the calculation of the metric, and that all reported values in the report matched the data source.

[3] Available as part of the SOMs reports Safety and Operational Metrics, Data Files

2.3.2 Metric 1.3 Management

The EH&S organization, under the leadership of the Senior Director of Safety, is responsible for Metric 1.3 management including data collection, certifying injury classification, reporting Metric 1.3 performance along with communication of Metric 1.3 performance with functional and executive management. On a monthly basis the team meets to evaluate all incidents, map the events into the SOMs definition for SIF incident, and certify the metric stream (Senior Director of Safety).

The EH&S organization provides advisory services to functional organizations, including the Review Team, with its efforts in the classification and management of Metric 1.3. Daily safety updates are created and shared within PG&E to provide a source for sharing injury prevention communications.

Once Metric 1.3 data is collected, verified, and validated, the EH&S team monitors current performance to the 1- and 5-year targets. If performance is off track relative to the target the Team will create a TIP sheet indicating the actions that will take place to improve performance.

The organization utilizes the Lean Operating Review and CIC meetings described in Section 1.4 above to review the Metric 1.3 status and any catch back work activities.

Discussions with PG&E staff revealed that Metric 1.3 performance is typically not routinely shared across the organization.

Throughout the audit period PG&E created and initiated several “work activities” focused on improving safety performance for the Public. The work activities can be categorized into efforts focused on operational safety initiatives in gas and electric operations organizations that protect the public, educational programs focused on hazard recognition, and transportation initiatives that improve operation of vehicle safety. A few examples of the gas operations work activities include the dedication of a Gas System Damage Prevention Team charged to manage the Damage Prevention program along with the Gas Public Awareness and Education Program designed to educate contractors, construction personnel and the public on safe excavation practices around pipelines. PG&E’s electric operations work activities include Vegetation Management practices, downed conductor detection with upgraded technology, inspections/patrols, along with numerous additional educational programs focused on a wide variety of risk areas including wire down events.

Observations on Metric 1.3 Management

PG&E’s utilization of the SIF Standard, Public Incident Safety Standard, along with the SPMs and SOM’s Process Overview documents provide a consistent methodology for collection, analysis, classification, and reporting of SOMs SIF Public incidents. The creation of internal SIF Injury Review Teams to utilize these tools should result in an objective evaluation of the injury relative to the Metric 1.3 definition and result in consistent classification documentation.

FEP notes that the utilization of Metric 1.3 performance is limited to senior management and those involved in the process of producing the SOM’s performance status information. Discussions with staff outside of those organizations revealed limited knowledge of Metric 1.3 performance.

2.3.3 Metric 1.3 Performance and Targets

The development of the Metric 1.3 target is initiated within the EH&S organization with a historical review of the metric performance. At the direction of executive management, for Metric 1.3, PG&E has established a directional improvement in performance to a goal of zero Public SIF actual events for 2023.

The following table displays PG&E's 2017 through 2023 Metric 1.3 results and the 1-year and 5-year metric targets.

Table 2-4: Metric 1-3 Results and Targets

Year	Metric Result	1-Year Target[1]	5-Year Target[1]
2017	1 Confirmed		
2018	86 Confirmed		
2019	1 Confirmed with 4 pending/unknown		
2020	0 Confirmed with 5 pending/unknown		
2021	3 Confirmed	Decrease	Decrease
2022	2 Confirmed	Decrease	Decrease
2023	4 Confirmed with 1 pending/unknown	Demonstrate progress to zero	Demonstrate progress to zero
[1]Targets reflect the target set in that report year (i.e. 2021 1-year target reflects 2022 target).			

Metric 1.3 performance during the audit period of 2021-2023 varied slightly with performance averaging three confirmed Public SIF actuals per year. During the audit period, the performance trend of decreasing to zero events has not been demonstrated. 2023 results demonstrate that PG&E is not making progress towards the target.

Observations on Metric 1.3 Performance and Targets

The definition for a Public SIF incident is uniquely specific to the Metric 1.3 reporting requirement and therefore FEP was not able to identify any direct comparable benchmarks. However, it is noted that the SPM report that is provided to the CPUC contains a Public SIF metric, which utilizes a different definition that may provide a broader view of PG&E's performance trend relative to peers. Utilizing both SPM and SOM performance trends may reveal opportunities for the organization to define operating strategies that reduce risk to the public.

As noted in the Metric 1.1 and 1.2 discussion above, it is FEP's experience that the utility industry establishes public safety performance goals in the first quartile of peer benchmarking. PG&E's directional goal of zero for Public SIF incidents is consistent with companies focused on aspirational objectives.

2.4 Metric 2.1: System Average Interruption Duration Index (SAIDI) (Unplanned)

The CPUC defines Metric 2.1 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.*

Metric 2.1 measures the average duration of sustained power interruptions per metered customer due to unplanned outages, excluding MED, within a calendar year. Metric 2.1 is calculated by summing the total customer unplanned outage hours and dividing by the number of customers served, providing a standardized measure of reliability. Metric 2.1 includes only unplanned events with all planned outage activities excluded.

MEDs are days with large numbers of customer minutes interrupted, often due to severe weather events like storms, but are cause-agnostic. The purpose of MEDs is to help isolate and analyze major events separately from routine operation, providing a clearer picture of normal system performance. The Institute of Electrical and Electronics Engineers ("IEEE") Guide for Electric Power Distribution Reliability Indices (Standard 1366) defines MEDs as days in which the daily SAIDI exceeds a statistically defined threshold based on the previous 5 years of daily SAIDI data[4]. In addition to storms, new causes of MEDs include PSPS events, which have been some of PG&E's largest MED days. IEEE released guidelines[5] for calculating the daily SAIDI threshold, which is discussed further in the "Observation on Accuracy" section.

The formula for calculating Metric 2.1 is:

$$= \frac{\sum(Duration\ of\ Interruption\ x\ \#\ of\ Customer\ Unplanned\ Interruptions)}{Total\ \#\ of\ Customers\ Served}$$

The following chart shows Metric 2.1 results compared to targets for 2013 through 2028, including results from the 2022 and 2023 mid-year reports. Mid-year values are substantially lower because they cover only six months of customer interruptions, whereas the annual values cover the full twelve months. All historical values reflect the most recent data available as of the 2023 report and may differ from previously reported figures.

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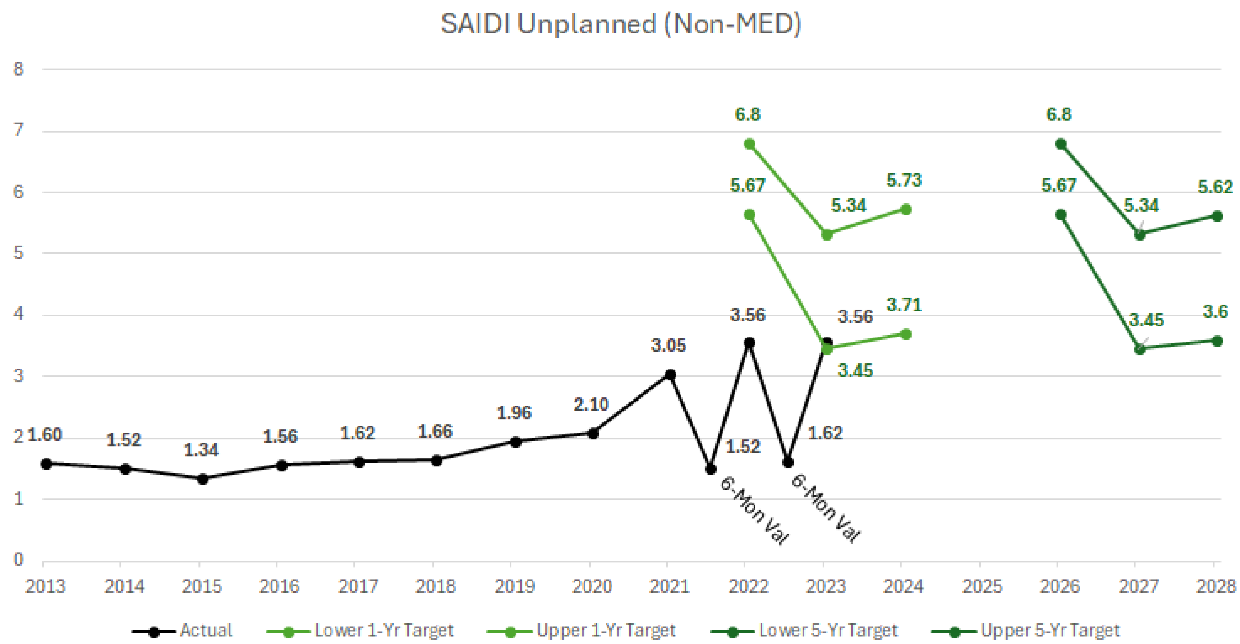
[4] A day in which the daily System Average Interruption Duration Index (SAIDI) exceeds a Major Event Day threshold (T_{MED}) value. For the purposes of calculating daily system SAIDI, any interruption that spans multiple calendar days is accrued to the day on which the interruption began. Statistically, days having a daily system SAIDI greater than T_{MED} are days on which the energy delivery system experienced stresses beyond that normally expected (such as during severe weather).

[5] https://standards.ieee.org/ieee/1366/7243/

Figure 2-5: Metric 2.1 Summary Chart



2.4.1 Metric 2.1 Accuracy and Consistency

Information for Metric 2.1 is extracted from the Integrated Logging Information System ("ILIS") Outage Database. Data enters ILIS through reports made by troubleshooters who respond to outages and other issues in the field. PG&E becomes aware of a downed wire or outage through several reporting streams such as Smart Meters, SCADA or customer reporting. Troubleshooters are sent to the scene to assess the incident. Once on-site, the troubleshooters complete digital forms to document the characteristics of the incident. Those incident reports are transmitted to the distribution operations/control center.

PG&E supplied the audit team with the "Outage Reporting Details and Accuracy Verification Process" documents that provides a detailed description of the proper method to input outage data into ILIS along with the process for verifying the accuracy of the reported outage events.

The data transmitted to the distribution outage center is reviewed and manually entered by distribution staff. Employees of the outage center conduct a quality review as data is entered into ILIS. After the entries are submitted to ILIS, a member of the Outage Quality Review Team conducts another accuracy review. If engineers wish to add new information or correct previously submitted information, they ask the operations team to make changes to the data. Individuals in troubleshooting, engineering, and related departments have read access to the outage data, but do not have the ability to make changes to the database directly.

PG&E uses the electric geographic information system ("EGIS") to inform this metric. EGIS is used to identify customers impacted by system outages.

Once Operations' entries are verified as correct, the staff of Electric System Planning and Reliability become the controllers of the outage information. This group initiates a secondary outage quality analysis review, with issues corrected by staff or sent back to Distribution Operators for further analysis and correction.

Once verified, the outage information becomes available for metric performance queries and modeling. Monthly performance reports are created and utilized by the Reliability staff members and senior management for trend analysis and determination of root causes for unplanned outages.

ILIS contains outage information, which is combined with infrastructure details from EGIS and customer counts from Customer Care and Billing to calculate the number of Customers Experiencing Sustained Outage ("CESO") for each event. EGIS contains infrastructure details like type of conductor (primary distribution, secondary distribution, etc.), and Customer Care and Billing contains customer count information. The data reported in ILIS is not the location of the cause of the outage, but instead the location of the operating device. Additionally, the data for the conductors does not come from field observations, but from the EGIS database.

The oversight and management process of these systems has been largely consistent for the past decade. The policies around data gathering, input, and extraction have been consistent throughout the reporting period with minimal changes to the reporting standard. However, the introduction of Public Safety Power Shutoff ("PSPS") and Enhanced Powerline Safety Settings ("EPSS") for operational wildfire mitigation strategies has impacted the organization's ability to accurately determine if the SAIDI performance trends observed during the audit period are related to general reliability issues or the function of these proactive operating strategies. PG&E uses data on SAIDI for internal tracking and regulatory reporting beyond the bi-annual SOMs report. To meet reporting requirements of the SOMs, PG&E processes the ILIS dataset into planned and unplanned outages along with MED and non-MED events.

Observations on Metric 2.1 Accuracy

To determine the overall accuracy of the metric results, FEP verified PG&E's MED designations as well as the SAIDI calculation. Overall, FEP found the Metric 2.1 results to be accurate. The process for undertaking those verifications is described in the sections below.

Verification of Major Event Days

A MED is a day where the daily SAIDI exceeds a defined threshold. According to IEEE Standard 1366, the threshold is defined by the following formula:

$$MED\ Threshold = e^{\propto + 2.5\beta}$$

The threshold is calculated by first taking the natural logarithm of the SAIDI values to normalize the dataset, which is typically right-skewed. Next, the mean ($\propto$) and standard deviation (β) of the log-transformed SAIDI values are calculated for every day included in the dataset over the past five years. The threshold is set 2.5 standard deviations above the mean in log-space, and the final threshold value is obtained by exponentiating the result to the original SAIDI scale.

PG&E performed these calculations for 2021, 2022, and 2023 using five years of data. PG&E listed the total daily SAIDI value for every day with a value above zero and calculated the logarithmic SAIDI value using Excel's LN function. PG&E calculated the mean ($\propto$) of the logarithmic SAIDI values using the AVERAGE function. The standard deviation (β) of the logarithmic SAIDI values was calculated using the STDEV function. PG&E then multiplied the standard deviation (β) by 2.5 then added the mean ($\propto$). The

MED threshold was calculated by applying the EXP function to the results of that equation. FEP verified PG&E's calculations and found the threshold values to be accurate.

For each day in the spreadsheet, PG&E indicated whether the day met the MED threshold with a "yes" or "no". For example, the MED threshold for 2023 was 5.033 and days with a threshold equal or exceeding that value were marked with a "yes". FEP verified those designations were correct.

Verification of SAIDI Calculation

The Metric 2.1 spreadsheet contain minimal calculations, with most values hardcoded. Metrics 2.1 and 2.2 share the same data sheets, where all values are pre-populated except for two formulas, one that calculates SAIDI and another that calculates SAIFI. The SAIDI formula takes the YTD SAIDI value and divides it by 60 to convert hours into SAIDI minutes. Aside from these two formulas, all other values in the spreadsheets are from the output of SAS stored procedures (essentially saved data queries to ILIS and other databases), which generate CSV files that are then manually copied and pasted into the Metric spreadsheets.

The SAS stored procedures pull outage details from ILIS, such as outage duration and causes. Additional data is incorporated from feeder metadata tables, which provide additional infrastructure-related details such as circuit assignments and customer counts to support outage categorization (see discussion on EGIS and the Customer Care and Billing databases above). The SAS stored procedures merge the outage records with MEDs, to allow the code to exclude or include them in the dataset. Then data is merged to link the data to the cause of each outage (vegetation or equipment caused). Outage minutes and customer impact data are aggregated at the division level and system level to produce the SAIDI/SAIFI/AIDI/AIFI, then exported into the CSV files that are copied into the Metric spreadsheets. The Average Interruption Duration Index ("AIDI") and the Average Interruption Frequency Index ("AIFI") represent division-level performance, as opposed to SAIDI and SAIFI that represent system-wide performance. Though the script aggregates at the division level as well, only the system level values are used in the Metric 2.1 calculation.

FEP reviewed these SAS stored procedures and received a walkthrough by PG&E employees, confirming that the code appears to be functioning correctly, pulling the right data and applying the correct transformations. However, since the code brings together information from many datasets and input tables, full verification of every data source was not viable. For instance, FEP did not verify if each outage was input correctly in ILIS, or if the EGIS and Customer Care and Billing databases were correct, but did verify that the SAS stored procedures appear to be combining the data from the databases correctly.

Verification of Metric Results

Since the Metric 2.1 spreadsheet performs minimal calculations, verification of the results relies primarily on the scripts that pull data into the sheet. Since FEP reviewed the scripts and found them to be functioning correctly, the reported values for 2021–2023 appear to be accurate and correctly calculated.

Site Visit

The FEP audit team also participated in a site visit of the Rocklin Distribution Control Center and interviewed staff members in the operations and reliability departments. FEP confirmed that the operators apply the standards defined in PG&E's "Outage Reporting Details and Accuracy Verification Process" document. Staff reported a continuous education effort on the established standards and approved modifications to the process. Feedback provided from the operational team indicated confidence in the experience and knowledge of the staff members involved in the data collection and reporting process with some concern about staffing levels for operators, who are responsible for receiving, documenting and addressing outages. To address this concern the management team shared that efforts are underway to onboard and train two new classes of apprentice operators.

2.4.2 Metric 2.1 Management

PG&E's Electric System Planning and Reliability department is responsible for managing, tracking, and setting targets for Metric 2.1 and the other reliability SOMs.

The department develops monthly reports to identify reliability metrics that are off track from 1- and 5-year thresholds or are trending in the wrong direction. The reports are utilized by regional and local reliability professionals and engineers to evaluate trends, identify causes for unplanned outages, and develop strategies that improve performance. Formal outage reviews are held with cross functional participation focused on root cause analysis and developing options to address the issue.

PG&E produces a Daily Reliability Scorecard that reveals daily, month to date, and year to date statistics on a variety of reliability metrics including unplanned T&D SAIDI actual performance and goals. The scorecard monitors regional and division outage information for both planned and unplanned events along with specific information on location and cause code of asset failures. The organization distributes the scorecard to a broad population of staff members and is utilized in daily reliability meetings.

The organization utilizes the Lean Operating Review and CIC meetings described in Section 1.4 to review the Metric 2.1 status and any catch back work activities.

PG&E has created and initiated a wide variety of "work activities" focused on improving reliability performance. While several of the programs, including Vegetation Management, Grid Design and System Hardening, along with Asset Replacement are related to wildfire mitigation efforts, there is a sense among the PG&E staff that successful implementation of these initiatives should provide some incremental reliability improvement. The feedback received indicated that quantifying the impact of these efforts was difficult to model or project into objective expectations for future performance.

PG&E incorporates external system reliability benchmarking in the process of monitoring performance and setting threshold targets for the Unplanned SAIDI metric. Discussions with staff revealed the utilization of industry benchmarking studies sponsored by IEEE and Energy Information Administration ("EIA"). In response to an information request, PG&E provided a list of industry reliability benchmarking studies that it actively participates in. The reliability team recognized the value of the obtained benchmarking information and PG&E's position as a SAIDI fourth quartile organization. PG&E's reliability team also noted the negative impact of the wildfire mitigation strategies in place on performance and that peer participants in the studies may not employ similar wildfire mitigation strategies.

Observations on Metric 2.1 Management

PG&E's process for tracking unplanned outage events appears to sufficiently capture power outage incidents. Troubleshooters responding to outages have access to technology in the field which is designed to capture relevant information in a way that limits data variability and reduces opportunities for mistakes. For example, PG&E utilizes forms for logging data related to both ignitions and outages which leverage binary fields or drop-down menus, reducing the need for text entries. While text entries can be helpful for comments or adding granularity, they have been shown across the industry to lead to varied reporting formats, spelling errors, or other challenges which impact data analysis. PG&E identified these issues and made changes to its platform independently.

The utilization of multiple internal outage data reviews by operations and support organizations introduces a level of confidence that the information utilized in the metric reporting is adequately managed.

The reliability department utilizes the outage data including root cause data to evaluate and determine the circuits that provide an opportunity to improve system reliability performance. Staff in both operations and asset management shared the challenge of limited funding to support meaningful system wide SAIDI improvement. In discussions focused on the impact of current “work activities” for asset health and wildfire mitigation efforts, the staff shared the difficulty encountered in quantifying specific reliability improvements that can be utilized in projecting improved system performance.

2.4.3 Metric 2.1 Performance and Targets

The Metric 2.1 target is proposed by the Electric System Planning and Reliability organization based on a review of historical data along with MED threshold information. The Reliability organization works with the designated Metric Owner to develop a proposal for each metric including a description of the rationale behind the targets. Once reviewed and approved by the metric owner, the proposal goes through a variety of approval steps of functional senior leadership within the organization. All reliability metrics require final approval of executive management.

Metric 2.1 targets are set with the goal of maintaining current performance within a range of calculated upper and lower thresholds. Methodology utilized to set targets varied slightly over the span of the audit period. Targets set in 2023 for the 2024 period determined the lower threshold by averaging the previous two year’s lower range target, applying a MED minutes adjustment resulting from a MED threshold change, and introducing a minimal reduction to set the target. The upper target within the range is a 50% increase to the 2- year adjusted average. PG&E maintains that (1) the uncertainty in the potential for weather, (2) MED threshold increases, and (3) unknown impacts of the EPSS program drive the requirement to have the 1-and 5-year targets for metric 2.1 set as a range with the upper range containing a significant buffer above previous performance levels. PG&E also notes that 2021 marked the initial deployment of EPSS and that Metric 2.1 results for that year are not indicative of an EPSS program that was fully implemented and was problematic for SOMS target setting.

The following table displays PG&E’s 2013 through 2023 Metric 2.1 results and the 1-year and 5-year metric targets.

Table 2-5: Metric 2-1 Results and Targets

Year	Metric Result	1-Year Target[1]	5-Year Target[1]
2013	1.60		
2014	1.52		
2015	1.34		
2016	1.56		
2017	1.62		
2018	1.66		
2019	1.96		
2020	2.10		
2021	3.05	Lower 5.67 Upper 6.80	Lower 5.67 Upper 6.80
2022	3.56	Lower 3.45 Upper 5.34	Lower 3.45 Upper 5.34
2023	3.56	Lower 3.71 Upper 5.73	Lower 3.60 Upper 5.62
[1]Targets reflect the target set in that report year (i.e. the 2021 1-year target reflects 2022 target).			

The average 2021-2023 performance is 3.39. The 1- and 5-year targets set in 2022 are lower than those established in 2021. However, targets set in 2023 increase to levels above actual performance experienced in 2022 and 2023. The 1-year upper target set in 2023 is higher than the three-year average by approximately 69.0% and actual 2023 performance by 61%.

Observations on Metric 2.1 Performance and Targets

PG&E monitors Metric 2.1 progress regularly and has a formalized process for course-correcting if metric results approach the off-track threshold. The "catch up" process includes defined goals, due dates, and action ownership assigned to specific staff. FEP's discussions with PG&E suggest that Metric 2.1 performance is one component of a larger overall monitoring effort associated with system reliability. In recent years, the utility industry has adopted planned and unplanned SAIDI as the primary performance metric for monitoring the total customer reliability experience.

The staff of the PG&E System Planning and Reliability department shared that the unplanned SAIDI performance is in the fourth quartile, but they believe it is driven by the EPSS wildfire mitigation efforts. Staff referenced the addition of circuits enabled with EPSS as the primary source of both recent deteriorating SAIDI performance and the lack of significant reduction in 1- and 5-year targets. In addition, the group communicated that a reduction in funding for reliability improvement projects results in uncertainty in proposing target metric ranges at a more aggressive level.

As discussed in previous sections of the report, PG&E has extensive access to industry benchmarking associated with reliability, including SAIDI. One study that is available to the organization is EIA's Annual Electric Power Survey Industry Report, Form EIA-861, whose associated data files provide an extensive database of company specific reliability data[6]. Utilization of the study may provide PG&E with the opportunity to evaluate its performance against specific California, regional, and western utilities. This

[6] EIA webpage titled "Annual Electric Power Industry Report, Form EIA-861 detailed data files" provides company-specific reliability data. Available at: https://www.eia.gov/electricity/data/eia861/.

may be helpful in comparing benchmarking performance with companies facing similar challenges with uncertain weather impacts and implementation of wildfire mitigation efforts. Data from this analysis may be utilized when determining the variables incorporated in the target setting model with a potential to plan for more substantial improvements in performance. Select benchmarking studies may also provide PG&E peer exposure to information and discussions on "Best Practices" in industry on reliability topics. It does not appear that the organization currently utilizes benchmarking as a factor in developing the specific target ranges for Metric 2.1.

While FEP recognizes that the influence of MED thresholds and the uncertainty of predicting MED events introduces potential for volatility, FEP is accustomed to observing organizations setting operational targets at levels that improve their performance beyond their current level of execution. In most cases these aspirational goals serve as important motivation for the company to develop and initiate strategies focused on improving system reliability. We note that PG&E's targets for Metric 2.1 do not indicate significant, if any, improvement from historical performance. We also note that until 2023, the 5-year targets have been historically set to the same value as the 1-year target. The targets set in 2023 for 5-year lower and upper ranges reflect a 2 -3% improvement from the 1-year target. These 5-year targets do not appear impactful in influencing long-term performance improvement.

2.5 Metric 2.2: System Average Interruption Frequency Index (SAIFI) (Unplanned)

The CPUC defines Metric 2.2 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.

Metric 2.2 measures the average frequency of sustained power interruptions per metered customer due to unplanned outages, excluding MED, within a calendar year. This metric is calculated by dividing the total number of customer interruptions that are greater than five minutes by the total number of customers served.

MEDs are days with large numbers of customer minutes interrupted, often due to severe weather events like storms, but are cause-agnostic. The purpose of MEDs is to help isolate and analyze major events separately from routine operation, providing a clearer picture of normal system performance. The IEEE Guide for Electric Power Distribution Reliability Indices (Standard 1366) defines MEDs as days in which the daily SAIDI exceeds a statistically defined threshold based on the previous 5 years of daily SAIDI data[7]. In addition to storms, new causes of MEDs include PSPS events, which have been some of PG&E's largest

[7] A day in which the daily System Average Interruption Duration Index (SAIDI) exceeds a Major Event Day threshold (T_{MED}) value. For the purposes of calculating daily system SAIDI, any interruption that spans multiple calendar days is accrued to the day on which the interruption began. Statistically, days having a daily system SAIDI greater than T_{MED} are days on which the energy delivery system experienced stresses beyond that normally expected (such as during severe weather).

MED days. IEEE released guidelines[8] for calculating the daily SAIDI threshold, which is discussed further in "Observation on Accuracy" section.

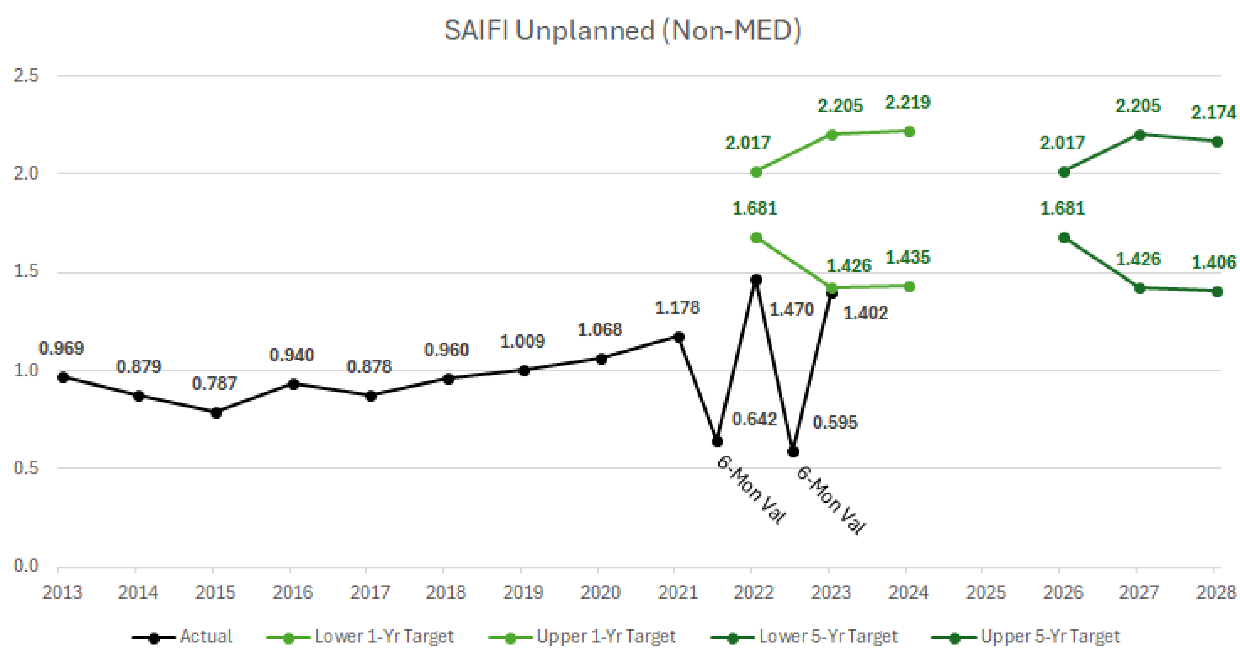
Metric 2.2 includes only unplanned events with all planned outage activities excluded.

The formula for calculating Metric 2.2 is:

$$= \frac{Total\ \#\ of\ Customer\ Interruptions}{Total\ \#\ of\ Customers\ Served}$$

The following chart shows Metric 2.2 results compared to targets for 2013 through 2028, including results from the 2022 and 2023 mid-year reports. Mid-year values are substantially lower because they cover only six months of customer interruptions, whereas the annual values cover the full twelve months. All historical values reflect the most recent data available as of the 2023 report and may differ from previously reported figures.

Figure 2-6: Metric 2.2 Summary Chart



2.5.1 Metric 2.2 Accuracy and Consistency

Information for Metric 2.2 is extracted from the Integrated Logging Information System (ILIS) Outage Database. Data enters ILIS through reports made by troubleshooters who respond to outages and other issues in the field. PG&E becomes aware of a downed wire or outage through several reporting streams such as Smart Meters, SCADA or customer reporting. Troubleshooters are sent to the scene to assess the incident. Once on-site, the troubleshooters complete digital forms to document the characteristics of the incident. Those incident reports are transmitted to the distribution outage center.

[8] https://standards.ieee.org/ieee/1366/7243/

PG&E supplied the audit team with the “Outage Reporting Details and Accuracy Verification Process” documents that provides a detailed description of the proper method to input outage data into ILIS along with the process for verifying the accuracy of the reported outage events.

The data transmitted to the distribution outage center is reviewed and manually entered by distribution staff. Employees of the outage center conduct a quality review as data is entered into ILIS. After the entries are submitted to ILIS, a member of the Outage Quality Review Team conducts another accuracy review. If engineers wish to add new information or correct previously submitted information, they ask the operations team to make changes to the data. Individuals in troubleshooting, engineering, and related departments have read access to the outage data, but do not have the ability to make changes to the database directly.

PG&E uses EGIS to inform this metric. EGIS is used to identify customers impacted by system outages.

Once operations’ entries have been verified as correct the staff of Electric System Planning and Reliability become the controllers of the outage information. This group initiates a secondary outage quality analysis review, with issues corrected by staff or sent back to Distribution Operators for further analysis and correction.

Once verified as correct the outage information becomes available for metric performance queries and modeling. Monthly performance reports are created and utilized by the Reliability staff members and senior management for trend analysis and determination of root causes for unplanned outages.

ILIS contains outage information, which is combined with infrastructure details from EGIS and customer counts from Customer Care and Billing to calculate the number of CESO for each event. EGIS contains infrastructure details like type of conductor (primary distribution, secondary distribution, etc.), and Customer Care and Billing contains customer count information. The data reported in ILIS is not the location of the cause of the outage, but instead the location of the operating device. Additionally, the data for the conductors does not come from field observations, but from the EGIS database.

The oversight and management process of these systems has been largely consistent for the past decade. The policies around data gathering, input, and extraction have been consistent throughout the reporting period with minimal changes to the reporting standard. The introduction of PSPS and EPSS for operational wildfire mitigation strategies has impacted the organization’s ability to accurately determine if audit period SAIFI performance trends are related to general reliability issues or the function of these proactive operating strategies. PG&E uses data on SAIFI for internal tracking and regulatory reporting beyond the bi-annual SOMs report. To meet reporting requirements of the SOMs metrics, PG&E processes the ILIS dataset into planned and unplanned outages along with MED and non-MED events.

Observations on Metric 2.2 Accuracy

To determine the overall accuracy of the metric results, FEP verified PG&E’s MED designations as well as the SAIFI calculation. Overall, FEP found the Metric 2.2 results to be accurate. The process for undertaking those verifications is described in the sections below.

Verification of Major Event Days

A MED is a day where the daily SAIDI exceeds a defined threshold. According to IEEE Standard 1366, the threshold is defined by the following formula:

$$MED\ Threshold = e^{\propto+2.5\beta}$$

The threshold is calculated by first taking the natural logarithm of the SAIDI values to normalize the dataset, which is typically right-skewed. Next, the mean ($\propto$) and standard deviation (β) of the log-transformed SAIDI values are calculated for every day included in the dataset over the past five years. The threshold is set 2.5 standard deviations above the mean in log-space, and the final threshold value is obtained by exponentiating the result to the original SAIDI scale.

PG&E performed these calculations for 2021, 2022, and 2023 in Excel using five years of data. PG&E listed the total daily SAIDI value for every day with a value above zero and calculated the logarithmic SAIDI value using Excel's LN function. PG&E calculated the mean ($\propto$) of the logarithmic SAIDI values using the AVERAGE function. The standard deviation (β) of the logarithmic SAIDI values was calculated using the STDEV function. PG&E then multiplied the standard deviation (β) by 2.5 then added the mean ($\propto$). The MED threshold was calculated by applying the EXP function to the results of that equation. FEP verified PG&E's calculations and found the threshold values to be accurate.

For each day in the spreadsheet, PG&E indicated whether the day met the MED threshold with a "yes" or "no". For example, the MED threshold for 2023 was 5.033 and days with a threshold equal or exceeding that value were marked with a "yes". To verify these designations, FEP used an Excel IF statement. Overall, FEP's dataset of MEDs matched PG&E's.

Verification of SAIFI Calculation

The Metric 2.2 spreadsheets[9] contain minimal calculations, with most values hardcoded. Metrics 2.1 and 2.2 share the same data sheets, where all values are pre-populated except for two formulas, one that calculates SAIDI and another that calculates SAIFI. The SAIFI formula simply references the YTD AIFI value for the entire system. Aside from these two formulas, all other values in the spreadsheets are from the output of SAS stored procedures which generate CSV files that are then manually copied and pasted into the calculation spreadsheets.

The SAS stored procedures pull outage details from ILIS, such as outage duration and causes. Additional data is incorporated from feeder metadata tables, which provide additional infrastructure-related details such as circuit assignments and customer counts to support outage categorization (see discussion on EGIS and the Customer Care and Billing databases above). The SAS stored procedures merge the outage records with MED, to allow the code to exclude or include them in the dataset. Then data is merged to link the data to the cause of each outage (vegetation or equipment caused). Outage minutes and customer impact data are aggregated at the division level and system level to produce the SAIDI/SAIFI/AIDI/AIFI, then exported into the CSV files that are copied into the Metric 2.2 spreadsheet. The Average Interruption Duration Index ("AIDI") and the Average Interruption Frequency Index("AIFI") represent division-level performance, as opposed to SAIDI and SAIFI that represent system-wide performance. Though the script aggregates at the division level as well, only the system level values are used in the metric calculation.

FEP reviewed these SAS stored procedures and received a walkthrough by PG&E employees, confirming that the code appears to be functioning correctly, pulling the right data and applying the correct transformations. However, since the code brings together information from many datasets and input tables, full verification of every data source was not viable. For instance, FEP did not verify if each outage

[9] Available as part of the SOMs reports Safety and Operational Metrics, Data Files

was input correctly in ILIS, or if the EGIS and Customer Care and Billing databases were correct, but did verify that the SAS stored procedures appear to be combining the data from the databases correctly.

Verification of Metric Results

Since the Metric 2.2 spreadsheet performs minimal calculations, verification of the results relies primarily on the scripts that pull data into the sheet. Since FEP reviewed the scripts and found them to be functioning correctly, the reported values for 2021–2023 appear to be accurate and correctly calculated.

Site Visit

The FEP audit team also participated in a site visit of the Rocklin Distribution Control Center and interviewed staff members in the operations and reliability departments. FEP confirmed that the operators apply the standards defined in PG&E's "Outage Reporting Details and Accuracy Verification Process" document. Staff reported a continuous education effort on the established standards and approved modifications to the process. Feedback provided from the operational team indicated confidence in the experience and knowledge of the staff members involved in the data collection and reporting process with some concern about staffing levels for operators, who are responsible for receiving, documenting and addressing outages. To address this concern the management team shared that efforts are underway to onboard and train two new classes of apprentice operators.

2.5.2 Metric 2.2 Management

PG&E's Electric System Planning and Reliability department is responsible for managing, tracking, and setting targets for Metric 2.2 and the other reliability SOMs metrics.

The department develops monthly reports to identify reliability metrics that are off track from one- and five-year thresholds or trending in the wrong direction. The reports are utilized by regional and local reliability professionals and engineers to evaluate trends, identify causes for unplanned outages, and develop strategies that improve performance. Formal outage reviews are held with cross functional participation focused on root cause analysis and developing options to address the issue.

PG&E produces a Daily Reliability Scorecard that reveals daily, month to date, and year to date statistics on a variety of reliability metrics including T&D SAIFI actual performance and goals. The scorecard monitors regional and division outage information on location and cause code of asset failures. The organization distributes the scorecard to a broad population of staff members and is utilized in daily reliability meetings.

The organization utilizes the Lean Operating Review and CIC meetings described in Section 1.4 to review the Metric 2.2 status and any catch back work activities.

PG&E has created and initiated a wide variety of "work activities" focused on improving reliability performance. While several of the programs including Vegetation Management, Grid Design and System Hardening, along with Asset Replacement are related to wildfire mitigation efforts, there is a sense among the PG&E staff that successful implementation of these initiatives should provide some incremental reliability improvement. The feedback received indicated that quantifying the impact of these efforts was difficult to model or project into objective expectations for future performance.

PG&E incorporates external system reliability benchmarking in the process of monitoring performance and setting threshold targets for Metric 2.2. Discussions with staff revealed the utilization of industry benchmarking studies sponsored by IEEE and EEI. In response to an information request PG&E provided a list of industry reliability benchmarking studies that it actively participates in. The reliability team recognizes the value of the obtained benchmarking information and PG&E's position as a SAIFI fourth quartile organization. PG&E's reliability team notes the impact of its wildfire mitigation strategies on performance and that peer participants in the studies may not employ similar wildfire mitigation strategies.

Observations on Metric 2.2 Management

PG&E's process for tracking unplanned outage events appears to sufficiently capture power outage incidents. Troubleshooters responding to outages have access to technology in the field which is designed to capture relevant information in a way that limits data variability and reduces opportunities for mistakes. For example, PG&E utilizes forms for logging data related to both ignitions and outages which leverage binary fields or drop-down menus, reducing the need for text entries. While text entries can be helpful for comments or adding granularity, they have been shown across the industry to lead to varied reporting formats, spelling errors, or other challenges which impact data analysis. PG&E identified these issues and made changes to its platform independently.

The utilization of multiple internal outage data reviews by operations and support organizations introduces a level of confidence that the information utilized in the metric reporting is adequately managed.

The reliability department utilizes the outage data including root cause data to evaluate and determine the circuits that provide an opportunity to improve system reliability performance. Staff in both operations and asset management shared the challenge of limited funding to support meaningful system wide SAIFI improvement. In discussions focused on the impact of current "work activities" for asset health and wildfire mitigation efforts the staff shared the difficulty encountered in quantifying specific reliability improvements that can be utilized in projecting improved system performance.

2.5.3 Metric 2.2 Performance and Targets

The Metric 2.2 target is proposed by the Electric System Planning and Reliability organization based on a review of historical data along with MED threshold information. The Reliability organization works with the designated Metric Owner to develop a proposal for each metric including a description of the rationale behind the targets. Once reviewed and approved by the metric owner the proposal goes through a variety of approval steps of functional senior leadership within the organization. All reliability metrics require final approval of executive management.

Metric 2.2 targets are set with the goal of maintaining current performance within a range of calculated upper and lower thresholds. PG&E utilizes historical yearly unplanned SAFI performance from 2022 and 2023 to establish the targets. The lower threshold was determined by averaging the previous year's actuals, applying a MED minutes adjustment resulting from a threshold change, and introducing a minimal reduction to set the target. The upper target within the range is a 50% increase to the 2-year average including the MED adjustment. PG&E maintains that (1) the uncertainty in the potential for weather, (2) MED threshold increases, and (3) unknown impacts of the EPSS program drive the requirement to have the one-and five-year targets for Metric 2.2 set as a range with the upper range containing a significant buffer above previous performance levels.

The following table displays PG&E's 2013 through 2023 Metric 2.2 results and the 1-year and 5-year metric targets.

Table 2-6: Metric 2-2 Results and Targets

Year	Metric Result	1-Year Target[1]	5-Year Target[1]
2013	0.969		
2014	0.879		
2015	0.787		
2016	0.940		
2017	0.878		
2018	0.960		
2019	1.009		
2020	1.068		
2021	1.178	Lower 1.681 Upper 2.017	Lower 1.681 Upper 2.017
2022	1.470	Lower 1.426 Upper 2.205	Lower 1.426 Upper 2.205
2023	1.402	Lower 1.435 Upper 2.219	Lower 1.406 Upper 2.174
[1]Targets reflect the target set in that report year (i.e. the 2021 1-year target reflects 2022 target).			

The average 2021-2023 performance is 1.35. The 1- and 5-year targets set in 2022 are lower than those established in 2021. However, targets set in 2023 increase. The 1-year upper target set in 2023 is higher than the three-year average by approximately 64.0% and actual 2023 performance by 58%. The 5-year targets are set at the same level as the 1-year targets for 2021 and 2022 and then in 2023 are approximately 2% lower than the 1-year target.

Observations on Metric 2.2 Performance and Targets

PG&E monitors Metric 2.2 progress regularly and has a formalized process for course-correcting if metric results approach the off-track threshold. The "catch up" process includes defined goals, due dates, and action ownership (commitment owner) assigned to specific staff. FEP's discussions with PG&E suggest that Metric 2.2 performance is one component of a larger overall monitoring effort associated with system reliability. In recent years the utility industry has adopted Planned and Unplanned SAIFI as a primary performance metric for monitoring the total customer reliability experience.

The staff of the PG&E System Planning and Reliability department shared the unplanned SAIFI performance is in the fourth quartile, but they believe it is driven by the EPSS wildfire mitigation efforts. Staff referenced the addition of circuits enabled with EPSS as the primary source of both recent deteriorating SAIFI performance and the lack of significant reduction in 1- and 5-year targets. In addition, the group communicated that a reduction in funding for reliability improvement projects results in uncertainty in proposing target metric ranges at a more aggressive level.

As discussed in previous sections of the report, PG&E has extensive access to industry benchmarking associated with reliability, including SAIFI. One study that is available to the organization is EIA's Annual Electric Power Survey Industry Report, Form EIA-861, whose associated data files provide an extensive database of company specific reliability data[10]. Utilization of the study may provide PG&E with the opportunity to evaluate its performance against specific California, regional, and western utilities. This may be helpful in comparing benchmarking performance with companies facing similar challenges with uncertain weather impacts and implementation of wildfire mitigation efforts. Data from this analysis may be utilized when determining the variables incorporated in the target setting model with a potential to plan for more substantial improvements in performance. Select benchmarking studies may also provide PG&E peer exposure to information and discussions on "Best Practices" in industry on reliability topics. It does not appear that the organization currently utilizes benchmarking as a factor in developing the specific target ranges for Metric 2.2.

While FEP recognizes that the influence of MED thresholds and the uncertainty of predicting MED events introduces potential for volatility, FEP is accustomed to observing organizations setting operational targets at levels that improve their performance beyond their current level of execution. In most cases these aspirational goals serve as important motivation for the company to develop and initiate strategies focused on improving system reliability. We note that PG&E's upper range targets for Metric 2.2 are significantly higher historical performance. We also note that until 2023, the 5-year targets have been historically set to the same value as the 1-year target. The most recent targets set for 5-year lower and upper ranges reflect a 2% improvement from the 1-year target. These 5-year targets do not appear impactful in influencing long-term performance improvement.

2.6 Metric 2.3: System Average Outages Due to Vegetation and Equipment Damage in HFTD Areas (On Major Event Days)

CPUC defines Metric 2.3 as:

Average number of sustained outages on 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.

Metric 2.3 measures the average number of sustained outages on MED per 100 circuit miles in HFTD per metered customer within a calendar year. A sustained outage is an interruption that lasts longer than five minutes. This metric provides a view into outage frequency in HFTD areas during MEDs.

MEDs are days with large numbers of customer minutes interrupted, often due to severe weather events like storms, but are cause-agnostic. The purpose of MEDs is to help isolate and analyze major events separately from routine operation, providing a clearer picture of normal system performance. The IEEE Guide for Electric Power Distribution Reliability Indices (Standard 1366) defines MEDs as days in which the daily SAIDI exceeds a statistically defined threshold based on the previous 5 years of daily SAIDI data[11]. In addition to storms, new causes of MEDs include PSPS events, which have been some of PG&E's largest

[10] EIA webpage titled "Annual Electric Power Industry Report, Form EIA-861 detailed data files" provides company-specific reliability data. Available at: https://www.eia.gov/electricity/data/eia861/.

[11] A day in which the daily System Average Interruption Duration Index (SAIDI) exceeds a Major Event Day threshold (T_{MED}) value. For the purposes of calculating daily system SAIDI, any interruption that spans multiple calendar days is accrued to the day on which the interruption began. Statistically, days having a daily system SAIDI greater than T_{MED} are days on which the energy delivery system experienced stresses beyond that normally expected (such as during severe weather).

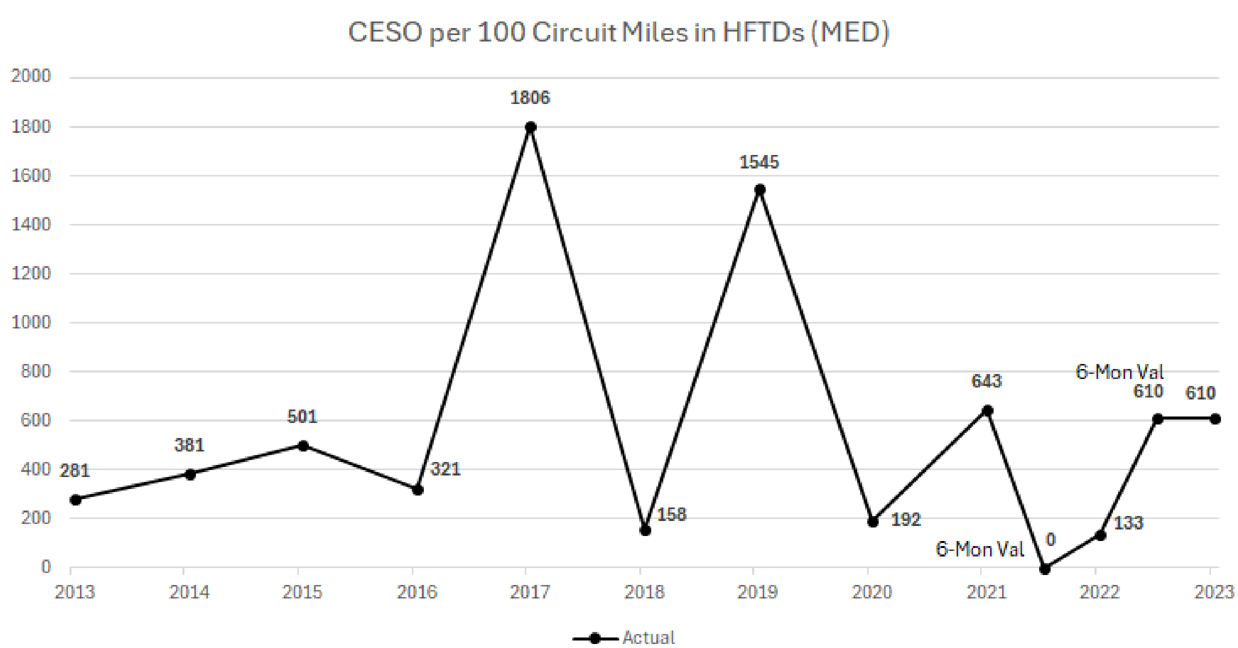
MED days. IEEE released guidelines[12] for calculating the daily SAIDI threshold, which is discussed further in "Observation on Accuracy" section. Metric 2.3, and other metrics which relate to MEDs, assess PG&E's practices and assets during very adverse weather conditions.

The formula for calculating Metric 2.3 is:

$$= \frac{\sum (Customers\ Interrupted\ on\ MED)\ x\ 100}{Total\ T\&D\ HFTD\ Line\ Miles}$$

The following chart shows Metric 2.3 results compared to targets for 2013 through 2023, including results from the 2022 and 2023 mid-year reports. All historical values reflect the most recent data available as of the 2023 report and may differ from previously reported figures.

Figure 2-7: Metric 2.3 Summary Chart



2.6.1 Metric 2.3 Accuracy and Consistency

Information for Metric 2.3 is extracted from the ILIS Outage Database. Data enters ILIS through reports made by troubleshooters who respond to outages and other issues in the field. PG&E becomes aware of a downed wire or outage through several reporting streams such as Smart Meters, SCADA or customer reporting. Troubleshooters are sent to the scene to assess the incident. Once on-site, the troubleshooters complete digital forms to document the characteristics of the incident. Those incident reports are transmitted to the distribution outage center.

[12] https://standards.ieee.org/ieee/1366/7243/

PG&E supplied the audit team with the "Outage Reporting Details and Accuracy Verification Process" documents that provides a detailed description of the proper method to input outage data into ILIS along with the process for verifying the accuracy of the reported outage events.

The data transmitted to the distribution outage center is reviewed and manually entered by distribution staff. Employees of the outage center conduct a quality review as data is entered into ILIS. After the entries are submitted to ILIS, a member of the Outage Quality Review Team conducts another accuracy review. If engineers wish to add new information or correct previously submitted information, they ask the operations team to make changes to the data. Individuals in troubleshooting, engineering, and related departments have read access to the outage data, but do not have the ability to make changes to the database directly.

Once operations' entries have been verified as correct the staff of Electric System Planning and Reliability become the controllers of the outage information. This group initiates a secondary outage quality analysis review, with issues corrected by staff or sent back to Distribution Operators for further analysis and correction.

Once verified as correct the outage information becomes available for metric performance queries and modeling. Monthly performance reports are created and utilized by the Reliability staff members and senior management for trend analysis and determination of root causes for unplanned outages.

ILIS contains outage information, which is combined with infrastructure details from EGIS and customer counts from Customer Care and Billing to calculate the number of CESO for each event. EGIS contains infrastructure details like type of conductor (primary distribution, secondary distribution, etc.), and Customer Care and Billing contains customer count information. The data reported in ILIS is not the location of the cause of the outage, but instead the location of the operating device. Additionally, the data for the conductors does not come from field observations, but from the EGIS database.

The oversight and management process of these systems has been largely consistent for the past decade. The policies around data gathering, input, and extraction have been consistent throughout the reporting period with minimal changes to the reporting standard. PG&E uses data on system outages for internal tracking and regulatory reporting beyond the bi-annual SOMs report. To meet reporting requirements of the SOMs, PG&E processes the ILIS dataset into planned and unplanned outages along with MED and non-MED events. The introduction of EPSS for operational wildfire mitigation strategies has impacted the organization's system reliability efforts and potentially increases the number of MEDs experienced.

Observations on Metric 2.3 Accuracy

To determine the overall accuracy of the metric results, FEP reviewed the following inputs to Metric 2.4:

1) MED designations
2) Circuit miles
3) CESO
4) HFTD classification

The process for undertaking those verifications is described in the sections below. Overall, FEP found that the Metric 2.3 results appear to have significant accuracy issues.

<u>Verification of Major Event Days</u>

A MED is a day where the daily SAIDI exceeds a defined threshold. According to IEEE Standard 1366, the threshold is defined by the following formula:

$$MED\ Threshold = e^{\propto + 2.5\beta}$$

The threshold is calculated by first taking the natural logarithm of the SAIDI values to normalize the dataset, which is typically right-skewed. Next, the mean ($\propto$) and standard deviation (β) of the log-transformed SAIDI values are calculated for every day included in the dataset over the past five years. The threshold is set 2.5 standard deviations above the mean in log-space, and the final threshold value is obtained by exponentiating the result to the original SAIDI scale.

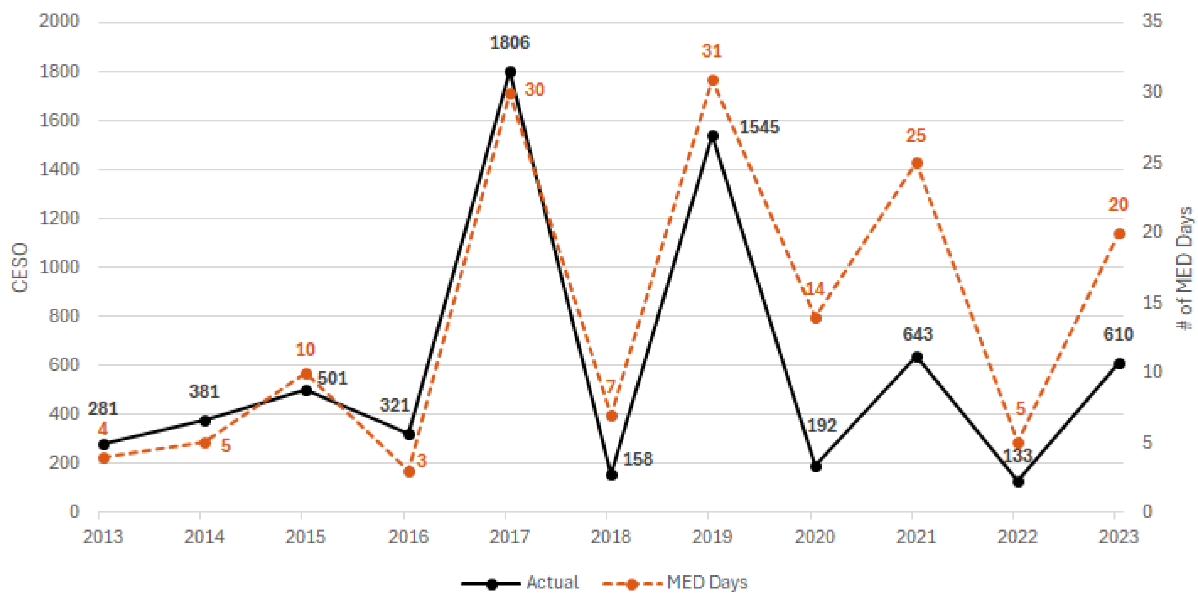
PG&E performed these calculations for 2021, 2022, and 2023 in Excel using five years of data. PG&E listed the total daily SAIDI value for every day with a value above zero and calculated the logarithmic SAIDI value using Excel's LN function. PG&E calculated the mean ($\propto$) of the logarithmic SAIDI values using the AVERAGE function. The standard deviation (β) of the logarithmic SAIDI values was calculated using the STDEV function. PG&E then multiplied the standard deviation (β) by 2.5 then added the mean ($\propto$). The MED threshold was calculated by applying the EXP function to the results of that equation. FEP verified PG&E's calculations and found the threshold values to be accurate.

For each day in the spreadsheet, PG&E indicated whether the day met the MED threshold with a "yes" or "no". For example, the MED threshold for 2023 was 5.033 and days with a threshold equal or exceeding that value were marked with a "yes". To verify these designations, FEP used an Excel IF statement. Overall, FEP's dataset of MEDs matched PG&E's.

<u>Commentary on Major Event Days</u>

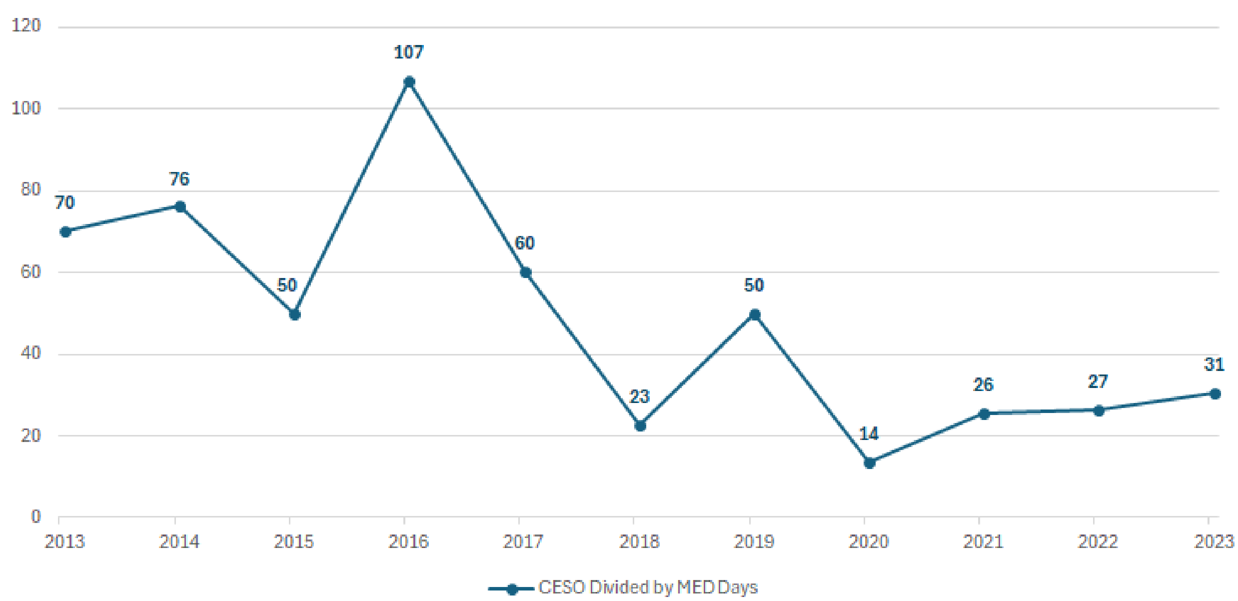
Since Metric 2.3 measures CESO per 100 HFTD line miles on only MEDs, the metric is significantly influenced by the number of MEDs, to the point of making it a straightforward reflection of overall storm activity. This makes it a useful indicator of overall system exposure to extreme weather but limits its ability to track reliability trends over time. The chart below shows a comparison of the Metric 2.3 results for each year or mid-year report, in comparison to the number of MEDs recorded that year. Though some MEDs may cause more significant outages than others, the number of MEDs appears to be the main driver of this metric result.

Figure 2-8: CESO Due to Vegetation and Equipment Damage in HFTD Areas



To show a clearer picture of reliability on a per-MED basis, the next chart normalizes the results by dividing each year's CESO in HFTD areas by the number of MEDs in the year. This shows the change in reliability of the system on an average storm day over time.

Figure 2-9: CESO in HFTD Areas/MEDs



Verification of Circuit Miles

Circuit Miles are presented in the Metric 2.3 spreadsheet on four separate tabs, split into overhead and underground transmission and distribution lines. The data therein contains mileage for each circuit in PG&E's territory, separated into mileage within zones T3, T2, T1, and Z1. Only Tier 2 and 3 miles are included for this metric. These HFTD line miles are summed up at the bottom of each tab and pulled together in the primary calculation tab to be one total T&D line mileage.

In the two distribution line mile tabs which list circuit mileage for each circuit on the system, some rows have no circuit names. These blank entries indicate idle lines, which are not active circuits. Idle lines were included in the total line mileage through 2022; however, they were removed from the total line mileage starting in 2023. Note that report years 2022 and prior use 2021 mileage. Years 2023 and beyond use mileage as of January first of that year (e.g. Jan 1, 2023, for the 2023 report, Jan 1, 2024, for the 2024 report). In the 2023 full-year metric, 39 idle line miles were excluded from a total of 28,064 miles.

In the two transmission line mile tabs with circuit-by-circuit mileage, PG&E identified that several facilities were no longer used for the transmission system and thus removed from the list in 2023. 40 miles of transmission lines were excluded from a total of 5,489 miles. Similar to distribution, report years 2022 and prior use 2021 mileage for the Metric 2.3 calculation. Years 2023 and beyond use mileage as of January first of that year.

Verification of CESO

CESO is the count of customers that experience a sustained outage (defined as lasting more than five minutes) within a given period. CESO counts unique customers affected, meaning if the same customer experiences multiple outages, they are counted multiple times. CESO counts are included in the Metric 2.3 spreadsheet, split by cause (vegetation or equipment failure), MEDs (yes or no), and year. These CESO figures are generated from SAS stored procedures (essentially saved data queries to ILIS and other databases) that generate CSV files that are then manually copied and pasted into the calculation spreadsheets.

The SAS stored procedures process unplanned outage data to calculate a variety of metrics, one of which is CESO. Outage data is sourced from ILIS (Integrated Logging and Information System), which serves as the outage database for these calculations. The SAS stored procedures pull outage details from ILIS, such as outage duration and causes. Additional data is incorporated from feeder metadata tables, which provide additional infrastructure-related details such as circuit assignments and customer counts to support outage categorization. The SAS stored procedures merge the outage records with MED, to allow the data to be split into MED and non-MED parts. The SAS stored procedures integrate cause data from ILIS, assigning each outage to a cause. The data is then further categorized into transmission vs distribution. Finally, the total number of customers affected is used to derive CESO, which is grouped by division and cause.

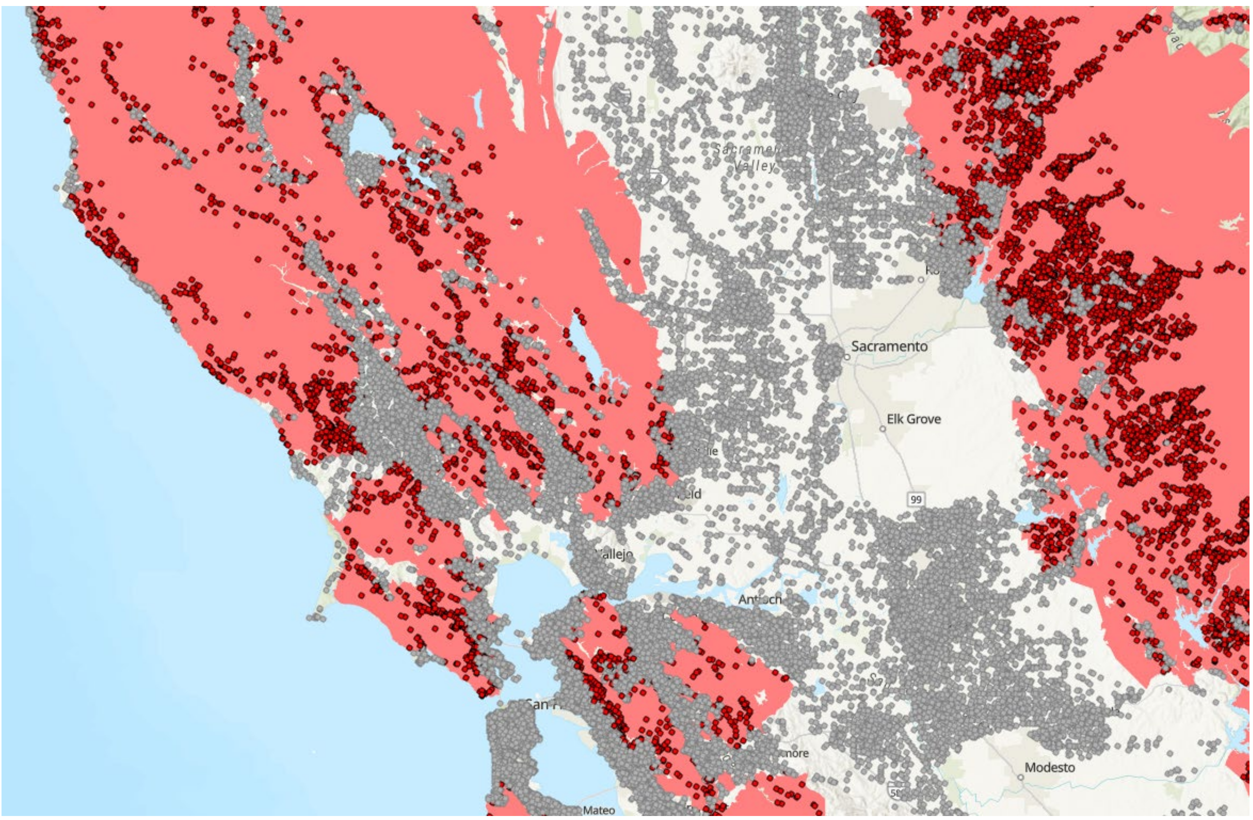
FEP reviewed these SAS stored procedures and received a walkthrough by PG&E employees, confirming that the code appears to be functioning correctly, pulling the right data and applying the correct transformations. However, since the code brings together information from many datasets and input tables, full verification of every data source was not viable. For instance, FEP did not verify if each outage was input correctly in ILIS, or if the EGIS and Customer Care and Billing databases were correct, but did verify that the SAS stored procedures appear to be combining the data from the databases correctly.

Verification of HFTD

The SAS stored procedures referenced before only report outages that occurred in HFTD areas, based on the location of the operating device associated with each outage. To verify the accuracy of this classification, FEP requested all outage data from 2021-2023, including the latitude and longitude of the first affected device for each outage. FEP then mapped these locations in ArcGIS, overlaying them with HFTD boundary layers.

The analysis revealed significant discrepancies. A significant number of outages labeled as non-HFTD appear to fall within the boundaries of the HFTD, and a small number of outages labeled as HFTD appear to be located just outside the boundaries of the HFTD. Additionally, there are a number of outages that do not appear to have latitude and longitude coordinates, as either one or both coordinates are set at 0 (there are 1,093 outages like this out of a dataset of 250,339). Figure 2-10 below shows a section of PG&E's service territory with HFTD boundaries (pink), as well as the locations of outages that were originally classified as non-HFTD. Gray dots represent outages that were reported as non-HFTD and also appear to be in non-HFTD areas. Red dots represent outages that were reported as non-HFTD but appear to be within the boundaries of the HFTD instead.

Figure 2-10: Non-HFTD Reported Outage Map



In a follow-up discussion regarding this HFTD assignment error, PG&E explained that "for distribution, the HFTD class is not stored directly in the outage database but instead joined in through logic specific to each report. In the outage data prepared for SOMs, the report uses a tool that assigns HFTD class one day after the event, based on latitude and longitude. If that location data was unavailable on the day after the event and added or updated later, the tool does not revise the historical assignment resulting in some HFTD classifications no longer reflecting the most accurate or consistent information. The practice of assigning the HFTD class one day after the event based on the location of the interruptive device is how this has been determined since the HFTD was established. This data set has been the foundation of PG&E's outage reporting relative to HFTD locations for all applications, including SOMs metrics." FEP did not verify that this is the cause of the discrepancy. FEP also notes that as a result of these findings, PG&E has entered this issue into their CAP and is developing a centralized, standardized data repository through WiRE, which aims to improve outage metric reporting.

FEP performed a spatial analysis in ArcGIS to understand how many outage locations that were labeled as non-HFTD fell in HFTD zones, and vice versa. In the outage data received via RFI from PG&E, there are a total of 67,873 outages caused by either vegetation or equipment failure from 2021-2023. Of these, 11,691 were reported to be HFTD outages (whose CESO contributed to this calculation of this metric), and 56,182 were reported to be Non-HFTD outages. However, FEP discovered through the mapping analysis that 21,173 outages appeared to be located within the boundaries of the HFTD instead of the 11,691 reported. The table below includes both the original HFTD and Non-HFTD outage counts (associated with vegetation or equipment failure) from 2021-2023, as well as the updated, map-based outage counts.

Table 2-7: Outage Counts

HFTD Designation	PG&E Provided Outage Count	Map-Based Outage Count	Percent of PG&E Outage Count
HFTD	11,691	21,173	181%
Non-HFTD	56,182	46,700	83%

FEP recalculated the metric using the CESO from the received outage data based on the updated HFTD classifications, as well as MED data shared with FEP via RFI. If the coordinates provided with the outage data are correct and the HFTD label should be applied based on those coordinates, the corresponding metric calculation would increase by 141% in 2021 to 221% in 2023. The results are shown in the table below.

Table 2-8: Revised Metric 2.3 Results

Year	Original 2.3 Result (Based on Original HFTD Classifications)	Updated 2.3 Result (Based on Map-Based HFTD Classifications)
2021	643	1,551
2022	133	326
2023	610	1,961

<u>Verification of Metric Results</u>

Once both CESO data and outage data are on the Metric 2.3 spreadsheet, the metric is calculated by summing the total CESO for the year due to vegetation and the total CESO for the year due to equipment failure. This sum is then multiplied by 100 and divided by the total HFTD T&D line miles, to normalize the

CESO to per 100 HFTD line miles. The CESO data generated by the SAS script is pasted into the Metric 2.3 spreadsheet in two tabs, one tab containing monthly data, the other containing annual summary data. In the 2023 mid-year data, FEP discovered that though the annual CESO was utilized for the calculation, the monthly CESO data did not match exactly. The annual data led to a total CESO of 204,029, and the monthly data for the same period led to a total CESO of 204,049. Furthermore, in the data provided for the 2023 full-year period, the monthly data for the January to June period had a total of 204,098 CESO, indicating that the data changes over time. PG&E clarified in a data request that not all outages may have been officially closed at the time of the 2023 mid-year report, and outages may still be reviewed and changed months after the fact due to internal findings. The difference in hours between the monthly and annual datasets would not affect the metric result of 610 reported for the 2023 mid-year report.

Based on the verification of PG&E's HFTD classifications, circuit miles, and CESO, there appear to be significant accuracy issues with the reported metric results. In addition to understanding the HFTD location data better, PG&E should ensure consistency between the monthly and annual outage data and standardize which dataset is used for calculations moving forward to maintain a consistent methodology.

Site Visit

The FEP audit team also participated in a site visit of the Rocklin Distribution Control Center and interviewed staff members in the operations and reliability departments. FEP confirmed that the operators apply the standards defined in PG&E's "Outage Reporting Details and Accuracy Verification Process" document. Staff reported a continuous education effort on the established standards and approved modifications to the process. Feedback provided from the operational team indicated confidence in the experience and knowledge of the staff members involved in the data collection and reporting process with some concern about staffing levels for operators, who are responsible for receiving, documenting and addressing outages. To address this concern the management team shared that efforts are underway to onboard and train two new classes of apprentice operators.

2.6.2 Metric 2.3 Management

PG&E's Electric Reliability and Metric Reporting department is responsible for managing, tracking, and setting targets for Metric 2.3 and the other reliability SOMs metrics.

The department develops monthly reports to identify reliability metrics that are off track from one- and five-year thresholds or trending in the wrong direction. The reports are utilized by regional and local reliability professionals and engineers to evaluate trends, identify causes for unplanned outages, and develop strategies that improve performance. Formal outage reviews are held with cross functional participation focused on root cause analysis and developing options to address the issue.

PG&E produces a Daily Reliability Scorecard that reveals daily, month to date, and year to date statistics on a variety of reliability metrics including T&D CESO actual performance and goals. The scorecard monitors regional and division outage information for both planned and unplanned events along with specific information on location and cause code of asset failures. The organization distributes the scorecard to a broad population of staff members and is utilized in daily reliability meetings.

The organization utilizes the Lean Operating Review and CIC meetings described in Section 1.4 to review the Metric 2.3 status and any catch back work activities.

PG&E has created and initiated a wide variety of "work activities" that have potential to improve reliability performance. While several of the programs including Vegetation Management, Grid Design and System

Hardening, along with Asset Replacement are related to wildfire mitigation efforts, there is a sense among the PG&E staff that successful implementation of these initiatives should provide some incremental reliability improvement. The feedback received indicated that quantifying the impact of these efforts was difficult to model or project into objective expectations for future performance.

PG&E incorporates external system reliability benchmarking, including studies conducted by IEEE and EIA in the process of monitoring performance and threshold targets analysis. Currently there appears to be no direct peer benchmarking initiative in place for Metric 2.3. SAIFI benchmarking studies can provide valuable insight and correlation to the target's performance for the organization relative to Metric 2.3. PG&E provided a list of industry reliability benchmarking studies that staff actively participate in. The reliability team recognizes the value of the obtained benchmarking information and PG&E's position as a SAIFI fourth quartile organization. PG&E's reliability team notes the impact of its wildfire mitigation strategies along with a reduction in reliability improvement investment and the effect on Metric 2.3 outages.

Observations on Metric 2.3 Management

PG&E's process for tracking system outages in HFTD on MED events appears to sufficiently capture vegetation and equipment damage incidents. Troubleshooters responding to outages have access to technology in the field which is designed to capture relevant information in a way that limits data variability and reduces opportunities for mistakes. For example, PG&E utilizes forms for logging data related to both ignitions and outages which leverage binary fields or drop-down menus, reducing the need for text entries. While text entries can be helpful for comments or adding granularity, they have been shown across the industry to lead to varied reporting formats, spelling errors, or other challenges which impact data analysis. PG&E identified these issues and made changes to its platform independently.

The utilization of multiple internal outage data reviews by operations and support organizations introduces a level of confidence that the information utilized in the metric reporting is adequately managed.

The reliability department utilizes the outage data including root cause data to evaluate and trend circuits that provide opportunity to improve system reliability performance. Staff in both operations and asset management shared the challenge of limited funding to support meaningful system wide reliability improvements. In discussions focused on the impact of current "work activities" for asset health and wildfire mitigation efforts the staff shared the difficulty encountered in quantifying specific reliability improvements that can be utilized in projecting improved system performance.

The utilization of multiple internal outage data reviews by operations and support organizations introduces a level of confidence that the information utilized in the metric reporting is adequately managed.

FEP observed that historical circuit mileage estimates seemed challenging for PG&E to recreate after the initial data pull occurred. FEP observes that this is likely because PG&E pulls circuit mileage estimates from EGIS, which changes as PG&E performs work on the system.

FEP discussed circuit mile estimates with PG&E during interviews and learned that, while PG&E uses a single circuit mile value as "the source of truth" for the year, the circuit mile values in EGIS change organically through the year. It may be useful for PG&E to choose and define a specific period for pulling circuit mile estimates (such as the first of January and June) and include the circuit mile values used to conduct calculations in each of the SOM reports. New circuit mile values should be consistently developed and utilized in calculations, rather than applying current mileage estimates to previous years.

2.6.3 Metric 2.3 Performance and Targets

The Metric 2.3 target is proposed by the Electric System Planning and Reliability organization based on a review of historical data along with MED threshold projections. The Reliability organization works with the designated Metric Owner to develop a proposal for each metric including a description of the rationale behind the targets. Once reviewed and approved by the metric owner the proposal goes through a variety of approval steps of functional senior leadership within the organization. All reliability metrics require final approval of executive management.

Metric 2.3 targets are set with the goal of maintaining current performance within a historical range of yearly execution. PG&E utilizes historical information from 2013 to present to observe the relationship between MED experienced and the Customers Experiencing Sustained Outages during the event. Since the target for 1- and 5-year targets is directional to maintain performance within the historical performance of the organization, the initial focus is on the projected estimate of MEDs. The estimate is then utilized by the Reliability organization for potential impact or development of performance expectations for the upcoming period.

The following table displays PG&E's 2013 through 2023 Metric 2.3 results and the 1-year and 5-year metric targets. Although there are no published specifics providing defined numerical range boundaries, performance for 2021 through 2023 appears somewhat consistent with the previous years' results.

Table 2-9: Metric 2-3 Results and Targets

Year	Metric Result	1-Year Target	5-Year Target
2013	281 with 4 MEDs		
2014	381 with 5 MEDs		
2015	501 with 10 MEDs		
2016	321 with 3 MEDs		
2017	1806 with 30 MEDs		
2018	158 with 7 MEDs		
2019	1545 with 31 MEDs		
2020	192 with 14 MEDs		
2021	643 with 25 MEDs	Maintain	Maintain
2022	133 with 5 MEDs	Maintain	Maintain
2023	610 with 20 MEDs	Maintain	Maintain
[1]Targets reflect the target set in that report year (i.e. the 2021 1-year target reflects 2022 target).			

The 11-year range of CESO impact is 133-1,806. For the 2021-2023 period, the CESO impact was in the low to middle side of this range, with the note that it is dependent on MED as discussed above. Historical modeling of CESO metric results and its relationship to the number of MEDs could lead to more comparable results and help inform Metric 2.3 targets. These values assume that PG&E's reported metric results are correct, which FEP is uncertain of based off the HFTD designation discrepancies discussed above.

Observations on Metric 2.3 Performance and Targets

PG&E monitors Metric 2.3 progress regularly and has a formalized process for course-correcting if metric results approach the off-track threshold. The "catch up" process includes defined goals, due dates, and action ownership (commitment owner) assigned to specific staff. FEP's discussions with PG&E suggest that Metric 2.3 performance is one component of a larger overall monitoring effort associated with system reliability. Focus on wildfire mitigation programs, reduction in historical reliability funding along with the continuing impacts of EPSS is providing headwinds in achieving improved performance.

Although there are no specific Metric 2.3 benchmarking studies available, PG&E has extensive access to industry benchmarking associated with reliability, including SAIDI and SAIFI. One study that is available to the organization EIA's Annual Electric Power Survey Industry Report, Form EIA-861, whose associated data files provide an extensive database of company specific reliability data[13]. Utilization of the study may provide PG&E with the opportunity to evaluate its general reliability performance against specific California, regional, and western utilities. Although not directly providing Metric 2.3 information, the benchmarking data available may serve in comparing performance with companies facing similar circumstances with uncertain weather impacts and implementation of wildfire mitigation efforts. It does not appear that the organization currently utilizes benchmarking as a factor in developing the specific target ranges for Metric 2.3

The CESO metric is a long-standing industry method in evaluating reliability performance and its direct impact on the customers served. PG&E developed the Daily Reliability Scorecard to share in real time the performance status of reliability operating metrics, including CESO, and how it compares to established goals. It appears that the Scorecard provides, through communication of daily, monthly and year-to-date information including regional location performance statistics, relevant data that can lead to identifying performance improvement opportunities. However, Metric 2.3 targets appear to establish a high-level view of broad performance levels that if exceeded would indicate degeneration in service. FEP notes that the Metric 2.3 objective of maintaining performance within a "non-defined" range of historical performance does not necessarily correlate with an operational improvement.

2.7 Metric 2.4: System Average Outages Due to Vegetation and Equipment Damage in HFTD Areas (Non- Major Event Days)

The CPUC defines Metric 2.4 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.

Metric 2.4 measures the average number of sustained outages on non-MEDs per 100 circuit miles in HFTD per metered customer within a calendar year. A sustained outage is an interruption that lasts longer than five minutes. This metric provides a view of outage frequency in HFTD areas during non-MEDs.

MEDs are days with large numbers of customer minutes interrupted, often due to severe weather events like storms, but are cause-agnostic. The purpose of MEDs is to help isolate and analyze major events separately from routine operation, providing a clearer picture of normal system performance. The IEEE

[13] EIA webpage titled "Annual Electric Power Industry Report, Form EIA-861 detailed data files" provides company-specific reliability data. Available at: https://www.eia.gov/electricity/data/eia861/.

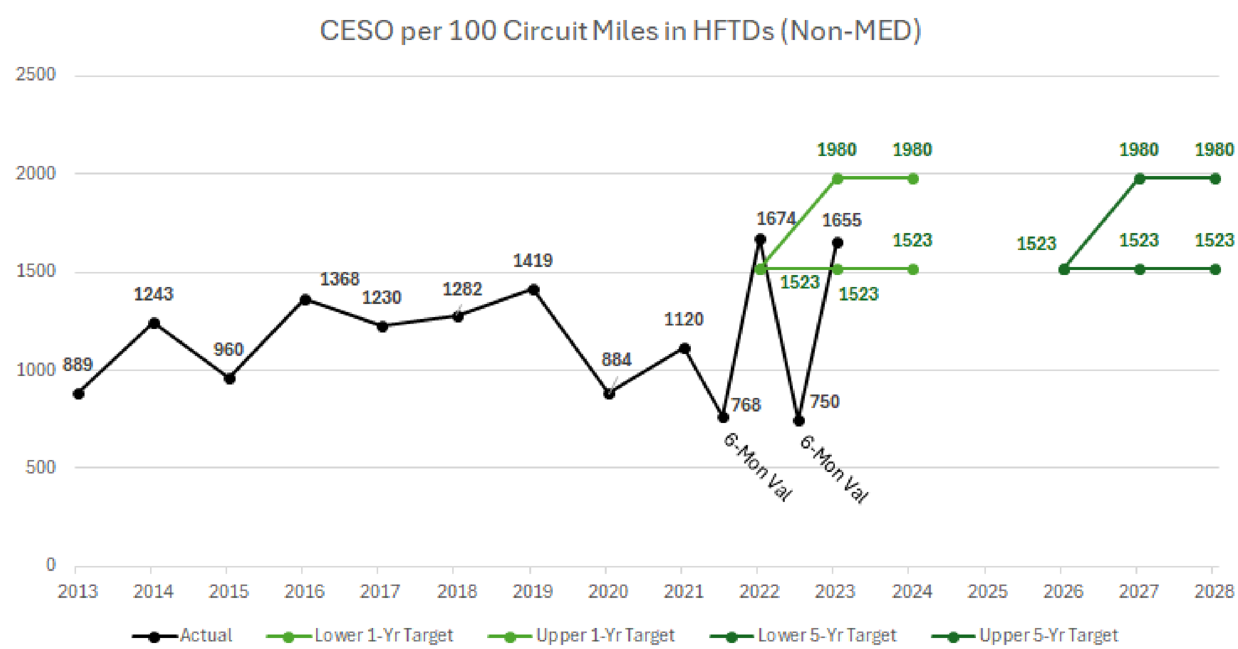
Guide for Electric Power Distribution Reliability Indices (Standard 1366) defines MEDs as days in which the daily SAIDI exceeds a statistically defined threshold based on the previous 5 years of daily SAIDI data[14]. In addition to storms, new causes of MEDs include PSPS events, which have been some of PG&E's largest MED days. IEEE released guidelines[15] for calculating the daily SAIDI threshold, which is discussed further in "Observation on Accuracy" section.

The formula for calculating Metric 2.4 is:

$$= \frac{\sum (Customers\ Interrupted\ on\ Non\text{-}MEDs)\ x\ 100}{Total\ T\&D\ Line\ Miles}$$

The following chart shows Metric 2.4 results compared to targets for 2013 through 2028, including results from the 2022 and 2023 mid-year reports. All historical values reflect the most recent data available as of the 2023 report and may differ from previously reported figures.

Figure 2-11: Metric 2.4 Summary Chart



2.7.1 Metric 2.4 Accuracy and Consistency

Information for Metric 2.4 is extracted from the ILIS Outage Database. Data enters ILIS through reports made by troubleshooters who respond to outages and other issues in the field. PG&E becomes aware of a downed wire or outage through several reporting streams such as Smart Meters, SCADA or customer

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14 A day in which the daily System Average Interruption Duration Index (SAIDI) exceeds a Major Event Day threshold (T_{MED}) value. For the purposes of calculating daily system SAIDI, any interruption that spans multiple calendar days is accrued to the day on which the interruption began. Statistically, days having a daily system SAIDI greater than T_{MED} are days on which the energy delivery system experienced stresses beyond that normally expected (such as during severe weather).

15 https://standards.ieee.org/ieee/1366/7243/

reporting. Troubleshooters are sent to the scene to assess the incident. Once on-site, the troubleshooters complete digital forms to document the characteristics of the incident. Those incident reports are transmitted to the distribution outage center.

PG&E supplied the audit team with the "Outage Reporting Details and Accuracy Verification Process" documents that provides a detailed description of the proper method to input outage data into ILIS along with the process for verifying the accuracy of the reported outage events.

The data transmitted to the distribution outage center is reviewed and manually entered by distribution staff. Employees of the outage center conduct a quality review as data is entered into ILIS. After the entries are submitted to ILIS, a member of the Outage Quality Review Team conducts another accuracy review. If engineers wish to add new information or correct previously submitted information, they ask the operations team to make changes to the data. Individuals in troubleshooting, engineering, and related departments have read access to the outage data, but do not have the ability to make changes to the database directly.

Once operations' entries have been verified as correct the staff of Electric System Planning and Reliability become the controllers of the outage information. This group initiates a secondary outage quality analysis review, with issues corrected by staff or sent back to Distribution Operators for further analysis and correction.

Once verified as correct the outage information becomes available for metric performance queries and modeling. Monthly performance reports are created and utilized by the Reliability staff members and senior management for trend analysis and determination of root causes for unplanned outages.

ILIS contains outage information, which is combined with infrastructure details from EGIS and customer counts from Customer Care and Billing to calculate the number of CESO for each event. EGIS contains infrastructure details like type of conductor (primary distribution, secondary distribution, etc.), and Customer Care and Billing contains customer count information. The data reported in ILIS is not the location of the cause of the outage, but instead the location of the operating device. Additionally, the data for the conductors does not come from field observations, but from the EGIS database.

The oversight and management process of these systems has been largely consistent for the past decade. The policies around data gathering, input, and extraction have been consistent throughout the reporting period with minimal changes to the reporting standard. PG&E uses data on system outages for internal tracking and regulatory reporting beyond the bi-annual SOMs report. To meet reporting requirements of the SOMs metrics, PG&E processes the ILIS dataset into planned and unplanned outages along with MED and non-MED events. The introduction of PSPS and EPSS for operational wildfire mitigation strategies has impacted the organization's system reliability efforts and potentially increases the number of MEDs experienced.

Observations on Metric 2.4 Accuracy

To determine the overall accuracy of the metric results, FEP reviewed the following inputs to Metric 2.4:

1) Non-MED designations
2) Circuit miles
3) CESO
4) HFTD classification

The process for undertaking those verifications is described in the sections below. Overall, FEP found that the Metric 2.4 results appear to have significant accuracy issues.

Verification of Major Event Days

A MED is a day where the daily SAIDI exceeds a defined threshold. According to IEEE Standard 1366, the threshold is defined by the following formula:

$$MED\ Threshold = e^{\propto + 2.5\beta}$$

The threshold is calculated by first taking the natural logarithm of the SAIDI values to normalize the dataset, which is typically right-skewed. Next, the mean ($\propto$) and standard deviation (β) of the log-transformed SAIDI values are calculated for every day included in the dataset over the past five years. The threshold is set 2.5 standard deviations above the mean in log-space, and the final threshold value is obtained by exponentiating the result to the original SAIDI scale.

PG&E performed these calculations for 2021, 2022, and 2023 in Excel using five years of data. PG&E listed the total daily SAIDI value for every day with a value above zero and calculated the logarithmic SAIDI value using Excel's LN function. PG&E calculated the mean ($\propto$) of the logarithmic SAIDI values using the AVERAGE function. The standard deviation (β) of the logarithmic SAIDI values was calculated using the STDEV function. PG&E then multiplied the standard deviation (β) by 2.5 then added the mean ($\propto$). The MED threshold was calculated by applying the EXP function to the results of that equation. FEP verified PG&E's calculations and found the threshold values to be accurate.

For each day in the spreadsheet, PG&E indicated whether the day met the MED threshold with a "yes" or "no". For example, the MED threshold for 2023 was 5.033, and days with a threshold equal or exceeding that value were marked with a "yes". To verify these designations, FEP used an Excel IF statement. Overall, FEP's dataset of MEDs matched PG&E's.

Verification of Circuit Miles

Circuit Miles are presented in the Metric 2.4 spreadsheet on four separate tabs, split into overhead and underground transmission and distribution lines. The data therein contains mileage for each circuit in PG&E's territory, separated into mileage within zones T3, T2, T1, and Z1. Only Tier 2 and 3 miles are included for this metric. These HFTD line miles are summed up at the bottom of each tab and pulled together in the primary calculation tab to be one total T&D line mileage.

In the two distribution line mile tabs which list circuit mileage for each circuit on the system, some rows have no circuit names. These blank entries indicate idle lines, which are not active circuits. Idle lines were included in the total line mileage through 2022, however they were removed from the total line mileage starting in 2023. Note that report years 2022 and prior use 2021 mileage. Years 2023 and beyond use mileage as of January first of that year (e.g. Jan 1, 2023, for the 2023 report, Jan 1, 2024, for the 2024 report). In the 2023 full-year metric, 39 idle line miles were excluded from a total of 28,064 miles.

In the two transmission line mile tabs with circuit-by-circuit mileage, in 2023 PG&E identified that several facilities were no longer used for the transmission system and thus removed from the list. 40 miles of transmission lines were excluded from a total of 5,489 miles. Similar to distribution, report years 2022 and prior use 2021 mileage for the metric calculation. Years 2023 and beyond use mileage as of January first of that year.

Verification of CESO

CESO is the count of customers that experience a sustained outage (defined as lasting more than five minutes) within a given period. CESO counts unique customers affected, meaning if the same customer experiences multiple outages, they are counted multiple times. CESO counts are included in the metric calculation file, split by cause (vegetation or equipment failure), MED (yes or no), and year. These CESO figures are generated from SAS stored procedures (essentially saved data queries to ILIS and other databases) that generate CSV files that are then manually copied and pasted into the calculation spreadsheets.

The SAS stored procedures process unplanned outage data to calculate a variety of metrics, one of which is CESO. Outage data is sourced from ILIS (Integrated Logging and Information System), which serves as the outage database for these calculations. The SAS stored procedures pull outage details from ILIS, such as outage duration and causes. Additional data is incorporated from feeder metadata tables, which provide additional infrastructure-related details such as circuit assignments and customer counts to support outage categorization. The SAS stored procedures merge the outage records with MED, to allow the data to be split into MED and non-MED parts. The SAS stored procedures integrate cause data from ILIS, assigning each outage to a cause. The data is then further categorized into transmission vs distribution. Finally, the total number of customers affected is used to derive CESO, which is grouped by division and cause.

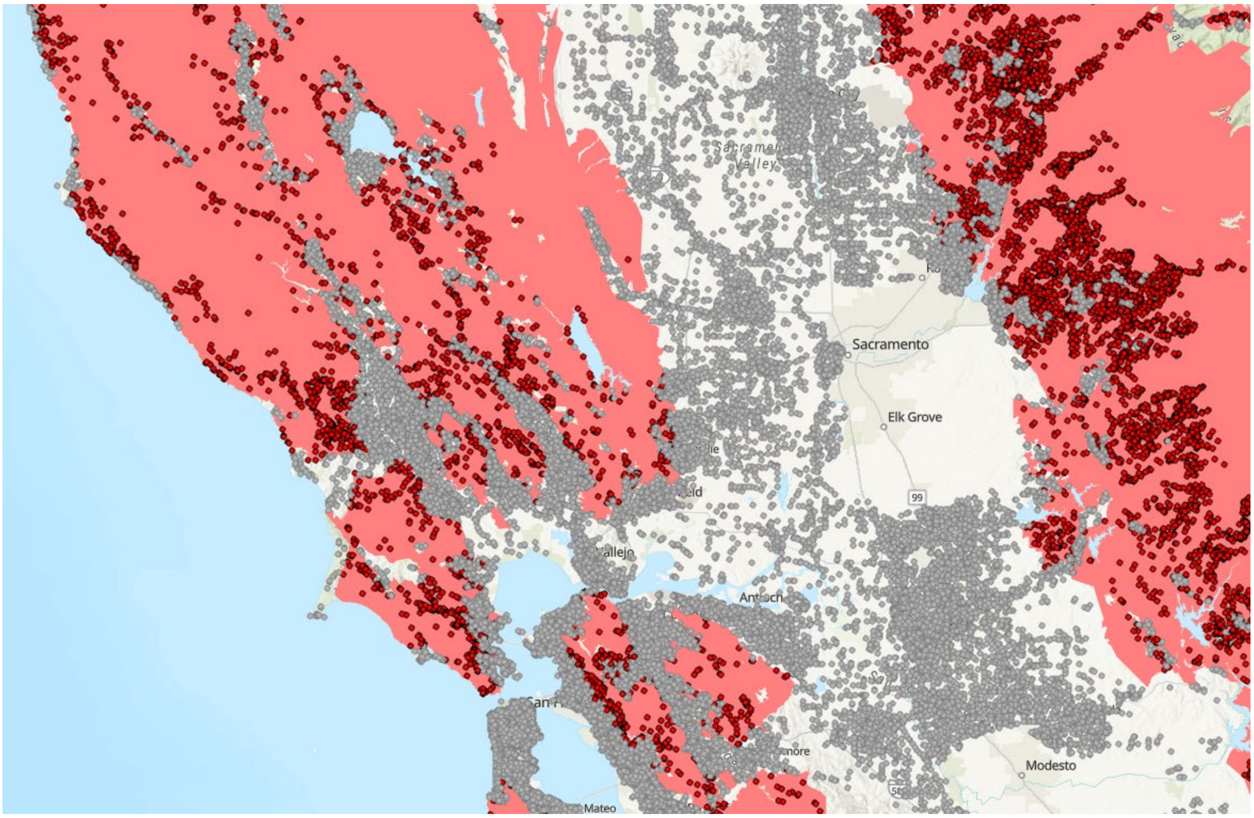
FEP reviewed these SAS stored procedures and received a walkthrough by PG&E employees, confirming that the code appears to be functioning correctly, pulling the right data and applying the correct transformations. However, since the code brings together information from many datasets and input tables, full verification of every data source was not viable. For instance, FEP did not verify if each outage was input correctly in ILIS, or if the EGIS and Customer Care and Billing databases were correct, but did verify that the SAS stored procedures appear to be combining the data from the databases correctly.

Verification of HFTD

The SAS stored procedures referenced before only report outages that occurred in HFTD areas, based on the location of the operating device associated with each outage. To verify the accuracy of this classification, FEP requested all outage data from 2021-2023, including the latitude and longitude for each outage. FEP then mapped these locations in ArcGIS, overlaying them with HFTD boundary layers.

The analysis revealed significant discrepancies. A significant number of outages labeled as Non-HFTD appear to fall within the boundaries of the HFTD, and a small number of outages labeled as HFTD appear to be located just outside the boundaries of the HFTD. Additionally, there are a number of outages that do not appear to have latitude and longitude coordinates, as either one of both coordinates are set at 0 (there are 1,093 outages like this out of a dataset of 250,339). Figure 2-12 below shows a section of PG&E's service territory with HFTD boundaries (pink), as well as the locations of outages that were originally classified as Non-HFTD. Gray dots represent outages that were reported as Non-HFTD and also appear to be in Non-HFTD areas. Red dots represent outages that were reported as Non-HFTD but appear to be within the boundaries of the HFTD instead.

Figure 2-12: Non-HFTD Reported Outage Map



In a follow-up discussion regarding this HFTD assignment error, PG&E explained that “for distribution, the HFTD class is not stored directly in the outage database but instead joined in through logic specific to each report. In the outage data prepared for SOMs, the report uses a tool that assigns HFTD class one day after the event, based on latitude and longitude. If that location data was unavailable on the day after the event and added or updated later, the tool does not revise the historical assignment resulting in some HFTD classifications no longer reflecting the most accurate or consistent information. The practice of assigning the HFTD class one day after the event based on the location of the interruptive device is how this has been determined since the HFTD was established. This data set has been the foundation of PG&E’s outage reporting relative to HFTD locations for all applications, including SOMs metrics.” FEP did not verify that this is the cause of the discrepancy. FEP also notes that as a result of these findings, PG&E has entered this issue into their CAP and is developing a centralized, standardized data repository through WiRE, which aims to improve outage metric reporting.

FEP performed a spatial analysis in ArcGIS to understand how many outage locations that were labeled as non-HFTD fell in HFTD zones, and vice versa. In the outage data received via RFI from PG&E, there are a total of 67,873 outages caused by either vegetation or equipment failure from 2021-2023. Of these, 11,691 were reported to be HFTD outages (whose CESO contributed to this calculation of this metric), and 56,182 were reported to be Non-HFTD outages. However, FEP discovered through the mapping analysis that 21,173 outages appeared to be located within the boundaries of the HFTD instead. The table below includes both the original HFTD and Non-HFTD outage counts (associated with vegetation or equipment failure) from 2021-2023, as well as the updated, map-based outage counts.

Table 2-10: Outage Counts

HFTD Designation	PG&E Provided Outage Count	Map-Based Outage Count	Percent of PG&E Outage Count
HFTD	11,691	21,173	181%
Non-HFTD	56,182	46,700	83%

FEP recalculated the metric using the CESO from the received outage data based on the updated HFTD classifications, as well as MED data shared with FEP via RFI. If the coordinates provided with the outage data are correct and the HFTD label should be applied based on those coordinates, the corresponding metric calculation would increase by 22% (2021) to 37% (2023). The results are shown in the table below.

Table 2-11: Revised Metric 2.4 Results

Year	Original 2.4 Result (Based on Original HFTD Classifications)	Updated 2.4 Result (Based on Map-Based HFTD Classifications)
2021	1,120	1,364
2022	1,679	2,202
2023	1,655	2,275

<u>**Verification of Metric Results**</u>

Once both CESO data and outage data are on the metric calculation sheet, the metric is calculated by summing the total CESO for the year due to vegetation and the total CESO for the year due to equipment failure. This sum is then multiplied by 100 and divided by the total HFTD T&D line miles, to normalize the CESO to per 100 HFTD line miles. The CESO data generated by the SAS script is pasted into the metric calculation sheet in two tabs, one tab containing monthly data, the other containing annual summary data. Similar to Metric 2.3, FEP discovered that there are discrepancies both between the monthly and yearly summary data in a given year, and also between the same yearly or monthly data of different vintages. For example, in 2021, the CESO for vegetation and equipment-caused outages excluding MEDs was 376,321. In the dataset provided for the 2023 full-year report, the total CESO for 2021 appears to be 376,279. Though this is a minor difference, it introduces concerns about the accuracy of the data. PG&E responded to a data request about that finding, saying "All mid-year and full-year results are slightly different because not all the outages may have been officially closed and, in some cases, outages may still be reviewed and changed months later due to internal findings. It is rare for our outages to be changed a year or years after they occur. The results of the prior year are expected to be closed within months after the close of the year." This appears to be a rare case of outages changing two years later.

FEP also found that either monthly or annual summary data was used, depending on the year. For the 2021 full-year report, monthly and annual data matched, and annual data was used. For the 2022 mid-year report, annual data was only available through May, meaning the monthly data was used (though the Jan-May CESO for monthly vs annual data was slightly different). For the 2022 full-year report, only monthly data was available, and monthly data was used. For the 2023 mid-year, monthly and yearly data were different, and yearly data was used. For the 2023 full-year report, monthly and annual data matched, and annual data was used. These differences in the mid-year reports may stem from the timing of the data pulls, as the data for the mid-year reports is pulled in July.

Though there appear to be potential differences in using the monthly vs annual data in any given month, the differences created by using the other were minor. For example, for the 2023 mid-year report, if PG&E has instead used the monthly data, the metric result would have been 748 instead of 750.

Based on the verification of PG&E's HFTD classifications, circuit miles, and CESO, there appear to be significant accuracy issues with the reported metric results. In addition to understanding the HFTD location data better, PG&E should ensure consistency between the monthly and annual outage data and standardize which dataset is used for calculations moving forward to maintain a consistent methodology.

Site Visit

The FEP audit team also participated in a site visit of the Rocklin Distribution Control Center and interviewed staff members in the operations and reliability departments. FEP confirmed that the operators apply the standards defined in PG&E's "Outage Reporting Details and Accuracy Verification Process" document. Staff reported a continuous education effort on the established standards and approved modifications to the process. Feedback provided from the operational team indicated confidence in the experience and knowledge of the staff members involved in the data collection and reporting process with some concern about staffing levels for operators, who are responsible for receiving, documenting and addressing outages. To address this concern the management team shared that efforts are underway to onboard and train two new classes of apprentice operators.

2.7.2 Metric 2.4 Management

PG&E's Electric Reliability and Metric Reporting department is responsible for managing, tracking, and setting targets for Metric 2.4 and the other reliability SOMs metrics.

The department develops monthly reports to identify reliability metrics that are off track from one- and five-year thresholds or trending in the wrong direction. The reports are utilized by regional and local reliability professionals and engineers to evaluate trends, identify causes for unplanned outages, and develop strategies that improve performance. Formal outage reviews are held with cross functional participation focused on root cause analysis and developing options to address the issue.

PG&E produces a Daily Reliability Scorecard that reveals daily, month to date, and year to date statistics on a variety of reliability metrics, including T&D CESO actual performance and goals. The scorecard monitors regional and division outage information for both planned and unplanned events along with specific information on location and cause code of asset failures. The organization distributes the scorecard to a broad population of staff members and is utilized in daily reliability meetings.

The organization utilizes the Lean Operating Review and CIC meetings described in Section 1.4 to review the Metric 2.4 status and any catch back work activities.

PG&E has created and initiated a wide variety of "work activities" that have potential to improve reliability performance. While several of the programs including Vegetation Management, Grid Design and System Hardening, along with Downed Conductor Detection are related to wildfire mitigation efforts, there is a sense among the PG&E staff that successful implementation of these initiatives should provide some incremental reliability improvement. The feedback received indicated that quantifying the impact of these efforts was difficult to model or project into objective expectations for future performance.

PG&E incorporates external system reliability benchmarking, including studies conducted by IEEE and EIA, in the process of monitoring performance and threshold targets analysis. Currently there appears to be no direct peer benchmarking initiative in place for Metric 2.4. SAIFI benchmarking studies can provide valuable insight and correlation to the target's performance for the organization relative to Metric 2.4. PG&E provided a list of industry reliability benchmarking studies that staff actively participate in. The reliability team recognizes the value of the obtained benchmarking information and PG&E's position as a SAIFI fourth quartile organization but communicates the impact of the wildfire mitigation strategies along with lack of funding for system reliability projects impact Metric 2.4 performance.

Observations on Metric 2.4 Management

PG&E's process for tracking system outages in HFTD on non-MED events appears to sufficiently capture vegetation and equipment damage incidents. Troubleshooters responding to outages have access to technology in the field which is designed to capture relevant information in a way that limits data variability and reduces opportunities for mistakes. For example, PG&E utilizes forms for logging data related to both ignitions and outages which leverage binary fields or drop-down menus, reducing the need for text entries. While text entries can be helpful for comments or adding granularity, they have been shown across the industry to lead to varied reporting formats, spelling errors, or other challenges which impact data analysis. PG&E identified these issues and made changes to its platform independently.

The utilization of multiple internal outage data reviews by operations and support organizations introduces a level of confidence that the information utilized in the metric reporting is adequately managed.

The reliability department utilizes the outage data including root cause data to evaluate and trend circuits that provide opportunity to improve system reliability performance. Staff in both operations and asset management shared the challenge of limited funding to support meaningful system wide reliability improvements. In discussions focused on the impact of current "work activities" for asset health and wildfire mitigation efforts the staff shared the difficulty encountered in quantifying specific reliability improvements that can be utilized in projecting improved system performance.

FEP observed that historical circuit mileage estimates seemed challenging for PG&E to recreate after the initial data pull occurred. FEP observes that this is likely because PG&E pulls circuit mileage estimates from EGIS, which changes as PG&E performs work on the system.

FEP discussed circuit mile estimates with PG&E during interviews and learned that, while PG&E uses a single circuit mile value as "the source of truth" for the year, the circuit mile values in EGIS change organically through the year. It may be useful for PG&E to choose and define a specific period for pulling circuit mile estimates (such as the first of January and June) and include the circuit mile values used to conduct calculations in each of the SOM reports. New circuit mile values should be consistently developed and utilized in calculations, rather than applying current mileage estimates to previous years.

2.7.3 Metric 2.4 Performance and Targets

The Metric 2.4 target is proposed by the Electric System Planning and Reliability organization based on a review of historical data along with MED threshold projections. PG&E provided information on the approval process for the SOMs' Reliability Metrics. The Reliability organization works with the designated

Metric Owner to develop a proposal for each metric including a description of the rationale behind the targets. Once reviewed and approved by the metric owner the proposal goes through a variety of approval steps of functional senior leadership within the organization. All reliability metrics require final approval of executive management.

Targets are set with the goal of maintaining current performance within a historical range of yearly execution. PG&E utilizes historical information from 2013 to the present to observe the number of Customers Experiencing Sustained Outages outside of a MED event. Increasing MED threshold index values have introduced the potential to reduce the number of significant weather events that qualify as a major event. In determining the targets, the Reliability organization focuses initial efforts on projecting an estimate for MED. That information is utilized to evaluate potential impact on non-MED performance expectations for the upcoming period. That along with uncertainty over the implementation of EPSS has led the company to set targets higher than historical performance.

The following table displays PG&E's 2013 through 2023 Metric 2.4 results and the 1-year and 5-year metric targets.

Table 2-12: Metric 2-4 Results and Targets

Year	Metric Result	1-Year Target	5-Year Target
2013	889		
2014	1,243		
2015	960		
2016	1,368		
2017	1,230		
2018	1,282		
2019	1,419		
2020	884		
2021	1,120	1,523	1,523
2022	1,674	1,523-1,980	1,523-1,980
2023	1,655	1,523-1,980	1,523-1,980
[1]Targets reflect the target set in that report year (i.e. the 2021 1-year target reflects 2022 target).			

The 2021-2023 average performance of Metric 2.4 was 1,483 and considering increased EPSS operations in 2022 and 2023 the average metric results were 1,665. The lower bound of the 2022 and 2023 targets is approximately 9% lower than the 2022-2023 average and the higher bound is 19% higher than the 2022-2023 average. As with other reliability Metrics PG&E shared that the implementation of wildfire mitigation efforts, including the implementation of EPSS, has impacted its performance for Metric 2.4. These values assume that PG&E's reported metric results are correct, which FEP is uncertain of based on the HFTD designation discrepancies discussed above.

Observations on Metric 2.4 Performance and Targets

PG&E monitors Metric 2.4, through a variety of means including the CIC workgroup, that regularly reviews the status of metric performance and has a formalized process for course-correcting if metric results approach the off-track threshold. The "catch up" process includes defined goals, due dates, and action ownership (commitment owner) assigned to specific staff. FEP's discussions with PG&E suggest that

Metric 2.4 performance is one component of a larger overall monitoring effort associated with system reliability. Focus on wildfire mitigation programs, reduction in historical reliability funding along with the continuing impacts of EPSS is providing headwinds in achieving improved performance.

Although there are no specific benchmarking studies available that are equivalent to the Metric 2.4 definition, PG&E has extensive access to industry benchmarking associated with reliability, including SAIFI, which the company has communicated as a relevant indicator of Metric 2.4 performance. One study that is available to the organization is EIA's Annual Electric Power Survey Industry Report, Form EIA-861, whose associated data files provide an extensive database of company specific reliability data[16]. Utilization of the study may provide PG&E with the opportunity to evaluate its general reliability performance against specific California, regional, and western utilities. Although not directly providing metric 2.4 information, the benchmarking data available may serve in comparing performance with companies facing similar uncertain weather impacts and implementation of wildfire mitigation efforts. This benchmarking information does not appear to be a major factor in determining the range targets for Metric 2.4.

The CESO metric is a long-standing industry method in evaluating reliability performance and its direct impact on the customers served. PG&E developed the Daily Reliability Scorecard to share in real time the performance status of reliability operating metrics, including CESO, and how it compares to established goals. It appears that the Scorecard provides, through communication of daily, monthly and year-to-date information including regional location performance statistics, relevant data that can lead to identifying performance improvement opportunities. However, SOMs Metric 2.4 targets seem to establish a high-level view of a broad range of performance levels that if exceeded may indicate performance degradation. We note that with EPSS established and PG&E’s consistent performance experienced in 2022 and 2023, the 1- and 5-year metric targets are identical with no improved targets.

2.8 Metric 3.1: HFTD Wires Down Distribution (MEDs)

The CPUC defines Metric 3.1 as:

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

Metric 3.1 assesses the rate of distribution Wires Down events in PG&E’s HFTD. A Wires Down event occurs when a normally energized overhead primary or transmission conductor is broken and falls from its intended position to rest on the ground or a foreign object. . Metric 3.1 relates only to Wires Down events which occur on primary or secondary distribution lines. The metric also only measures Wires Down events in HFTDs on MEDs.

MEDs are days with large numbers of customer minutes interrupted, often due to severe weather events like storms, but are cause-agnostic. The purpose of MEDs is to help isolate and analyze major events separately from routine operation, providing a clearer picture of normal system performance. The IEEE Guide for Electric Power Distribution Reliability Indices (Standard 1366) defines MEDs as days in which the

[16] EIA webpage titled “Annual Electric Power Industry Report, Form EIA-861 detailed data files” provides company-specific reliability data. Available at: https://www.eia.gov/electricity/data/eia861/.

daily SAIDI exceeds a statistically defined threshold based on the previous 5 years of daily SAIDI data[17]. In addition to storms, new causes of MEDs include PSPS events, which have been some of PG&E's largest MED days. IEEE released guidelines[18] for calculating the daily SAIDI threshold, which is discussed further in "Observation on Accuracy" section.

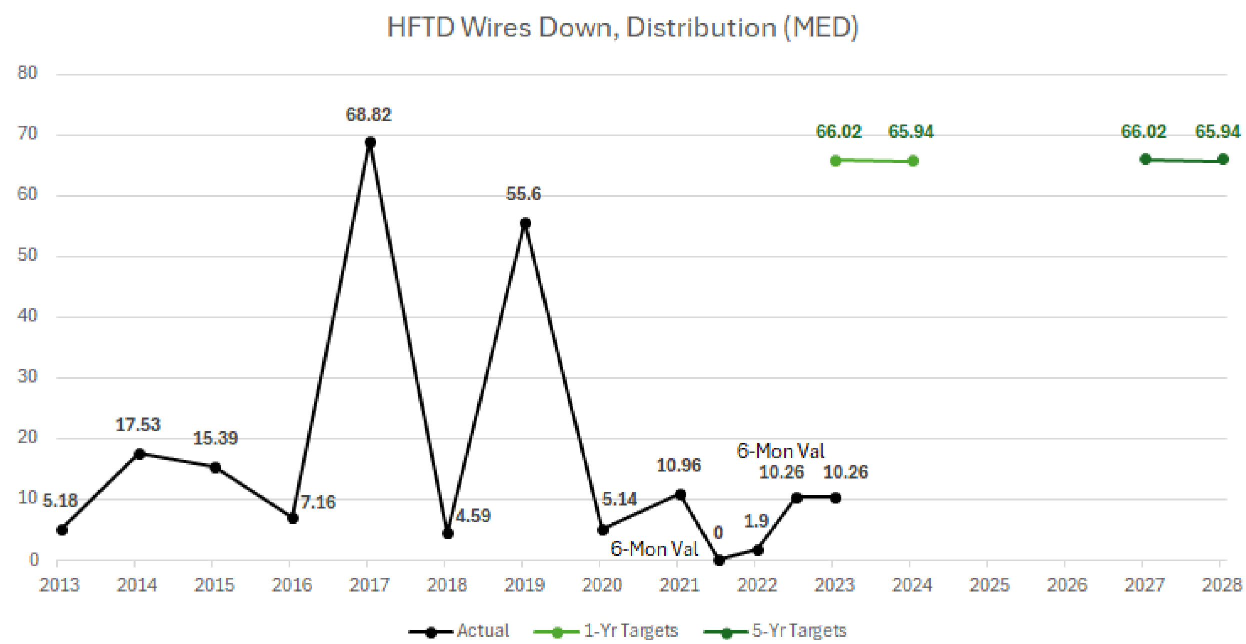
Metric 3.1, and other metrics which relate to MEDs, assess PG&E's practices and assets during very adverse weather conditions.

The formula for calculating Metric 3.1 is:

$$= \frac{\#\ of\ Wires\ Down\ Events\ on\ MEDs\ in\ HFTDs}{Total\ Primary\ \&\ Secondary\ Distribution\ Line\ Miles\ in\ HFTDs}\ X\ 1000$$

The following chart shows Metric 3.1 results compared to targets for 2013 through 2028, including results from the 2022 and 2023 mid-year reports. All historical values reflect the most recent data available as of the 2023 report and may differ from previously reported figures.

Figure 2-13: Metric 3.1 Summary Chart



2.8.1 Metric 3.1 Accuracy and Consistency

Information for Metric 3.1 is extracted from the ILIS Outage Database. Data enters ILIS through reports made by troubleshooters who respond to outages and other issues in the field. PG&E becomes aware of

[17] A day in which the daily System Average Interruption Duration Index (SAIDI) exceeds a Major Event Day threshold (T_{MED}) value. For the purposes of calculating daily system SAIDI, any interruption that spans multiple calendar days is accrued to the day on which the interruption began. Statistically, days having a daily system SAIDI greater than T_{MED} are days on which the energy delivery system experienced stresses beyond that normally expected (such as during severe weather).

[18] https://standards.ieee.org/ieee/1366/7243/

a downed wire or outage through several reporting streams such as Smart Meters, SCADA or customer reporting. Troubleshooters are sent to the scene to assess the incident. Once on-site, the troubleshooters complete digital forms to document the characteristics of the incident. Those incident reports are transmitted to the distribution outage center.

PG&E supplied the audit team with the "Outage Reporting Details and Accuracy Verification Process" documents that provides a detailed description of the proper method to input outage data into ILIS along with the process for verifying the accuracy of the reported outage events.

The data transmitted to the distribution outage center is reviewed and manually entered by distribution staff. Employees of the outage center conduct a quality review as data is entered into ILIS. A member of the Outage Quality Review Team conducts another accuracy review. If engineers wish to add new information or correct previously submitted information, they ask the operations team to make changes to the data. Individuals in troubleshooting, engineering, and related departments have read access to the data, but do not have the ability to make changes to the database directly.

The ILIS database has broad utilization across PG&E operations, and the data is used for differing PG&E workstreams. As the database was not specially designed for this metric, some of the datapoints are used as approximations rather than ideal descriptors. For example, PG&E staff communicated in an interview that the location associated with the Wires Down metrics is logged as being associated with the operating device rather than the location the affected wire made contact. However, PG&E staff subsequently noted through an RFI that the location of Wires Down events for SOMs is generated by a tool that assigns HFTD classification based on longitude and latitude. If that location is unavailable or changes later, the tool does not revise the HFTD classification but may update the coordinates. PG&E also logs the span location of equipment-caused Wires Down events in the Wires Down Database. The Wires Down Database does not include vegetation-caused events and is not used for the calculation of this metric.

Importantly, the events logged in ILIS are outages and not specifically Wires Down events. Wires Down events are tracked through a notation on the outage to indicate that it involved a downed wire. The result of this system is that the number of Wires Down is approximated by the number of outages. PG&E staff stated that this methodology aligns with PG&E's interpretation of the CPUC definition of "Wires Down events". PG&E defines "Wires Down events" as the number of outages caused by one or more Wires Down faults. FEP notes that CPUC Decision D.21-100-09 says Wires Down events are 'when normally energized overhead primary or transmission conductor is broken, or remains intact, and falls from its intended position to rest on the ground or foreign object.[19]"

If a downed wire trips multiple operating devices, then it will be logged as multiple events. Meanwhile, while downed wires on the primary distribution system may result in the creation of multiple Wires Down records, it is possible that Wires Down events on the secondary distribution system are unrecorded if they do not result in the trip of an operating device. Through discussions with PG&E staff, it is evident that they are aware of these limitations and that it is their perspective that the ILIS database is the best database available to serve as a record for this metric. Wires Down events are tracked based on associated outages, and PG&E does not differentiate in ILIS between outages associated with primary or secondary distribution lines. If there is no outage associated with the event, then it is not logged as a Wires Down event for the purpose of metric tracking. PG&E acknowledges these limitations and is evaluating their procedure to determine if its calculation of this metric can be adjusted to address these limitations.

[19] CPUC Decision 21-100-09, p. 84.

PG&E uses EGIS to inform this metric. EGIS is also used to identify the feeder, whether the assets are located in HFTDs, and to calculate the total number of line miles. The circuit mile calculations are a snapshot in time, meaning they are continuously updated as circuits expand and contract. Once Operations entries have been verified as correct the staff of Electric System Planning and Reliability become the controllers of the outage information. This group initiates a secondary outage quality analysis review, with issues corrected by staff or sent back to Distribution Operators for further analysis and correction.

The oversight and management process has been largely consistent for the past decade. The policies around data gathering, input, and extraction have been consistent throughout the reporting period with minimal changes to the reporting standard. PG&E uses data on Wires Down for internal tracking and regulatory reporting beyond the bi-annual SOMs report. Specific divisions that are required for SOMs reporting, like the separation of MED and non-MED events occur in post-processing using the ILIS dataset.

PG&E adopted the CPUC's Fire-Threat Map in 2018[20] and added fields to ILIS identifying assets as belonging to HTFDs. PG&E uses EGIS to determine if assets involved in Wires Down events are within HTFD boundaries. The historical SOMs dataset (2013 – 2020) partially predates HFTD designations, so PG&E used 2021 HTFD boundaries to retroactively determine which Wires Down events applied to this metric.

Observations on Metric 3.1 Accuracy

To determine the overall accuracy of the metric results, FEP reviewed the following inputs to Metric 3.1:

1) MED designations
2) Circuit mile values
3) Event characteristics
4) HFTD classification

The process for undertaking those verifications is described in the sections below. In addition, FEP benchmarked the SOMs results to other PG&E published reports regarding Wires Down. Overall, FEP found that the Metric 3.1 results appear to have significant accuracy issues.

Verification of Major Event Days

MEDs are days with large numbers of customer minutes interrupted, often due to severe weather events like storms, but are cause-agnostic. According to IEEE Standard 1366, the threshold is defined by the following formula:

$$MED\ Threshold = e^{\propto + 2.5\beta}$$

The threshold is calculated by first taking the natural logarithm of the SAIDI values to normalize the dataset, which is typically right-skewed. Next, the mean ($\propto$) and standard deviation (β) of the log-transformed SAIDI values are calculated for every day included in the dataset over the past five years. The threshold is set 2.5 standard deviations above the mean in log-space, and the final threshold value is obtained by exponentiating the result to the original SAIDI scale.

[20] https://www.cpuc.ca.gov/industries-and-topics/wildfires/fire-threat-maps-and-fire-safety-rulemaking#:~:text=On%20December%2021%2C%202017%2C%20we,more%20information%20about%20the%20Sept.

PG&E performed these calculations for 2021, 2022, and 2023 in Excel using five years of data. PG&E listed the total daily SAIDI value for every day with a value above zero and calculated the logarithmic SAIDI value using Excel's LN function. PG&E calculated the mean ($\propto$) of the logarithmic SAIDI values using the AVERAGE function. The standard deviation (β) of the logarithmic SAIDI values was calculated using the STDEV function. PG&E then multiplied the standard deviation (β) by 2.5 then added the mean ($\propto$). The MED threshold was calculated by applying the EXP function to the results of that equation. FEP verified PG&E's calculations and found the threshold values to be accurate.

For each day in the spreadsheet, PG&E indicated whether the day met the MED threshold with a "yes" or "no". For example, the MED threshold for 2023 was 5.033 and days with a threshold equal or exceeding that value were marked with a "yes". To verify these designations, FEP used an Excel IF statement. Overall, FEP's dataset of MEDs matched PG&E's.

Verification of Circuit Miles

PG&E calculated the primary and secondary distribution circuit miles using EGIS. PG&E stated that the number of distribution circuit miles in HTFDs can vary yearly, or even monthly, as PG&E undertakes construction projects on the system. As PG&E adds new above-ground assets the distribution mileage expands, and undergrounding, grid hardening efforts, or re-routing can reduce above-ground line miles.

The circuit mile values are captured using GIS polygons of HTFDs. These values change as work is conducted on the system, so FEP relied on PGE's circuit mile values. PG&E's process of using EGIS polygons to identify the circuit miles included in specific asset groups is common in the industry.

PG&E produced the 2021 SOMs report in 2022. The total distribution circuit mile value in HFTDs was calculated at that point, using the above-ground mileage that existed at the time. PG&E did not record a mileage estimate using the 2021 asset configuration. Therefore, the same mileage value was used for both 2021 and 2022, based on the 2022 asset configuration. The 2022 mileage estimate was also used for calculating historical (2013 – 2020) metric results. This resulted in metric values for 2021 and earlier which are likely different than what the values would have been if PG&E used actual circuit mile values.

Verification of Event Characteristics

FEP reviewed instances where multiple Wires Down events occurred on the same feeder on the same day. The purpose of this review was to ensure that those records were not duplicates and to understand the drivers behind multiple Wires Down events occurring at a similar location and time. FEP first considered the percentage of Wires Down events which occurred on the same day and time to assess if it was in keeping with industry norms. Out of the entire 2013 – 2023 dataset for Metric 3.1, approximately 75 percent of the feeder/day combinations which had Wires Down events experienced a single event.

FEP then reviewed the event characteristics on days where a single feeder experienced a high number of events. The highest number of events experienced on a single feeder during an MED is 25. These events were vegetation events during snow and bad weather. For comparison, the highest number of events experienced on a single feeder on a non-MED was 6.

FEP discussed drivers of multiple Wires Down events on the same feeder with PG&E staff. There are instances where events like bad weather or fires can result in multiple wires making contact with the ground or other objects on the same feeder. Additionally, PG&E staff communicated that they use the ILIS database in the calculation of this metric. ILIS is formatted to track outages, and a new data entry is created for each operating device that trips. Therefore, there are cases where a single precipitating instance results in multiple operating devices tripping and multiple associated ILIS entries. PG&E is aware that this results in reporting more Wires Down events than actually occurred. In the absence of a more tailored database of record, PG&E communicated that this process best fits its resource constraints.

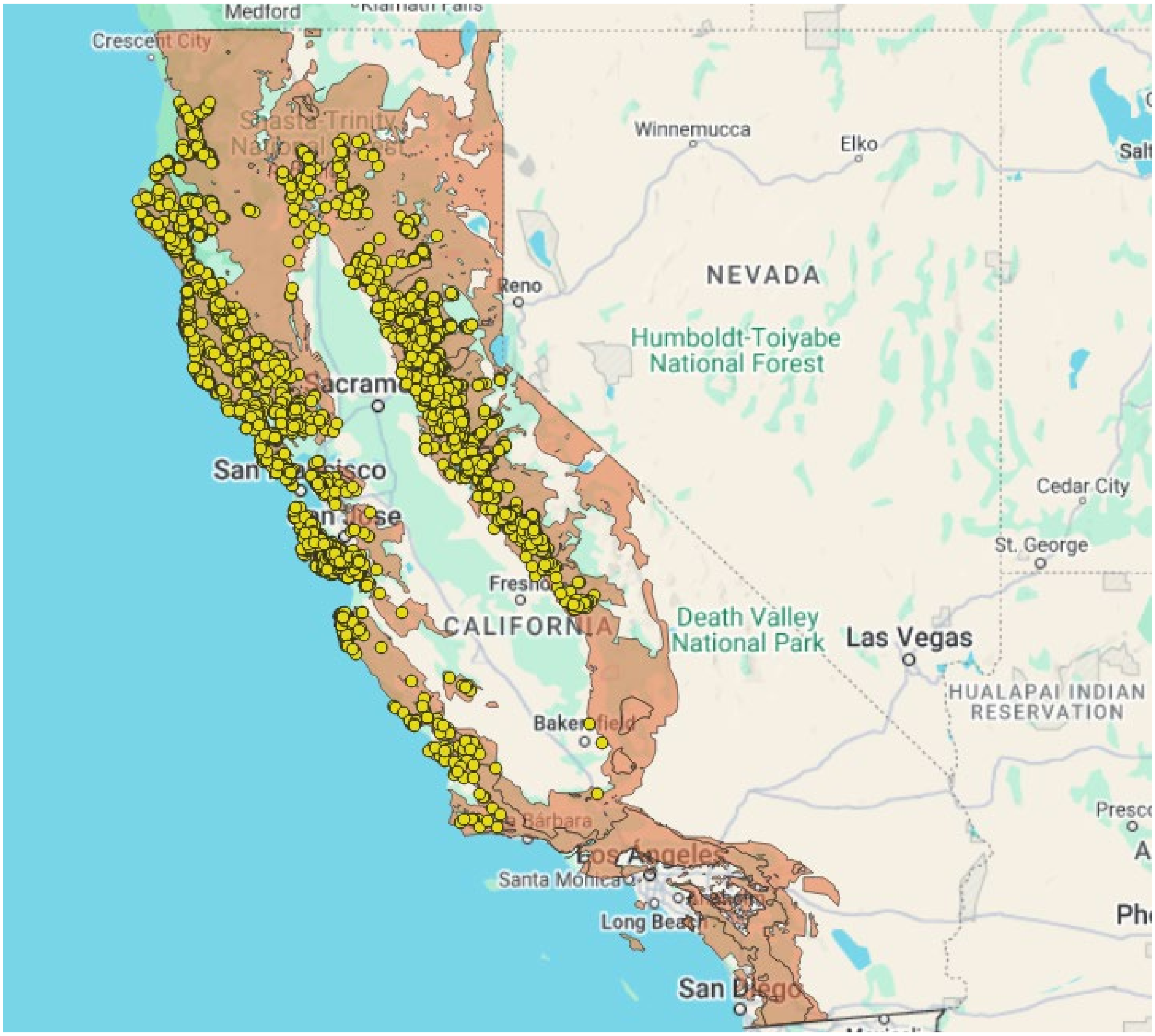
While there are instances of a single downed wire resulting in multiple outage records (and therefore being counted as multiple Wires Down events for the purpose of this metric), it seems likely that there are Wires Down events on the secondary distributions system which are left out of the dataset. A downed wire on the secondary distribution system may not result in the associated operating device activating. Therefore, based on how ILIS is used to track this metric, it seems likely that some of these events are not captured by ILIS. FEP was unable to verify the number of secondary Wires Down events which may be missing. FEP observes that, while relying on the ILIS database as the database of record for this metric likely produced efficiencies for PG&E, it was not designed specifically for this purpose and leads to accuracy compromises for metric calculations. PG&E acknowledges these limitations and is evaluating their procedure to determine if their calculation of this metric can be adjusted to address these limitations.

Verification of HFTD Designations

During the evaluation process, FEP requested that PG&E provide data on all outages (which includes Wires Down events) which occurred in both the HFTD and non-HFTD areas. FEP used GIS software to plot the coordinates for the operating devices involved in the outages. FEP compared these plotted GIS locations to PG&E's HFTD/non-HFTD designations. A spatial selection in GIS was used to identify outage points that intersected with the HFTDs. The intersecting points were then analyzed to assess the accuracy of PG&E's HFTD/Non-HFTD identification field.

FEP identified significant discrepancies between PG&E's HFTD/non-HFTD designations and those implied by the mapped data. While there were a small number of points designated as HFTD which were plotted in non-HFTD areas, there were many points designated as non-HFTD that were well within the HFTD boundaries. The following figure shows a map of California with the HFTD (Tier 2 and Tier 3) highlighted in light red. The yellow points are 2021 – 2023 distribution Wires Down events (located to the associated operating devices) that overlap with HFTD areas but were marked as occurring in non-HFTD areas.

Figure 2-14: Distribution Wires Down Events Classified as "Non-HFTD" in HFTD Areas



In a follow-up discussion regarding this HFTD assignment error, PG&E explained that "for distribution, the HFTD class is not stored directly in the outage database but instead joined in through logic specific to each report. In the outage data prepared for SOMs, the report uses a tool that assigns HFTD class one day after the event, based on latitude and longitude. If that location data was unavailable on the day after the event and added or updated later, the tool does not revise the historical assignment resulting in some HFTD classifications no longer reflecting the most accurate or consistent information. The practice of assigning the HFTD class one day after the event based on the location of the interruptive device is how this has been determined since the HFTD was established. This data set has been the foundation of PG&E's outage reporting relative to HFTD locations for all applications, including SOMs metrics." FEP did not verify that this is the cause of the discrepancy. FEP also notes that as a result of these findings, PG&E has entered this issue into their CAP and is developing a centralized, standardized data repository through WiRE, which aims to improve outage metric reporting.

Benchmark to Other PG&E Reports

To further assess the accuracy of this metric, FEP considered a number of data sources where PG&E reports on Wires Down events. While all of these data sources report on Wires Down events, some focus only on HFTDs while others look at Wires Down events across PG&E's full system. FEP considered whether the SOMs reported values made sense in the context of these other PG&E reports. The following list defines the various sources of data considered:

1) **SOMs Data:** Data on Wires Down events that PG&E transmitted as part of its SOMs reporting requirements. This data was pre-filtered to include only events PG&E classified as occurring in HFTDs and is separated into distribution and transmission datasets.
2) **Mapped Outage Dataset:** This is a dataset that FEP requested from PG&E that shows all outages occurring across the PG&E system. It can be filtered to identify only outages which included Wires Down events. Additional filtering can be applied to identify outages by line type (transmission or distribution) and by location (HFTD or non-HFTD). FEP took the outage data provided by PG&E and mapped the location of the Wires Down events using the provided coordinates in GIS. As described in the section above, the results of FEPs mapping process did not align with PG&E's HFTD designations.
3) **Quarterly Data Report (QDR):** The QDRs are submitted along with PG&E's wildfire mitigation plans. The reports include Wires Down event counts (transmission and distribution) both at an HFTD level and the full system level.
4) **SPM Results:** California utilities report to the CPUC on SPMs, required by Decision 19-04-020. The number of Wires Down events occurring across the full system is reported in SPM 2.

Based on the definitions and requirements of these reporting streams, FEP concluded that there should be fairly consistent Wires Down rates across the data sources. As shown in the table below, the reports presenting full-system Wires Down rates are fairly consistent. However, the reports presenting HFTD-only data do not match. The mapped outage data showed many more Wires Down events in HFTDs than were reported by SOMs Metric 3.1 – 3.6 or in the QDR.

Table 2-13: Wires Down Report Comparison

Year	In HFTDs			Full System		
	SOM Metric 3.1 – 3.6 total	QDR in HFTDs	Mapped Outage Data	QDR in Full System	SPM # 2	Mapped Outage Data
2023	787	1,281	3,526	7,133	7,173	7,514
2022	522	525	1,002	3,159	3,132	3,315
2021	777	809	2,977	5,896	5,819	6,035

The difference between the reported Wires Down values in HFTDs further suggests that there may be a problem with the SOMs data for this metric. In response to questions regarding the differences, PG&E noted that that the data reflects "snapshots in time" and changes are made based on the findings of further investigations and many other factors. Since the SOMs data and QDR data were pulled at different times, they reflect different information. Though the QDR data and SOMs data are pulled using different processes, the results should be the same if they are pulled at the same time. PG&E repulled the data in response to FEP's RFI (April 2025), and both processes produced 3,377 Wires Down in HFTDs in 2023. A change from 1,281 to 3,377 appears to be larger than one would expect as a result of normal data updates and further suggests data issues.

This new value is similar to what FEP identified using the outage data. However, the result is very different than what was previously reported. This leads FEP to believe there are significant errors in PG&E's metric results for SOM Metric 3.1 – 3.6.

Verification of Metric Results

FEP was unable to verify PG&E's metric results in light of the HFTD designation discrepancy. PG&E included 257 Wires Down events in its 2023 SOMs Metric 3.1 reporting. However, FEP found 2,339 events that qualified for the metric based on the SOM's definition. If accurate, the 2023 result for this metric would be nine times higher than what was reported.

Table 2-14: Metric 3.1 Reported Results vs FEP's Calculated Results

Year	Events Reported in Metric 3.1	Reported Metric 3.1 Result	FEP Count of Wires Down Events (based on mapped outages)	FEP Metric 3.1 Result
2023	257	10.26	2,339	93.34
2022	48	1.90	162	6.41
2021	277	10.96	2,049	81.08

2.8.2 Metric 3.1 Management

PG&E's Electric Asset Management ("EAM") department is responsible for managing, tracking, and setting targets for Metric 3.1 and the other Wires Down metrics. PG&E tracks the repair and investigation of Wires Down events daily for internal reporting.

ESS produces a monthly report with the Wires Down statistics for Metric 3.1. Once the data is validated, the performance results are added to the Centralized Metrics Repository (CMR) reporting tool. The reports are then validated and approved by the Asset Strategy and Standards team (Asset Strategy). Each month, Asset Strategy considers the year-to-date performance of the metric to determine if the metric is on track to achieve the one-year target and assess progress towards the 5-year target.

Additionally, PG&E conducts an efficiency review following major events to understand the causes of equipment failures on MEDs. This review includes assessing all types of equipment failures, including conductors. The main goal of the post-event assessment is to consider if the design standards of the failing assets are sufficient.

The organization utilizes the Lean Operating Review and CIC meetings described in Section 1.4 to review the Metric 3.1 status and any catch back work activities. The team reviews controls and mitigations which are currently in place through the electric asset and vegetation management groups to determine corrective actions.

Though not directly related to the management of the SOMs metric, PG&E does undertake management activities for Wires Down more generally which may affect the metric results. If anomalies or problematic data trends are identified in the Wires Down data, ESS works with the reliability teams to do a deep dive into the causes of the trends. The most common drivers of downed wires are vegetation, weather, and contact from third-party objects. If problematic trends are identified, ESS brainstorms with the relevant departments, such as the reliability teams or the vegetation teams to understand mitigation options. Often, the adjustments and mitigations drive improvement to Wires Down rates in the longer term, rather than resulting in immediate improvement for the current year. Vegetation issues can be addressed more quickly overall than asset issues, as asset issues often require longer-term construction projects.

Observations on Metric 3.1 Management

Troubleshooters responding to outages have access to technology in the field which is designed to capture relevant information in a way that limits data variability and reduces opportunities for mistakes. For example, PG&E utilizes forms for logging data related to both ignitions and outages which leverage binary fields or drop-down menus, reducing the need for text entries. While text entries can be helpful for comments or adding granularity, they have been shown across the industry to lead to varied reporting formats, spelling errors, or other challenges which impact data analysis. PG&E identified these issues and made changes to its platform independently.

However, metric specific considerations may improve the meaningfulness of Metric 3.1. FEP observed that historical circuit mileage estimates seemed challenging for PG&E to recreate after the initial data pull occurred. FEP observes that this is likely because PG&E pulls circuit mileage estimates from EGIS, which changes as PG&E performs work on the system.

FEP discussed circuit mile estimates with PG&E during interviews and learned that, while PG&E uses a single circuit mile value as “the source of truth” for the year, the circuit mile values in EGIS change organically through the year. It may be useful for PG&E to choose and define a specific period for pulling circuit mile estimates (such as the first of January and June) and include the circuit mile values used to conduct calculations in each of the SOM reports. New circuit mile values should be consistently developed and utilized in calculations, rather than applying current mileage estimates to previous years.

2.8.3 Metric 3.1 Performance and Targets

The Metric 3.1 target is proposed by ESS based on a review of historical data. The proposed target is sent to PG&E leadership for approval. From there, the officers review the target to ensure it’s justifiable and to gain alignment across the other teams involved in the workstream, like the transmission team.

PG&E staff stated that no benchmarking was used to set the target for Metric 3.1 because the specificity of the definition makes it incomparable to peer utilities. However, PG&E does benchmark system-wide Wires Down performance with other California utilities. This more generalized data is available to the public on a quarterly basis, and PG&E shares it with other regulatory agencies like the California Office of Energy Infrastructure Safety (“OEIS”). PG&E sets internal Wires Down performance targets based on this and other sources of information.

Metric 3.1 targets are set with the goal of maintaining current performance, which was calculated using ten historical years of data. PG&E set the target for Metric 3.1 at the upper limit of two standard deviations from the 10-year average performance. FEP learned from PG&E that the goal of the Metric 3.1 target is not to drive a reduction of Wires Down events, but rather to maintain consistent performance. This intention is reflected by the overall consistency of PG&E’s 1-year and 5-year 3.1 metric targets.

The following table displays PG&E’s 2013 through 2023 Metric 3.1 results and the 1-year and 5-year metric targets.

Table 2-15: Metric 3-1 Results and Targets

Year	Metric Result	1-Year Target[1]	5-Year Target[1]
2013	5.18		
2014	17.53		
2015	15.39		
2016	7.16		
2017	68.82		
2018	4.59		
2019	55.60		
2020	5.14		
2021	10.96	"Maintain"	"Maintain"
2022	1.90	66.02	66.02
2023	10.26	65.94	65.94
[1] Targets reflect the target set in that report year (i.e. the 2021 1-year target reflects 2022 target).			

Considering the 2021 through 2023 period, Metric 3.1 targets are approximately six times higher than company performance in 2021 and 2023. However, 2017 and 2019 had metric results of 69 and 56 respectively. If these years are excluded, the next highest result of 18 occurred in 2014. PG&E's average metric result from 2013 – 2023 was 18.41 and 7.71 from 2021 – 2023. PG&E's 1- and 5-year targets set in 2023 are 258% above the 11-year average and 756% above the 2021-2023 average. Overall, PG&E's Metric 3.1 result has generally trended downward. These values assume that PG&E's reported metric results are correct, which FEP is uncertain of based off the HFTD designation discrepancies discussed above.

The reported metric results were comparatively very high for 2017 and 2018. There were over 1300 events in quarter one of both of those years, while the other years experienced between zero and 285 events. No single feeder experienced an extraordinary number of outages compared to other years, but many feeders were impacted. This could suggest widespread challenges with weather during the first quarter of these years. For example, on January 8, 2017, California experienced strong winds, heavy rain, and flooding.[21] However, based on the HFTD designation inconsistencies, it is difficult to assume validity in any of the Wires Down metric results.

Observations on Metric 3.1 Performance and Targets

FEP's discussions with PG&E on Wires Down performance drivers suggest that Metric 3.1, on a standalone basis, is not a major contributor to the company's operational behavior. Additionally, the level of discrepancy found when the Wires Down events were mapped suggests that there may be errors in the process and no clear cause has been identified by staff.

The Metric 3.1 definition is very specific, applying only to Wires Down events which occur on distribution assets, in HTFDs, on MEDs. Industry-wide, benchmarking related to the rate of Wires Down, though limited, generally occur on a systemwide level. Benchmarks often include both transmission and distribution assets. For example, in the "2019 Benchmarking Report", EIA tracks interruptions per mile

[21] National Weather Service, Atmospheric Rivers January 2 – 10, 2017. https://www.weather.gov/mtr/AR_1_2017?utm_source=chatgpt.com

without focusing on specific high-risk areas or asset types.[22] The rate of transmission Wires Down events tends to be significantly lower than distribution events, making any systemwide benchmarking inapplicable to a distribution-only value.

Metric 3.1 also considers only MEDs, which adds additional specificity. Discussions with PG&E staff suggested that the distinction between MED and non-MEDs may be meaningful from an operational perspective, as Wires Down during MEDs were challenging to prevent due to extreme weather conditions and falling vegetation. While the concept of MEDs and the threshold calculation is standardized and accepted across the electric industry, it is more commonly used when considering SAIDI values than Wires Down rates. Operationally there is value in comparing company performance on MEDs and non-MEDs, but highly specific metrics are more challenging for utilities to benchmark either through formalized reports or in organic peer-utility conversations.

Finally, PG&E employees noted that the metric includes only Wires Down in HTFDs. They stated that designations for areas of higher risk are primarily used in California, which limits the availability of comparable benchmarking data. However, FEP notes that the designation of areas of higher wildfire risk is no longer exclusive to only California. Other utilities, many in the western part of the United States, have such designations or are in the process of developing them. While these utilities may use different criteria for high risk are designations, the methodologies used to make the designations may be of lesser relevance than the utility's determination that the asset management practices in those areas need to reflect higher risk. Therefore, benchmarking of Wires Down rates in designated high-risk areas may be applicable, even if utilities use slightly different strategies to determine the areas included. However, such efforts would require those utilities to perform Wires Down calculations just for those areas, and to be comparable to 3.1, only for distribution and on MED days.

The concepts relevant to Metric 3.1 (the distinction between transmission and distribution, MEDs, and HTFDs) are not exclusive to PG&E or California utilities. However, when applied collectively, it makes benchmarking difficult for Metric 3.1. These distinctions are also inconsistent with PG&Es internal operational practices, which appear to focus on system-wide Wires Down. The result is that, though PG&E does internally use Wires Down data and benchmarking to improve performance, Metric 3.1 itself may not have a significant impact on PG&E's actions.

2.9 Metric 3.2: HFTD Wires Down Distribution (Non-MED)

The CPUC defines Metric 3.2 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.

Metric 3.2 assesses the rate of distribution Wires Down events in PG&E's High Fire Threat Districts (HFTD).Wires Down A Wires Down event occurs when a normally energized overhead primary or transmission conductor is broken and falls from its intended position to rest on the ground or a foreign object. Metric 3.2 considers wires down events on non-Major Event Days (MEDs). MEDs are days with large numbers of customer minutes interrupted, often due to severe weather events like storms, but are cause-agnostic. The purpose of MEDs is to help isolate and analyze major events separately from routine

[22] EIA 2019 Benchmarking Report, p. 11.
https://www.publicpower.org/system/files/documents/Sample_2019%20eRT%20Annual%20Benchmarking%20Report.pdf

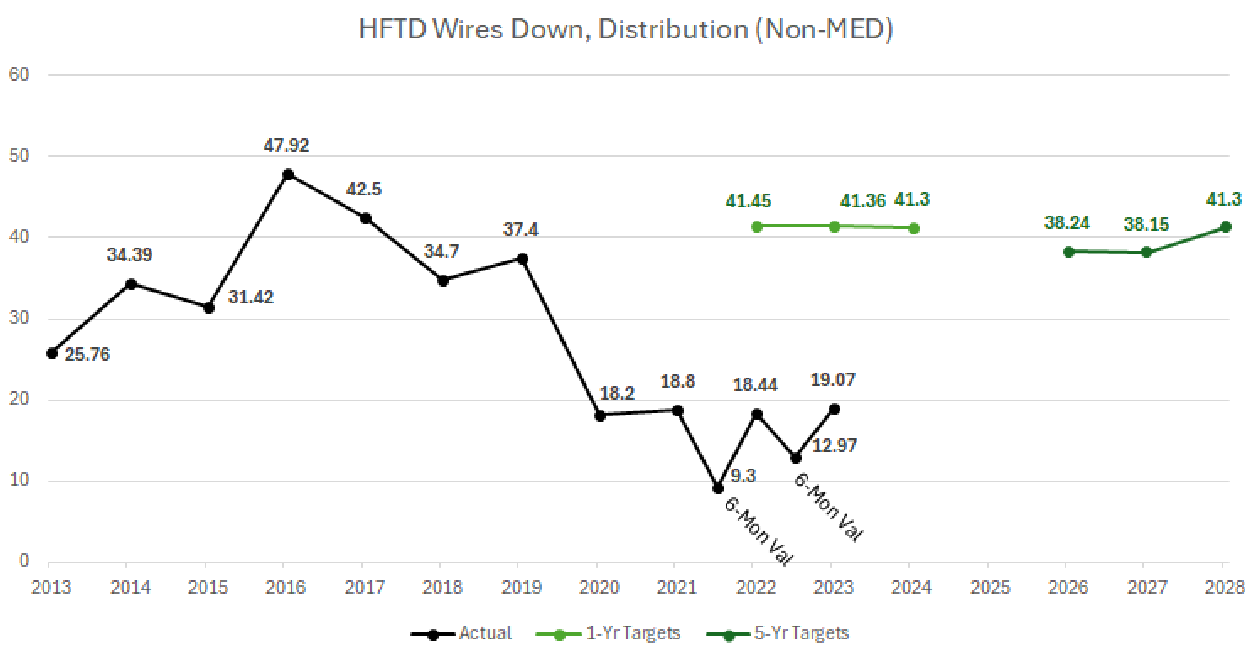
operation, providing a clearer picture of normal system performance. The IEEE Guide for Electric Power Distribution Reliability Indices (Standard 1366) defines MEDs as days in which the daily SAIDI exceeds a statistically defined threshold based on the previous 5 years of daily SAIDI data[23]. In addition to storms, new causes of MEDs include PSPS events, which have been some of PG&E's largest MED days. IEEE released guidelines[24] for calculating the daily SAIDI threshold, which is discussed further in "Observation on Accuracy" section.

The formula for calculating Metric 3.2 is:

$$= \frac{\#\ of\ Wires\ Down\ Events\ on\ non\ MEDs\ in\ HFTDs}{Total\ Primary\ Distribution\ Line\ Miles\ in\ HFTDs}\ X\ 1000$$

The following chart shows Metric 3.2 results compared to targets for 2013 through 2028, including results from the 2022 and 2023 mid-year reports. All historical values reflect the most recent data available as of the 2023 report and may differ from previously reported figures.

Figure 2-15: Metric 3.2 Summary Chart



2.9.1 Metric 3.2 Accuracy and Consistency

Information for Metric 3.2 is extracted from the ILIS Outage Database. Data enters ILIS through reports made by troubleshooters who respond to outages and other issues in the field. PG&E becomes aware of

[23] A day in which the daily System Average Interruption Duration Index (SAIDI) exceeds a Major Event Day threshold (T_{MED}) value. For the purposes of calculating daily system SAIDI, any interruption that spans multiple calendar days is accrued to the day on which the interruption began. Statistically, days having a daily system SAIDI greater than T_{MED} are days on which the energy delivery system experienced stresses beyond that normally expected (such as during severe weather).

[24] https://standards.ieee.org/ieee/1366/7243/

a downed wire or outage through several reporting streams such as Smart Meters, SCADA or customer reporting. Troubleshooters are sent to the scene to assess the incident. Once on-site, the troubleshooters complete digital forms to document the characteristics of the incident. Those incident reports are transmitted to the distribution outage center.

PG&E supplied the audit team with the "Outage Reporting Details and Accuracy Verification Process" documents that provides a detailed description of the proper method to input outage data into ILIS along with the process for verifying the accuracy of the reported outage events.

The data transmitted to the distribution outage center is reviewed and manually entered by distribution staff. Employees of the outage center conduct a quality review as data is entered into ILIS. A member of the Outage Quality Review Team conducts another accuracy review. If engineers wish to add new information or correct previously submitted information, they ask the operations team to make changes to the data. Individuals in troubleshooting, engineering, and related departments have read access to the data, but do not have the ability to make changes to the database directly.

The ILIS database has broad utilization across PG&E operations, and the data is used for differing PG&E workstreams. As the database was not specially designed for this metric, some of the datapoints are used as approximations rather than ideal descriptors. For example, PG&E staff communicated in an interview that the location associated with the Wires Down metrics is logged as being associated with the operating device rather than the location the affected wire made contact. However, PG&E staff subsequently noted through a RFI that the location of Wires Down events for SOMs is generated by a tool that assigns HFTD classification based on longitude and latitude. If that location is unavailable or changes later, the tool does not revise the HFTD classification but may update the coordinates. PG&E also logs the span location of equipment-caused Wires Down events in the Wires Down Database. The Wires Down Database does not include vegetation-caused events and is not used for the calculation of this metric.

Importantly, the events logged in ILIS are outages and not specifically Wires Down events. Wires Down events are tracked through a notation on the outage to indicate that it involved a downed wire. The result of this system is that the number of Wires Down is approximated by the number of outages. PG&E staff stated that this methodology aligns with PG&E's interpretation of the CPUC definition of "Wires Down events". PG&E defines "Wires Down events" as the number of outages caused by one or more Wires Down. FEP notes that CPUC Decision D.21-100-09 says Wires Down events are 'when normally energized overhead primary or transmission conductor is broken, or remains intact, and falls from its intended position to rest on the ground or foreign object.[25]"

If a downed wire trips multiple operating devices, then it will be logged as multiple events. Meanwhile, while downed wires on the primary distribution system may result in the creation of multiple Wires Down records, it is possible that Wires Down events on the secondary distribution system are unrecorded if they do not result in the trip of an operating device. Through discussions with PG&E staff, it is evident that they are aware of these limitations and that it is their perspective that the ILIS database is the best database available to serve as a record for this metric. Wires Down events are tracked based on associated outages, and PG&E does not differentiate in ILIS between outages associated with primary or secondary distribution lines. If there is no outage associated with the event, then it is not logged as a Wires Down event for the purpose of metric tracking. PG&E acknowledges these limitations and is evaluating their procedure to determine if their calculation of this metric can be adjusted to address these limitations.

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[25] CPUC Decision 21-100-09, p. 84.

PG&E uses EGIS to inform this metric. EGIS is also used to identify the feeder, whether the assets are located in HFTDs, and to calculate the total number of line miles. The circuit mile calculations are a snapshot in time, meaning they are continuously updated as circuits expand and contract. Once Operations entries have been verified as correct the staff of Electric System Planning and Reliability become the controllers of the outage information. This group initiates a secondary outage quality analysis review, with issues corrected by staff or sent back to Distribution Operators for further analysis and correction.

The oversight and management process has been largely consistent for the past decade. The policies around data gathering, input, and extraction have been consistent throughout the reporting period with minimal changes to the reporting standard. PG&E uses data on Wires Down for internal tracking and regulatory reporting beyond the bi-annual SOMs report. Specific divisions that are required for SOMs reporting, like the separation of MED and non-MED events occur in post-processing using the ILIS dataset.

PG&E adopted the CPUC's Fire-Threat Map in 2018[26] and added fields to ILIS identifying assets as belonging to HTFDs. PG&E uses EGIS to determine if assets involved in Wires Down events are within HTFD boundaries. The historical SOMs dataset (2013 – 2020) partially predates HFTD designations, so PG&E used 2021 HTFD boundaries to retroactively determine which Wires Down events applied to this metric.

Observations on Metric 3.2 Accuracy

To determine the overall accuracy of the metric results, FEP reviewed the following inputs to Metric 3.2:

1) Non-MED designations
2) Circuit mile values
3) Event characteristics
4) HFTD classification

The process for undertaking those verifications is described in the sections below. In addition, FEP benchmarked the SOMs results to other PG&E published reports regarding Wires Down. Overall, FEP found that the Metric 3.2 results appear to have significant accuracy issues.

Verification of Non-Major Event Days

A MED is a day where the daily SAIDI exceeds a defined threshold. Using SAIDI data provided by PG&E, FEP verified the SAIDI threshold above which a day was considered an MED. FEP verified PG&E's threshold calculations for 2021 through 2023.

PG&E provided a spreadsheet with daily SAIDI values. For each day in the spreadsheet, PG&E indicated whether the day met the MED threshold with a "yes" or "no". For example, the MED threshold for 2023 was 5.033 and days with a threshold equal or exceeding that value were marked with a "yes". FEP verified these designations and determined that they were accurate. This list was used to ensure that the Wires Down events included in Metric 3.2 occurred on non-MEDs.

[26] https://www.cpuc.ca.gov/industries-and-topics/wildfires/fire-threat-maps-and-fire-safety-rulemaking#:~:text=On%20December%2021%2C%202017%2C%20we,more%20information%20about%20the%20Sept.

Verification of Circuit Miles

PG&E calculated the primary distribution circuit miles using EGIS. PG&E stated that the number of distribution circuit miles in HTFDs can vary yearly, or even monthly, as PG&E undertakes construction projects on the system. As PG&E adds new above-ground assets the distribution mileage expands, and undergrounding, grid hardening efforts, or re-routing can reduce above-ground line miles.

The circuit mile values are captured using GIS polygons of HTFDs. These values change frequently, so FEP relied on PGE's circuit mile values. PG&E's process of using EGIS polygons to identify the circuit miles included in specific asset groups is common in the industry.

PG&E produced the 2021 SOMs report in 2022. The total distribution circuit mile value in HFTDs was calculated at that point, using the above-ground mileage that existed at the time. PG&E did not record a mileage estimate using the 2021 asset configuration. Therefore, the same mileage value was used for both 2021 and 2022, based on the 2022 asset configuration. The 2022 mileage estimate was also used for calculating historical (2013 – 2020) metric results. This resulted in metric values for 2021 and earlier which are likely different than what the values would have been if PG&E used actual circuit mile values.

Verification of Event Characteristics

FEP reviewed instances where multiple Wires Down events occurred on the same feeder on the same day. The purpose of this review was to ensure that those records were not duplicates and to understand the drivers behind multiple Wires Down events occurring at a similar location and time. FEP first considered the percentage of Wires Down events which occurred on the same day and time to assess if it was in keeping with industry norms. Out of the entire 2013 – 2023 dataset for Metric 3.2, approximately 96 percent of the feeder/day combinations which had Wires Down events experienced a single event.

FEP then reviewed the event characteristics on days where a single feeder experienced a high number of events. The highest number of events experienced on a single feeder during a non-MED is 6. For comparison, the highest number of events experienced on a single feeder on a MED was 25.

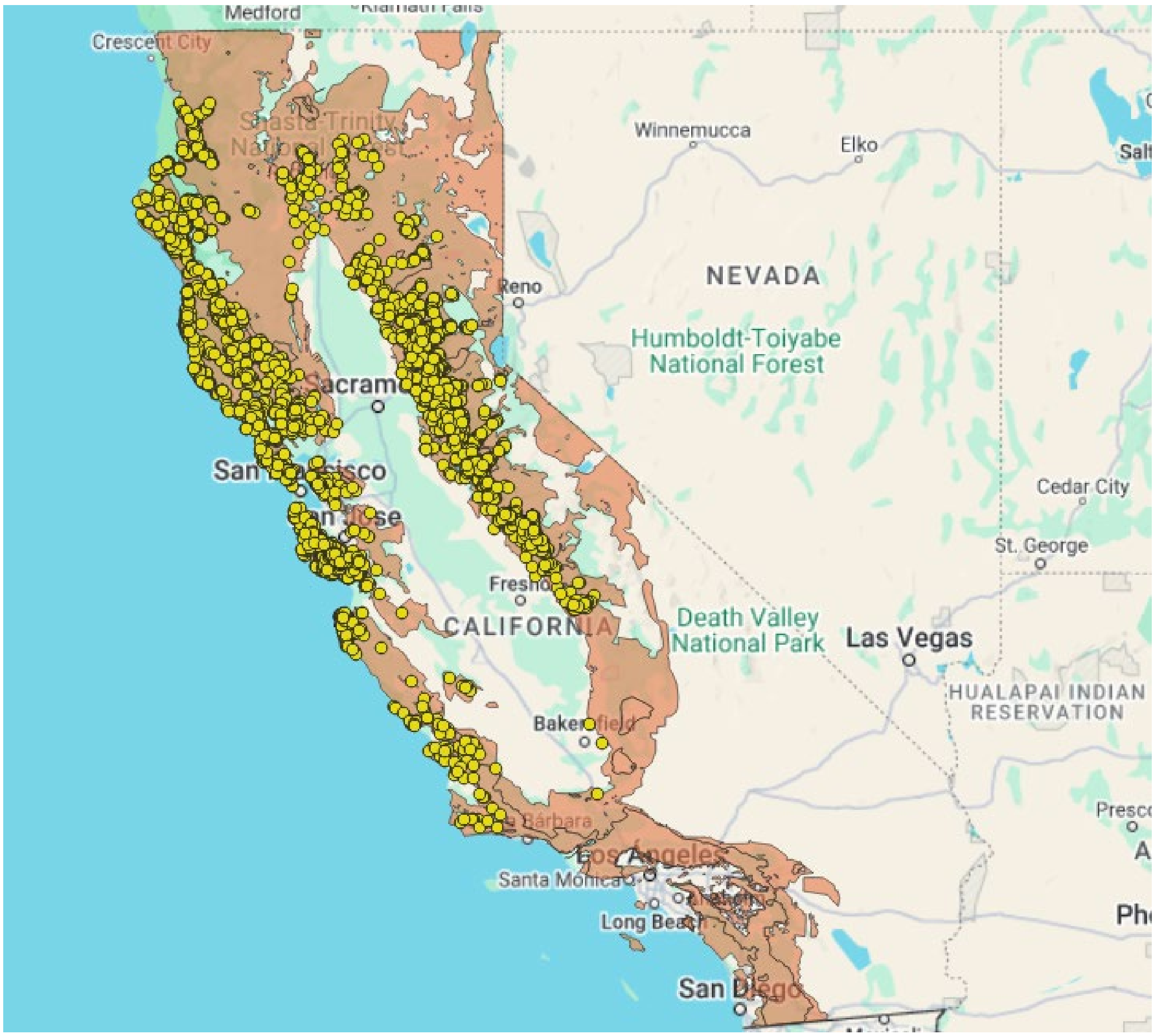
FEP discussed drivers of multiple Wires Down events on the same feeder with PG&E staff. There are instances where events like bad weather or fires can result in multiple wires making contact with the ground or other objects on the same feeder. Additionally, PG&E staff communicated that they use the ILIS database in the calculation of this metric. ILIS is formatted to track outages, and a new data entry is created for each operating device that trips. Therefore, there are cases where a single precipitating instance results in multiple operating devices tripping and multiple associated ILIS entries. PG&E is aware that this results in SOMS metric reporting more Wires Down events than actually occurred. In the absence of a more tailored database of record, PG&E communicated that this process best fits its resource constraints. PG&E acknowledges these limitations and is evaluating their procedure to determine if their calculation of this metric can be adjusted to address these limitations.

Verification of HFTD Designations

During the evaluation process, FEP requested that PG&E provide data on all outages (which includes Wires Down events) which occurred in both the HFTD and non-HFTD areas. FEP used GIS software to plot the coordinates for the operating devices involved in the outages. FEP compared these plotted GIS locations to PG&E's HFTD/non-HFTD designations. A spatial selection in GIS was used to identify outage points that intersected with the HFTDs. The intersecting points were then analyzed to assess the accuracy of PG&E's HFTD/Non-HFTD identification field.

FEP identified significant discrepancies between PG&E's HFTD/non-HFTD designations and those implied by the mapped data. While there were a small number of points designated as HFTD which were plotted in non-HFTD areas, there were many points designated as non-HFTD that were well within the HFTD boundaries. The following image shows a map of California with the HFTD (Tier 2 and Tier 3) highlighted in light red. The yellow points are 2021 – 2023 distribution Wires Down events (located to the associated operating devices) that overlap with HFTD areas but were marked as occurring in non-HFTD areas.

Figure 2-16: Distribution Wires Down Events Classified as "Non-HFTD" in HFTD Areas



In a follow-up discussion regarding this HFTD assignment error, PG&E explained that "for distribution, the HFTD class is not stored directly in the outage database but instead joined in through logic specific to each report. In the outage data prepared for SOMs, the report uses a tool that assigns HFTD class one day after the event, based on latitude and longitude. If that location data was unavailable on the day after the event and added or updated later, the tool does not revise the historical assignment resulting in some HFTD classifications no longer reflecting the most accurate or consistent information. The practice of assigning the HFTD class one day after the event based on the location of the interruptive device is how this has been determined since the HFTD was established. This data set has been the foundation of PG&E's outage reporting relative to HFTD locations for all applications, including SOMs metrics." FEP did not verify that this is the cause of the discrepancy. FEP also notes that as a result of these findings, PG&E has entered this issue into their CAP and is developing a centralized, standardized data repository through WiRE, which aims to improve outage metric reporting.

Benchmark to Other PG&E Reports

To further assess the accuracy of this metric, FEP considered a number of data sources where PG&E reports on Wires Down events. While all of these data sources report on Wires Down events, some focus only on HFTDs while others look at Wires Down events across PG&E's full system. FEP considered whether the SOMs reported values made sense in the context of these other PG&E reports. The following list defines the various sources of data considered:

1) **SOMs Data:** Data on Wires Down events that PG&E transmitted as part of its SOMs reporting requirements. This data was pre-filtered to include only events PG&E classified as occurring in HFTDs and is separated into distribution and transmission datasets.
2) **Mapped Outage Dataset:** This is a dataset that FEP requested from PG&E that shows all outages occurring across the PG&E system. It can be filtered to identify only outages which included Wires Down events. Additional filtering can be applied to identify outages by line type (transmission or distribution) and by location (HFTD or non-HFTD). FEP took the outage data provided by PG&E and mapped the location of the Wires Down events using the provided coordinates in GIS. As described in the section above, the results of FEPs mapping process did not align with PG&E's HFTD designations.
3) **QDR:** The QDRs are submitted along with PG&E's wildfire mitigation plans. The reports include Wires Down event counts (transmission and distribution) both at an HFTD level and the full system level.
4) **SPM Results:** California utilities report to the CPUC on SPMs, required by Decision 19-04-020. The number of Wires Down events occurring across the full system is reported in SPM 2.

Based on the definitions and requirements of these reporting streams, FEP concluded that there should be fairly consistent Wires Down rates across the data sources. As shown in the table below, the reports presenting full-system Wires Down rates are fairly consistent. However, the reports presenting HFTD-only data do not match. The mapped outage data showed many more Wires Down events in HFTDs than were reported by SOMs Metric 3.1 – 3.6 or in the QDR.

Table 2-16 Wires Down Report Comparison

Year	In HFTDs			Full System		
	SOM Metric 3.1 – 3.6	QDR in HFTDs	Outage Data	QDR in Full System	SPM # 2	Outage Data
2023	787	1,281	3,526	7,133	7,173	7,514
2022	522	525	1,002	3,159	3,132	3,315
2021	777	809	2,977	5,896	5,819	6,035

The difference between the reported Wires Down values in HFTDs further suggests that there may be a problem with the SOMs data for this metric. In response to questions regarding the differences, PG&E noted that that the data reflects "snapshots in time" and changes are made based on the findings of further investigations and many other factors. Since the SOMs data and QDR data were pulled at different times, they reflect different information. Though the QDR data and SOMs data is pulled using different processes, the results should be the same if they are pulled at the same time. PG&E repulled the data in response to FEP's RFI (April 2025), and both processes produced 3,377 Wires Down in HFTDs in 2023. A change from 1,281 to 3,377 appears to be larger than one would expect as a result of normal data updates and further data issues.

This new value is similar to what FEP identified using the outage data. However, the result is very different than what was previously reported. This leads FEP to believe there are significant errors in PG&E's metric results for SOM Metric 3.1 – 3.6.

Verification of Metric Results

FEP was unable to verify PG&E's metric results in light of the HFTD designation discrepancy. PG&E included 478 Wires Down events in its 2023 SOMs Metric 3.2 reporting. However, FEP found 1,043 events that qualified for the metric based on the SOM's definition. If accurate, the 2023 result for this metric would be two times higher than what was reported.

Table 2-17: Metric 3.2 Reported versus Mapped Wires Down

Metric 3.2 PG&E Reported and FEP Results				
Year	Events Reported in Metric 3.2	Metric 3.2 Reported Result	FEP Cout of Wires Down Events	FEP Metric 3.2 Result
2023	478	19.07	1,043	41.62
2022	466	18.44	789	31.22
2021	475	18.80	850	33.64

2.9.2 Metric 3.2 Management

PG&E's EAM department is responsible for managing, tracking, and setting targets for Metric 3.2 and the other Wires Down metrics. PG&E tracks the repair and investigation of Wires Down events daily for internal reporting.

EAM produces a monthly report with the Wires Down statistics for Metric 3.2. Once the data is validated, the performance results are added to the CMR reporting tool. The reports are then validated and approved by the Asset Strategy and Standards team (Asset Strategy). Each month, Asset Strategy considers the year-to-date performance of the metric to determine if the metric is on track to achieve the one-year target and assess progress towards the five-year target.

Additionally, PG&E conducts an efficiency review following major events to understand the causes of equipment failures on MEDs. This review includes assessing all types of equipment failures, including conductors. The main goal of the post-event assessment is to consider if the design standards of the failing assets are sufficient.

The organization utilizes the Lean Operating Review and CIC meetings described in Section 1.4 to review the Metric 3.2 status and any catch back work activities. The team reviews controls and mitigations which are currently in place through the electric asset and vegetation management groups to determine corrective actions.

Though not directly related to the management of the SOMs metric, PG&E does undertake management activities for Wires Down more generally which may affect the metric results. If anomalies or problematic data trends are identified in the Wires Down data, ESS works with the reliability teams to do a deep dive into the causes of the trends. The most common drivers of downed wires are vegetation, weather, and contact from third-party objects. If problematic trends are identified, ESS brainstorms with the relevant departments, such as the reliability teams or the vegetation teams to understand mitigation options. Often, the adjustments and mitigations drive improvement to Wires Down rates in the longer term, rather than resulting in immediate improvement for the current year. Vegetation issues can be addressed more quickly overall than asset issues, as asset issues often require longer-term construction projects.

Observations on Metric 3.2 Management

In Decision D.21-10-009, the CPUC states that MEDs are currently excluded from many utility reporting requirements, but it believes that PG&E equipment must show greater resiliency to MEDs over the long-term, even if there is year-to-year volatility.[27] The idea that reliability needs to be managed regardless of weather conditions is consistent with current industry sentiment. However, FEP observes some challenges associated with separate MED and non-MED metrics, compared to assessing Wires Down collectively.

First, PG&E stated that many Wires Down events occur on days directly before or after MEDs. FEP considered the number of Wires Down events in 2021 which occurred in the two days before or after MEDs. FEP identified 37 days directly before or after MEDs which did not qualify as MEDs themselves. In those 37 days, 103 events occurred. This represents 22 percent of the total population of events. Among the population of days where events occurred, there were almost three times as many events per day surrounding MEDs than on other days. This suggests that weather is an important factor for both the MED and non-MED metrics, complicating distinctions made between the two.

Second, benchmarking for Wires Down metrics is challenging generally. As discussed in 3.1, there are no national benchmarking studies which publicly track Wires Down rates. However, EIA and other sources do discuss reliability and interruptions per line mile. Additionally, informal benchmarking activities are undertaken between utilities. This type of information may be better able to inform cumulative Wires Down target setting.

2.9.3 Metric 3.2 Performance and Targets

The targets for Metric 3.2 were set with the goal of maintaining current performance, which was calculated using five historical years of data. PG&E set the target for Metric 3.2 at the upper limit of one standard deviation historical average performance. For 2021, PG&E used five years of data but then switched to using ten years of historical data for 2022 and 2023.

The following table displays PG&E's 2013 through 2023 metric results and the 1-year and 5-year metric targets.

[27] D.21-10-009, p.79.

Table 2-18: Metric 3-2 Results and Targets

Year	Metric Result	1-Year Target	5-Year Target
2013	25.76		
2014	34.39		
2015	31.42		
2016	47.92		
2017	42.50		
2018	34.70		
2019	37.40		
2020	18.20		
2021	18.80	41.45	38.24
2022	18.44	41.36	38.15
2023	19.07	41.30	41.30
[1] Targets reflect the target set in that report year (i.e. the 2021 1-year target reflects 2022 target).			

PG&E's average metric result from 2013 -2023 was 29.87 and 18.77 from 2021-2023. PG&E's 1-and 5-year targets set in 2023 were 38% above the 2013 – 2023 average and 120% above the 2021-2023 average. Overall, PG&E's Metric 3.2 result has generally trended downward since 2019. These values assume that PG&E's reported metric results are correct, which FEP is uncertain of based off the HFTD designation discrepancies discussed above.

FEP discussed the drop in Wires Down events which occurred in 2021 then plateaued for 2021 – 2023. PG&E stated that work was undertaken to reduce the risk in HFTDs during 2019. Grid hardening and wildfire mitigations are ongoing, but a comparatively large portion of the risk was addressed in 2019 by undertaking projects which efficiently addressed risk. As more risk is mitigated, it generally becomes more challenging and expensive to achieve greater reduction. PG&E does not attribute the trend change in 2020 to anything related to modeling or metric calculation.

Observations on Metric 3.2 Performance and Targets

PG&E stated that it used one standard deviation from the 5-year average performance for Metric 3.2 to set the 2021 target and then 10 -year average beginning in 2022. FEP observes that beginning in 2020, the actual performance results are significantly lower. This could be attributed to wildfire mitigation efforts. However, it is worth noting that the data was produced by looking backwards and attributing outages to HFTD or non-HFTD zones. Given the discrepancies that exist in the HFTD labelling, it is difficult to determine if the presented data is valid, and if the trend is reflective of effective wildfire mitigations.

Assuming the metric results are correct, FEP notes that utilizing data that pre-dates grid hardening to set targets does not seem to focus on performance improvement based the current conditions. Both the 1-year and 5-year targets are significantly higher than performance since 2020 which is contrary to driving performance improvement. Additionally, the 5-year target in 2023 was set to the 1-year target which is also contrary to performance improvement.

2.10 Metric 3.3: HFTD Wires Down, Transmission (MED)

The CPUC defines Metric 3.3 as:

Number of Wires Down events on Major Event Days (MED) involving overhead transmission circuits divided by total circuit miles of overhead transmission X 1000, in High Fire Threat Districts (HFTD) in a calendar year.

Metric 3.3 assesses the rate of transmission Wires Down events in PG&E's High Fire Threat Districts (HFTD). A Wires Down event occurs when a normally energized overhead primary or transmission conductor is broken and falls from its intended position to rest on the ground or a foreign object. The metric also only measures Wires Down events in HFTDs on Major Event Days (MEDs).

MEDs are days with large numbers of customer minutes interrupted, often due to severe weather events like storms, but are cause-agnostic. The purpose of MEDs is to help isolate and analyze major events separately from routine operation, providing a clearer picture of normal system performance. The IEEE Guide for Electric Power Distribution Reliability Indices (Standard 1366) defines MEDs as days in which the daily SAIDI exceeds a statistically defined threshold based on the previous 5 years of daily SAIDI data[28]. In addition to storms, new causes of MEDs include PSPS events, which have been some of PG&E's largest MED days. IEEE released guidelines[29] for calculating the daily SAIDI threshold, which is discussed further in "Observation on Accuracy" section.

Metric 3.3, and other metrics which relate to MEDs, assess PG&E's practices and assets during very adverse weather conditions.

The formula for calculating Metric 3.3 is:

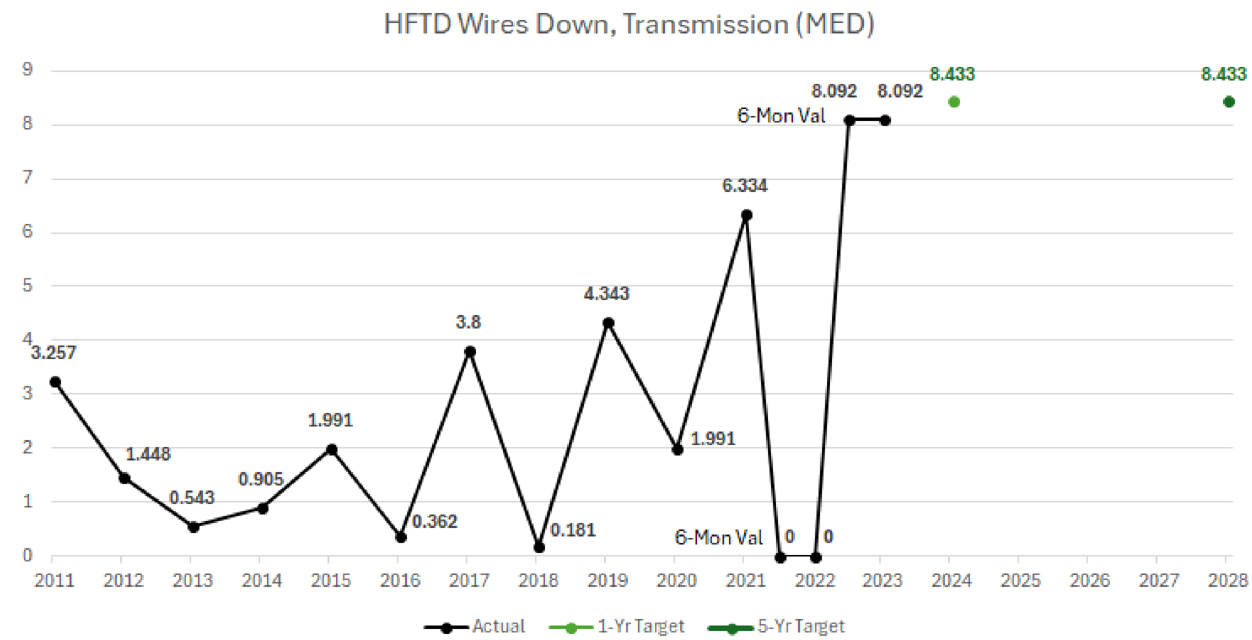
$$= \frac{\#\ of\ Wires\ Down\ Events\ on\ MEDs\ in\ HFTDs}{Total\ Tranmission\ Line\ Miles\ in\ HFTDs}\ X\ 1000$$

The following chart shows Metric 3.3 results compared to targets for 2011 through 2028, including results from the 2022 and 2023 mid-year reports. All historical values reflect the most recent data available as of the 2023 report and may differ from previously reported figures.

[28] A day in which the daily System Average Interruption Duration Index (SAIDI) exceeds a Major Event Day threshold (T_{MED}) value. For the purposes of calculating daily system SAIDI, any interruption that spans multiple calendar days is accrued to the day on which the interruption began. Statistically, days having a daily system SAIDI greater than T_{MED} are days on which the energy delivery system experienced stresses beyond that normally expected (such as during severe weather).

[29] https://standards.ieee.org/ieee/1366/7243/

Figure 2-17: Metric 3.3 Summary Chart



2.10.1 Metric 3.3 Accuracy and Consistency

The database used for managing Metrics 3.3 is the Transmission Operations Tracking and Logging (TOTL) application. The TOTL application is used for tracking unplanned electric transmission outages. If distribution customers are impacted by a transmission Wires Down event, PG&E merges the transmission data in TOTL with the data from PG&E's ILIS platform.

When PG&E originally responds to and collects data about a transmission Wires Down event, troubleshooters typically have incomplete information relating to the cause of the outage. Therefore, the Transmission Operations, Tracking and Logging team logs the initial findings and updates the record as additional reviews are completed. They coordinate with vegetation management teams and the meteorology team to determine a specific cause of the Wires Down event.

The oversight and management process for ILIS, TOTL and EGIS has been consistent throughout the reporting period. As previously mentioned in Metric 3.1, Section II, PG&E tracked Wires Down data prior to SOMs reporting requirements and uses the data for internal metrics and tracking.

PG&E adopted the CPUC's Fire-Threat Map in 2018[30] and added fields to ILIS and TOTL identifying assets as belonging to HTFDs. PG&E uses EGIS to determine if assets involved in Wires Down events are within HTFD boundaries. The historical SOMs dataset (2013 – 2021) partially predates HFTD designations, so

[30]https://www.cpuc.ca.gov/industries-and-topics/wildfires/fire-threat-maps-and-fire-safety-rulemaking#:~:text=On%20December%2021%2C%202017%2C%20we,more%20information%20about%20the%20Sept.

PG&E used 2022 HTFD boundaries to retroactively determine which Wires Down events applied to this metric.

Observations on Metric 3.3 Accuracy

To determine the overall accuracy of the metric results, FEP reviewed the following inputs to Metric 3.3:

1) MED designations
2) Circuit mile values
3) Event characteristics
4) HFTD classification

The process for undertaking those verifications is described in the sections below. In addition, FEP benchmarked the SOMs results to other PG&E published reports regarding Wires Down. Overall, FEP found that the Metric 3.3 results appear to be accurate.

Verification of Major Event Days

MEDs are days with large numbers of customer minutes interrupted, often due to severe weather events like storms, but are cause-agnostic. According to IEEE Standard 1366, the threshold is defined by the following formula:

$$MED\ Threshold = e^{\propto + 2.5\beta}$$

The threshold is calculated by first taking the natural logarithm of the SAIDI values to normalize the dataset, which is typically right-skewed. Next, the mean ($\propto$) and standard deviation (β) of the log-transformed SAIDI values are calculated for every day included in the dataset over the past five years. The threshold is set 2.5 standard deviations above the mean in log-space, and the final threshold value is obtained by exponentiating the result to the original SAIDI scale.

PG&E performed these calculations for 2021, 2022, and 2023 in Excel using five years of data. PG&E listed the total daily SAIDI value for every day with a value above zero and calculated the logarithmic SAIDI value using Excel's LN function. PG&E calculated the mean ($\propto$) of the logarithmic SAIDI values using the AVERAGE function. The standard deviation (β) of the logarithmic SAIDI values was calculated using the STDEV function. PG&E then multiplied the standard deviation (β) by 2.5 then added the mean ($\propto$). The MED threshold was calculated by applying the EXP function to the results of that equation. FEP verified PG&E's calculations and found the threshold values to be accurate.

For each day in the spreadsheet, PG&E indicated whether the day met the MED threshold with a "yes" or "no". For example, the MED threshold for 2023 was 5.033 and days with a threshold equal or exceeding that value were marked with a "yes". To verify these designations, FEP used an Excel IF statement. Overall, FEP's dataset of MEDs matched PG&E's.

Verification of Transmission Circuit Miles

FEP reviewed PG&E's process for determining circuit mile values. PG&E used ETGIS to calculate transmission circuit miles in HTFDs. The circuit mile values are captured using ETGIS polygons of HTFDs. These values can change over the course of a year, so FEP relied on PGE's circuit mile values. PG&E's process of using GIS polygons to identify the circuit miles included in specific asset groups is common in the industry.

PG&E produced the 2021 SOMs report in 2022. The total transmission circuit mile value in HFTDs was calculated at that point, using the above-ground mileage that existed at the time. PG&E did not record a mileage estimate using the 2021 asset configuration.

Therefore, the same mileage value was used for both 2021 and 2022, based on the 2022 asset configuration. The 2022 mileage estimate was also used for calculating historical (2013 – 2020) metric results. This resulted in metric values for 2021 and earlier which are likely different than what the values would have been if PG&E used actual circuit mile values. When FEP discussed this with PG&E staff, they stated that they agreed that the actual circuit miles prior to 2022 would be different from the 2022 mileage estimate, but the yearly change since 2022 has been less than 1% annually. They felt that it was reasonable to assume the 2022 mileage estimate would be close to the actual circuit miles and have little impact on the metric results. FEP agrees that the results are likely very similar to what they would have been if actual 2021 circuit mile values were used.

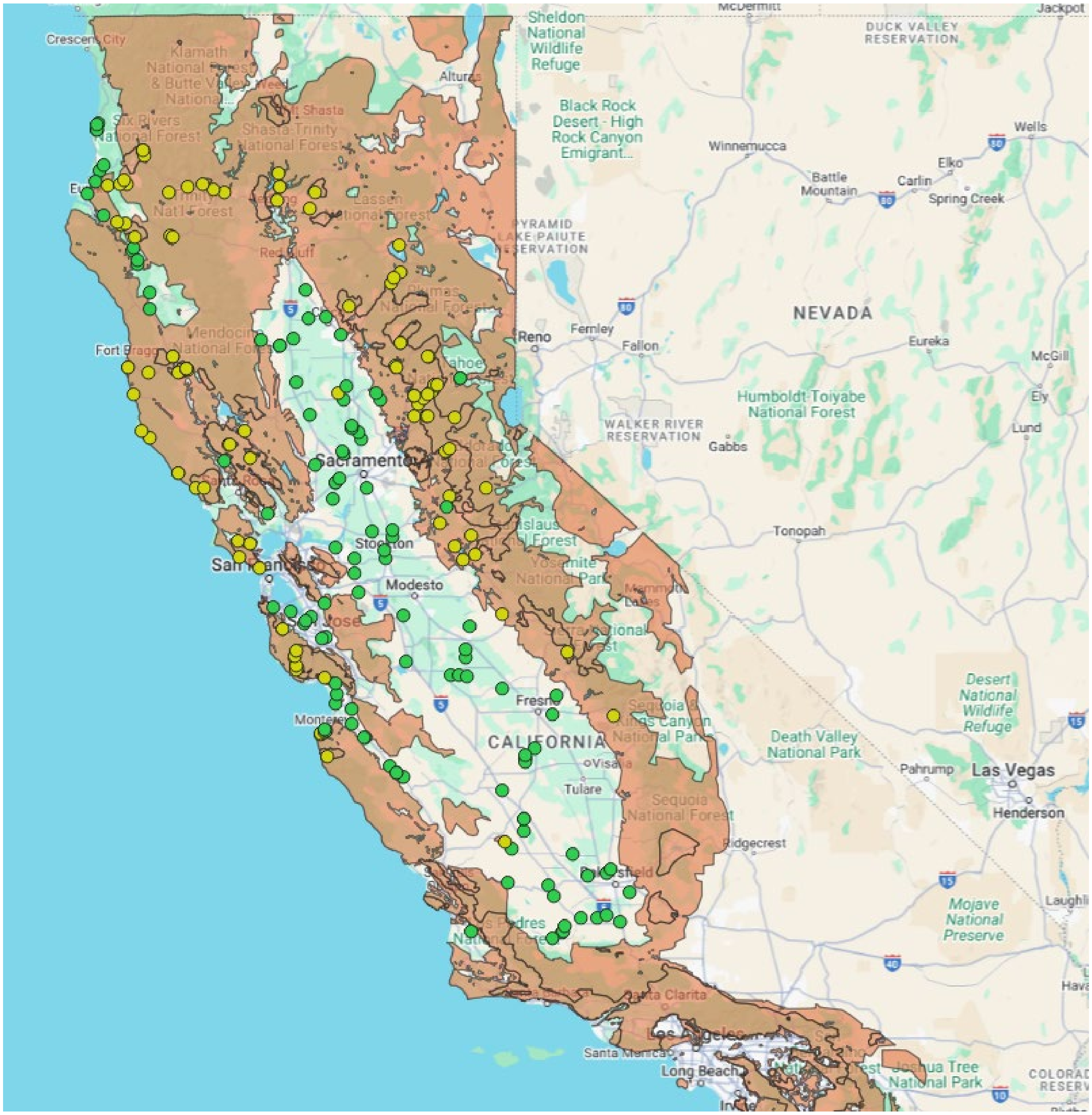
Verification of HFTD Designations

During the evaluation process, PG&E provided coordinates (longitude and latitude) associated with transmission Wires Down events. According to PG&E, the location of transmission Wires Down is tracked in the Transmission Outage Database sourcing the information from TOTL and utilizes Electric Transmission Geographic Information System ("ETGIS") for HFTD mapping. While ILIS is the system of record for outages, it is FEP's understanding that PG&E uses it for reference only for transmission. Transmission Wires Down location are identified based on field observation and is captured at the structure/span level for accuracy in determining HFTD/non-HFTD.

As discussed in Sections 3.1 and 3.2, FEP identified significant discrepancies between PG&E's HFTD/non-HFTD designations and those implied by the mapped data for distribution Wires Down events. Overall, the HFTD designations for transmission Wires Down events appear to better align when the coordinates are mapped in GIS.

FEP used GIS software to plot the coordinates for the operating devices involved in the outages. FEP compared these plotted GIS locations to PG&E's HFTD/non-HFTD designations. A spatial selection in GIS was used to identify outage points that intersected with the HFTDs. The intersecting points were then analyzed to assess the accuracy of PG&E's HFTD/non-HFTD identification field. The following map shows HFTD boundaries in light red. The green points are transmission Wires Down events (from 2021 – 2023) labeled as occurring in non-HFTD. The yellow points are events that were labeled as occurring in HFTDs. Overall, there is good alignment between PG&E's HFTD labeling and the coordinates. FEP did note one location that was labeled as HFTD but appears to be located in non-HFTD. This location had an incorrect latitude and longitude association and is actually located HFTD. Additionally, FEP found one transmission Wires Down event which was labelled as occurring in non-HFTD areas but overlapped with HFTD boundaries. This occurred on non-MED days and is discussed more in Metric 3.4.

Figure 2-18: Transmission Wires Down Events



Benchmark to Other PG&E Reports

To further assess the accuracy of this metric, FEP considered a number of data sources where PG&E reports on Wires Down events. While all of these data sources report on Wires Down events, some focus only on HFTDs while others look at Wires Down events across PG&E's full system. FEP considered whether the SOMs reported values made sense in the context of these other PG&E reports. The following list defines the various sources of data considered:

1) **SOMs Data:** Data on Wires Down events that PG&E transmitted as part of its SOMs reporting requirements. This data was pre-filtered to include only events PG&E classified as occurring in HFTDs and is separated into distribution and transmission datasets.
2) **Mapped Outage Dataset:** This is a dataset that FEP requested from PG&E that shows all outages occurring across the PG&E system. It can be filtered to identify only outages which included Wires Down events. Additional filtering can be applied to identify outages by line type (transmission or distribution) and by location (HFTD or non-HFTD). FEP took the outage data provided by PG&E and mapped the location of the Wires Down events using the provided coordinates in GIS. As described in the section above, the results of FEPs mapping process did not align with PG&E's HFTD designations.
3) **QDR:** The QDRs are submitted along with PG&E's wildfire mitigation plans. The reports include Wires Down event counts (transmission and distribution) both at an HFTD level and the full system level.
4) **SPM Results:** California utilities report to the CPUC on SPMs, required by Decision 19-04-020. The number of Wires Down events occurring across the full system is reported in SPM 2.

Based on the definitions and requirements of these reporting streams, FEP concluded that there should be fairly consistent Wires Down rates across the data sources. As shown in the table below, the reports presenting full-system Wires Down rates are similar. However, the reports presenting HFTD-only data do not match. The mapped outage data showed many more Wires Down events in HFTDs than were reported by SOMs Metric 3.1 – 3.6 or in the QDR.

Table 2-19: Wires Down Report Comparison

Year	In HFTDs			Full System		
	SOM Metric 3.1 – 3.6	QDR in HFTDs	Outage Data	QDR in Full System	SPM # 2	Outage Data
2023	787	1,281	3,526	7,133	7,173	7,514
2022	522	525	1,002	3,159	3,132	3,315
2021	777	809	2,977	5,896	5,819	6,035

The difference between the reported Wires Down values in HFTDs suggests that there may be a problem with the SOMs data for Wires Down metrics generally. However, based on the good correlation between PG&E's HFTD destinations for transmission Wires Down events and the plotted event locations and the issues identified in Metric 3.1 and 3.2 for distribution Wires Down, FEP surmises that the wires down discrepancies described above largely stem from distribution Wires Down events. However, FEP was unable to conduct an in-depth analysis as the QDR data is not categorized into distribution and transmission events.

<u>Verification of Metric Results</u>

FEP was able to recreate PG&E's results for 2022 and 2023. For 2021, using the Metric 3.3 spreadsheet[31], FEP identified a total of 34 Wires Down events for a metric result of 6.15. PG&E reported 35 Wires Down events and a metric result of 6.334.

[31] [31] Available as part of the SOMs reports Safety and Operational Metrics, Data Files

FEP sent an exploratory data request and PG&E responded that the date this event occurred, December 28, 2021, was originally determined to be a non-MED. After PG&E's data scrubbing process occurred the SAIDI value exceeded the MED threshold, so the day was determined to be an MED. This change was reflected in PG&E's calculations but not the underlying dataset. After understanding this change, FEP was able to recreate PG&E's results for 2021.

2.10.2 Metric 3.3 Management

The Electric Transmission team facilitates the calculation of the transmission Wires Down metric results. Reports for Metric 3.3 are run monthly. The reports are run by analysts then reviewed by the supervisors and managers. Once the data is validated, the performance results are added to the CMR reporting tool. The reports are then validated and approved by the Asset Strategy and Standards team (Asset Strategy). Each month, Asset Strategy considers the year-to-date performance of the metric to determine if the metric is on track to achieve the one-year target and assess progress towards the five-year target.

The Electric Transmission team reviews the cause of all outages. The transmission teams can conduct in-depth cause investigations for all transmission Wires Down due to the limited number of Wires Down which occur per year. The cause investigations occur both for Wires Down and for other types of transmission outages. Sometimes investigations result in new information being revealed months after the initial Wires Down incident was reported. The results of the investigation can change the cause of the outage reported in the database. PG&E conducts an efficiency review following major events to understand the causes of equipment failures on MEDs. This review includes assessing all types of equipment failures, including conductors. The main goal of the post-event assessment is to consider if the design standards of the failing assets are sufficient.

The organization utilizes the Lean Operating Review and CIC meetings described in Section 1.4 to review Metric 3.3 and any catch back work activities. The team reviews controls and mitigations which are currently in place through the electric asset and vegetation management groups to determine corrective actions.

Observations on Metric 3.3 Management

The Electric Transmission team facilitates the calculation of the transmission Wires Down metric results. Reports for Metric 3.3 are run monthly. The reports are run by analysts then reviewed by the supervisors and managers. Once the data is validated, the performance results are added to the CMR reporting tool. The reports are then validated and approved by the Asset Strategy and Standards team (Asset Strategy). Each month, Asset Strategy considers the year-to-date performance of the metric to determine if the metric is on track to achieve the one-year target and assess progress towards the five-year target.

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The organization utilizes the Lean Operating Review and CIC meetings described in Section 1.4 to review the Metric 3.3 status and any catch back work activities. The team reviews controls and mitigations which are currently in place through the electric asset and vegetation management groups to determine corrective actions.

Though not directly related to the management of the SOMs metric, PG&E does undertake management activities for Wires Down more generally which may affect the metric results. If anomalies or problematic data trends are identified in the Wires Down data, ESS works with the reliability teams to do a deep dive into the causes of the trends. The most common drivers of downed wires are vegetation, weather, and contact from third-party objects. If problematic trends are identified, ESS brainstorms with the relevant departments, such as the reliability teams or the vegetation teams to understand mitigation options. Often, the adjustments and mitigations drive improvement to Wires Down rates in the longer term, rather than resulting in immediate improvement for the current year. Vegetation issues can be addressed more quickly overall than asset issues, as asset issues often require longer-term construction projects.

PG&E conducts an efficiency review following major events to understand the causes of equipment failures on MEDs. This review includes assessing all types of equipment failures, including conductors. The main goal of the post-event assessment is to consider if the design standards of the failing assets are sufficient.

2.10.3 Metric 3.3 Performance and Targets

PG&E set the targets for Metrics 3.3 with a goal of maintaining performance. PG&E calculated the 1- and 5-year targets set in the 2023 report by taking average historical performance (2013 – 2022) and adding three standard deviations. The following table displays PG&E's 2013 through 2023 metric results and the 1-year and 5-year metric targets.

Table 2-20: Metric 3-3 Results and Targets

Year	Metric Result	1-Year Target[1]	5-Year Target[1]
2013	0.543		
2014	0.905		
2015	1.991		
2016	0.362		
2017	3.800		
2018	0.181		
2019	4.343		
2020	1.991		
2021	6.334	Maintain	Maintain
2022	0.00	Maintain	Maintain
2023	8.092	8.433	8.433
[1] Targets reflect the target set in that report year (i.e. the 2021 1-year target reflects 2022 target).			

PG&E's average metric result from 2013 -2023 was 2.59 and 4.81 from 2021-2023. PG&E's 1- and 5-year target set in 2023 is 225% above the 11-year average and 75% above the 2021-2023 average.

Observations on Metric 3.3 Performance and Targets

The lower frequency of transmission Wires Down events allows PG&E to conduct in-depth cause investigations for each event. Despite this, FEP observes that Metric 3.3 is highly variable. This is likely due to the influence of extreme weather events and changing weather cycles. For example, 2022 experienced no transmission Wires Down events on MEDs and 2023 experienced the highest rate of the reporting period.

The high degree of variability in the data for Metric 3.3 supports PG&E's decision to base the target on three standard deviations from the average, rather than the one or two used for the distribution metrics. The specific definition for Metric 3.3 results in a limited data set. Prior to the target set in 2023, there was no quantitative target. Setting a quantitative target in 2023 was an important step towards defining what it meant for PG&E to maintain historical performance levels.

2.11 Metric 3.4: HFTD Wires Down, Transmission (Non-Med)

The CPUC defines Metric 3.4 as:

Number of Wires Down events on Non-Major Event Days (MED) involving overhead transmission circuits divided by total circuit miles of overhead transmission X 1000, in High Fire Threat Districts (HFTD) in a calendar year.

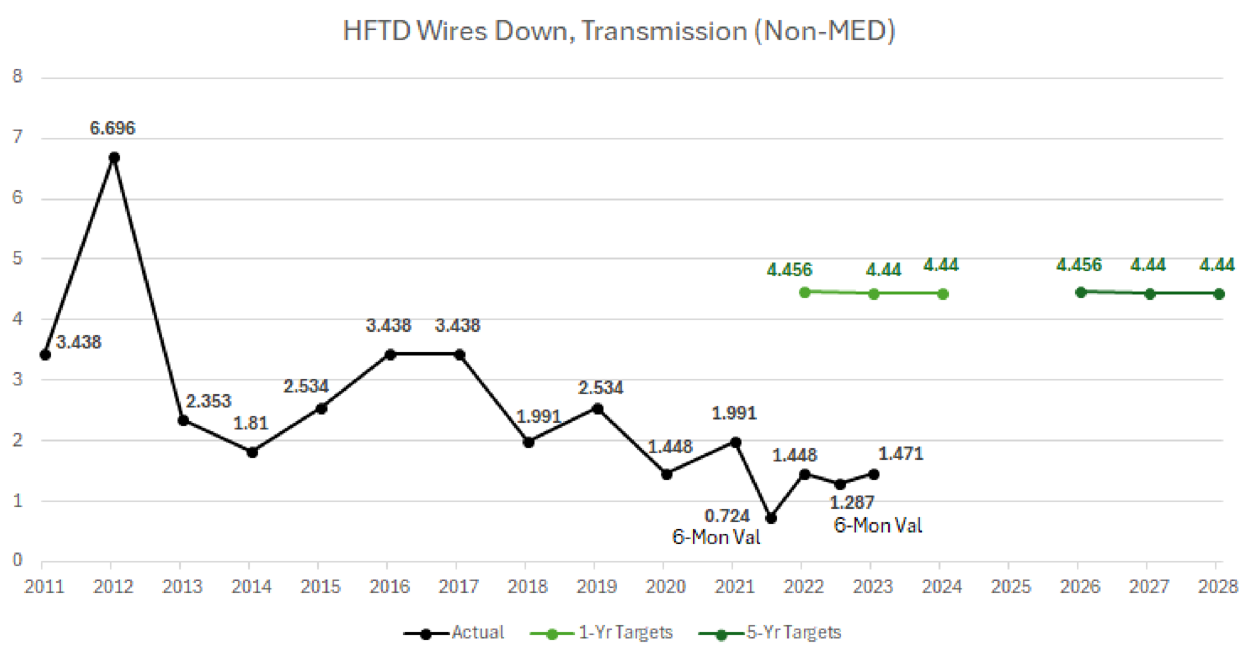
Metric 3.4 assesses the rate of transmission Wires Down events in PG&E's High Fire Threat Districts (HFTD). Wires DownA Wires Down event occurs when a normally energized overhead primary or transmission conductor is broken and falls from its intended position to rest on the ground or a foreign object. The metric also only measures Wires Down events in HFTDs on non-Major Event Days (MEDs).

The formula for calculating Metric 3.4 is:

$$\frac{\#\ of\ Wires\ Down\ Events\ on\ Non\ MEDs\ in\ HFTDs}{Total\ Tranmission\ Line\ Miles\ in\ HFTDs}\ X\ 1000$$

The following chart shows Metric 3.4 results compared to targets for 2011 through 2028, including results from the 2022 and 2023 mid-year reports. All historical values reflect the most recent data available as of the 2023 report and may differ from previously reported figures.

Figure 2-19: Metric 3.4 Summary Chart



2.11.1 Metric 3.4 Accuracy and Consistency

The database used for managing Metrics 3.4 is the Transmission Operations Tracking and Logging (TOTL) application. The TOTL application is used for tracking unplanned electric transmission outages. If distribution customers are impacted by a transmission Wires Down event, PG&E merges the transmission data in TOTL with the data from PG&E's ILIS platform.

When PG&E originally responds to and collects data about a transmission Wires Down event, troubleshooters typically have incomplete information relating to the cause of the outage. Therefore, the TOTL team logs the initial findings and updates the record as additional reviews are completed. They coordinate with vegetation management teams and the meteorology team to determine a specific cause of the Wires Down event.

The oversight and management process for ILIS, TOTL and EGIS has been consistent throughout the reporting period. PG&E adopted the CPUC's Fire-Threat Map in 2018 and added fields to ILIS and TOTL identifying assets as belonging to HTFDs. PG&E uses EGIS to determine if assets involved in Wires Down events are within HTFD boundaries. The historical SOMs dataset (2013 – 2020) partially predates HFTD designations, so PG&E used 2021 HTFD boundaries to retroactively determine which Wires Down events applied to this metric.

Observations on Metric 3.4 Accuracy

To determine the overall accuracy of the metric results, FEP reviewed the following inputs to Metric 3.4:

1) Non-MED designations
2) Circuit mile values
3) Event characteristics
4) HFTD classification

The process for undertaking those verifications is described in the sections below. In addition, FEP benchmarked the SOMs results to other PG&E published reports regarding Wires Down. Overall, FEP found that Metric 3.4 results to have possible minor accuracy issues.

Verification of Non-Major Event Days

A MED is a day where the daily SAIDI exceeds a defined threshold. Using SAIDI data provided by PG&E, FEP verified the SAIDI threshold above which a day was considered an MED. FEP verified PG&E's threshold calculations for 2021 through 2023.

PG&E provided a spreadsheet with daily SAIDI values. For each day in the spreadsheet, PG&E indicated whether the day met the MED threshold with a "yes" or "no". For example, the MED threshold for 2023 was 5.033 and days with a threshold equal or exceeding that value were marked with a "yes". FEP verified these designations and determined that they were accurate. This list was used to ensure that the Wires Down events included in Metric 3.4 occurred on non-MEDs.

Verification of Transmission Circuit Miles

FEP reviewed PG&E's process for determining circuit mile values. PG&E used ETGIS to calculate transmission circuit miles in HTFDs. The circuit mile values are captured using ETGIS polygons of HTFDs. These values can change over the course of a year, so FEP relied on PGE's circuit mile values. PG&E's

process of using GIS polygons to identify the circuit miles included in specific asset groups is common in the industry.

PG&E produced the 2021 SOMs report in 2022. The total transmission circuit mile value in HFTDs was calculated at that point, using the above-ground mileage that existed at the time. PG&E did not record a mileage estimate using the 2021 asset configuration.

Therefore, the same mileage value was used for both 2021 and 2022, based on the 2022 asset configuration. The 2022 mileage estimate was also used for calculating historical (2013 – 2020) metric results. This resulted in metric values for 2021 and earlier which are likely different than what the values would have been if PG&E used actual circuit mile values. When FEP discussed this with PG&E staff, they stated that they agreed that the actual circuit miles prior to 2022 would be different from the 2022 mileage estimate, but the yearly change since 2022 has been less than 1% annually. They felt that it was reasonable to assume the 2022 mileage estimate would be close to the actual circuit miles and have little impact on the metric results. FEP agrees that the results are likely very similar to what they would have been if actual 2021 circuit mile values were used.

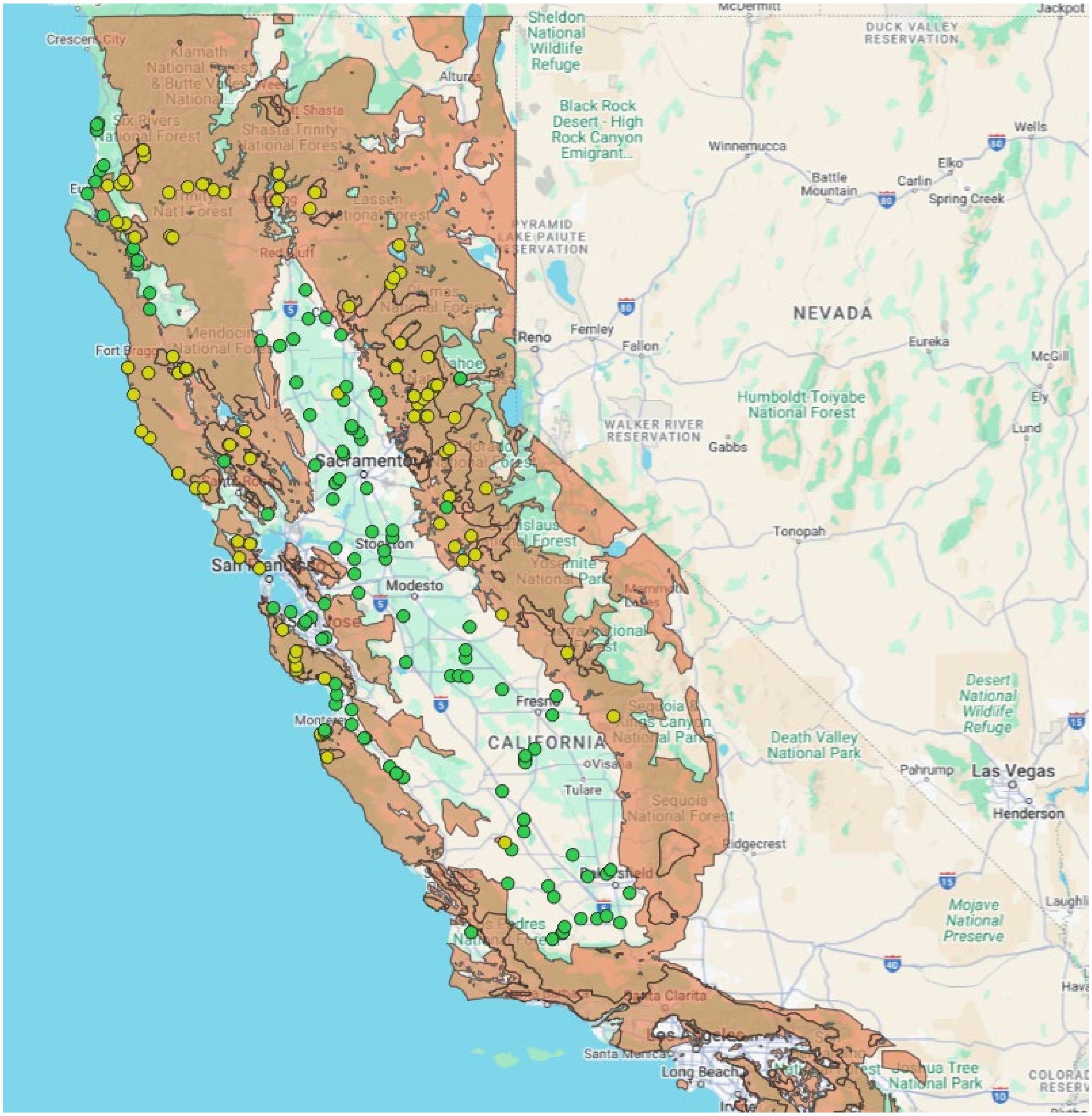
Verification of HFTD Designations

During the evaluation process, PG&E provided coordinates (longitude and latitude) associated with transmission wires down events. According to PG&E, the location of transmission Wires Down is tracked in the Transmission Outage Database sourcing the information from TOTL and utilizes ETGIS for HFTD mapping. While ILIS is the system of record for outages, it is FEP's understanding that PG&E uses it for reference only for transmission. Transmission Wires Down location are identified based on field observation and is captured at the structure/span level for accuracy in determining HFTD/non-HFTD.

As discussed in Sections 3.1 and 3.2, FEP identified significant discrepancies between PG&E's HFTD/non-HFTD designations and those implied by the mapped data for distribution Wires Down events. Overall, the HFTD designations for transmission Wires Down events appear to better align when the coordinates are mapped in GIS.

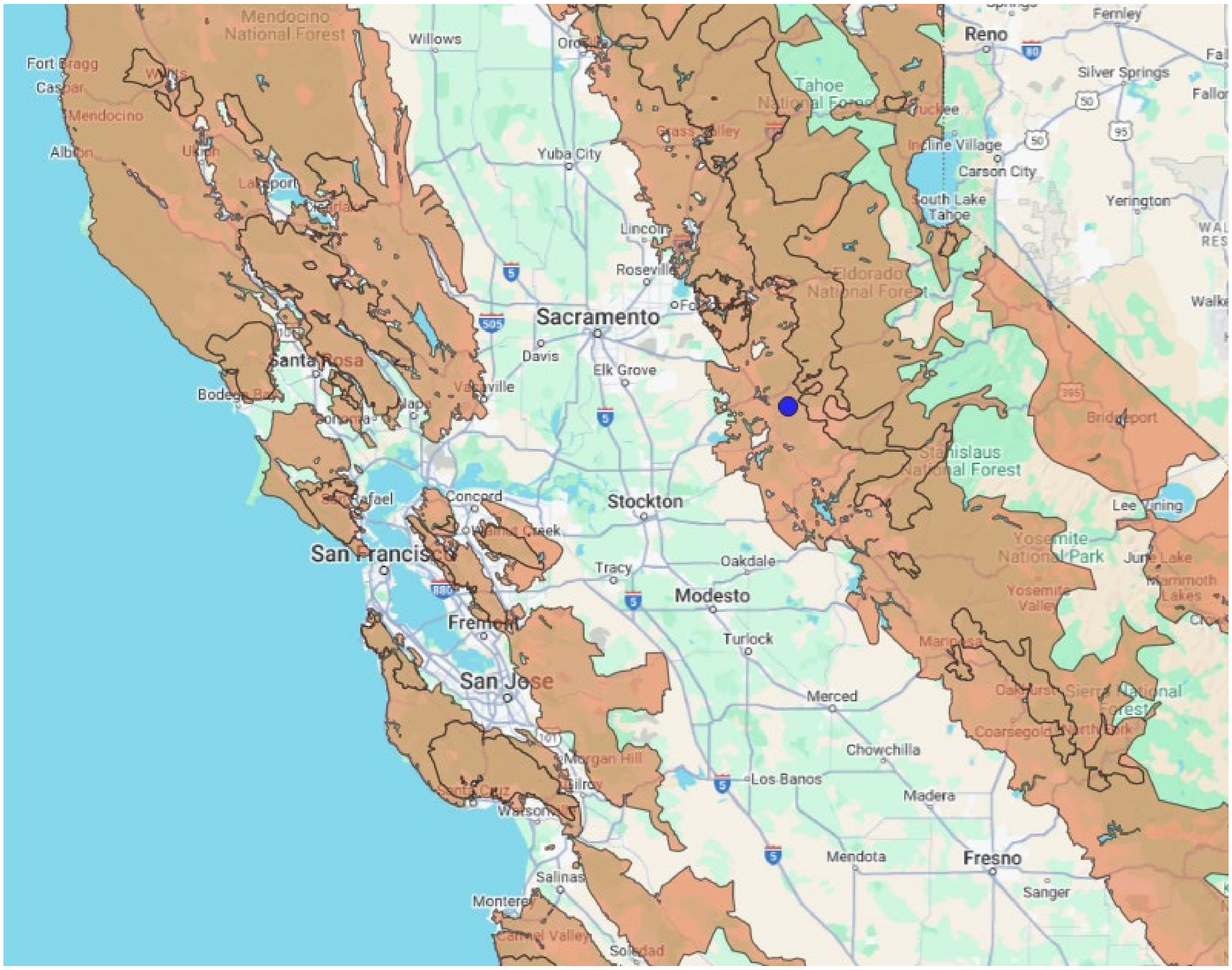
FEP used GIS software to plot the coordinates for the operating devices involved in the outages. FEP compared these plotted GIS locations to PG&E's HFTD/non-HFTD designations. A spatial selection in GIS was used to identify outage points that intersected with the HFTDs. The intersecting points were then analyzed to assess the accuracy of PG&E's HFTD/non-HFTD identification field. The following map shows HFTD boundaries in light red. The green points are transmission Wires Down events (from 2021 – 2023) labeled as occurring in non-HFTD. The yellow points are events that were labeled as occurring in HFTDs. Overall, there is good alignment between PG&E's HFTD labeling and the coordinates. FEP did note one location that was labeled as HFTD but appears to be located in non-HFTD. This location had an incorrect latitude and longitude association and is actually located HFTD.

Figure 2-20: Transmission Wires Down Events



FEP found one transmission Wires Down event on non-MEDs which was labelled as occurring in non-HFTD areas but overlapped with HFTD boundaries which occurred in 2022 and is shown as a blue dot below. As this is one point out of a population of 299 (across over 10 years) FEP did not find this to be a significant accuracy issue.

Figure 2-21: Transmission Wires Down Events Classified as "Non-HFTD" in HFTD Areas



Benchmark to Other PG&E Reports

To further assess the accuracy of this metric, FEP considered a number of data sources where PG&E reports on Wires Down events. While all of these data sources report on Wires Down events, some focus only on HFTDs while others look at Wires Down events across PG&E's full system. FEP considered whether the SOMs reported values made sense in the context of these other PG&E reports. The following list defines the various sources of data considered:

1) **SOMs Data:** Data on Wires Down events that PG&E transmitted as part of its SOMs reporting requirements. This data was pre-filtered to include only events PG&E classified as occurring in HFTDs and is separated into distribution and transmission datasets.
2) **Mapped Outage Dataset:** This is a dataset that FEP requested from PG&E that shows all outages occurring across the PG&E system. It can be filtered to identify only outages which included Wires Down events. Additional filtering can be applied to identify outages by line type (transmission or distribution) and by location (HFTD or non-HFTD). FEP took the outage data provided by PG&E and mapped the location of the Wires Down events using the provided coordinates in GIS. As described in the section above, the results of FEPs mapping process did not align with PG&E's HFTD designations.

3) **QDR:** The QDRs are submitted along with PG&E's wildfire mitigation plans. The reports include Wires Down event counts (transmission and distribution) both at an HFTD level and the full system level.
4) **SPM Results:** California utilities report to the CPUC on SPMs, required by Decision 19-04-020. The number of Wires Down events occurring across the full system is reported in SPM 2.

Based on the definitions and requirements of these reporting streams, FEP concluded that there should be fairly consistent Wires Down rates across the data sources. As shown in the table below, the reports presenting full-system Wires Down rates are similar. However, the reports presenting HFTD-only data do not match. The mapped outage data showed many more Wires Down events in HFTDs than were reported by SOMs Metric 3.1 – 3.6 or in the QDR.

Table 2-21: Wires Down Report Comparison

Year	In HFTDs			Full System		
	SOM Metric 3.1 – 3.6	QDR in HFTDs	Outage Data	QDR in Full System	SPM # 2	Outage Data
2023	787	1,281	3,526	7,133	7,173	7,514
2022	522	525	1,002	3,159	3,132	3,315
2021	777	809	2,977	5,896	5,819	6,035

The difference between the reported Wires Down values in HFTDs suggests that there may be a problem with the SOMs data for Wires Down metrics generally. However, based on the good correlation between PG&E's HFTD destinations for transmission Wires Down events and the plotted event locations and the issues identified in Metric 3.1 and 3.2 for distribution Wires Down, FEP surmises that the wires down discrepancies described above largely stem from distribution Wires Down events. However, FEP was unable to conduct an in-depth analysis as the QDR data is not categorized into distribution and transmission events.

<u>Verification of Metric Results</u>

PG&E included 8 Wires Down events in its 2022 SOMs Metric 3.4 reporting. However, FEP found 9 events that qualified for the metric based on the SOM's definition and the mapped GIS coordinates. If the additional event did occur within HFTD boundaries, that would bring the 2022 metric result from 1.45 to 1.63.

Table 2-22: Metric 3.4 Reported versus Mapped Wires Down

Metric 3.4 Reported and FEP Results				
Year	**Wires Down Events in SOMs**	**Reported Result**	**FEP Count of Wires Down Events**	**FEP Metric 3.4 Result**
2021	11	1.99	11	1.99
2022	8	1.45	9	1.63
2023	8	1.47	8	1.47

Assuming PG&E's original HFTD designations were correct, FEP verified that all the Wires Down events included in Metric 3.4 occurred on non-MED days and related to transmission assets. FEP then summed the total number of events per year. FEP's calculations matched PG&E's results for Metric 3.4, with the caveat discussed above that PG&E used the same transmission circuit mile value for 2021, 2022, and the historical years.

2.11.2 Metric 3.4 Management

The Electric Transmission team facilitates the calculation of the transmission Wires Down metric results. Reports for Metric 3.4 are run monthly. The reports are run by analysts then reviewed by the supervisors and managers. Once the data is validated, the performance results are added to the CMR reporting tool. The reports are then validated and approved by the Asset Strategy and Standards team (Asset Strategy). Each month, Asset Strategy considers the year-to-date performance of the metric to determine if the metric is on track to achieve the one-year target and assess progress towards the five-year target.

The Electric Transmission team reviews the cause of all outages. The transmission teams can conduct in-depth cause investigations for all transmission Wires Down due to the limited number of Wires Down which occur per year. The cause investigations occur both for Wires Down and for other types of transmission outages. Sometimes investigations result in new information being revealed months after the initial Wires Down incident was reported. The results of the investigation can change the cause of the outage reported in the database.

The organization utilizes the Lean Operating Review and CIC meetings described in the Section 1.4 to review the Metric 3.4 status and any catch back work activities. The team reviews controls and mitigations which are currently in place through the electric asset and vegetation management groups to determine corrective actions.

Though not directly related to the management of the SOMs metric, PG&E does undertake management activities for Wires Down more generally which may affect the metric results. If anomalies or problematic data trends are identified in the Wires Down data, ESS works with the reliability teams to do a deep dive into the causes of the trends. The most common drivers of downed wires are vegetation, weather, and contact from third-party objects. If problematic trends are identified, ESS brainstorms with the relevant departments, such as the reliability teams or the vegetation teams to understand mitigation options. Often, the adjustments and mitigations drive improvement to Wires Down rates in the longer term, rather than resulting in immediate improvement for the current year. Vegetation issues can be addressed more quickly overall than asset issues, as asset issues often require longer-term construction projects.

PG&E conducts an efficiency review following major events to understand the causes of equipment failures on MEDs. This review includes assessing all types of equipment failures, including conductors. The main goal of the post-event assessment is to consider if the design standards of the failing assets are sufficient.

Observations on Metric 3.4 Management

Transmission troubleshooters responding to events have access to technology in the field which is designed to capture relevant information in a way that limits data variability and reduces opportunities for mistakes. Additionally, the transmission team thoroughly reviews the cause of all transmission Wires Down and reports the information to multiple regulatory agencies, including CAISO.

The accuracy of transmission metrics would benefit from PG&E utilizing and communicating a clearer process for calculating transmission circuit miles. PG&E could calculate circuit miles on a set schedule, communicated in the report, and list the values used in calculations in each SOMs report.

2.11.3 Metric 3.4 Performance and Targets

PG&E set the targets for Metrics 3.4 with a goal of maintaining performance. PG&E determined average performance by calculating an average of the historical data (2021 report: 2013 – 2020 & 2022 report: 2013 – 2021) and adding three standard deviations. PG&E did not adjust the target in the 2023 report. The following table displays PG&E's 2013 through 2023 metric results and the 1-year and 5-year metric targets.

Table 2-23: Metric 3-4 Results and Targets

Year	Metric Result	1-Year Target	5-Year Target
2011	3.438		
2012	6.696		
2013	2.353		
2014	1.810		
2015	2.534		
2016	3.438		
2017	3.438		
2018	1.991		
2019	2.534		
2020	1.448		
2021	1.991	4.456	4.456
2022	1.448	4.440	4.440
2023	1.471	4.440	4.440
[1] Targets reflect the target set in that report year (i.e. the 2021 1-year target reflects 2022 target).			

PG&E's average metric result from 2011 -2023 was 2.66 and 1.64 from 2021-2023. PG&E's 1 and 5-year target set in 2023 is 171% higher than the 2021-2023 average and 67% higher than the 13-year average.

Observations on Metric 3.4 Performance and Targets

The lower frequency of transmission Wires Down events allows PG&E to conduct in-depth cause investigations for each event. FEP notes that the 1- and 5-year targets are significantly higher than the 2020-2023 average and the 1- and 5-year targets are the same. This is not aligned with driving performance improvement. FEP also considered if comparing Metric 3.3 and 3.4 results could be useful for drawing conclusions about if weather or low incident frequency contributed most to the variation in Metric 3.3. Ten years of data on Metric 3.4 suggests that useful conclusions about PG&E's performance could be drawn should a significant change emerge. The same is not necessarily true of Metric 3.3.

As previously mentioned, the major difference between Metric 3.3 and 3.4 is the MED designation. However, Metric 3.4 also has a much larger dataset than Metric 3.3. This is because there are typically less than 20 MEDs a year and Metric 3.4 captures transmission Wires Down on the other 340+ days. Therefore, it's still challenging to determine if the variation is more attributable to weather or to low frequency. Overall, FEP's comparison of Metric 3.4 to the other transmission Wires Down metrics (MEDs and RFWs) has suggested that, while the transmission dataset as a whole is large enough to draw useful conclusions, additional delimitations based on weather make the dataset smaller and more difficult to assess for trends.

2.12 Metric 3.5: HFTD Wires Down, Distribution (Red Flag)

The CPUC defines Metric 3.5 as:

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

A Red Flag Warning (RFW) is an alert sent to fire managers on federal lands that conditions are such that sparks or controlled burns may lead to especially dangerous wildfire growth.[32] Three conditions are used to determine if a RFW should be issued for a specific geographic area. The conditions are:

- Ten-hour fuels of 8% or less: Ten-hour fuels are grass, leaves, mulch and other small vegetation that takes approximately 10 hours to respond to changes in weather conditions.
- Relative humidity less than 25%: Relative humidity describes how much moisture is in the air, relative to the temperature. The condition must be sustained for several hours.
- Wild Speeds Above 15 mph: Wind speed is measured 20 feet off the ground and must be sustained for several hours.

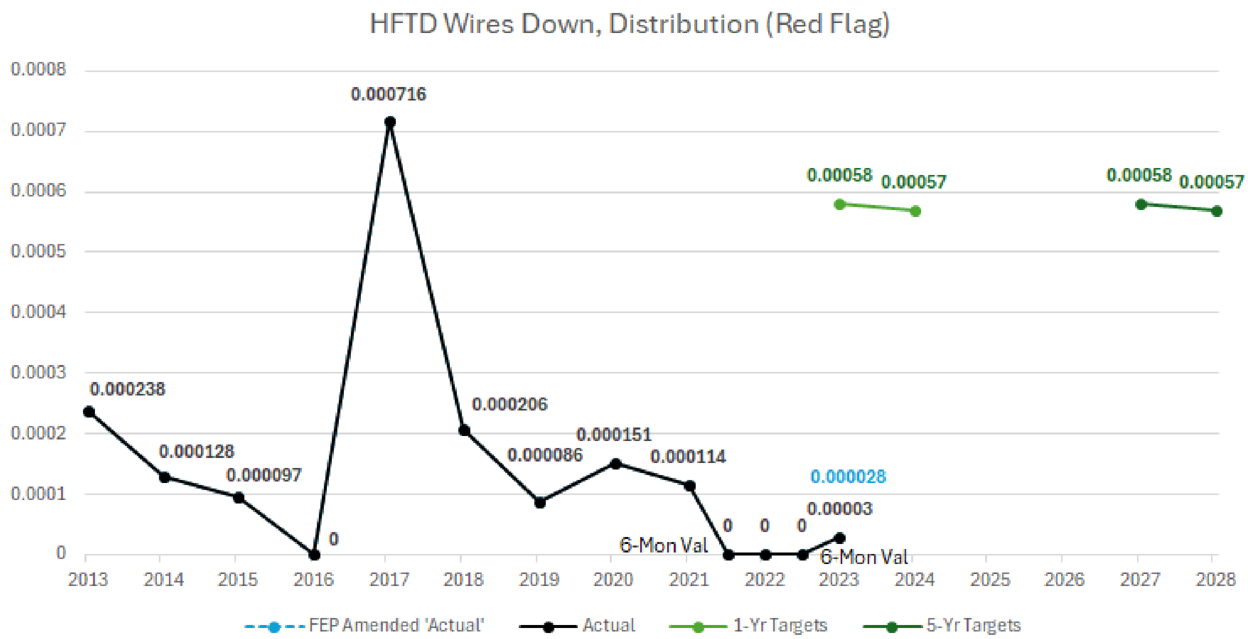
The formula for calculating Metric 3.5 is:

$$= \frac{\#\ of\ Wires\ Down\ Events\ on\ RFW\ Days\ in\ HFTDs}{RFW\ Distribution\ Circuit\ Mile\ Days\ in\ HFTD\ Areas}$$

The following chart shows Metric 3.5 results compared to targets for 2013 through 2028, including results from the 2022 and 2023 mid-year reports. All historical values reflect the most recent data available as of the 2023 report and may differ from previously reported figures.

[32] https://www.weather.gov/media/lmk/pdf/what_is_a_red_flag_warning.pdf

Figure 2-22: Metric 3.5 Summary Chart



2.12.1 Metric 3.5 Accuracy and Consistency

Information for Metric 3.5 is extracted from the ILIS Outage Database. Data enters ILIS through reports made by troubleshooters who respond to outages and other issues in the field. PG&E becomes aware of a downed wire or outage through several reporting streams such as Smart Meters, SCADA or customer reporting. Troubleshooters are sent to the scene to assess the incident. Once on-site, the troubleshooters complete digital forms to document the characteristics of the incident. Those incident reports are transmitted to the distribution outage center. PG&E supplied the audit team with the "Outage Reporting Details and Accuracy Verification Process" documents that provides a detailed description of the proper method to input outage data into ILIS along with the process for verifying the accuracy of the reported outage events.

The data transmitted to the distribution outage center is reviewed and manually entered by distribution staff. Employees of the outage center conduct a quality review as data is entered into ILIS. A member of the Outage Quality Review Team conducts another accuracy review. If engineers wish to add new information or correct previously submitted information, they ask the operations team to make changes to the data. Individuals in troubleshooting, engineering, and related departments have read access to the data, but do not have the ability to make changes to the database directly.

The ILIS database has broad utilization across PG&E operations, and the data is used for differing PG&E workstreams. As the database was not specially designed for this metric, some of the datapoints are used as approximations rather than ideal descriptors. For example, PG&E staff communicated in an interview that the location associated with the Wires Down metrics is logged as being associated with the operating device rather than the location the affected wire made contact. However, PG&E staff subsequently noted through a RFI that the location of Wires Down events for SOMs is generated by a tool that assigns HFTD classification based on longitude and latitude. If that location is unavailable or changes later, the tool does not revise the HFTD classification but may update the coordinates. PG&E also logs the span location of equipment-caused Wires Down events in the Wires Down Database. The Wires Down Database does not include vegetation-caused events and is not used for the calculation of this metric.

Importantly, the events logged in ILIS are outages and not specifically Wires Down events. Wires Down events are tracked through a notation on the outage to indicate that it involved a downed wire. The result of this system is that the number of Wires Down is approximated by the number of outages. PG&E staff stated that this methodology aligns with PG&E's interpretation of the CPUC definition of "Wires Down events". PG&E defines "Wires Down events" as the number of outages caused by one or more Wires Down faults number of outages caused by one or more Wires Down faults. FEP notes that CPUC Decision D.21-100-09says Wires Down events are 'when normally energized overhead primary or transmission conductor is broken, or remains intact, and falls from its intended position to rest on the ground or foreign object.[33]"

If a downed wire trips multiple operating devices, then it will be logged as multiple events. Meanwhile, while downed wires on the primary distribution system may result in the creation of multiple Wires Down records, it is possible that Wires Down events on the secondary distribution system are unrecorded if they do not result in the trip of an operating device. Through discussions with PG&E staff, it is evident that they are aware of these limitations and that it is their perspective that the ILIS database is the best database available to serve as a record for this metric. Wires Down events are tracked based on associated outages, and PG&E does not differentiate in ILIS between outages associated with primary or secondary distribution lines. If there is no outage associated with the event, then it is not logged as a Wires Down event for the purpose of metric tracking. PG&E acknowledges these limitations and is evaluating their procedure to determine if its calculation of this metric can be adjusted to address these limitations.

The primary data source for managing RFW data is PG&E's EGIS. The geographic boundaries, known as polygons, for RFW areas are downloaded weekly. The polygons are formatted as a database table. The tables include the HTFD designation, if applicable, and the shape of the polygon. If RFW days were issued for the reporting month, the data would be transmitted for processing via a python script. RFWs are seasonal, primarily occurring during the summer months. The python script compares the RFW polygons with the applicable durations, to the time and location of distribution Wires Down events in HFTDs. Wires Down instances which occurred in HFTDs in the RFW polygons are included in the dataset for Metric 3.5.

Observations on Metric 3.5 Accuracy

To determine the overall accuracy of the metric results, FEP reviewed the following inputs to Metric 3.5:

1) RFW designations
2) Circuit mile values
3) HFTD classification

The process for undertaking those verifications is described in the sections below. In addition, FEP benchmarked the SOMs results to other PG&E published reports regarding Wires Down. Overall, FEP found that the Metric 3.5 results appear to have significant accuracy issues.

[33] CPUC Decision 21-100-09, p. 84.

Verification of Red Flag Warning Days and Circuit Miles

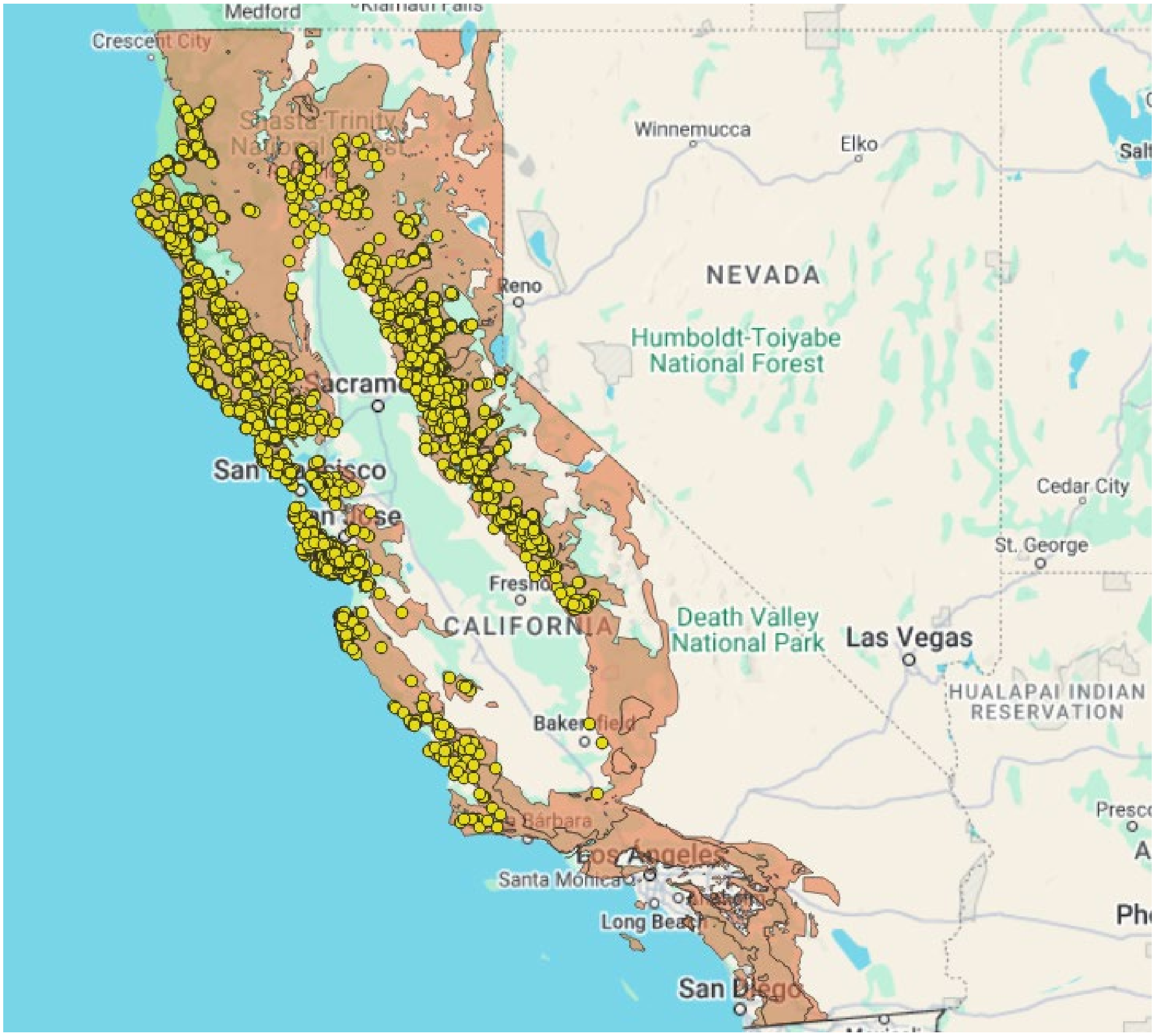
Through an interview with PG&E and a review of documentation, FEP determined that PG&E uses a python script to identify individual Wires Down events which occur in the time and geographic location indicated by an RFW. The same script is used to calculate the denominator of the Metric 3.5 formula (RFW Distribution Circuit Mile Days in HFTD Areas). GIS polygons are used to identify areas in HTFDs with red-flag warnings. This value represents the total distribution line miles in HTFDs with RFWs issued for the geographic location. Based on FEPs experience, both the high-level methodology and the execution of the script is reasonable.

Verification of HFTD Designations

During the evaluation process, FEP requested that PG&E provide data on all outages (which includes Wires Down events) which occurred in both the HFTD and non-HFTD areas. FEP used GIS software to plot the coordinates for the operating devices involved in the outages. FEP compared these plotted GIS locations to PG&E's HFTD/non-HFTD designations. A spatial selection in GIS was used to identify outage points that intersected with the HFTDs. The intersecting points were then analyzed to assess the accuracy of PG&E's HFTD/non-HFTD identification field.

FEP identified significant discrepancies between PG&E's HFTD/non-HFTD designations and those implied by the mapped data. While there were a small number of points designated as HFTD which were plotted in non-HFTD areas, there were many points designated as non-HFTD well within the HFTD boundaries. The following image shows a map of California with the HFTD (Tier 2 and Tier 3) highlighted in light red. The yellow points are 2021 – 2023 distribution Wires Down events (located to the associated operating devices) that overlap with HFTD areas but were marked as occurring in non-HFTD areas.

Figure 2-23: Distribution Wires Down Events Classified as “Non-HFTD” in HFTD Areas



In a follow-up discussion regarding this HFTD assignment error, PG&E explained that “for distribution, the HFTD class is not stored directly in the outage database but instead joined in through logic specific to each report. In the outage data prepared for SOMs, the report uses a tool that assigns HFTD class one day after the event, based on latitude and longitude. If that location data was unavailable on the day after the event and added or updated later, the tool does not revise the historical assignment resulting in some HFTD classifications no longer reflecting the most accurate or consistent information. The practice of assigning the HFTD class one day after the event based on the location of the interruptive device is how this has been determined since the HFTD was established. This data set has been the foundation of PG&E’s outage reporting relative to HFTD locations for all applications, including SOMs metrics.” FEP did not verify that this is the cause of the discrepancy. FEP also notes that as a result of these findings, PG&E has entered this issue into their CAP and is developing a centralized, standardized data repository through WiRE, which aims to improve outage metric reporting.

Benchmark to Other PG&E Reports

To further assess the accuracy of this metric, FEP considered a number of data sources where PG&E reports on Wires Down events. While all of these data sources report on Wires Down events, some focus only on HFTDs while others look at Wires Down events across PG&E's full system. FEP considered whether the SOMs reported values made sense in the context of these other PG&E reports. The following list defines the various sources of data considered:

1) **SOMs Data:** Data on Wires Down events that PG&E transmitted as part of its SOMs reporting requirements. This data was pre-filtered to include only events PG&E classified as occurring in HFTDs and is separated into distribution and transmission datasets.
2) **Mapped Outage Dataset:** This is a dataset that FEP requested from PG&E that shows all outages occurring across the PG&E system. It can be filtered to identify only outages which included Wires Down events. Additional filtering can be applied to identify outages by line type (transmission or distribution) and by location (HFTD or non-HFTD). FEP took the outage data provided by PG&E and mapped the location of the Wires Down events using the provided coordinates in GIS. As described in the section above, the results of FEPs mapping process did not align with PG&E's HFTD designations.
3) **QDR:** The QDRs are submitted along with PG&E's wildfire mitigation plans. The reports include Wires Down event counts (transmission and distribution) both at an HFTD level and the full system level.
4) **SPM Results:** California utilities report to the CPUC on SPMs, required by Decision 19-04-020. The number of Wires Down events occurring across the full system is reported in SPM 2.

Based on the definitions and requirements of these reporting streams, FEP concluded that there should be fairly consistent Wires Down rates across the data sources. As shown in the table below, the reports presenting full-system Wires Down rates are fairly consistent. However, the reports presenting HFTD-only data do not match. The mapped outage data showed many more Wires Down events in HFTDs than were reported by SOMs Metric 3.1 – 3.6 or in the QDR.

Table 2-24: Wires Down Report Comparison

Year	In HFTDs			Full System		
	SOM Metric 3.1 – 3.6	QDR in HFTDs	Outage Data	QDR in Full System	SPM # 2	Outage Data
2023	787	1,281	3,526	7,133	7,173	7,514
2022	522	525	1,002	3,159	3,132	3,315
2021	777	809	2,977	5,896	5,819	6,035

The difference between the reported Wires Down values in HFTDs further suggests that there may be a problem with the SOMs data for this metric. In response to questions regarding the differences, PG&E noted that that the data reflects "snapshots in time" and changes are made based on the findings of further investigations and many other factors. Since the SOMs data and QDR data were pulled at different times, they reflect different information. Though the QDR data and SOMs data is pulled using different processes, the results should be the same if they are pulled at the same time. PG&E repulled the data in response to FEP's RFI (April 2025), and both processes produced 3,377 Wires Down in HFTDs in 2023. A change from 1,281 to 3,377 appears to be larger than one would expect as a result of normal data updates and further data issues.

This new value is similar to what FEP identified using the outage data. However, the result is very different than what was previously reported. This leads FEP to believe there are significant errors in PG&E's metric results for SOM Metric 3.1 – 3.6. The discrepancies described above applied to both the distribution and transmission data. In addition to these discrepancies, FEP was unable to align the transmission outage data (Data Source #2: Mapped Outage Data, discussed above) acquired through RFI with the data PG&E submitted as part of their SOMs filing. In past conversations, PG&E stated that the outage data changes over time as investigations are undertaken, so it is possible that these types of changes resulted in different transmission outage counts when the outage data was queried months after the SOMs filing was submitted. The data that PG&E included with their 2023 SOMs filing showed 34 transmission Wires Down events. This number was used as the basis for calculating their metric result. However, there were only 19 transmission outages shown in the outage data.

Verification of Metric Results

Based on the high number of Wires Down events labeled as non-HFTD which are located in HFTDs based on coordinates, FEP is unable to verify the accuracy of Metric 3.5. The data used to map the Wires Down events in GIS did not include if the event occurred during a red flag warning, so FEP is unable to recalculate the metric result based on the mapped data. Assuming the HFTD designations originally provided by PG&E are correct, FEP found PG&E's calculation of the metric results to be accurate.

2.12.2 Metric 3.5 Management

PG&E's ESS department is responsible for managing, tracking, and setting targets for Metric 3.5 and the other Wires Down metrics. PG&E tracks the repair and investigation of Wires Down events daily for internal reporting.

ESS produces a monthly report with the Wires Down statistics for Metric 3.5. Once the data is validated, the performance results are added to the CMR reporting tool. The reports are then validated and approved by the Asset Strategy and Standards team. Each month, Asset Strategy considers the year-to-date performance of the metric to determine if the metric is on track to achieve the one-year target and assess progress towards the five-year target.

The organization utilizes the Lean Operating Review and CIC meetings described in Section 1.4 to review the Metric 3.5 status and any catch back work activities. The team reviews controls and mitigations which are currently in place through the electric asset and vegetation management groups to determine corrective actions.

Though not directly related to the management of the SOMs metric, PG&E does undertake management activities for Wires Down more generally which may affect the metric results. If anomalies or problematic data trends are identified in the Wires Down data, ESS works with the reliability teams to do a deep dive into the causes of the trends. The most common drivers of downed wires are vegetation, weather, and contact from third-party objects. If problematic trends are identified, ESS brainstorms with the relevant departments, such as the reliability teams or the vegetation teams to understand mitigation options. Often, the adjustments and mitigations drive improvement to Wires Down rates in the longer term, rather than resulting in immediate improvement for the current year. Vegetation issues can be addressed more quickly overall than asset issues, as asset issues often require longer-term construction projects.

Additionally, PG&E conducts an efficiency review following major events to understand the causes of equipment failures on RFWs. This review includes assessing all types of equipment failures, including conductors. The main goal of the post-event assessment is to consider if the design standards of the failing assets are sufficient.

Observations on Metric 3.5 Management

FEP observes that there may be overlap in Wires Down events included across the three distribution Wires Down metrics (3.1, 3.2 & 3.5). Events in Metrics 3.1 and 3.2 are mutually exclusive due to the MED and non-MED distinction. However, all events on RFW days are also included in one of the other distribution Wires Down metrics. The fact that the Wires Down events included in Metric 3.5 are also reflected in other SOMs metrics is not necessarily a problem since the metric results cannot be added together to get an overall picture of PG&E's wires down rates.

2.12.3 Metric 3.5 Performance and Targets

PG&E set the target for Metric 3.5 at the upper limit of two standard deviations of the 10-year historical average performance. The following table displays PG&E's 2013 through 2023 metric results and the 1-year and 5-year metric targets.

Table 2-25: Metric 3-5 Results and Targets

Year	Metric Result	1-Year Target[1]	5-Year Target[1]
2013	0.000238		
2014	0.000128		
2015	0.000097		
2016	0.000000		
2017	0.000716		
2018	0.000206		
2019	0.000086		
2020	0.000151		
2021	0.000114	Maintain	Maintain
2022	0.000000	0.00058	0.00058
2023	0.000030	0.00057	0.00057
[1] Targets reflect the target set in that report year (i.e. the 2021 1-year target reflects 2022 target).			

PG&E's average metric result from 2013 -2023 was 0.000160 and 0.000047 from 2021-2023. PG&E's 1-year and 5-year targets are over 12 times higher than the 2021-2023 actual performance although lower than its highest year of 0.00076 in 2017. These values assume that PG&E's reported metric results are correct, which FEP is uncertain of based off the HFTD designation discrepancies discussed above.

Observations on Metric 3.5 Performance and Targets

FEP notes that the 1- and 5-year targets are significantly higher than the 2021-2023 average. This is generally not aligned with driving performance improvement. However, FEP notes that there is significant variability in Metric 3.5. In 2016, the metric result was zero but then the next year it had its highest result of 0.000716. Currently, there are few Wires Down events in HFTDs during RFWs (reported 2023:1, 2022:0, 2023:13) so each new event has a large impact on metric statistics. The impact of weather on Wires Down metrics is also significant, especially when considering extreme events like RFW days. If, through continued data collection, it becomes clear that the small and varied sample size is a barrier to setting targets in keeping with continuous improvement, strategies for looking at a larger subset of data might be considered. Additionally, in light of the magnitude of the difference between PG&E's HFTD labels and the mapped HFTD designations it is possible that this dataset is larger than it currently appears.

2.13 Metric 3.6: HFTD Wires Down, Transmission (Red Flag)

The California Public Utilities Commission (CPUC) defines Metric 3.6 as:

Number of Wires Down events in HFTDs on Red Flag Warning (RFW) Days involving transmission circuits divided by Red Flag Warning Transmission Circuit-Mile Days in HFTDs in a calendar year

Metric 3.6 assesses the rate of transmission Wires Down events in PG&E's HFTD. A Wires Down event is defined as an event where wire conductors fail and fall, making contact with the ground, a vehicle, or other object.

A RFW is an alert sent to fire managers on federal lands that conditions are such that sparks or controlled burns may lead to dangerous wildfire growth.[34] Three conditions are used to determine if a RFW should be issued for a specific geographic area. The conditions are:

- Ten-hour fuels of 8% or less: Ten-hour fuels are grass, leaves, mulch and other small vegetation that takes approximately 10 hours to respond to changes in weather conditions.
- Relative humidity less than 25%: Relative humidity describes how much moisture is in the air, relative to the temperature. The condition must be sustained for several hours.
- Wild Speeds Above 15 mph: Wind speed is measured 20 feet off the ground and must be sustained for several hours.

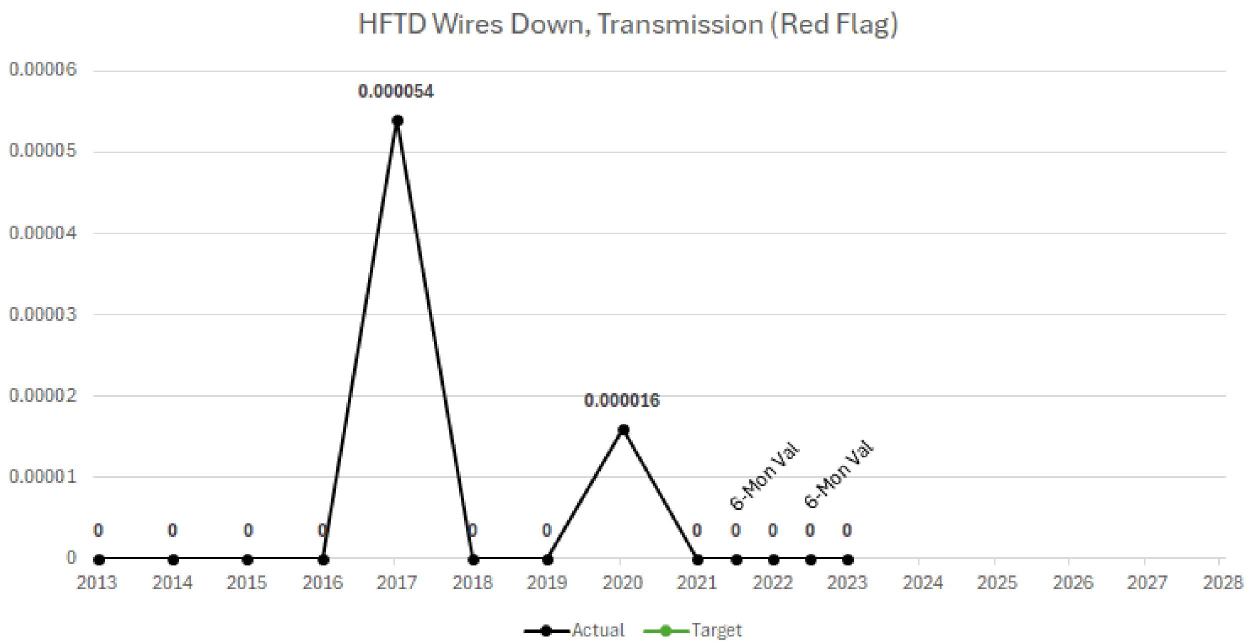
The formula for calculating Metric 3.6 is:

$$\frac{\#\ of\ Wires\ Down\ Events\ on\ RFW\ Days\ in\ HFTDs}{RFW\ Transmission\ Circuit\ Mile\ Days\ in\ HFTD\ Areas}$$

The following chart shows Metric 3.6 results compared to targets for 2013 through 2028, including results from the 2022 and 2023 mid-year reports. All historical values reflect the most recent data available as of the 2023 report and may differ from previously reported figures.

[34] https://www.weather.gov/media/lmk/pdf/what_is_a_red_flag_warning.pdf

Figure 2-24: Metric 3.6 Summary Chart



2.13.1 Metric 3.6 Accuracy and Consistency

The database used for managing Metric 3.6 is the Transmission Operations Tracking and Logging TOTL application. If distribution customers are impacted by a transmission Wires Down event, PG&E merges the transmission data in TOTL with the data from PG&E's ILIS platform.

When PG&E originally responds to and collects data about a transmission Wires Down event, troubleshooters typically have incomplete information relating to the cause of the outage. Therefore, the Transmission Operations, Tracking and Logging team logs the initial findings and updates the record as additional reviews are completed. They coordinate with vegetation management teams and the meteorology team to determine a specific cause of the Wires Down event.

PG&E uses EGIS to inform this metric. EGIS is used to identify conductors by type, such as primary distribution, secondary distribution and transmission. EGIS is also used to identify the feeder, whether the assets are located in HFTDs, and to calculate the total number of line miles. The circuit mile calculations are a snapshot in time, meaning they are continuously updated as circuits expand and contract.

The oversight and management process of these two systems has been largely consistent for the past decade. The policies around data gathering, input, and extraction have been consistent throughout the reporting period with minimal changes to the reporting standard. PG&E uses data on Wires Down for internal tracking and regulatory reporting beyond the bi-annual SOMs report. Specific divisions that are required for SOMs reporting, like the separation of MED and non-MED events, occurs in post-processing using the ILIS dataset.

PG&E adopted the CPUC's Fire-Threat Map in 2018 and added fields to ILIS and TOTL identifying assets as belonging to HTFDs. PG&E uses EGIS to determine if assets involved in Wires Down events are within HTFD boundaries. The historical SOMs dataset (2013 – 2020) partially predates HFTD designations, so PG&E used 2021 HTFD boundaries to retroactively determine which Wires Down events applied to this metric.

Observations on Metric 3.6 Accuracy

To determine the overall accuracy of the metric results, FEP reviewed the following inputs to Metric 3.6:

1) RFW designations
2) Circuit mile values
3) HFTD classification

The process for undertaking those verifications is described in the sections below. In addition, FEP benchmarked the SOMs results to other PG&E published reports regarding Wires Down. Overall, FEP found that the Metric 3.6 results appear to be accurate.

Verification of Red Flag Warning Days and Circuit Miles

Through an interview with PG&E and a review of documentation, FEP determined that PG&E uses a python script to identify individual Wires Down events which occur in the time and geographic location indicated by an RFW. The same script is used to calculate the denominator of the Metric 3.6 formula (RFW Transmission Circuit Mile Days in HFTD Areas). GIS polygons are used to identify areas in HTFDs with red-flag warnings. This value represents the total distribution line miles in HTFDs with RFWs issued for the geographic location. Based on FEPs experience, both the high-level methodology and the execution of the script is reasonable.

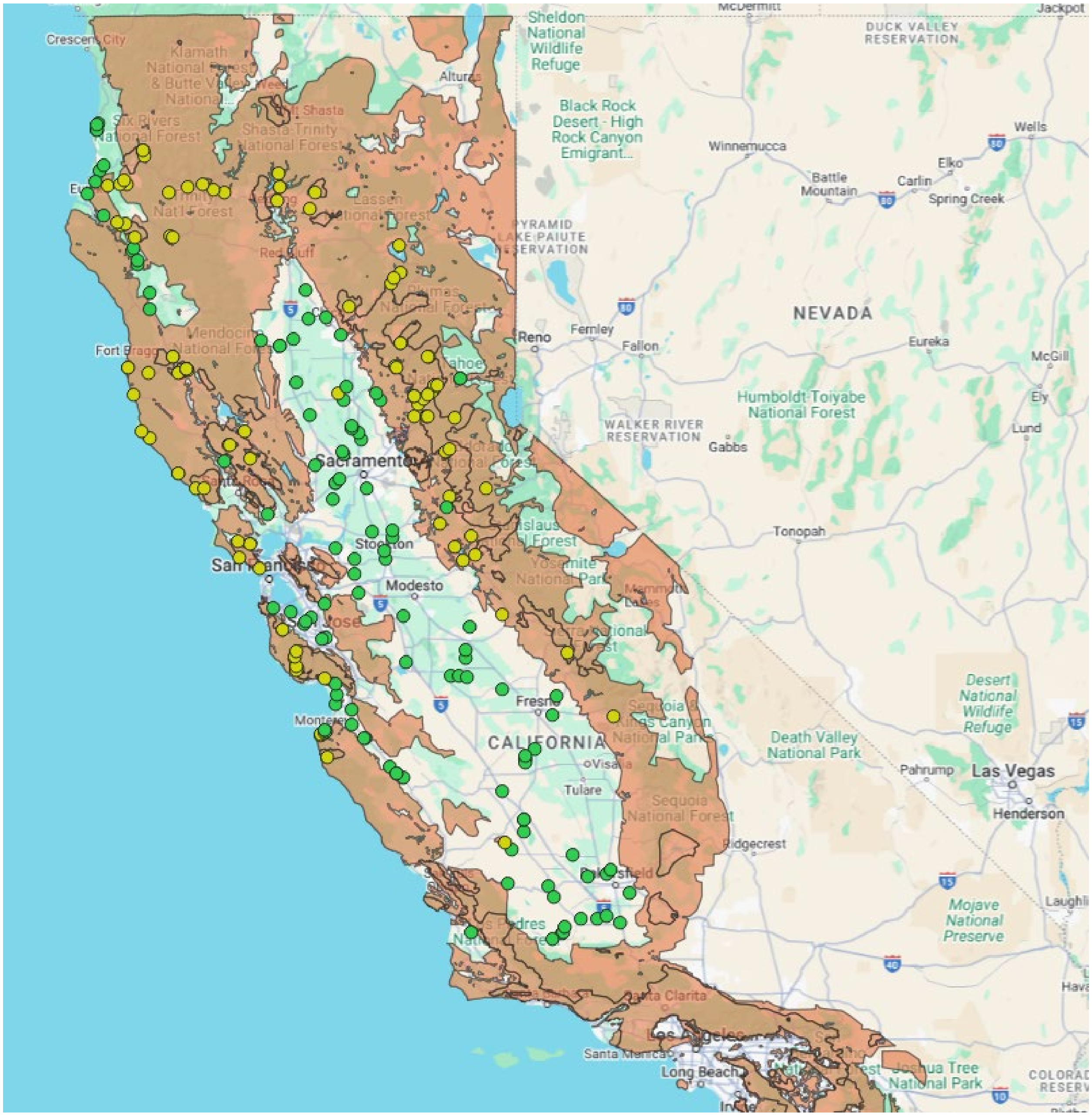
Verification of HFTD Designations

During the evaluation process, PG&E provided coordinates (longitude and latitude) associated with transmission Wires Down events. According to PG&E, the location of transmission Wires Down is tracked in the Transmission Outage Database sourcing the information from TOTL and utilizes ETGIS for HFTD mapping. While ILIS is the system of record for outages, it is FEP's understanding that PG&E uses it for reference only for transmission. Transmission Wires Down location are identified based on field observation and is captured at the structure/span level for accuracy in determining HFTD/non-HFTD.

As discussed in Sections 3.1 and 3.2, FEP identified significant discrepancies between PG&E's HFTD/non-HFTD designations and those implied by the mapped data for distribution Wires Down events. Overall, the HFTD designations for transmission Wires Down events appear to better align when the coordinates are mapped in GIS.

FEP used GIS software to plot the coordinates for the operating devices involved in the outages. FEP compared these plotted GIS locations to PG&E's HFTD/non-HFTD designations. A spatial selection in GIS was used to identify outage points that intersected with the HFTDs. The intersecting points were then analyzed to assess the accuracy of PG&E's HFTD/non-HFTD identification field. The following map shows HFTD boundaries in light red. The green points are transmission Wires Down events (from 2021 – 2023) labeled as occurring in non-HFTD. The yellow points are events that were labeled as occurring in HFTDs. Overall, there is good alignment between PG&E's HFTD labeling and the coordinates. FEP did note one location that was labeled as HFTD but appears to be located in non-HFTD. This location had an incorrect latitude and longitude association and is actually located HFTD. As discussed in Metric 3.4, FEP also found one transmission Wires Down events which was labeled as occurring in non-HFTDs but overlapped with HFTD boundaries. FEP was unable to verify from the data if this event occurred during RFWs, so FEP's assessment of this metric's accuracy is based on the generally strong correlation between PG&E's HFTD designations and the mapped event coordinates

Figure 2-25: Transmission Wires Down Events



Benchmark to Other PG&E Reports

To further assess the accuracy of this metric, FEP considered a number of data sources where PG&E reports on Wires Down events. While all of these data sources report on Wires Down events, some focus only on HFTDs while others look at Wires Down events across PG&E's full system. FEP considered whether the SOMs reported values made sense in the context of these other PG&E reports. The following list defines the various sources of data considered:

1) **SOMs Data:** Data on Wires Down events that PG&E transmitted as part of its SOMs reporting requirements. This data was pre-filtered to include only events PG&E classified as occurring in HFTDs and is separated into distribution and transmission datasets.
2) **Mapped Outage Dataset:** This is a dataset that FEP requested from PG&E that shows all outages occurring across the PG&E system. It can be filtered to identify only outages which included Wires Down events. Additional filtering can be applied to identify outages by line type (transmission or distribution) and by location (HFTD or non-HFTD). FEP took the outage data provided by PG&E and mapped the location of the Wires Down events using the provided coordinates in GIS. As described in the section above, the results of FEPs mapping process did not align with PG&E's HFTD designations.
3) **QDR:** The QDRs are submitted along with PG&E's wildfire mitigation plans. The reports include Wires Down event counts (transmission and distribution) both at an HFTD level and the full system level.
4) **SPM Results:** California utilities report to the CPUC on SPMs, required by Decision 19-04-020. The number of Wires Down events occurring across the full system is reported in SPM 2.

Based on the definitions and requirements of these reporting streams, FEP concluded that there should be fairly consistent Wires Down rates across the data sources. As shown in the table below, the reports presenting full-system Wires Down rates are similar. However, the reports presenting HFTD-only data do not match. The mapped outage data showed many more Wires Down events in HFTDs than were reported by SOMs Metric 3.1 – 3.6 or in the QDR.

Table 2-26: Wires Down Report Comparison

Year	In HFTDs			Full System		
	SOM Metric 3.1 – 3.6	QDR in HFTDs	Outage Data	QDR in Full System	SPM # 2	Outage Data
2023	787	1,281	3,526	7,133	7,173	7,514
2022	522	525	1,002	3,159	3,132	3,315
2021	777	809	2,977	5,896	5,819	6,035

The difference between the reported Wires Down values in HFTDs suggests that there may be a problem with the SOMs data for Wires Down metrics generally. However, based on the good correlation between PG&E's HFTD destinations for transmission Wires Down events and the plotted event locations and the issues identified in Metric 3.1 and 3.2 for distribution Wires Down, FEP surmises that the wires down discrepancies described above largely stem from distribution Wires Down events. However, FEP was unable to conduct an in-depth analysis as the QDR data is not categorized into distribution and transmission events.

<u>**Verification of Metric Results**</u>

Assuming the HFTD designations originally provided by PG&E are correct, FEP found PG&E's calculation of the metric results to be accurate.

2.13.2 Metric 3.6 Management

The Electric Transmission team facilitates the calculation of the transmission Wires Down metric results. Reports for Metric 3.6 are run monthly. The reports are run by analysts then reviewed by the supervisors and managers. Once the data is validated, the performance results are added to the CMR reporting tool.

The reports are then validated and approved by the Asset Strategy and Standards team (Asset Strategy). Each month, Asset Strategy considers the year-to-date performance of the metric to determine if the metric is on track to achieve the one-year target and assess progress towards the five-year target.

The Electric Transmission team reviews the cause of all outages. The transmission teams can conduct in-depth cause investigations for all transmission Wires Down due to the limited number of Wires Down which occur per year. The cause investigations occur both for Wires Down and for other types of transmission outages. Sometimes investigations result in new information being revealed months after the initial Wires Down incident was reported. The results of the investigation can change the cause of the outage reported in the database.

The organization utilizes the Lean Operating Review and CIC meetings described in Section 1.4 to review the Metric 3.6 status and any catch back work activities. The team reviews controls and mitigations which are currently in place through the electric asset and vegetation management groups to determine corrective actions.

Though not directly related to the management of the SOMs metric, PG&E does undertake management activities for Wires Down more generally which may affect the metric results. If anomalies or problematic data trends are identified in the Wires Down data, ESS works with the reliability teams to do a deep dive into the causes of the trends. The most common drivers of downed wires are vegetation, weather, and contact from third-party objects. If problematic trends are identified, ESS brainstorms with the relevant departments, such as the reliability teams or the vegetation teams to understand mitigation options. Often, the adjustments and mitigations drive improvement to Wires Down rates in the longer term, rather than resulting in immediate improvement for the current year. Vegetation issues can be addressed more quickly overall than asset issues, as asset issues often require longer-term construction projects.

Observations on Metric 3.6 Management

Like the distribution process, transmission troubleshooters responding to events have access to technology in the field which is designed to capture relevant information in a way that limits data variability and reduces opportunities for mistakes. Additionally, the transmission team thoroughly reviews the cause of all transmission Wires Down and reports the information to multiple regulatory agencies, including CAISO.

Like FEP's observations for the distribution Wires Down metrics, the accuracy of transmission metrics would benefit from PG&E utilizing and communicating a clearer process for calculating transmission circuit miles. PG&E could calculate circuit miles on a set schedule, communicated in the report, and list the values used in calculations in each SOMs report. PG&E stated that beginning in 2023, circuit mile data was extracted annually on January 1, which would address this issue.

2.13.3 Metric 3.6 Performance and Targets

PG&E set the targets for Metrics 3.6 with a goal of maintaining performance. PG&E stated that it was unable to set a numerical target based on the limited dataset. The following table displays PG&E's 2013 through 2023 metric results and the 1-year and 5-year metric targets.

Table 2-27: Metric 3-6 Results and Targets

Year	Metric Result	1-Year Target	5-Year Target
2013	0.00		
2014	0.00		
2015	0.00		
2016	0.00		
2017	0.000054		
2018	0.00		
2019	0.00		
2020	0.000016		
2021	0.00	“Maintain”	“Maintain”
2022	0.00	“Maintain”	“Maintain”
2023	0.00	“Maintain”	“Maintain”
[1] Targets reflect the target set in that report year (i.e. the 2021 1-year target reflects 2022 target).			

PG&E only had measurable results in 2017 and 2020 with the remaining years being 0. PG&E does not have numerical targets for this metric. These values assume that PG&E’s reported metric results are correct, which FEP is uncertain of based off the HFTD designation discrepancies discussed above.

Observations on Metric 3.6 Performance and Targets

The lower frequency of transmission Wires Down events allows PG&E to conduct in-depth cause investigations for each event. FEP observes that the dataset is very small, which complicates target setting. PG&E emphasized this challenge in the 2021 SOMs report by stating that there were not enough events included in Metric 3.6 to set a quantitative target. However, without a quantitative target FEP observes that it may be difficult to identify a clear threshold at which point enforcement action is triggered. Without a clear threshold, FEP observes that using the metric for enforcement purposes could be more challenging for all parties, should there be disagreement on its necessity or appropriateness.

2.14 Metric 3.7: Missed HFTD Distribution Patrols

The CPUC defines Metric 3.7 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.

Metric 3.7 measures the percentage of missed patrols in a given time period, for distribution assets within the HFTD. A missed patrol is considered one that does not meet the GO 165 requirements. While PG&E performs patrols on all distribution assets this metric reports only on those in HFTD areas.

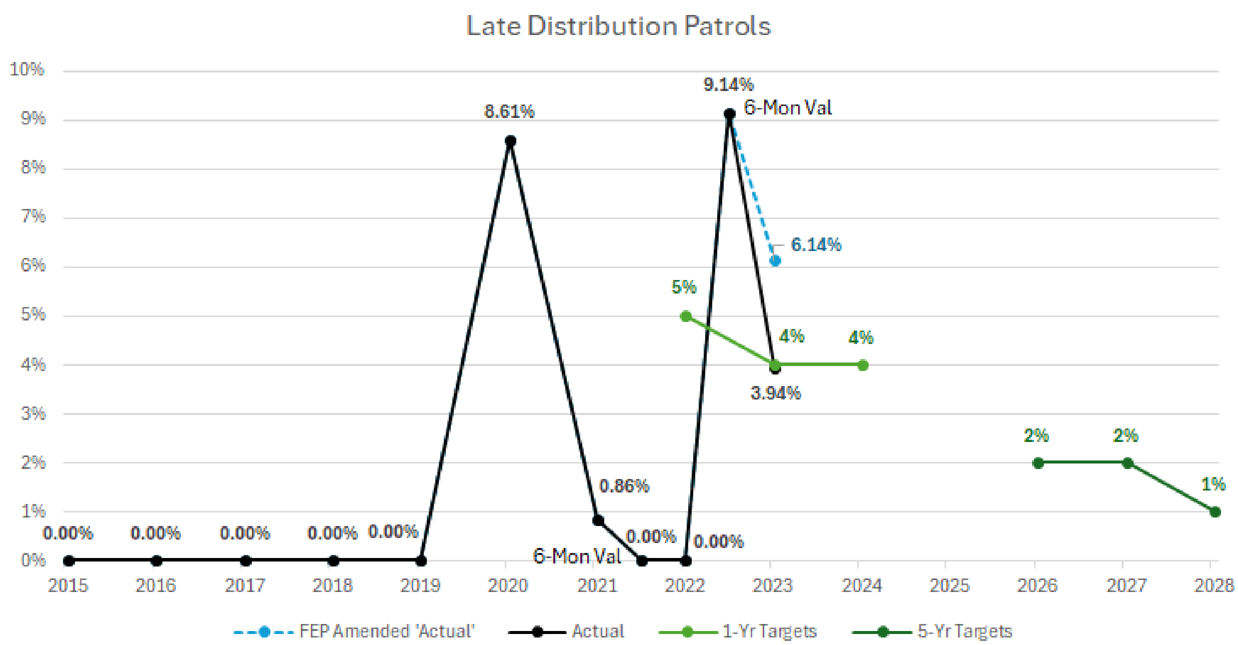
Patrols involve simple visual observations to identify obvious structural problems and hazards affecting safety or reliability. Within the HFTD, nonconformances identified by patrols can involve conditions that represent a wildfire ignition risk. Performing the required patrols on time ensures that nonconformances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

The formula for calculating Metric 3.7 is:

$$= \frac{\#\ of\ Distribution\ Structures\ Patrolled\ Late}{Total\ \#\ of\ Overhead\ Electric\ Distribution\ Structures\ Requiring\ Patrols}$$

The following chart shows Metric 3.7 results compared to targets for 2015 through 2028, including results from the 2022 and 2023 mid-year reports. All historical values reflect the most recent data available as of the 2023 report and may differ from previously reported figures.

Figure 2-26: Metric 3.7 Summary Chart



2.14.1 Metric 3.7 Accuracy and Consistency

Information for Metric 3.7 is extracted from two sources. Patrol information is gathered by the field personnel and then submitted to the division office to be entered into excel spreadsheets which are then manually entered into the SAP system (which contains all of PG&E's asset records). PG&E's electric distribution operations are divided into various geographic divisions, each responsible for a specific region. Each division has a local office to better serve the customers in that division. The patrol information in SAP is compared back to each individual excel spreadsheet to ensure that all assets have been updated with patrol information. This process has been consistent since 2015. PG&E notes that there are plans to automate the data collection process for patrols which will feed the SAP system automatically. Metric 3.7 is currently reported for HFTD areas only. Prior to 2020 the data within the SAP system was not identified as HFTD or non-HFTD. As a result, years 2015-2019 include systemwide data, whereas years 2020-2023 include HFTD-specific results. PG&E primarily adheres to the requirements of General Order 165 for reporting timelines.

Under GO 165, the month of each due date for each patrol is determined by the month of the last completed patrol. If a patrol is required in the current year, the new patrol must be completed by three months following the month of the most recent patrol, but still within the calendar year. For example, if the last patrol was completed in January 2020, and a patrol is required in 2023, the due date would be by the end of April 2023. If the last patrol was completed in November 2020, then the new patrol due date would be by the end of December 2023 instead, as to not pass the end of the calendar year. Separate rules under GO 165 determine how frequently patrols are required, based on whether a structure is located in an urban or rural area. The year in which a patrol is due is based on the location of the asset (i.e. rural, urban, etc.). For purposes of this analysis, FEP assumed that the annual Metric spreadsheets appropriately captured the patrols due in that year and tested the due date based on the month requirement.

While the GO 165 requirement has remained consistent, PG&E has applied two different interpretations of it over time. The approach described above reflects the interpretation used for the 2023 full-year report, where the patrol due date is calculated based on the most recent patrol. For reports prior to the 2023 full-year report, PG&E determined the due date for a patrol based on the most recent completed work, which could be either a patrol or an inspection. For example, if the last time a structure was inspected was January 2020, and the last time it was patrolled was June 2021, then the due date for the next patrol (if required in 2022) would be considered September 2022.

Additionally, in 2020, the company implemented an internal deadline of August 31 for completing all HFTD patrols as part of an enhancement to PG&E's Wildfire Mitigation Plan. PG&E prioritized patrols around the internal August 31 deadline instead of the GO 165 deadlines, leading to an uptick in missed patrols, according to the Metric 3.7 definition, in 2020 and 2021. Theoretically it would have been possible for PG&E to complete all patrols by both its internal August 31 deadline and the GO 165 deadlines. If PG&E had finished all patrols by August 31, patrols due by GO 165 regulations in September through December would have been completed early. However, because it prioritized its work based on the August 31 due date, patrols that could have been on-time by GO 165 regulations and early for the internal deadline may not have been done by the GO 165 deadline. For example, if it patrolled an asset in May that was due by GO 165 in April, it would have been late for GO 165 regulations but on-time for the internal PG&E deadline. Beginning in 2022, PG&E returned to completing patrols in compliance with GO 165.

In short, while the GO 165 patrol deadlines have not changed, PG&E's interpretation of them has. PG&E's initial interpretation of GO 165 was that the next patrol due date was based off of the last completed work (patrol or inspection). PG&E updated its interpretation of GO 165 deadlines for the 2023 report, instead assuming the next patrol due date was based on the last patrol date. In 2020 and 2021, although GO 165 was applicable and the metric was calculated using GO 165 deadlines, PG&E prioritized an internal August 31 deadline over GO 165 deadlines, leading to the increase in missed patrols during those years.

Observations on Metric 3.7 Accuracy

To determine the accuracy of the Metric 3.7 results, FEP verified PG&E's patrol methodology based on GO 165, the process for identifying assets within HFTDs, the late vs. on-time calculation, and the overall metric calculation methodology, particularly for mid-year reports. Based on this analysis, FEP found several accuracy issues:

1) There were several inconsistencies in the due date data and alignment with the GO 165 definition.

2) There was a methodology change for the full year 2023 report that is not consistent with prior reports regarding how non-HFTD assets are counted when included as part of an order that includes a HFTD asset. FEP believes the methodology change is flawed and results in a lower patrol rate than would otherwise have been reported.
3) There was a methodology change for the mid-year 2023 result from including only patrols due by June, to including any patrols completed by June, regardless of their due dates.

Verification of Patrol Requirement

For the analysis detailed below, FEP assumed that all patrols listed in the Metric 3.7 spreadsheet were required in that year, and that the spreadsheet captured all patrols that were due in the reporting year. FEP did not independently review the asset database to verify which structures required a patrol.

Verification of Patrol Due Date

To validate the accuracy of due dates used in the Metric 3.7 spreadsheet[35], FEP performed a calculation to see if the Due Date column (used to calculate a late or on-time patrol) was set to be 3 months beyond the previous patrol date (but in the relevant calendar year), or end of the year. FEP found inconsistencies with regard to PG&E's due dates in the Metric 3.7 spreadsheet versus FEP's derived due dates.

RFI responses revealed that PG&E set up its Metric 3.7 spreadsheet to show the due date for each patrol as the earlier of either the GO 165 due date, or an internal deadline used for its Wildfire Mitigation Plan ("WMP"). For example, if a patrol is due by September 2023 by GO 165 deadlines, but PG&E has an internal due date of July for that patrol, the date in the 'Due Date' column of the Metric 3.7 spreadsheet would show as July 2023. This means that given the metric calculation files as they stand, it is not possible to calculate the metric correctly. If that particular patrol was completed in August 2023, it would appear late on the spreadsheet, even though it was completed on time by GO 165 regulations used for the metric.

However, FEP also found that in some cases, the due date column appeared to show the later of the two due dates. For example, a patrol was due in June by GO 165 regulations and completed in August but not marked as late because the internal deadline for that patrol was December. This finding led to additional conversations with PG&E and led to PG&E reanalyzing the due dates for both the 2022 and 2023 full-year reports. This led to a change for 2023 from 21,853 assets patrolled late to 21,888 patrolled late. The reanalysis of 2022 due dates led to the same result of 0 patrols missed. A reanalysis of the 2021 due dates was not provided, nor were the last work dates provided in order to calculate the due dates. PG&E did not provide these due to the difficulty involved with recreating CPUC due dates years later due to changes to assets (GIS changes, systematic changes, changes to maintenance plans, etc.). However, given the issues in 2023 it's likely that the 2021 result is not correct as currently reported.

Verification of HFTD Classification

The Metric 3.7 spreadsheet contains a database of all completed patrols within the reporting timeframe, with each row representing a single patrol order. A patrol order is a collection of assets within the same patrol map that all share the same due date and completion date. When a patrol order is completed, the number of assets patrolled (referred to as Actual Units) is recorded.

[35] Available as part of the SOMs reports Safety and Operational Metrics, Data Files

Each patrol order is classified as either HFTD or Not HFTD. However, since HFTD boundaries do not align perfectly with patrol map boundaries, not all assets within a patrol order necessarily fall within an HFTD. If any assets in an order are located within an HFTD, the entire order is classified as HFTD. For the purposes of this analysis, HFTD classifications provided in the Metric 3.7 spreadsheet were assumed to be accurate and were not independently verified.

When calculating Metric 3.7 (late patrols divided by total required patrols), late patrols were historically counted as the sum of all Actual Units associated with orders that included any HFTD assets. The denominator, like the numerator, was also based on the total number of assets in orders that contained at least one HFTD asset. This approach led to an inflation effect, where both the numerator (late patrols) and denominator (total required patrols) were larger than the actual number of HFTD assets patrolled.

For the 2023 full-year report, PG&E modified the methodology for calculating the number of late patrols. Instead of counting all assets within a late HFTD order, the new approach identified and counted only the assets that are within HFTD boundaries and were patrolled late. For example, a patrol (plat map) may have 140 assets included, only 80 of which are within the boundaries of an HFTD area. Under the previous method, all 140 assets would have been counted as late and under the new method, only the 80 HFTD assets would be counted as late. However, the denominator calculation remains unchanged, still including all assets from orders that contain at least one HFTD asset. In the prior example, both methods would use 140 assets as the denominator. Under the old method, the late percentage would be 140/140 (100%) for that particular patrol. Under the new method, the late percentage would be 80/140 (57%), even though the entire patrol was completed late. This change reduced the final metric result, as fewer late patrols were counted in relation to the total required patrols. In response to a data request, PG&E commented "The 2023 mid-year methodology for metric calculation changed because the mid-year methodology inflated the late HFTD % by inadvertently including non HFTD units. This is because patrols are performed by map and not by asset which makes it difficult to remove non-HFTD units for the mid-year report. However, at the end of the year the non-HFTD units are removed from the metric. For the 2023 full-year report, the denominator did not change." In FEP's view, the numerator should not be reduced by removing the non-HFTD units unless the denominator is also reduced by removing the non-HFTD units. Otherwise, the methodology for numerator and denominator are different in a way that will make the percentage of late inspections appear smaller than it really is. Using the example early in this paragraph, 80/80 units in that particular plat map should be counted late if the methodology is to only include the assets within HFTD areas, since the denominator should also reflect only those units within HFTD areas.

To illustrate this, in the 2023 mid-year report (data through June), 29,032 patrols were reported as late. By the end of 2023, after applying the refined methodology, only 21,888 patrols were counted as late in the 2023 full-year report. The methodology to calculate the denominator remained unchanged between mid-year and full year 2023. The reported metric result for 2023 full year was 3.94%, however if the original methodology had been used (in line with all other calculation years), the result would have been 6.14%, as the late count for end of year 2023 would have been 34,100 instead of the 21,888 used. FEP calculated the 34,100 as the number of patrols that appear to be completed late using the original methodology used until the 2023 end of year change, where the number of late patrols is inflated by counting all structures within patrols orders that contained any HFTD assets as late, rather than just the HFTD assets themselves. This ensures that the numerator and denominator are both aligned with the same methodology. The table below indicates the numerator and denominator used for each report year. As shown, the 2023 Full-Year reflects how the numerator methodology changes but the denominator remains the same. The yellow highlighted cell shows what the result would have been if the same methodology as previous years had been applied. Note that the 2023 numbers are using the corrected due dates, as noted in the Verification of Patrol Due Date section above.

Table 2-28: Metric 3.7 Metric Calculation Methodology Differences

	Numerator	Numerator	Denominator
	Original Late Methodology: Counting All Units in Late Patrol Orders Containing HFTD Assets	New Late Methodology: Counting Only HFTD Assets in Late Patrol Orders Containing HFTD Assets	Total Methodology: Counting All Units in Patrol Orders Containing HFTD Assets
2023 Full-Year	34,100 (6.14%)	21,888 (3.94%)	555,194
2023 Mid-Year	29,032 (9.14%)		317,752
2022 Full-Year	0 (0.00%)		363,928
2022 Mid-Year	0 (0.00%)		132,790
2021 Full-Year	3,012 (0.86%)		352,120
2020	38,331 (8.61%)		445,113

There is an additional issue of uncertainty in the late counts under either methodology. When attempting to isolate the late HFTD assets within the late HFTD patrols, it sometimes resulted in numbers of late HFTD assets greater than the actual units initially recorded from the completed patrol. In many cases there were fewer HFTD assets than total assets in an HFTD patrol, since only one asset needs to be HFTD to make the entire patrol considered as HFTD[36]. However, in some cases the opposite was true, where more assets were recorded late than total units recorded in the patrol for the 2023 full-year dataset. This occurred in 45 out of 591 total late patrol orders in 2023. FEP followed up on this with several specific examples, one of which was for a patrol order that contained 70 total assets (actual units), but 71 assets were listed as late in the updated methodology. PG&E commented that "Assets are constantly updated within our system. The late asset list was based on the dataset pulled previously where one asset 103530337, was still active; hence = 71." PG&E further explained that the changes in asset counts are due to the difference between HFTD assignments that existed in GIS in 2023 versus the HFTD assignments that existed when the analysis to separate only HFTD assets was completed. Another example was for a patrol where 103 actual units were input into SAP (and this dataset), however when broken down by asset, 120 assets were considered late. PG&E clarified that in this case, "103 actual units were input in SAP in error. Actual units were 120." In the first case, the late asset list had been developed from a previous dataset, however in the second example, the late asset list had the most updated number of assets. Because of this, FEP cannot completely validate the late asset counts under either methodology, as the differences in datasets and system updates create uncertainty in the reported numbers.

__**Verification of Late/On-Time Calculation**__

FEP verified PG&E's late/on-time classification by analyzing whether patrols were marked as completed within their assigned due dates. For the 2023 mid-year report, FEP identified four patrol orders marked as "Pend" (pending) in the 'Completed' column, despite having due dates before June 30. These orders were marked as on time, even though they were not completed at the time of the report. When asked about these four, PG&E clarified that two of them were completed on time, one was completed late, and the fourth was a duplicate of an on-time report. The calculation file did not reflect these completion dates

[36] If there are 100 assets in a patrol, and only 1 of them is in the HFTD, the methodology used for all reports except for the 2023 full-year report would count all 100 assets as HFTD even though only 1 of them is in the HFTD.

due to late data entry. These maps were still pending closure at the time this data sheet was constructed. FEP recommends that all data to calculate the final metric result should be included in the data sheets as support.

FEP also inquired about the duplicate patrol record (two entries in the database for the same patrol), and PG&E responded with “Due to bordered maps (e.g. assets split between main work centers of same division or split between multiple divisions), duplicates may exist until validated by field inspectors. System Inspections Maintenance Planners review and update changes to structures and maintenance plans to avoid duplicate asset[s].” This duplicate had no ‘Actual Units’ listed, so was not included in the metric calculation. However, the existence of duplicates in the database brings into question whether all have been identified and removed from both numerator and denominator of the metric. FEP attempted to identify duplicate patrols, however given the data at hand it was not possible to confirm with certainty if two patrols were duplicates or simply shared many similarities. FEP recommends removing duplicates from the metric calculation sheet entirely when identified.

FEP also notes that only the 2023 mid-year data included pending patrol data, which depending on the methodology used (described in section below) could be included in the calculation for late patrols.

<u>Verification of Metric Definition Applied to Mid-Year Reports</u>

FEP reviewed how PG&E applied the Metric 3.7 definition in the mid-year reports for 2022 and 2023 and noted a difference in how required patrols were counted between the two years.

Metric 3.7 is calculated as the total number of structures that fell below the minimum patrol frequency requirements divided by the total number of structures that required patrols within the reporting period. For the 2023 mid-year report, the calculation included all patrols completed by June 30, regardless of their original due dates (including those after June). Under this interpretation, the numerator consists of all patrols completed as of June 30, while the denominator includes both completed and still-required patrols for the period. This means that if patrols are completed before June but with due dates after June, they are included in the denominator of the metric. Additionally, if patrols that are due before the end of June are not completed by the end of June, they are not marked as late until they are completed (which would be in the full-year report). An alternative interpretation would focus the metric calculation only on patrols with due dates up to June 30, ensuring that early patrol completions for later due dates are excluded. This approach would adjust both the numerator and denominator. The numerator would include patrols that were not completed but were due by the end of June, ensuring that patrols that were intended to be completed by the mid-year report would actually be marked late in the mid-year report. The denominator would shrink to include only those patrols that were required to be completed before the end of June, not patrols completed before the end of June but with deadlines beyond June. Using this alternative approach, the 2023 mid-year metric result would have been 16.45%, compared to the reported 9.14%. The table below highlights this difference. Note that using the ‘Due by June’ methodology, the late patrols increase slightly due to a patrol that was marked as pending in the 2023 mid-year report, had 37 planned units, and 37 actual units once the patrol was ultimately completed.

Table 2-29: 2023 Mid-Year Due Date Methodology Differences

	Metric Result	Late Patrols	Total Patrols
2023 Mid-Year, Due by June	16.45%	29,069	176,671
2023 Mid-Year, Completed by June	9.14%	29,032	317,752

In a response to a data request, PG&E responded that "We have used the methodology to include all units completed through June even if those units were due later in the year. This methodology is also used for the full year's report i.e. we include all inspections completed by December 31st. We believe this approach is reasonable and provides consistency." Based on this response, it appears that PG&E is indicating that the end of year reports use the same methodology. However, based on a later conversation this does not appear to be the case. For example, for the 2022 mid-year report, the dataset in in the Metric 3.7 spreadsheet only included patrols with due dates up to June 30. This implies that PG&E's calculation for mid-year 2022 inherently followed the alternative interpretation, counting only patrols that were actually due within the mid-year period. The dataset for the 2022 full-year dataset included many patrols that were due beyond June but completed before June, confirming that the mid-year report specifically excluded these early completions, unlike in the 2023 mid-year report. Additionally, it was clarified that for the year-end reports, if a patrol were outstanding as of the end of the year, it would be marked as late in the year it should have been completed, not the following year. This would match the alternative methodology originally used for the 2022 mid-year report, but not the 2023 mid-year report, as the 2023 mid-year report only considers inspections late if they were completed in the timeframe of the mid-year report.

2.14.2 Metric 3.7 Management

Metric 3.7 is managed within the Electric System Inspections organization. The Asset Strategy, Performance Measurement and Reporting and Electric Program Management teams provide support in gathering the data and providing the metric results to the metric owner for review. After the metric owner approves, the SOMs reports are reviewed on a monthly basis by Asset Strategy, Electric Program Management and Transmission System Inspection Directors for validation.

When the metric data is gathered and calculated for Metric 3.7, it is first extracted from SAP, which serves as the system of record for all assets and inspections. SAP maintains patrol dates, due dates, and related asset data. When additional patrols are completed, SAP is updated with the patrol date and any relevant details, and the next scheduled patrol date is set accordingly. Once exported, the data is used to calculate the final metric result in excel.

There are daily and weekly operations meetings within the distribution and transmission organizations. During these meetings, the metrics are reviewed and discussed for progress toward targets. On a monthly basis the metric results are calculated and reviewed by the Asset Strategy and Performance Measurement and Reporting teams. When they complete their review, the reports are forwarded to the Director of Program Management and Directors of Transmission Systems Inspections and Distribution System Inspections for their review. If they have questions, they will ask at that time. When they are all in agreement with the results, they are submitted to the electronic routing system which sends the reports to the program management team as well as the CIC for review.

Based on interviews with metric owners and various management personnel, it was determined that Metric 3.7 is not used to manage daily operations. The field personnel that perform the patrols are, in most cases, not even aware of the metrics. The teams managing the metric do not use it to measure performance but rather as a reporting tool performed as part of their daily responsibilities as it relates to SOMs reporting.

Observations on Metric 3.7 Management

The reporting system used to track the metric uses a "red light/green light" methodology that indicates the status of the metric at any given time within the month. If any metric is red the teams do a review to determine what the causes are and what needs to be done to get the metric back on track. If there are any cases where the metric may not recover, the teams notify the executive management as well as the CPUC to alert them to a possible miss of the target. While PG&E staff are actively monitoring this Metric, FEP notes that there are other initiatives within the organization, such as its Quality Pass Rate L1 metric which tracks the quality of Distribution Inspections HFTD, Transmission Inspections in HFTD, and Routine Vegetation Management Inspections in HFTD that likely drive the overall operations and management of patrols and inspections more so than the SOMs[37].

2.14.3 Metric 3.7 Performance and Targets

The Asset Strategy group within the Electric System Inspections group establishes the 1-year and 5-year targets for each of these metrics. PG&E states that it bases the high range of the targets on a review of historical data. In the 2021 SOM report PG&E stated the average for 2015 – 2019 was 0 –1% and used that as well as the 2020 result to set the 0 – 5% target for 2022. FEP found that based on the supporting data the 2015 – 2019 average calculated to be .00000045 which is .00045% and not 1% as stated by PG&E. In interviews with metric owners, it was determined that the internal goal that PG&E strives to achieve is 0%. PG&E does not use any benchmarking to assist in setting targets for these metrics. This is primarily due to the fact that PG&E reports only on those assets in HFTD areas, which are different for each utility.

The following table displays PG&E's 2015 through 2023 metric results and the 1-year and 5-year metric targets. FEP notes that there is confusion around what the targets were intended to be in the SOMs reports. For all reports up to the 2023 report, targets appear to have been incorrectly written as values such as "0 – 0.04 percent" for the 1-year target in the 2022 report. Based on data request responses and the language in the 2023 report, FEP interprets that to have meant 0 – 4% (or 0.00 to 0.04).

Table 2-30: Metric 3-7 Results and Targets

Year	Metric Result	1-Year Target[1]	5-Year Target[1]
2015	0.00%		
2016	0.00%		
2017	0.00%		
2018	0.00%		
2019	0.00%		
2020	8.61%		
2021	0.86%	0 – 5%	0 – 2%
2022	0.00%	0 – 4%	0 – 2%
2023	3.94%	0 – 4%	0 – 1%
[1] Targets reflect the target set in that report year (i.e. the 2021 1-year target reflects 2022 target).			

The 2020-2023 average has been 3.35%. The highest year of 8.61% late patrols (38,000 out of 445,000) in 2020 was due to prioritizing and planning to an internal deadline instead of GO 165. The metric improved by almost 90% in 2021 to 0.86% (3012 out of 352,000), even with the same internal deadlines. 2022 showed zero missed inspections. The spike in 2023 to 3.94% (22,000 out of 555,000) was partly due to

[37] Pacific Gas and Electric Company, Advice Letter ELEC_6705-E (Sept. 22, 2022), p. 42, https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_6705-E.pdf.

missed patrols in April and May due to PG&E incorrectly calculating due dates. However, close to 4,000 patrols were late with June and July due dates (see table below).

Table 2-31: 2023 Late Patrol Count by Month

Month	Late Patrol Count (FEP Methodology)
1	0
2	0
3	0
4	29,635
5	929
6	2,018
7	1,635
8	0
9	0
10	0
11	0
12	0

However, given the accuracy issues reported above, FEP is not confident the results presented are accurate and consistent.

Observations on Metric 3.7 Performance and Targets

As shown in the targets table above, PG&E's targets have generally decreased year over year and we note that the 5-year targets are set at levels significantly lower than the 1-year target, which is directionally consistent with the target setting for performance improvement. We also note that using zero for the low end of the range is consistent with an aspirational target although we note that the upper end of the range seems to be the more significant factor since that is what presumably could trigger EOE. That said, given actual performance, the targets, particularly the 5-year targets do appear to be set at levels that would drive performance improvement. GO 165 is a CPUC regulation and any missed patrol would constitute a failure to meet the Order requirement. While PG&E has an internal goal of achieving 0% misses, it uses the range of target values to provide an indicator when the results are moving away from 0%. FEP recommends that PG&E and CPUC develop a formal process for PG&E to explain any variance from 0% that could be used to consider if any EOE is required.

While FEP is not aware of any benchmarks available to benchmark Metric 3.7, given its specific definition for HFTD, we do note that there is an SPM for missed inspections and patrols by distribution and transmission (all areas) which could be used as a directional benchmark.

2.15 Metric 3.8: Missed HFTD Distribution Inspections

The CPUC defines Metric 3.8 as:

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.

Metric 3.8 measures the percentage of missed inspections in a given time period, for distribution assets within the HFTD. A missed inspection is considered one that does not meet the GO 165 requirements. While PG&E performs inspections on all distribution assets this metric reports only on those in HFTD areas.

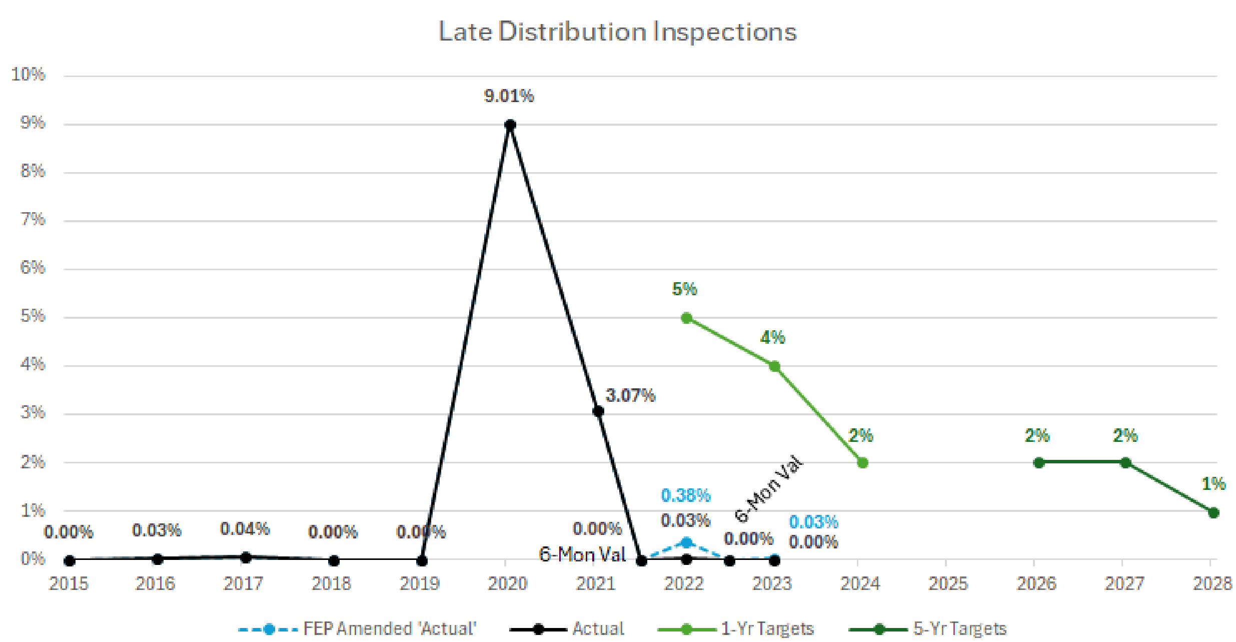
Detailed inspections are performed to identify non-conformances affecting safety or reliability. Inspections often involve a more systematic evaluation of the assets. It involves a much closer look at the asset versus a patrol and can include testing of components, thermal imaging of the assets or checking for wear and tear. A patrol on the other hand is a more "surface level" observation to detect obvious hazards or abnormalities. Within the HFTD, non-conformances 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.

The formula for calculating Metric 3.8 is:

$$= \frac{\#\ of\ Distribution\ Structures\ Inspected\ Late}{Total\ \#\ of\ Overhead\ Electric\ Distribution\ Structures\ Requiring\ Inspections}$$

The following chart shows Metric 3.8 results compared to targets for 2015 through 2028, including results from the 2022 and 2023 mid-year reports. All historical values reflect the most recent data available as of the 2023 report and may differ from previously reported figures.

Figure 2-27: Metric 3.8 Summary Chart



2.15.1 Metric 3.8 Accuracy and Consistency

Information for Metric 3.8 is entered at the field level for inspections using handheld devices that are used by the inspectors. This information goes into the SAP system, which contains all of PG&E's assets. Attainment Reports are the output of SAP inspection data, which are used to calculate the percentage of missed inspections in the Metric 3.8 spreadsheets[38]. This process has been consistent for the SOM reporting period.

Information for Metric 3.8 is extracted from two sources. Inspection information is gathered by the field personnel and entered in the hand-held device used by the inspector. The data is then automatically fed into the SAP (which contains all of PG&E's asset records). A daily attainment report is also created, with data extracted from SAP for each asset. PG&E's electric distribution operations are divided into various geographic divisions, each responsible for a specific region. Each division has a local office to better serve the customers in that division. This process has been consistent since 2015. Metric 3.8 is currently reported for HFTD areas only. Prior to 2020 the data within the SAP system was not identified as HFTD or non-HFTD. As a result, years 2015-2019 include systemwide data, whereas years 2020-2023 include HFTD-specific results. PG&E primarily adheres to the requirements of General Order 165 for reporting timelines.

Under GO 165, the month of each due date for each inspection is determined by the month of the last completed inspection. If an inspection is required in the current year, the new inspection must be completed by three months following the month of the most recent inspection, but still within the calendar year. For example, if the last inspection was completed in January 2020, and an inspection is required in 2023, the due date would be by the end of April 2023. If the last inspection was completed in November 2020, then the new inspection due date would be by the end of December 2023 instead, as to not pass the end of the calendar year. GO 165 requires overhead inspections every five years. PG&E, however, sets its HFTD inspection cycles at 1, 2, or 3 years. Although those shorter intervals aren't mandated by GO 165, in years when an inspection isn't scheduled, a patrol is required, and these more frequent inspections effectively substitute for patrols. As a result, even if an inspection occurs fewer than five years after the previous one, it can still be considered late depending on when it was completed since it replaces a required annual patrol under GO 165. In all cases, the "next due" date for an inspection is calculated from the prior inspection's completion date, regardless of whether than inspection stood in for a patrol. For purposes of this analysis, FEP assumed that the annual Metric spreadsheets appropriately captured the patrols due in that year and tested the due date based on the month requirement.

While the GO 165 requirement has remained consistent, PG&E has applied two different interpretations of it over time. The approach described above reflects the interpretation used for the 2023 full-year report, where the inspection due date is calculated based on the most recent inspection. For reports prior to the 2023 full-year report, PG&E determined the due date for an inspection based on the most recent completed work, which could be either an inspection or a patrol. For example, if the last time a structure was inspected was January 2020, and the last time it was patrolled was June 2021, then the due date for the next inspection (if required in 2022) would be considered September 2022.

Additionally, in 2020, the company implemented an internal deadline of August 31 for completing all HFTD inspections as part of an enhancement to PG&E's Wildfire Mitigation Plan. PG&E prioritized inspections around the internal August 31 deadline instead of the GO 165 deadlines, leading to an uptick in missed inspections, according to the Metric 3.8 definition, in 2020 and 2021. Theoretically it would have been

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[38] Available as part of the SOMs reports Safety and Operational Metrics, Data Files

possible for PG&E to complete all inspections by both its internal August 31 deadline and the GO 165 deadlines. If PG&E had finished all inspections by August 31, inspections due by GO 165 regulations in September through December would have been completed early. However, because it prioritized its work based on the August 31 due date, inspections that could have been on-time by GO 165 regulations and early for the internal deadline may not have been done by the GO 165 deadline. For example, if it inspected an asset in May that was due by GO 165 in April, it would have been late for GO 165 regulations but on-time for the internal PG&E deadline. Beginning in 2022, PG&E returned to completing inspections in compliance with GO 165.

In short, while the GO 165 inspection deadlines have not changed, PG&E's interpretation of them has. PG&E's initial interpretation of GO 165 was that the next inspection due date was based off of the last completed work (patrol or inspection). PG&E updated its interpretation of GO 165 deadlines for the 2023 report, instead assuming the next inspection due date was based on the last inspection date. In 2020 and 2021, although GO 165 was applicable and the metric was calculated using GO 165 deadlines, PG&E prioritized an internal August 31 deadline over GO 165 deadlines, leading to the increase in missed patrols during those years.

Observations on Metric 3.8 Accuracy

To determine the accuracy of the metric results, FEP verified PG&E's inspection methodology based on GO 165, the process for identifying assets within High Fire Threat Districts (HFTDs), the late vs. on-time calculation, and the overall metric calculation methodology, particularly for mid-year reports. Based on this analysis, FEP found several accuracy issues:

1) There were inconsistencies in the due date data and alignment with the GO 165 definition.
2) Several RFIs asking about due date calculations led to the discovery of 50 additional late inspections in 2023, and 1365 additional late inspections in 2022
3) FEP discovered an error in reporting late inspections in 2020.
4) Verification of the late/on-time status revealed that due to missing data on the Metric 3.8 spreadsheet, it's not possible to recreate the late vs on-time calculations PG&E performed.
5) The methodology for the mid-year 2022 and 2023 reports appear to include any patrols completed by June, regardless of their due dates.
6) Total inspection counts in the mid-year 2022 and 2023 reports are unclear and unable to be validated.
7) Multiple inspections on the same asset (of different inspection types) inflated the denominator of the metric.

Verification of Inspection Requirement

For the analysis detailed below, FEP assumed that all inspections listed in the Metric 3.8 spreadsheet were required in that year, and that the spreadsheet captured all inspections that were due in the reporting year. FEP did not independently review the asset database to verify which structures required an inspection.

<u>Verification of Inspection Due Date</u>

To validate the accuracy of due dates used in the Metric 3.8 spreadsheet, FEP attempted to perform a calculation to see if the Due Date column (used to calculate a late or on-time inspection) was set to be 3 months beyond the previous inspection date (but in the relevant calendar year), or end of year if that comes first. However, last inspection dates were not originally available in the Metric 3.8 spreadsheet.

Upon receiving these inspection dates, FEP recalculated each due date. This review identified 32 additional inspections that were late in 2023 (which PG&E confirmed) instead of the 10 originally reported. In combination with the error in 2023 identified in the Verification of Late/On-Time Calculation section below, the total late inspections for 2023 were 60. This would bring the metric result for the 2023 full-year report to 0.03% instead of 0.004% (rounded to 0.00% for reporting).

Upon receiving the last inspection or patrol dates for inspections in the 2022 Metric 3.8 spreadsheet, FEP and PG&E identified 1,484 late inspections, as opposed to the 119 that were originally reported. PG&E reported that since the initial conversation on due dates and last inspection dates with FEP, PG&E has undergone a deep dive analysis to identify the issues that caused this level of error (primarily manual human errors), and have put new processes in place to prevent this from happening in the future, like improving the peer review process and reformatting the SOMs spreadsheets. This updated late inspection count would bring the metric result to 0.38% instead of the originally reported 0.03%.

Last inspection dates to calculate the correct due dates were not provided for 2021 due to the difficulty involved with recreating CPUC due dates years later due to changes to assets (GIS changes, systematic changes, changes to maintenance plans, etc.), so FEP was unable to fully verify the metric result. However, given the significant errors in 2022 and 2023, it appears likely that there would be errors in the 2021 data as well.

Verification of HFTD Classification

FEP verified that PG&E only included inspections for structures it classified as being within the HFTD. However, for the purposes of this analysis, HFTD classifications provided in the Metric 3.8 spreadsheet were assumed to be accurate and were not independently verified.

Verification of Late/On-Time Calculation

FEP verified PG&E's late/on-time classifications by validating that each inspection marked as on-time was completed before its due date, and each inspection marked as late was completed after its due date.

For the 2023 full-year report, FEP identified a total of 28 inspections that appeared to be late based on the due dates originally in the Metric 3.8 spreadsheet (where the completion dates for these inspections were after the corresponding due dates). In addition to the previously identified additional 32 late inspections (discussed in the Verification of Inspection Due Date section), a total of 60 inspections appears to be late in 2023, instead of the originally reported 10. PG&E acknowledged both of these errors, and confirmed that 60 is the correct number of late inspections in 2023.

Additionally, FEP identified 115 additional late inspections in 2020 (31,650 rather than 31,535). PG&E acknowledged this error, indicating in an RFI response that "we made an error in calculating late and on-time resulting in an additional 115 late HFTD inspections. PG&E will provide this correction in the March 2025 Report."

Verification of Metric Definition Applied to Mid-Year Reports

Metric 3.8 is calculated as the total number of structures that fell below the minimum inspection frequency requirements divided by the total number of structures that required inspections within the reporting period. For the 2022 and 2023 mid-year report, the calculation included all inspections completed by June 30, regardless of their original due date. Under this interpretation, the numerator consists of all inspections completed as of June 30, while the denominator includes both completed and still-required inspections for the period. This means that if inspections are completed before June but with due dates after June, they are included in the denominator of the metric. Additionally, if the inspections that are due before the end of June are not completed by the end of June, they are not marked as late until they are completed (which would be in the full-year report). An alternative interpretation would focus the metric calculation only on inspections with due dates up to June 30, ensuring that early inspection completions for later due dates are excluded. This approach would adjust both the numerator and denominator. The numerator would include inspections that were not completed but were due by the end of June, ensuring that inspections that were intended to be completed by the mid-year report would actually be marked late in the mid-year report. The denominator would shrink to include only those inspections that were required to be completed before the end of June, not inspections completed before the end of June but with deadlines beyond June. In an RFI response, PG&E confirmed that one late inspection was not included in the 2023 mid-year report due to it being completed in July, even though it had a pre-June 30 due date. For the 2022 mid-year metric, PG&E reported one inspection missed out of 247,673. With the alternative methodology, including only inspections whose due dates are on or before June 30, PG&E missed one inspection out of 42,165. For the 2023 mid-year metric, PG&E reported 0 inspections missed out of 77,138 but FEP identified one inspection missed out of a total of 9,068, leading to a metric result of 0.01% instead of 0.00%, if this alternative interpretation is to be used. The table below highlights these differences.

Table 2-32: 2022 and 2023 Mid-Year Methodology Differences

	Metric Result	Late Inspections	Total Inspections
2023 Mid-Year, Due by June	0.01%	1	9,068
2023 Mid-Year, Completed by June	0.00%	0	77,138
2022 Mid-Year, Due by June	0.00%	1	42,165
2022 Mid-Year, Completed by June	0.00%	1	247,673

<u>Total Inspection Count Verification</u>

For the 2022 mid-year report, using PG&E's approach to mid-year reports (which is to include only those inspections completed by June 30, regardless of due date), FEP identified a total of 247,745 inspections instead of the 247,673 that PG&E reported. An RFI response from PG&E for this issue was as follows: "We are unable to validate which inspections were excluded from the dataset. However, upon further inspection of the spreadsheet we noticed certain inspections that should have been excluded because (1) They were completed in July and September and (2) some assets were non-HFTD. However, the identified exclusions are so few that they would have no material impact on the metric. Though the change was identified as having no material impact, FEP is concerned about the lack of ability to validate the reported total inspection count, and the new issues identified by looking into the total inspection count.

<u>Multiple and Duplicate Inspections Verification</u>

FEP submitted an RFI asking about why there are multiple inspections recorded for many Equipment IDs in the dataset. PG&E responded by indicating that duplicate inspections occur when assets are on the border of two main work centers or divisions and are mistakenly added to multiple orders. As a result, these assets are inspected twice, and both inspections are included in the dataset and counted as completed inspections. In FEP's view, these duplicates should not be included in the denominator of this metric, since the GO 165 requirement is only for one inspection or patrol per year, not two. Including multiple inspections per asset inflates the denominator (since none of these duplicates were for inspections that were late), leading to a lower metric result than should be reported. Although in 2023 only 13 assets were inspected twice out of 230,803 total assets (leading to a very small change in denominator), the denominator should only include one inspection per asset.

Other

FEP discovered that not all inspections in the Metric 3.8 Spreadsheet are required for the reporting year, which led to discrepancies in the identification of late inspections. Specifically, there were 5 assets in the 2023 Metric 3.8 Spreadsheet that had last inspection dates of June 2020 and were completed in December 2023. The +3 month methodology would put the due date for those inspections at September 2023, making those 5 inspections late. However, PG&E clarified in an interview that those 5 assets were installed in 2021, meaning an inspection was not required by the CPUC in 2023 and therefore should not be considered late. PG&E clarified that even though the last inspection dates were reported as June 2020, that date refers to the last time that location had been inspected as opposed to that particular asset, which was installed in 2021. FEP was under the assumption that all inspections that are in the Metric 3.8 Spreadsheet were required to be completed in that year. Since these 5 assets were not required to be completed in 2023 by CPUC requirements, they should not be part of the metric calculation and should not be included in the denominator of the metric. Additionally, the presence of a 2020 inspection date for assets installed in 2021 raises questions about whether the reported “last inspection date” refers to the current asset or to a different structure previously located at the same site.

In the 2021 full-year report, FEP noted that PG&E mistakenly reported 4.10% missed inspections instead of the 3.07% that the Metric 3.8 spreadsheet reflects. In a data request response, PG&E responded that in responding to the request it had discovered a computational error that was found in the calculation of 4.10%. PG&E reported that the percentage should show 3.07% based on the underlying data. FEP came to the same conclusion.

2.15.2 Metric 3.8 Management

Metric 3.8 is managed within the Electric System Inspections organization. The Asset Strategy, Performance Measurement and Reporting and Electric Program Management teams provide support in gathering the data and providing the metric results to the metric owner for review. After the metric owner approves, the results are reviewed by Asset Strategy, Electric Program Management and Transmission System Inspection Directors for validation on a monthly basis.

When the metric data is gathered and calculated for Metric 3.8, it is first extracted from SAP, which serves as the system of record for all assets and inspections. SAP maintains inspection dates, due dates, and related asset data. When additional patrols are completed, SAP is updated with the inspection date and any relevant details, and the next scheduled inspection date is set accordingly. Once exported, the data is used to calculate the final metric result in excel.

There are daily and weekly operations meetings within the distribution and transmission organizations. During these meetings, the metrics are reviewed and discussed for progress toward targets. On a monthly basis the metric results are calculated and reviewed by the Asset Strategy and Performance Measurement and Reporting teams. When they complete their review, the reports are forwarded to the Director of Program Management and Director of Transmission Systems Inspections or Distribution System Inspections for their review. If they have questions, they will ask at that time. When they are all in agreement with the results, they are submitted to the electronic routing system which sends the reports to the program management team as well as the CIC for review.

Based on interviews with metric owners and various management personnel, it was determined that Metric 3.8 is not used to manage daily operations. The field personnel that perform the inspections are, in most cases, not even aware of the metrics. The teams managing the metric do not use it to measure performance but rather as a reporting tool performed as part of their daily responsibilities as it relates to SOMs reporting.

Observations on Metric 3.8 Management

The reporting system used to track the metric uses a "red light/green light" methodology that indicates the status of the metric at any given time within the month. If any metric is red the teams do a review to determine what the causes are and what needs to be done to get the metric back on track. If there are any cases where the metric may not recover, the teams notify the executive management as well as the CPUC to alert them to a possible miss of the target. While PG&E staff is actively monitoring this Metric, FEP notes that there are other initiatives within the organization, such as its Quality Pass Rate L1 metric which tracks the quality of Distribution Inspections HFTD, Transmission Inspections in HFTD, and Routine Vegetation Management Inspections in HFTD that likely drive the overall operations and management of patrols and inspections more so than the SOMs.

2.15.3 Metric 3.8 Performance and Targets

The Asset Strategy group within the Electric System Inspections group establishes the 1-year and 5-year targets for each of these metrics. PG&E states that it bases the high range of the targets on a review of historical data. In the 2021 SOM report PG&E stated the range for 2015 – 2019 was 0.01 to 0.04% and used that as well as the 2020 result to set the 0 – 5% target for 2021. FEP found that based on the supporting data the 2015 – 2019 average calculated to be .00015 which is .015% and not .04% as stated by PG&E. In interviews with metric owners, it was determined that the internal goal that PG&E strives to achieve is 0%. PG&E does not use any benchmarking to assist in setting targets for these metrics. This is primarily due to the fact that PG&E reports only on those assets in HFTD areas, which are different for each utility.

The following table displays PG&E's 2015 through 2023 metric results and the 1-year and 5-year metric targets. FEP notes that there is confusion around what the targets were intended to be in the SOMs reports. For all reports up to the 2023 report, targets appear to have been incorrectly written as values such as "0 – 0.04 percent" for the 1-year target in the 2022 report. Based on data request responses and the language in the 2023 report, FEP interprets that to have meant 0 – 4% (or 0.00 to 0.04).

Table 2-33: Metric 3-8 Results and Targets

Year	Metric Result	1-Year Target[1]	5-Year Target[1]
2015	0.00%		
2016	0.00%		
2017	0.00%		
2018	0.00%		
2019	0.00%		
2020	9.01%		
2021	3.07%[2]	0 – 5%	0 – 2%
2022	0.03%	0 – 4%	0 – 2%
2023	0.00%	0 – 2%	0 – 1%

[1] Targets reflect the target set in that report year (i.e. the 2021 1-year target reflects 2022 target).
[2] Reflects update to the metric

The 2021-2023 average has been 1.03%. The highest year of 9.01% late inspections (32,000 out of 350,000) in 2020 was due to prioritizing and planning to the August 31 internal deadline discussed above, instead of GO 165. The metric improved by almost 66% in 2021 to 3.07% (14,000 out of 452,000), even with the same internal deadline issue. 2022 showed 0.03% and 2023 showed 0% late inspections.

However, given the accuracy issues reported above, we are not confident the results presented are accurate and consistent.

Observations on Metric 3.8 Performance and Targets

As shown in the table above, PG&E's targets have generally decreased year over year and we note that the 5-year targets are set at levels significantly lower than the 1-year target, which is directionally consistent with the target setting for performance improvement. We also note that using zero for the low end of the range is consistent with an aspirational target although we note that the upper end of the range seems to be the more significant factor since that is what presumably could trigger EOE. That said, given actual performance, the targets, particularly the 5-year targets, appear to be set at levels that would drive performance improvement. GO 165 is a CPUC regulation and any missed inspection would constitute a failure to meet the Order requirement. While PG&E has an internal goal of achieving 0% misses, it uses the range of target values to provide an indicator when the results are moving away from 0%. FEP would recommend that PG&E and CPUC develop a formal process for PG&E to explain any variance from 0.

While FEP is not aware of any data available to benchmark Metric 3.8, given its specific definition for HFTD, we do note that there is an SPM for missed inspections and patrols by distribution and transmission (all areas) which could be used as a directional benchmark.

2.16 Metric 3.9: Missed HFTD Transmission Patrols

The CPUC defines Metric 3.9 as:

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.*

Metric 3.9 measures the percentage of late patrols in a given time period, for transmission assets within the HFTD. A late patrol is one that was conducted later than July 31 (for 2021-2023), with different exceptions made based on the year.

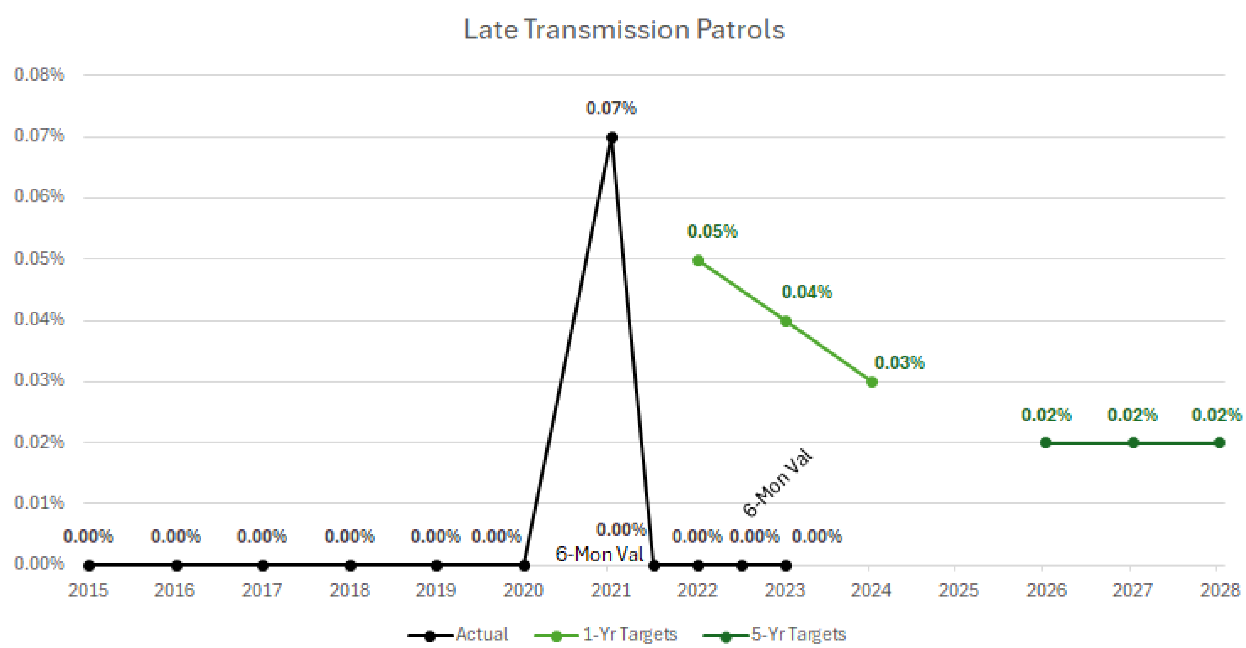
Patrols involve simple visual observations to identify obvious structural problems and hazards affecting safety or reliability. Within the HFTD, nonconformances identified by patrols can involve conditions that represent a wildfire ignition risk. Performing the required patrols on time ensures that nonconformances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

The formula for calculating Metric 3.9 is:

$$= \frac{\#\ of\ Transmission\ Structures\ Patrolled\ Late}{Total\ \#\ of\ Electric\ Transmission\ Structures\ Requiring\ Patrols}$$

The following chart shows Metric 3.9 results compared to targets for 2015 through 2028, including results from the 2022 and 2023 mid-year reports. All historical values reflect the most recent data available as of the 2023 report and may differ from previously reported figures.

Figure 2-28: Metric 3.9 Summary Chart



2.16.1 Metric 3.9 Accuracy and Consistency

Information for Metric 3.9 is extracted from two sources. Patrol information is gathered by the field personnel and then submitted to the division office to be entered into excel spreadsheets which are then manually entered into the SAP system (which contains all of PG&E's asset records). PG&E's electric transmission operations are divided into various geographic divisions, each responsible for a specific region. Each division has a local office to better serve the customers in that division. The patrol information in SAP is compared back to each individual excel spreadsheet to ensure that all assets have been updated with patrol information. PG&E notes that there are plans to automate the data collection process and entry into SAP. This process has been consistent for the SOM reporting period since 2015. Metric 3.9 is currently reported for HFTD areas only. Prior to 2020 the data within the SAP system was not identified as HFTD or non-HFTD. As a result, years 2015-2019 include systemwide data, whereas years 2020-2023 include HFTD-specific results.

All HFTD transmission assets must have a patrol or inspection done each year. For Metric 3.9, there was no specific deadline for completing patrols within the year for 2020. Starting in 2021 and for following years, there was a July 31 deadline. In 2021 there were exceptions made for access issues and weather that may have prevented a helicopter from flying. Starting in 2022, there were exceptions made for assets added to the asset registry or assets whose HFTD status was changed after July 31, granting an additional 90 days in these situations to complete the patrol and not be counted late.

Observations on Metric 3.9 Accuracy

To determine the accuracy of the metric results, FEP verified PG&E's late patrol counts, total patrol counts, and HFTD designations for each report year.

Verification of Patrol Requirement

For the analysis detailed below, FEP assumed that all patrols listed in the Metric 3.9 spreadsheet were required in that year, and that the spreadsheet captured all patrols that were due in the reporting year. FEP did not independently review the asset database to verify which structures required a patrol.

HFTD Verification

FEP verified that the metric results include only patrols conducted in HFTDs, specifically Tier 2 and Tier 3. For the purposes of this analysis, HFTD classifications provided in the Metric 3.9 spreadsheet were assumed to be accurate and were not independently verified. FEP discovered an inconsistency in the 2023 full-year dataset and report, which incorrectly includes patrols in Tier 2, Tier 3, as well as HFRA, and Zone 1 areas. This was identified and confirmed by PG&E in an RFI response. Since the numerator for the 2023 full-year metric was zero, any change in the total patrol count does not affect the final metric result. However, the reported denominator of 44,981 was incorrect. Excluding HFRA and Zone 1 patrols alone reduces the total to 44,145.

Late Patrols Verification

By definition for Metric 3.9, a late patrol is one completed past a designated deadline, with different exceptions applied depending on the year. In 2020, the implied deadline was December 31. Starting in 2021, the deadline shifted to July 31. Additionally, in 2021 exceptions were made for access issues and weather conditions that may have prevented helicopter patrols. Starting in 2022, additional exceptions were introduced for assets that were either newly added to the registry or had to HFTD status changed after July 31. In these cases, a 90-day extension was granted. PG&E also has separate regulatory requirements to patrol certain assets quarterly, primarily on the Diablo Canyon circuits.

PG&E states that its calculation method involved identifying patrols completed after the Required End Date for quarterly patrols and excluding those that qualify for exceptions. However, FEP's analysis suggests that PG&E applies an additional filter, that a patrol is only considered late if it was completed after both its Required End Date and after July 31 in that year (for 2021–2023). Applying this logic to the publicly available datasets provided results in 45 late patrols in 2021, and none in any other years.

This filtering method raises the question of whether or not patrols completed after July 31 but still before the Required End Dates should be counted as late, since July 31 represents the Metric 3.9 due date, and the Required End Dates represent internal commitment dates other requirements. When filtering the data only by patrols completed after July 31, the 2023 full-year data shows that 2,912 patrols were completed after that date. However, all of these patrols had required end dates of either September 30 or December 31, indicating quarterly patrol requirements. Because of the quarterly patrol requirements, there are multiple patrols completion dates recorded for each of these assets (4 per year if the structure was installed prior to the start of the year). Because of this, many of the 2,912 patrols that were completed after July 31 also had inspection dates before July 31 (for the inspections in the first two quarters). By Metric 3.9 standards, since there were already patrols completed earlier in the year, these should not be counted as late. After removing patrols that had an earlier patrol completed prior to July 31, only 18 records remained as potentially late patrols for 2023, and these 18 structures were identified as having exceptions. In 2022, 4 structures were patrolled after July 31, had quarterly Required End Dates, and did not have a patrol before July 31. For 2021, 94 such records fit in this category. Since all of these structures had the first Required End Date in a quarter after July 31, this suggests they were not yet in service before that date. If so, they would have been granted a 90-day extension, meaning they did not require a quarterly patrol before July 31. PG&E confirmed that all 18 pieces of equipment in 2023, 4 in 2022, and 49 of the 94 in 2021 were not late because they were first patrolled within 90 days of installation. For example, one of the structures in 2022 was installed on July 12, 2022, but not patrolled until August 17, 2022, making the first patrol within 90 days of installation. The remaining 45 patrols in 2021 were marked late by PG&E.

FEP identified many cases of duplicate inspection records being present in the data. Specifically, 138 in 2023, 1 in 2022, and 12 in 2021. In these cases, the inspection records appear to be the exact same. FEP presented PG&E with a sample of 3 of the 151 total to provide detailed explanations for. PG&E responded by indicating that in all 3 cases, duplicate notifications had been created in error. These duplicate cases were included in the metric results, however, they should be excluded to avoid inflating the metric denominator due to errors.

The database in the Metric 3.9 spreadsheet[39] for each year contains duplicate patrols in some cases and multiple different patrols for the same asset when inspected quarterly. Metric 3.9 appears to be intended as a ratio of late patrols to required patrols, where required patrols would refer to only one patrol conducted before July 31 for each asset. However, the current denominator includes duplicate patrols and multiple patrols for the same asset (due to repeats from quarterly patrols), which inflates the total patrols. To ensure accuracy, all patrols beyond one per structure should be excluded from the denominator. Making this change for previously reported metrics would only result in a change in metric result for 2021, since it’s the only year with a non-zero numerator. Metric 3.9 for 2021 was originally calculated to be 0.07% (45/64,168), however correcting for this issue would result in 0.08% (45/59,909).

2.16.2 Metric 3.9 Management

The Electric Systems Inspection department has overall responsibility for Metric 3.9. The Asset Strategy, Performance Measurement and Reporting and Electric Program Management teams provide support in

[39] Available as part of the SOMs reports Safety and Operational Metrics, Data Files

gathering the data, performing analysis and then providing the metric results to the metric owner for review.

When the metric data is gathered and calculated for the SOM, the Asset Strategy and Performance Measurement and Reporting groups review the results and compare them to the metric targets. The data is then tracked against each asset in the SAP database to track what assets have been addressed with a patrol. As each patrol is done the record is updated with that date and with the relevant data noted in the patrol. The date for the next patrol is also established at this point.

There are daily and weekly operations meetings within the distribution and transmission organizations. During these meetings, the metrics are reviewed and discussed for progress toward targets. On a monthly basis the metric results are calculated and reviewed by the Asset Strategy and Performance Measurement and Reporting teams. When they complete their review, the reports are forwarded to the Director of Program Management and Director of Transmission Systems Inspections or Distribution System Inspections for their review. If they have questions, they will ask at that time. When they are all in agreement with the results, they are submitted to the metric owner for approval who then submits the report to the electronic routing system which sends the reports to the program management team as well as the CIC for review.

Based on interviews with metric owners and various management personnel, it was determined that Metric 3.9 is not used to manage daily operations. The field personnel that perform the patrols are, in most cases, not even aware of the metrics. The teams managing the metrics do not use them to measure performance but rather as a reporting tool performed as part of their daily responsibilities as it relates to SOMs reporting.

Observations on Metric 3.9 Management

The reporting system used to track the metric uses a “red light/green light” methodology that indicates the status of the metric at any given time within the month. If any metric is red the teams do a review to determine what the causes are and what needs to be done to get the metric back on track. If there are any cases where the metric may not recover, the teams notify the executive management as well as the CPUC to alert them to a possible miss of the target. While PG&E staff are actively monitoring this Metric, FEP notes that there are other initiatives within the organization, such as its Quality Pass Rate L1 metric which tracks the quality of Distribution Inspections HFTD, Transmission Inspections in HFTD, and Routine Vegetation Management Inspections in HFTD that likely drive the overall operations and management of patrols and inspections more so than the SOMs.

2.16.3 Metric 3.9 Performance and Targets

The Asset Strategy group within the Electric Systems Inspection group establishes the 1-year and 5-year targets for each of these metrics. PG&E states that it bases the high range of the targets on a review of historical data, particularly the 2021 results of .07%. In interviews with metric owners, it was determined that the internal goal that PG&E strives to achieve is 0%. PG&E does not use any benchmarking to assist in setting targets for these metrics. This is primarily due to the fact that PG&E reports only on those assets in HFTD areas, which are different for each utility. It's also impacted because PG&E performs these activities based on a company-specific wildfire mitigation plan.

The following table displays PG&E’s 2015 through 2023 metric results and the 1-year and 5-year metric targets.

Table 2-34: Metric 3-9 Results and Targets

Year	Metric Result	1-Year Target[1]	5-Year Target[1]
2015	0.00%		
2016	0.00%		
2017	0.00%		
2018	0.00%		
2019	0.00%		
2020	0.00%		
2021	0.07%	0.00 – 0.05%	0.00 – 0.02%
2022	0.00%	0.00 – 0.04%	0.00 – 0.02%
2023	0.00%	0.00 – 0.03%	0.00 – 0.02%
[1] Targets reflect the target set in that report year (i.e. the 2021 1-year target reflects 2022 target).			

Observations on Metric 3.9 Performance and Targets

As shown, the only missed patrols currently reported were in 2021. The upper range of the 2022 target of 0.05% was set at a level indicating an improvement of approximately 28% from 2021 performance. Each subsequent year PG&E's 1-year targets have decreased, and we note that the 5-year targets are set at levels lower than the 1-year target, which is directionally consistent with target setting for performance improvement. We also note that using zero for the low end of the range is consistent with an aspirational target although we note that the upper end of the range seems to be the more significant factor since that is what presumably could trigger EOE. That said, the decreasing 1-year targets and lower 5-year targets are directionally consistent with performance improvement, noting that PG&E has performed at 0% in the past two years and therefore is not in a position to improve further. While FEP is not aware of any data available to benchmark Metric 3.9, given its specific definition for HFTD, we do note that there is an SPM for missed inspections and patrols by distribution and transmission (all areas) which could be used as a directional benchmark.

2.17 Metric 3.10: Missed HFTD Transmission Inspections

The CPUC defines Metric 3.10 as:

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.

Metric 3.10 measures the percentage of late inspections in each time period, for transmission assets within the HFTD. A late inspection is one that was conducted later than July 31 (for 2021-2023), with different exceptions made based on the year, detailed below.

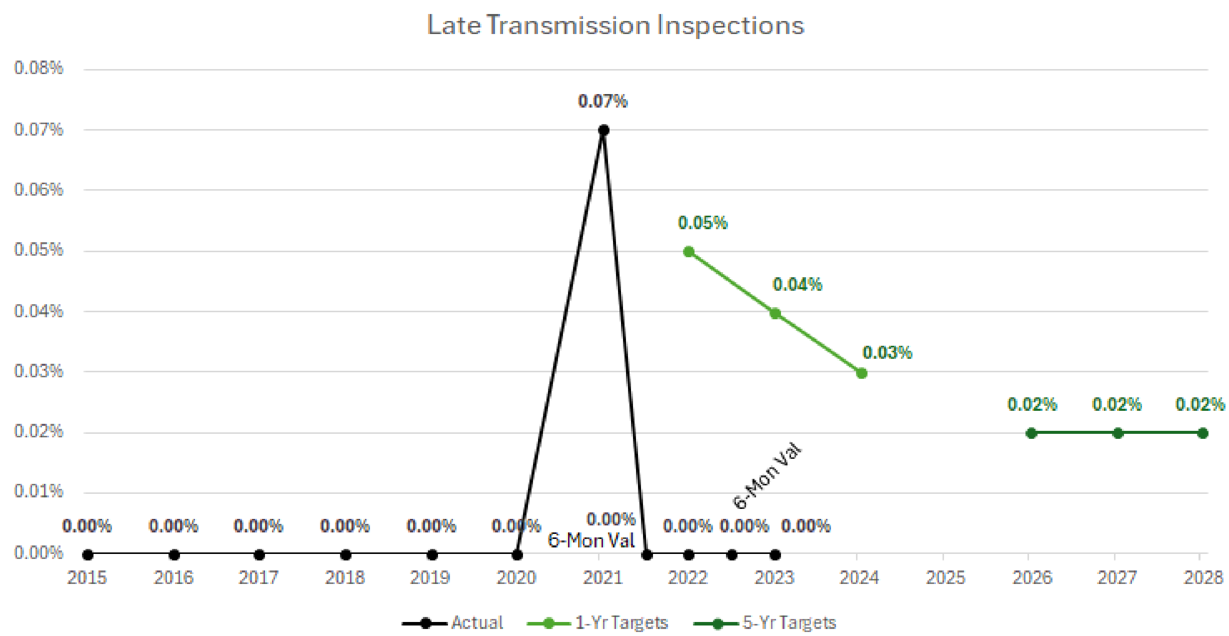
Detailed inspections are performed to identify non-conformances affecting safety or reliability. Inspections often involve a more systematic evaluation of the assets. It involves a much closer look at the asset versus a patrol and can include testing of components, thermal imaging of the assets, or checking for wear and tear. A patrol on the other hand is a more "surface level" observation to detect obvious hazards or abnormalities. Within the HFTD, non-conformances 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.

The formula for calculating Metric 3.10 is:

$$= \frac{\#\ of\ Transmission\ Structures\ Inspected\ Late}{Total\ \#\ of\ Electric\ Transmission\ Structures\ Requiring\ Inspections}$$

The following chart shows Metric 3.10 results compared to targets for 2015 through 2028, including results from the 2022 and 2023 mid-year reports. All historical values reflect the most recent data available as of the 2023 report and may differ from previously reported figures.

Figure 2-29: Metric 3.10 Summary Chart



2.17.1 Metric 3.10 Accuracy and Consistency

Information for Metric 3.10 is extracted from the SAP system. Transmission data is entered at the field level for inspections using handheld devices that are used by the inspectors. This information goes directly into the SAP system (which contains all PG&E's asset records). An SAP query creates the attainment reports that are used in the Metric 3.10 spreadsheet[40]. This process has been consistent for the SOM reporting period.

[40] Available as part of the SOMs reports Safety and Operational Metrics, Data Files

PG&E's electric transmission operations are divided into various geographic divisions, each responsible for a specific region. Each division has a local office to better serve the customers in that division. Metric 3.10 is currently reported for HFTD areas only. Prior to 2020 the assets were not designated in SAP as HFTD or non-HFTD. As a result, years 2015-2019 include systemwide data, whereas years 2020-2023 include HFTD-specific results.

All HFTD transmission assets must have a patrol or inspection done each year. For Metric 3.10, there was no specific deadline for completing inspections within the year for 2020. Starting in 2021 and for following years, there was a July 31 deadline. Starting in 2022, there were exceptions made for assets added to the asset registry or assets whose HFTD status was changed after July 31, granting an additional 90 days in these situations to complete the inspection and not be counted late.

Observations on Metric 3.10 Accuracy

To determine the accuracy of the metric results, FEP verified PG&E’s late inspection counts, total inspection counts, and HFTD designations for each report year.

Verification of Patrol Requirement

For the analysis detailed below, FEP assumed that all inspections listed in the Metric 3.10 spreadsheet were required in that year, and that the spreadsheet captured all inspections that were due in the reporting year. FEP did not independently review the asset database to verify which structures required an inspection.

HFTD Verification

FEP verified that the metric results include only patrols conducted in HFTDs, specifically Tier 2 and Tier 3. For the purposes of this analysis, HFTD classifications provided in the Metric 3.10 spreadsheet were assumed to be accurate and were not independently verified. FEP discovered an inconsistency in the 2023 full-year dataset and report, which incorrectly includes inspections in Tier 2, Tier 3, HFRA, and Zone 1 areas. This was identified and confirmed by PG&E in an RFI response. Since the numerator for the 2023 full-year metric was zero, any change in the total patrol count does not affect the final metric result. However, the reported denominator of 54,717 was incorrect. Excluding HFRA and Zone 1 patrols alone reduces the total to 52,200.

Late Inspections Verification

Metric 3.10 defines a late inspection as one completed past a designated deadline, with different exceptions applied depending on the year. In 2020, the deadline was December 31. Starting in 2021, the deadline shifted to July 31. In 2022, exceptions were introduced for assets that were either newly added to the registry or had an HFTD status changed after July 31. In these cases, a 90-day extension was granted.

To validate the reported late inspections for each year, FEP filtered the raw data provided in the Metric 3.10 spreadsheets to determine whether PG&E’s reported numbers aligned with the records.

FEP filtered the data to show only inspections that occurred after July 31. Then, FEP excluded assets added after July 31 since all inspections for these assets were completed within 90 days of their addition date. Due to there being multiple inspection types (ground, climbing, and drone), there are often multiple inspections per asset. Because of this, there are cases where an inspection was completed after July 31, however an additional inspection was completed for the same asset earlier in the year with a different inspection type. For example, a drone inspection was completed in August for a structure, but a ground inspection was completed for the asset in June. This structure has therefore been inspected before the due date, regardless of other inspections completed later in the year. In those cases, FEP marked the inspection that initially appeared late as not late.

For 2023, after conducting the above process, FEP identified 30 inspections that appeared late given the data included in the Metric 3.10 spreadsheet. However, after submitting an RFI to PG&E to confirm if this was the case, PG&E provided additional inspection data for each of the 30 assets showing that it did have an additional inspection for each, completed before July 31. After asking how the attainment report was created and why it didn't initially include all earlier inspections, the response was that the attainment report is from custom data sources that have been created to extract data from SAP. This does not provide clarity to FEP on how these 30 inspection records were not included in the attainment report in the first place. It is FEP's view that all data to calculate the same result as what PG&E reported should be available in the Metric spreadsheet.

For 2022, FEP's review process described above resulted in 0 late inspections, matching what PG&E reported.

In 2021, PG&E reported 36 late inspections out of a total of 53,112. However, FEP originally identified 40. PG&E clarified by RFI response that 1 of those inspections was a CGI and thus had an extended deadline. The other three inspections were identified to have had earlier inspections in the year that were not recorded in the database. PG&E cited that only the most recent inspection for each asset is included in the Metric 3.10 spreadsheet (for the same inspection type). Although this makes up the difference between the late inspections PG&E and FEP identified, FEP recommends that this information should be included in the metric calculation spreadsheet in the future when applicable, so a user can calculate the correct result from the provided data alone.

Multiple Inspection Types

Many transmission assets in the Metric 3.10 spreadsheet have multiple inspections recorded for the same asset within a year, due to inspections of multiple types (ground, air, climbing). All inspections recorded over the time period are included in the denominator of the metric, leading to an inflated denominator. The metric appears to be intended as a ratio of late inspections to required inspections, where required inspections would refer to only one inspection conducted before July 31 for each asset. To ensure accuracy, all inspections beyond one per structure should be excluded from the denominator. Making this change for previously-reported metrics would only result in a change for 2021, since it's the only year with a non-zero numerator. Accounting for the multiple inspection types per asset, removing these from the total moves the total inspections from 54,717 inspections for 2023 that were reported, to 41,205. For 2021, after accounting for one inspection type per asset, the denominator would be 26,890 instead of 53,112, leading to a metric result of 0.13%.

2.17.2 Metric 3.10 Management

Metric 3.10 is managed within the Electric System Inspections organization. The Asset Strategy, Performance Measurement and Reporting and Electric Program Management teams provide support in gathering the data, performing analysis and then providing the metric results to the metric owner for review.

When the metric data is gathered and calculated for the SOM, the Asset Strategy and Performance Measurement and Reporting groups review the results and compare them to the metric targets. The data is then tracked against each asset in the SAP database to track what assets have been addressed with a patrol. As each patrol is done the record is updated with that date and with the relevant data noted in the patrol. The date for the next patrol is also established at this point.

There are daily and weekly operations meetings within the distribution and transmission organizations. During these meetings, the metrics are reviewed and discussed for progress toward targets. On a monthly basis the metric results are calculated and reviewed by the Asset Strategy and Performance Measurement and Reporting teams. When they complete their review, the reports are forwarded to the Director of Program Management and Director of Transmission Systems Inspections and Distribution System Inspections for their review. If they have questions, they will ask at that time. When they are all in agreement with the results, they are submitted to the metric owner for approval who then submits the report to the electronic routing system which sends the reports to the program management team as well as the CIC for review.

Based on interviews with metric owners and various management personnel, it was determined that Metric 3.10 is not used to manage daily operations. The field personnel that perform the patrols are, in most cases, not even aware of the metrics. The teams managing the metrics do not use them to measure performance but rather as a reporting tool performed as part of their daily responsibilities as it relates to SOMs reporting.

Observations on Metric 3.10 Management

The reporting system used to track the metric uses a “red light/green light” methodology that indicates the status of the metric at any given time within the month. If any metric is red, the teams will review it to determine what the causes are and what needs to be done to get the metric back on track. If there are any cases where the metric may not recover, the teams notify the executive management and the CPUC to alert them to a possible target miss. While PG&E staff is actively monitoring this metric, FEP notes that there are other initiatives within the organization, such as its Quality Pass Rate L1 metric which tracks the quality of Distribution Inspections HFTD, Transmission Inspections in HFTD, and Routine Vegetation Management Inspections in HFTD that likely drive the overall operations and management of patrols and inspections more so than Metric 3.10.

2.17.3 Metric 3.10 Performance and Targets

The Asset Strategy group within the Electric Systems Inspection department establishes the 1-year and 5-year targets for each of these metrics. PG&E states that it bases the high range of the targets on a review of historical data, particularly the 2010 results of .07%. In interviews with metric owners, it was determined that the internal goal that PG&E strives to achieve is 0%. PG&E does not use any benchmarking to assist in setting targets for these metrics. This is primarily due to the fact that PG&E reports only on those assets in HFTD areas, which are different for each utility. It's also impacted because PG&E performs these activities based on a company-specific wildfire mitigation plan.

The following table displays PG&E’s 2015 through 2023 metric results and the 1-year and 5-year metric targets.

Table 2-35: Metric 3-10 Results and Targets

Year	Metric Result	1-Year Target	5-Year Target
2015	0.00%		
2016	0.00%		
2017	0.00%		
2018	0.00%		
2019	0.00%		
2020	0.00%		
2021	0.07%	0.00 – 0.05%	0.00 – 0.02%
2022	0.00%	0.00 – 0.04%	0.00 – 0.02%
2023	0.00%	0.00 – 0.03%	0.00 – 0.02%

Observations on Metric 3.10 Performance and Targets

As shown, the only missed patrols currently reported were in 2021. The upper range of the 2022 target of 0.05% was set at a level indicating an improvement of approximately 28% from 2021 performance. Each subsequent year PG&E's 1-year targets have decreased, and we note that the 5-year targets are set at levels lower than the 1-year target, which is directionally consistent with target setting for performance improvement. We also note that using zero for the low end of the range is consistent with an aspirational target although we note that the upper end of the range seems to be the more significant factor since that is what presumably could trigger EOE. That said, the decreasing 1-year targets and lower 5-year targets are directionally consistent with performance improvement, noting that PG&E has performed at 0% in the past two years and therefore is not in a position to improve further. While FEP is not aware of any benchmarks available to benchmark Metric 3.10, given its specific definition for HFTD, we do note that there is an SPM for missed inspections and patrols by distribution and transmission (all areas) which could be used as a directional benchmark.

2.18 Metric 3.11: General Order (GO) 95 Corrective Actions in HFTDs

The CPUC defines Metric 3.11 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.

Metric 3.11 assesses 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 PG&E's Failure of Electric Distribution Overhead Asset Risk and Wildfire Risk, which are part of the 2020 Risk Assessment and Mitigation Phase Report filing. The Risk Assessment and Mitigation Phase Report was updated in 2024 but was not reviewed as it was not in the scope of the audit. 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 tag.

General Order 95 was established to provide requirements for resolution and reporting of safety hazards discovered by utilities. A key factor from that general order as it applies to metric 3.11 involves the establishment of priority levels for each notification. Those priority levels are as follows:

Level 1:

- Immediate safety and/or reliability risk with high probability for significant impact.
- Take action immediately, either by fully repairing the condition, or by temporarily repairing and reclassifying the condition to a lower priority.

Level 2:

- Variable (non-immediate high to low) safety and/or reliability risk.
- Take action to correct within a specified time period (fully repair, or by temporarily repairing and reclassifying the condition to a lower priority).
- Time period for correction to be determined at the time of identification by a qualified company representative, but not to exceed: (1) six months for nonconformances that create a fire risk located in Tier 3 of the High Fire-Threat District; (2) 12 months for nonconformances that create a fire risk located in Tier 2 of the High Fire-Threat District; (3) 12 months for nonconformances that compromise worker safety; and (4) 59 months for all other Level 2 nonconformances.

Level 3:

- Acceptable safety and/or reliability risk.
- Take action (re-inspect, re-evaluate, or repair) as appropriate.

Correction times may be extended under reasonable circumstances, such as:

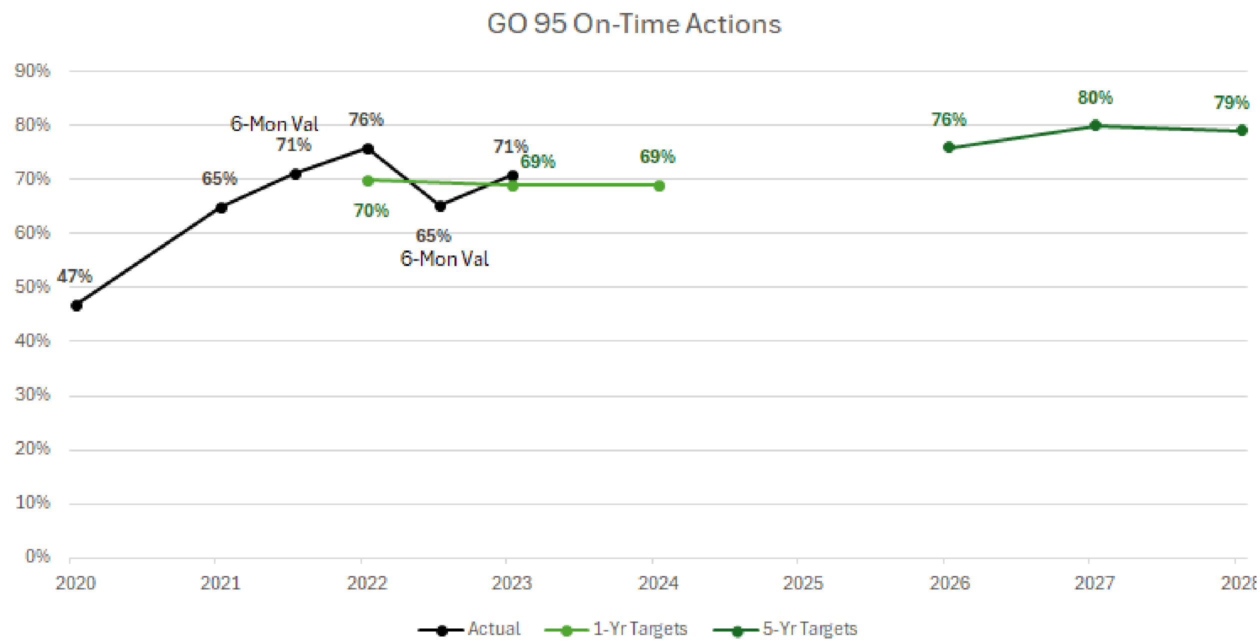
- Third party refusal
- Customer issue
- No access
- Permits required
- System emergencies (e.g. fires, severe weather conditions)

The formula for calculating Metric 3.11 is:

$$= \frac{Number\ of\ Level\ 2\ Priority\ Tags\ Completed\ on\ Time\ in\ HFTDs}{Total\ Number\ of\ Level\ 2\ Priority\ Tags\ in\ HFTDs}$$

The following chart shows Metric 3.11 results compared to targets for 2020 through 2028, including results from the 2022 and 2023 mid-year reports. All historical values reflect the most recent data available as of the 2023 report and may differ from previously reported figures.

Figure 2-30: Metric 3.11 Summary Chart



2.18.1 Metric 3.11 Accuracy and Consistency

Information for Metric 3.11 is extracted from two databases. PG&E extracts information from the Work Management System for distribution and transmission notifications. The vegetation management department maintains separate systems to record its vegetation management inspection notifications. PG&E's inspectors create notifications while performing patrols and inspections of company assets. This includes transmission and distribution assets as well as vegetation management. For distribution and transmission asset inspections, if the inspector finds an issue in the field, they will note the issue. The inspector can repair the issue if it is minor in nature. If it cannot be repaired, a ticket is created in the work management system by the inspector for that asset and includes a priority rating. The Centralized Inspection Review Team (CIRT) will then get this notification. This team reviews the issue documented in the notification as well as the priority assigned by the inspector. The CIRT team can change the priority if determined to be appropriate. They then enter all the data into SAP and identify maintenance work that needs to be done. 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 corrective action notification (tag). The action items are then placed on work schedules based on the assigned priority by the system maintenance teams. Vegetation management notifications are handled separately by the vegetation management personnel and are recorded in a separate system based on the inspector's identification of a clearance condition or a potential tree hazard. The notifications are assigned for transmission, distribution and vegetation management individually. The maintenance groups for each department are responsible for executing and closing each notification.

The data collection process has been consistent for the entire period. Each group manages their metric data that then gets consolidated into the aggregated numbers reported in the SOM. The major change that occurred was in 2018 when the company developed the Wildfire Mitigation Plan. The CPUC created the Fire-Threat Maps and Fire-Safety Rules which created the HFTD tiers 2 and 3 that are reported on in this metric. Prior to that time there was no designation for the company assets as to whether or not they were in an HFTD area. This prevents any comparison to reported results prior to 2018. PG&E reported historical data only back to 2020 in the SOMs reports.

Observations on Metric 3.11 Accuracy

To verify the accuracy of Metric 3.11, FEP assessed the percentage of on-time tags for distribution, transmission, and the three categories of vegetation. Next, FEP summed the results to produce a single metric value for each year. FEP verified PG&E's results and found them to be accurate for 2022 and 2023 but found errors in 2021 and historical data. Overall, tags are considered "on-time" if they are resolved within six months in Tier 3 and 12 months in Tier 2. If PG&E is unable to address the condition due to permitting challenges or weather, PG&E is allowed an extension. When there is an extension, PG&E logs the date and the reason for the extension. For tags with extensions, PG&E sets the due date as later of the original compliance due date or 30 days after the reason for extension is resolved (such as a permitting problem).

Verification of Due Date and "On-Time" Designations

FEP first verified PG&E's compliance dates for all the conditions found in the field. For conditions without extensions, the compliance date is calculated by adding months to the date the condition was found in the field. FEP calculated six or twelve months from the date the condition was found in the field. FEP's compliance date calculations matched PG&E's for 2023.

For tags with extensions, FEP calculated the due date to be 30 days after the delay (such as a permitting issue) was resolved. If this date was longer than the ticket's original compliance due date, FEP used the extension due date to assess if the ticket was resolved on time.

FEP then checked to ensure the work was completed before the due date. FEP first determined if the work status was marked as complete. As the data only included work that was scheduled to be completed in the given year, any work which was outstanding (without an extension) was past due. If the status of the work was complete, FEP checked to make sure the work occurred on or before PG&E's compliance date. If the work was not complete or was completed after the due date, the work was marked "Late". FEP's results matched PG&E's for 2022 and 2023.

2021 Verification Gaps and Errors

For 2021 vegetation tags (P2, Dead and Dying Trees & EVM), PG&E based its "on-time" designations on the month, rather than the day. For example, if the actual due date was calculated as 3/05/2021 and the work was completed on 3/26/2021, PG&E marked this tag as "on-time". This procedure was not repeated in 2022 and 2023 but affected 2021 and prior years. The following numbers of records were marked as "on-time" when FEP determined the work was completed after the required due date:

Table 2-36: Number of Late 2021 Vegetation Tags

Category	Number of 2021 Records
P2	1
Dead and Dying Trees	284
EVM	263
Total	**548**

In the 2021 transmission and distribution dataset, FEP identified a group of records where the completion fell after PG&E's compliance due dates. Through discussions with PG&E staff, FEP learned that the compliance due dates are based on the original required end date, which may not change even if the priority of the tag is reclassified (thus extending the due date). However, FEP was unable to verify the accuracy of the due dates based on the data provided. This issue did not arise in the 2022 and 2023 dataset, where FEP was able to verify both the compliance due dates and the "on-time" designations.

In total, there were 281 transmission tags due in 2021 which had completion dates after the compliance date but were marked as "on-time". There were approximately another 200 transmission tags where FEP and PG&E's due dates did not align. Those 200 records are not assumed to be errors for the purpose of recalculating the metric results below but raise questions about the accuracy of the 2021 data and historical data.

Additionally, there were 220 distribution tags in 2021 which had completion dates that fell after the compliance due date or did not have listed completion dates. FEP identified similar due date discrepancies in the historical data (2020 and earlier).

Verification of Metric Results

FEP calculated the number of late and on time tags for distribution, vegetation, and transmission separately for each year. FEP summed the number of records with on time or late designations. FEP then calculated percentages for the three categories, for each year. To calculate the final metric result, FEP summed the three categories to get an overall on-time percentage. FEP's result matched PG&Es for 2022 and 2023.

FEP calculated the 2021 performance adjusting for the confirmed errors in the vegetation data. FEP also assumed that all of the unclear records in the distribution and transmission data are errors, though this may not be the case. The following table presents 2021 reported results and FEP's recalculated results:

Table 2-37: Recalculated 3.11 Metric Results

Tag Category	Reported %	FEP Calculated %
Total Metric Result	64.8%	64.2%
Distribution	16.5%	16.1%
Transmission	48.7%	46.0%
Vegetation Management	94.8%	94.2%

Differences in the Analyses

In addition to the errors identified above, FEP found a number of small differences between the vegetation, distribution, and transmission calculations. Additionally, there were small differences between how the yearly results were calculated. This does not appear to meaningfully impact the metric result or overall accuracy of the calculations.

For example, FEP was best able to match PG&E's compliance due date for distribution and transmission tickets by adding months (6 months or 12 months, depending on HFTD tier) to the date the condition was identified. Meanwhile, FEP was best able to match PG&E's vegetation compliance due dates by adding days (180 for Tier 3, 365 for Tier 2).

Additionally, PG&E inconsistently adjusted due dates to include weekends and holidays. For example, the 2023 P2 vegetation data included due dates which fell on July 4th. Meanwhile, the EVM vegetation due dates for 2022 and 2023 were adjusted so the due date did not fall on weekends or holidays. For example, if a due date fell on a Saturday, PG&E would extend the due date to the following Monday. If that day was a holiday, PG&E might extend the due date further. For example, if a due date fell on July 2, 2022 (Saturday), PG&E would extend the due date until July 5, 2022 (Tuesday) because of the July 4th holiday. The number of tags impacted by these extensions vary by tag category and year. However, it is relatively small. For example, among the 2022 EMV tags, approximately 4% were extended due to holidays or weekends.

FEP observes that the calculations are valid using days or months, and regardless of whether PG&E adjusts due dates to avoid holidays and weekends, as the CPUC is comfortable with PG&E's process. However, choosing a consistent practice would increase replicability and transparency for third parties reviewing PG&E's data.

2.18.2 Metric 3.11 Management

This metric is managed by the Electric Asset Management department. Metric management involves multiple groups due to there being three different areas included in the results. The other areas that have management responsibilities are Distribution Overhead Asset Management, Performance Management and Reporting, Transmission and Compliance and the Vegetation Management department. Each department is responsible for daily management of its portion of this metric as well as the target setting for the metric.

Each metric group reviews its data on a daily and weekly basis. The data is reviewed in daily and weekly operational meetings. It is common for executives to sit in on some of the weekly and monthly meetings. The status of each component of this metric is reviewed and compared to the target established for each one. They then submit their individual reports to the Performance Management and Reporting group responsible for consolidating the results. This metric is reported in aggregate for the three components of transmission, distribution and vegetation management. The aggregated results are then submitted to the VP and the Directors for review. Once all numbers are approved the VP submits the monthly information to the CIC for its review.

When the SOM report is prepared monthly to be submitted to the CIC for review, any metric not meeting the target or projected to be off target must include an explanation as to why the metric is off-target and a plan for getting it back on track. The CIC then reviews this information. If a metric is off-target, the metric owner is required to attend the meeting as well to discuss its metric status.

As a result of the implementation in 2019 of its Wildfire Safety Inspection Program ("WSIP"), PG&E adjusted its process for managing the risk involved with this metric. The WSIP generated a volume much greater than what had typically been experienced for the annual electric corrective notifications, with the majority of electric corrective notifications being of lower risk (e.g., Level 2 Priority "E" & Level 3). Risk levels and priority levels are established based on GO 95 requirements as referenced in Section I of this report. Level 2 priority B corrective notifications would be managed first and the level 2 priority E and Level 3 notifications would be handled as follows: (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. It should be noted that PG&E also has notifications that are Level 1 priority. These require immediate corrective action. This audit did not assess the success rate of closure for the Level 1 notifications. Per the 2023 SOM report, PG&E was to implement a new Priority X in 2024. Since 2024 was not in the scope of this audit those notifications were not reviewed.

Observations on Metric 3.11 Management

The SOM reports this metric as a percentage of the aggregated results of closed notifications. As shown in the table below, the aggregation tends to mask the problem of distribution and transmission notifications being closed on time.

Table 2-38: Metric 3.11 Components

	2021	**20222**	**2023**	**2024**	**2028**
	Target	Target	Target	Target	Target
Distribution	16%	17%	8%	11%	39%
Transmission	49%	46%	47%	80%	98%
Veg. Mgmt	95%	96%	98%	98%	98%
Aggregate	65%	76%	71%	69%	79%

For 2023, the distribution departments implemented a new process for managing their open notifications. They began “bundling” the open notifications based on circuits and isolation zones to schedule completion of repairs. Isolation zones are circuit segments located between sectionalizing devices. A distribution sectionalizing device is an electrical device used in power distribution networks to isolate or sectionalize different parts of the system. It helps improve reliability by automatically disconnecting faulty sections while keeping the rest of the network operational. These devices are crucial for fault isolation, load management, and maintenance without affecting the entire distribution system. A bundle consists of all open notifications within a given isolation zone. Bundles are created across all asset types. This was implemented to address a larger number of open notifications during one site visit to a zone rather than on an individual notification basis. This new approach is intended to help reduce the number of open notifications as well as fire risk. In response to an RFI regarding the bundling program, PG&E stated that in 2023, 14,516 notifications were completed in 4,183 isolation zone bundles. In response to an RFI, PG&E stated higher priority tags are managed based on the GO-95 due dates. The lower-priority tags are bundled for more efficient corrections. Transmission and Vegetation management continue to manage open notifications based on risk assessment and GO 95 due dates.

GO 95 provides for extensions of corrective actions under specific definitions. Based on the data provided by PG&E, and shown in the table below, the number of extensions for Distribution tags was minimal.

Table 2-39: Extensions on Distribution Tags

Year	**Exemptions**	**Total Tags**	**Exemption %**
2021	307	58,468	0.53%
2022	276	62,786	0.44%
2023	222	70,906	0.31%

In discussions with the teams that manage this metric, the teams stated their preference to manage and report on these metrics individually rather than as an aggregate. PG&E interpreted the definition for the metric to require them to report in aggregate. FEP recommends that PG&E and the CPUC align on the necessity to report in aggregate and if reporting this metric by individual areas may be more appropriate.

2.18.3 Metric 3.11 Performance and Targets

Metric 3.11 targets are set by the Electric Asset Management department. Targets are based on historical performance as well as projected volume of Level 2 notifications and the projected success of the distribution bundling program. Changing wildfire mitigation risks are also factored in setting targets. Generally, the targets for this metric have been set to show improved performance. The target for 2023 was lowered due to the potential that the bundling of distribution notifications by isolation zones could cause some Level 2 Priority E notifications to be completed late or reprioritized if they were not included in any of the isolation zones that were assigned to be completed. The actual results for 2023 exceeded the lowered 2023 target. The 5-year target, established based on 2023 results, does project an increase of approximately 10% with the expected increase in closure of the distribution notifications and transmission notifications.

PG&E staff stated that no benchmarking was used to set the target for Metric 3.11, primarily due to the aggregated results of the three components of transmission, distribution and vegetation management. There are SPMs for transmission and distribution individually which allows for comparison of parts of this metric to other California utilities. To allow for benchmarking and to promote more consistency with the SPMs, the CPUC should discuss separating these three components of this metric going forward. The following table displays PG&E's 2019 through 2023 metric results and the 1-year and 5-year metric targets.

Table 2-40: Metric 3-11 Results and Targets

Year	Metric Result	1-Year Target[1]	5-Year Target[1]
2020	46.9%		
2021	64.8%	70%	76%
2022	75.8%	69%	80%
2023	70.9%	69%	79%
[1] Targets reflect the target set in that report year (i.e. the 2021 1-year target reflects 2022 target).			

PG&E's average metric result from 2021 – 2023 was 71%. PG&E's 1-year target set in 2023 was 2% below the 2021 – 2023 average. For this metric, performance above the target indicates stronger performance. Overall PG&E's metric results have generally trended upward.

Observations on Metric 3.11 Performance and Targets

As noted in the table above, the metric results, as reported in aggregate, have shown improvement from 2020 to 2022. However, the 2023 performance decreased by approximately 5% and was attributed to the change to the bundling process for Level 2 Priority E and F notifications and also some higher priority Level 2 notifications being late due to access issues, weather issues and some more higher priority notifications being completed than expected. The process created some situations where lower Level 2 Priority E and F notifications were not completed on time due to them not being in one of the newly created bundles. The 71% closed in 2023 was better than the target of 69%. The 1-year target set in 2023 was the same

69% as 2023 due to an expected reduction in the number of vegetation management notifications to be addressed in 2024. Since the vegetation management notifications have been closed at such a high rate (98%), a small reduction in the number of notifications completed could have a downward impact on the overall aggregate percentage forecasted in the 1-year target since PG&E did not anticipate any increased results in transmission and distribution. PG&E stated that current resource levels would not allow them to close out more of the notifications than currently planned. PG&E also stated the number of newly created Level 2 notifications could not be accurately predicted. The 5-year (2028) target of 79% does, however, project a significant improvement, an increase of approximately 8% over 2023 results.

2.19 Metric 3.12: Electric Emergency Response Time

The CPUC defines Metric 3.12 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 hotlines.

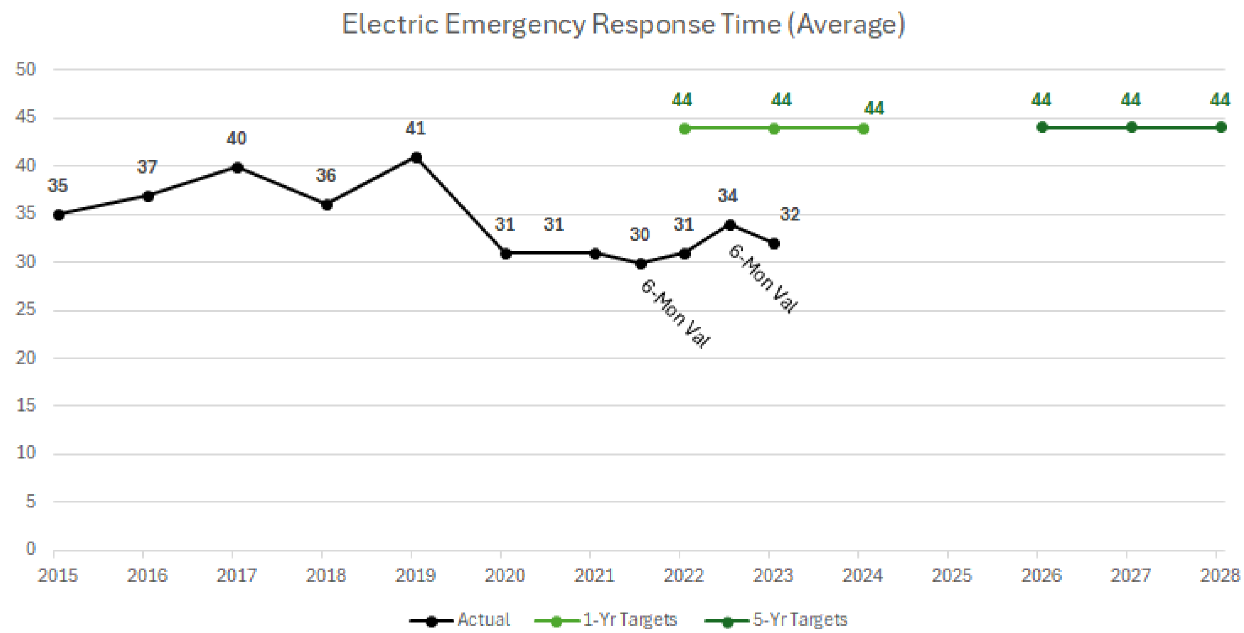
Metric 3.12 measures the average and median time for Pacific Gas and Electric Company (PG&E) to respond on-site to an electric emergency once a notification is received.

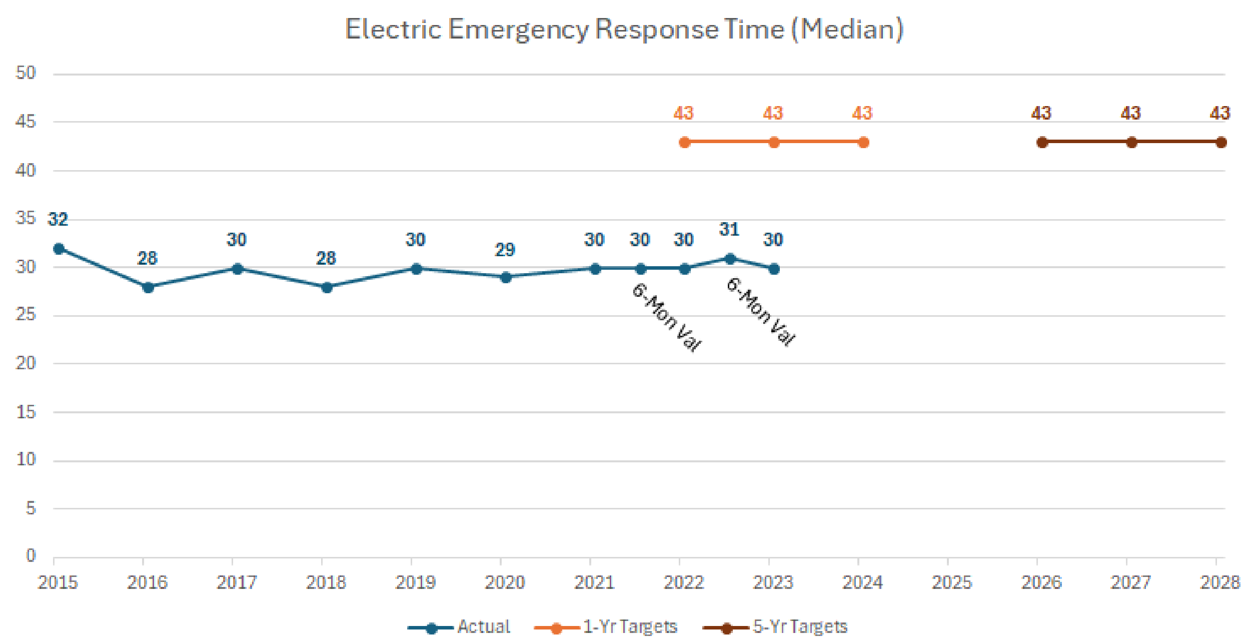
Metric 3.12 includes both a median and average calculation. The mathematical formula for calculating the median of a dataset depends on if the dataset has an odd or even number of values. The median is the number in the middle of an ordered data set from lowest to highest values. Medians are most often calculated using a function, such as Excel's MEDIAN function. The formula for calculating the average time to respond onsite is as follows:

$$Average\ Time\ to\ Respond\ Onsite = Sum\ of\ \frac{Relief\ Minutes}{Number\ of\ Emergencies}$$

The following charts show Metric 3.12 results compared to targets for 2015 through 2028, including results from the 2022 and 2023 mid-year reports. All historical values reflect the most recent data available as of the 2023 report and may differ from previously reported figures.

Figure 2-31: Metric 3.12 Summary Charts





2.19.1 Metric 3.12 Accuracy and Consistency

The data for this metric has been collected in and reported from the Outage Information System (OIS) which is part of the Distribution Management System (DMS). This is the database which has been in use since the beginning of the metric reporting period. Each 911 call has a time stamp. The start time of a 911 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 the PG&E personnel are on the phone with the 911 dispatch agency (there is a direct 911 stand-by line into Gas Dispatch, where all 911 stand by calls are routed). This process of rolling over to the Gas Dispatch 911 if normal lines are full removes the delay between the time the call is received and entered into the system. 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 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, the Electric Dispatch team will validate the exact arrival time by leveraging GPS data from the employee's vehicle and/or mobile data terminals. The response time in minutes is calculated by the difference between the two-time stamps. The collection process has been the same for the entire reporting period in SOMs.

The Electric System Operations department has overall responsibility for this metric. The Distribution Grid Operations department as well as the Performance Measurement and Reporting group provide support for the metric reporting and for target setting.

Observations on Metric 3.12 Accuracy

To determine the overall accuracy of the metric results, FEP verified PG&E's calculated "relief minutes" for each emergency. The relief minutes are the minutes between when PG&E received an emergency call and when a PG&E responder arrived onsite. Next, FEP calculated the median and average for each year to verify the metric results. Those processes are described below, followed by an overall discussion of PG&E's methodology.

Verification of Relief Minutes

PG&E keeps a log of all emergency calls, identifiably by a unique call number. For each call, PG&E lists a relief minute value. PG&E then takes a median and average of these relief minute values to calculate Metric 3.12 results. FEP verified the relief minute value in Excel.

FEP used the following formula in Excel to verify PG&E's relief minutes:

$$Relief\ Minutes = (Arrived\ Date + Arrived\ Time) - (Call\ Date + Call\ Time) * 24 * 60$$

When executed in Excel, this formula produced negative values for many PG&E calls. FEP learned that there are negative response times when PG&E employees arrived onsite prior to an emergency notification. This is possible because PG&E employees received notification of the emergency through some other means, such as internal system monitoring. When the calculated relief minutes are negative, PG&E converts the value to zero. FEP replicated this process using an Excel IF statement which replaced negative values for zero.

Verification of Metric Results

After verifying the relief minutes, FEP calculated a median and average for each year. Using this process, FEP's values matched PG&E's results for all reports except the 2023 mid-year report. For the 2023 mid-year average, FEP calculated 35 minutes while PG&E reported 34 minutes.

Through an RFI, FEP learned that the mid-year dataset originally provided to FEP included 18 calls that PG&E's data validation process determined were later cancelled. PG&E stated that it received a large number of emergency calls during the first quarter of 2023 and the data validation process was still underway when the mid-year dataset was generated. FEP replicated the reported mid-year results using the finalized 2023 dataset.

Discussion of PG&E's Methodology

Overall, FEP was able to replicate PG&E's results for Metric 3.12. However, as observed above, the results for this metric are influenced (though minorly) by the inclusion of response times for emergencies that PG&E received earlier notification on. Response times were zero or negative for 18 calls out of a total of 15,402 in 2023. Additionally, PG&E employees arrived onsite minutes or seconds after the notification was logged. For example, PG&E arrived on site in less than five minutes for about 300 calls in 2023. It seems likely that employees were already in route for many of these calls. While PG&E is adhering to the definition of this metric, FEP observes that its response times would likely be higher if responses to outages PG&E was already aware of were removed.

Additionally, FEP observed duplicate call identifiers while reviewing the dataset. Duplicates occurred when multiple data entries were associated with a single emergency. FEP sent a request for information to PG&E to discuss the duplicates and learned that duplicates occur when multiple responders arrive at the same time to the same trouble call. The data query produces the response time for the first responder to arrive on scene. When two responders arrive at the same time, both entries are queried.

PG&E stated that this occurrence is very rare and only impacted 13 duplicates for a population of 15,402 calls for 2023. FEP agrees that the circumstance is rare and not likely to have a meaningful impact on the metric results. However, going forward, removing the duplicate values would improve the accuracy of the process and reduce confusion for future audits.

2.19.2 Metric 3.12 Management

PG&E's Electric Systems Operations department has overall responsibility for this metric. During interviews with the teams that manage this metric it was determined that the median and average times are not used at all for any of the daily activities or to manage performance improvement. The focus of PG&E, based on the L1 metric for call answer time, is a 60-minute threshold which measures the percent of calls responded to within the 60-minute target time. Metric 3.12 results are verified only at reporting time.

Reports are run daily to extract all call information from the previous day. The data is then analyzed to compare it to the 60-minute threshold and ensure all data has been reviewed for duplications. The percentage of calls responded to within 60 minutes is one of PG&E's L1 metrics and is reviewed throughout the operations organization on a daily basis, so it has very high visibility. While PG&E measures its L1's performance against this metric, the SOM reports are based on the average and median times to respond. The SOM metric is calculated and reported each month. The calculation of average and median times for the report uses the data for calculating the response time compared to the 60-minute target. At report time the data is pulled, and checks are made to be sure it is the same data that was used to calculate the 60-minute results. Once that is confirmed, the average and median times are then calculated from that data and included in the SOM report. It should be noted that PG&E also participates in benchmarking activities related to emergency response time for the L1 metric of 60-minute response time.

PG&E has a formalized processes for reporting and responding to metrics which are off target or may shortly become off target. If anomalies or problematic data trends are identified for Metric 3.12, the metric owner is required to submit, along with the SOM report, an explanation for the metric being off target as well as the plan to get the metric back on target. For this metric PG&E states that it is in the first quartile compared to other CA utilities based on the L1 metric definition and has not had any instance of the metric being off target.

The organization utilizes the Lean Operating Review and CIC meetings described in the Section 1.4 to review the Metric 3.12 status and any catch back work activities. The team reviews controls and mitigations which are currently in place through the electric asset and vegetation management groups to determine corrective actions.

Observations on Metric 3.12 Management

To help with continuous improvement PG&E has added some enhancements to the 911 system. It has teamed up with the meteorology department to train the forecasting model, based on historical events, to better predict major weather events that impact outages in the system. When events are predicted to occur, a meteorologist is assigned to the operations center to help monitor the expected weather events and better prepare for any resulting outages.

2.19.3 Metric 3.12 Performance and Targets

PG&E's Electric Systems Operations department has overall responsibility for this metric. Metric 3.12 targets are set based on past performance. PG&E stated in an RFI response that, in 2021 the L1 metric for response time was benchmarked using PSEG data. This data was reviewed, and it was determined - that an average response time of 44 minutes was in line with remaining in the first quartile for responding within 60 minutes. Based on history, the median times had been lower than averages by 1 minute, so the median time was set at 43 minutes. PG&E considers these levels as the "not to exceed" levels that could result in additional oversight actions by the CPUC. While the targets are substantially higher than any historical performance, PG&E maintains those levels to account for the fact that there are unforeseen occurrences in weather, PSPS, etc. that could impact the response times. The company does not manage to these targets, instead focusing on the percent of responses within 60 minutes.

The following table displays PG&E's 2015 through 2023 metric results and the 1-year and 5-year metric targets.

Table 2-41: Metric 3-12 Results and Targets

Year	Metric Result (average/median)	1-Year Target[1] (average/median)	5-Year Target[1] (average/median)
2015	35/32		
2016	37/28		
2017	40/30		
2018	36/28		
2019	41/30		
2020	31/29		
2021	31/30	44/43	44/43
2022	31/30	44/43	44/43
2023	32/30	44/43	44/43
[1] Targets reflect the target set in that report year (i.e. the 2021 1-year target reflects 2022 target).			

PG&E's average metric result from 2015 – 2023 was 34.89 and 31.33 from 2021 – 2023. PG&E's 1- and 5-year targets set in 2023 are 26% above the 11-year average and 40% above the 2021-2023 average.

The company has generally improved performance from years prior to 2020 but maintained performance since 2020. The 1-year and 5-year targets have remained the same at a level approximately 30% higher than actual performance from 2020-2023. PG&E states this target level is still lower than the 60-minute answer time target that the company measures for performance and as part of the L1 incentive metrics. The average and median times are not used to measure performance.

PG&E staff stated that no benchmarking was used to set the target for Metric 3.12 since it does not measure based on the average and median times to respond. As noted above PG&E does do benchmarking on the percentage of responses within 60 minutes. The SPM reports do include a metric for the average and median times and are compared to other California utilities. In those comparisons PG&E shows itself to be performing better than its competitors.

Observations on Metric 3.12 Performance and Targets

The metric targets established by PG&E are significantly higher than any past performance and do not appear to drive any performance improvement. The company states that this target is set so that it will be sure it does not approach a level that would impact its top quartile performance based on a 60-minute response tim. However, as noted this metric is not aligned with the way the company operates and tracks response performance within the organization.

2.20 Metric 3.13: HFTD Ignitions (Distribution)

The CPUC defines Metric 3.13 as:

Number of CPUC-reportable ignitions involving overhead distribution circuits in High Fire Threat Districts (HFTDs).

Metric 3.13 assesses the number of CPUC-reportable ignitions on distribution circuits in PG&E’s HFTDs. The CPUC defines reportable ignitions as fire incidents which meet the following criteria:

1) The ignition is associated with PG&E electric assets,

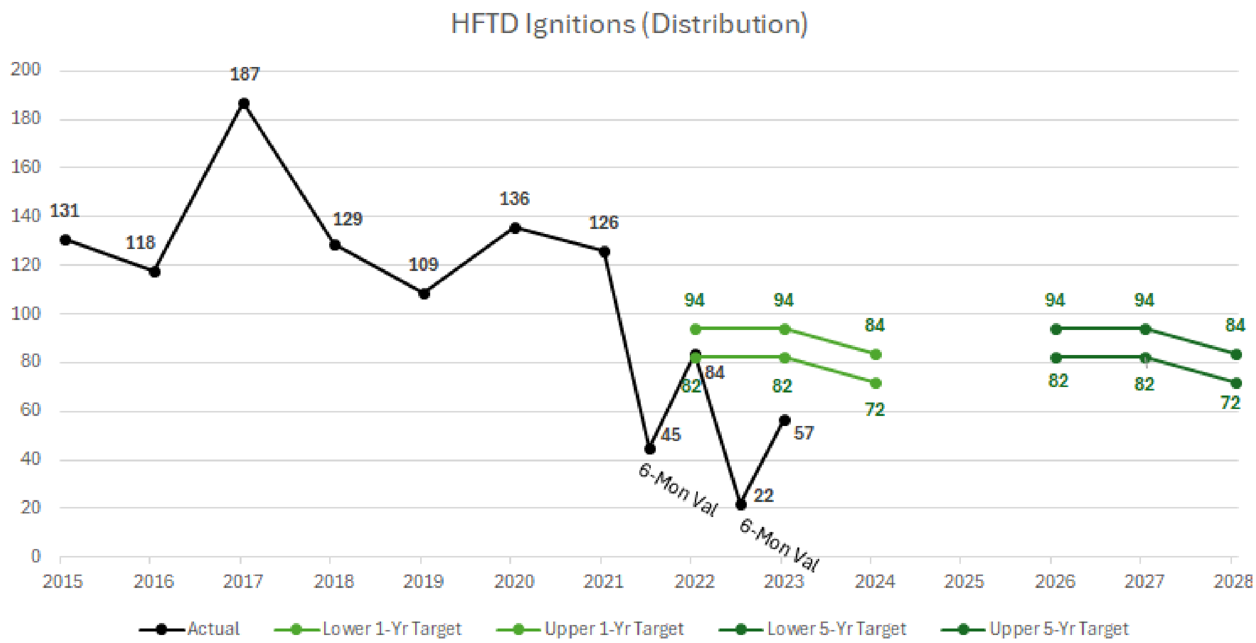
2) something other than PG&E facilities burned and

3) the resulting fire travelled more than one linear meter from the ignition point.

The number of ignitions is a useful measure of wildfire risk exposure from electric assets.

The following chart shows Metric 3.13 results compared to targets for 2015 through 2028, including results from the 2022 and 2023 mid-year reports. All historical values reflect the most recent data available as of the 2023 report and may differ from previously reported figures. Mid-year values are substantially lower because they cover only six months of ignitions, whereas the annual values cover the full twelve months.

Figure 2-32: Metric 3.13 Summary Chart



2.20.1 Metric 3.13 Accuracy and Consistency

The data for Metric 3.13 is housed in the ignition database, called Foundry. The database was built in 2021. PG&E departments that need access to ignition data, like distribution, transmission, wildfire mitigation, vegetation, and asset management have read access to the data. The Distribution Grid Operations team controls write access to ignition data. PG&E has documented procedures for editing, accessing, and writing ignition data.[41]

Prior to 2021, PG&E managed ignition data with an online tracker. A larger group of PG&E employees had the ability to view and edit the ignitions data, which led to errors such as accidentally deleted rows or changes to specific cells within the tracker. After 2021, the access was restricted such that even individuals with editor-level access don't have the ability to access all fields or delete data.

Most often, PG&E becomes aware of an ignition when field personnel are dispatched to an outage location and discover evidence of an ignition. The field personnel access an app on their tablet and fill out information about the outage. This is the same app utilized to document outage events without evidence of ignition. The personnel will indicate on that app that there is evidence of an ignition. The form offers ignition specific information if the box is checked, such as suspected cause. Once the form is complete, the data is transmitted to Foundry. PG&E uses EGIS to determine if the outage occurred in HTFDs.

The management of ignition data changed throughout the reporting period. PG&E was required by the CPUC to report ignition data starting in 2015. PG&E began utilizing ignition data to a greater degree in 2017 when it began data mining and conducting more in-depth data analysis exercises using ignition data. At that stage, PG&E staff realized that ignition events were getting "missed", meaning field personnel

[41] Documented in PG&E RISK-6306 Standard and Risk-6306P

responded to asset outages but failed to indicate an associated ignition. To resolve that problem, PG&E began conducting a daily audit on outage data, looking for signs of associated ignitions.

The historical ignition data (pre-2020) reported through the SOMs report results from a large post-processing audit of historical ignition records that PG&E conducted using trouble reports. PG&E reviewed historical outage information, looking for signs of ignition events. PG&E searched through outage comments looking for words like, ignition, fire, or spark to identify outages which may have been CPUC-reportable ignitions.

Observations on Metric 3.13 Accuracy

To assess the accuracy of Metric 3.13, FEP evaluated PG&E's process for determining if ignitions were reportable or non-reportable. Then, FEP summed the total reportable ignitions for each year. Additionally, FEP verified the HFTD designations by plotting event coordinates in GIS. FEP found PG&E's calculations for Metric 3.13 to be accurate.

Verification of Reportability

The first step in the accuracy verification process was to review the classification of whether ignitions are reportable or non-reportable. Ignitions are considered reportable if the ignition is associated with PG&E assets, if something other than PG&E facilities burned, and the resulting fire traveled more than one linear meter from the ignition point. There are fields in the dataset detailing the involvement of PG&E assets, the fire size, and ignited materials. Additionally, only ignitions in the HTFDs meeting the above criteria are included in Metric 3.13.

FEP confirmed the classification criteria and the reportable vs non-reportable designation for each fire incident. FEP verified that all of the ignitions which were labeled as "reportable" had corresponding data to demonstrate that they met the criteria for reportability. Similarly, FEP verified that the ignitions which were excluded from reportability did not meet the criteria according to the dataset.

Verification of HFTD Designations

As previously described, FEP found discrepancies in PG&E's outage HFTD designations. FEP requested that PG&E provide data on all outages which occurred in both the HFTD and non-HFTD areas. FEP used GIS software to plot the coordinates for the operating devices involved in the outages. FEP compared these plotted GIS locations to PG&E's HFTD/non-HFTD designations. A spatial selection in GIS was used to identify outage points that intersected with the HFTDs. The intersecting points were then analyzed to assess the accuracy of PG&E's HFTD/non-HFTD identification field. FEP found that many outages had latitude/longitude coordinates that fell within HFTD boundaries but were classified by PG&E as occurring in non-HFTD areas.

FEP undertook a similar assessment using the location of PG&E's ignitions. PG&E's 2021 – 2023 ignitions dataset included ignitions across PG&E's full service territory (HFTD & non-HFTD) and both reportable and non-reportable ignitions. Of over 1,300 reportable ignitions, FEP found 4 labeled as non-HFTD that fell within HFTD boundaries when the coordinates were plotted. However, when FEP examined the notes and addresses associated with each ignition, it appeared that they were properly classified as non-HFTD and therefore excluded from the metric.

Verification of Ignition Counts

Once FEP verified the reportable classifications were accurate, FEP summed the total number of reportable ignitions by year. For Metric 3.13, FEP found 126 reportable ignitions in 2021, 84 reportable ignitions in 2022 and 57 reportable ignitions in 2023. These results match the values reported by PG&E.

2.20.2 Metric 3.13 Management

PG&E's ignition data is used by many internal departments. The data is continuously audited and scrubbed. Additionally, many other teams like distribution, transmission, vegetation, wildfire, and asset management review the data as they use and access it. Therefore, the ignition dataset is reviewed daily.

Once ignition data is collected in the field, it's added to the database daily. Daily ignition reports go out to a wide audience. The daily ignition reports show fire size, circuit, the closest city, suspected ignition event, and the type of conduct involved. Along with the daily reports, dispatchers send dispatch notices to departments involved in the investigations, such as dispatches for arborists or field investigators.

Before a completed ignition evaluation, the information included in the report and database is based on the troubleshooter's initial findings. Troubleshooters are trained to evaluate evidence and categorize data in a specific way that facilitates data analysis. However, the findings are subject to change pending a completed ignition evaluation.

All ignitions are reviewed at a "desktop level" by ignition specialists. This means that ignition specialists review the data and make an assessment to determine if a more in-depth evaluation is necessary. This is also an opportunity for PG&E ignition specialists to conduct a quality control assessment of the data gathered by troubleshooters in the field. Evaluators gather information from fire agencies, first responders, and arborists to discover if vegetation may have been involved with the ignition. If the ignition is reportable, PG&E undertakes an enhanced ignition investigation which includes a forensic engineering exercise. Investigators collect material associated with the event and go onsite to assess the area. Evaluators produce a preliminary investigation report and high-level findings are shared with regulatory agencies like the CPUC.

Whenever a troubleshooter or preliminary evaluator indicates that vegetation may have been involved with the ignition, the vegetation team receives notification of a new event. They proactively dispatch arborists to the ignition location but also receive dispatches from the daily ignition dispatch notifications. Onsite vegetation reviews for ignitions need to occur quickly to avoid condition changes, so the vegetation team typically assesses the ignition site within 48 business hours.

Throughout this process, ignition data receives many layers of review. Preliminary reviews are conducted every morning and the desktop quality control reviews by ignition specialists are completed shortly after. Preliminary investigation reports are produced and shared with the Office of Energy Infrastructure Safety (OEIS"). Additionally, the Wildfire Management Team produces quarterly ignition reports. During the production of the quarterly reports, the Wildfire Management Team reviews ignitions data again. The final review of the quarterly data is conducted at the management level. Annual reports are compiled by the Communication Department. During the production of the annual report, staff review previous years of data in aggregate to assess ignition trends. Annual reports are dispersed to regulatory agencies like the CPUC and the telecommunication companies. Additionally, ignitions data for the SOMs are reviewed and summarized monthly. The data is certified internally every month.

Like other metrics, ignition SOMs data is reported to PG&E's CIC. PG&E discusses the status of the ignition metrics and makes catch back plans if the metrics are off track.

Observations on Metric 3.13 Management

PG&E's process for tracking and investigating ignitions appears to sufficiently capture ignitions data. PG&E conducts multiple levels of ignition investigations, including troubleshooter data collection, desktop reviews by ignitions specialists, enhanced investigations by specialists, and on-site reviews by vegetation and asset teams. Ignition data is widely dispersed to PG&E staff, and reports are produced daily, monthly, quarterly, and annually. Despite the wide dispersal of ignition data, write access is tightly controlled to prevent errors.

The accuracy of ignition SOMs reporting appeared to be impacted by circuit line mile calculations. This is the same phenomena that impacted some of the Wires Down metrics. PG&E could improve the accuracy of ignition SOMs reporting by including line mile values in the SOMs reports and instituting a process that allows the circuit mile values to be verified internally.

2.20.3 Metric 3.13 Performance and Targets

PG&E set the 2021 target by reducing the previous three-year average by 25 percent. PG&E developed this target by considering historical data trends, the regulatory requirements of D.14-02-015 and external factors. Decision 14-02-015 revised General Order 95 to include modified rules designed to reduce the fire risk associated with overhead power lines and required investor-owned utilities to report fire incidents. This decision relates to PG&E's target setting process because it defined a "reportable" ignition, which is measured by Metric 3.13. As for external factors, PG&E considered the implication of EOE and the potential for an increase in severe weather due to climate change. PG&E kept the same targets in the 2022 and 2023 reports.

The following table displays PG&E's 2015 through 2023 metric results and the 1-year and 5-year metric targets.

Table 2-42: Metric 3-13 Results and Targets

Year	Metric Result	1-Year Target	5-Year Target
2015	131		
2016	118		
2017	187		
2018	129		
2019	109		
2020	136		
2021	126	94	94
2022	84	94	94
2023	57	84	84
[1] Targets reflect the target set in that report year (i.e. the 2021 1-year target reflects 2022 target).			

PG&E's average metric result from 2015 -2023 was 119.67 and 89.00 from 2021-2023. PG&E's target is 21% below the nine-year average and 6% above the 2021-2023 average. Overall, PG&E's Metric 3.13 result has trended downward.

PG&E stated that it did not use benchmarking from other utilities to set its targets for this metric. However, PG&E does engage in ignition benchmarking with other California utilities. PG&E stated that it works closely with other California utilities on its wildfire mitigation plans, which are filed with the Office of Energy Infrastructure Safety. Overall, PG&E staff felt that its ignition programs and practices were comparable to its peers, despite differing ignition drivers in northern and southern California.

Observations on Metric 3.13 Performance and Targets

PG&E used the same target for both 2021 and 2022. In the 2022 report, PG&E stated that the target would continue to be challenging based on the variability of ignition factors like weather, migratory bird patterns, red flag warning days, and contact from external parties.[42]

PG&E's 2021 target setting strategy reflected a reduction to historical ignitions, and FEP would expect to see continued reduction for each subsequent yearly target, if the targets were meant to drive performance improvement. In addition to not reducing the target reported in 2022, PG&E uses the same value for the 5-year targets as the corresponding 1-year targets. FEP acknowledges that a 25% reduction of historical averages every year is likely unrealistic. However, some downward pressure seems appropriate. PG&E did reduce the targets in 2023 but still set the 5-year target to the 1- year target.

PG&E has, however, greatly reduced distribution ignitions since 2015. Ignition rates are a significant companywide focus. Reportable ignitions are an L1 metric as well as an SPM. PG&E's ignition rates are consistently higher than its utility peers in SPM 4. Downward pressure placed by these metrics will likely influence the performance of Metric 3.13 as well.

2.21 Metric 3.14: HFTD Ignitions/1000 miles (Distribution)

The CPUC defines Metric 3.14 as:

Number of CPUC-reportable ignitions involving overhead distribution circuits divided by circuit-miles of overhead primary distribution lines X 1000 in High Threat Fire Districts (HFTDs).

Metric 3.14 assesses the number of CPUC-reportable ignitions on distribution circuits per 1,000 distribution circuit miles in HFTDs. The CPUC defines reportable ignitions as fire incidents which meet the following criteria:

1) The ignition is associated with PG&E electric assets,

2) something other than PG&E facilities burned and

3) the resulting fire travelled more than one linear meter from the ignition point.

Assessing the rate of ignitions per 1,000-line miles allows for ignition rate comparisons across utilities of varying sizes. The formula for Metric 3.14 is:

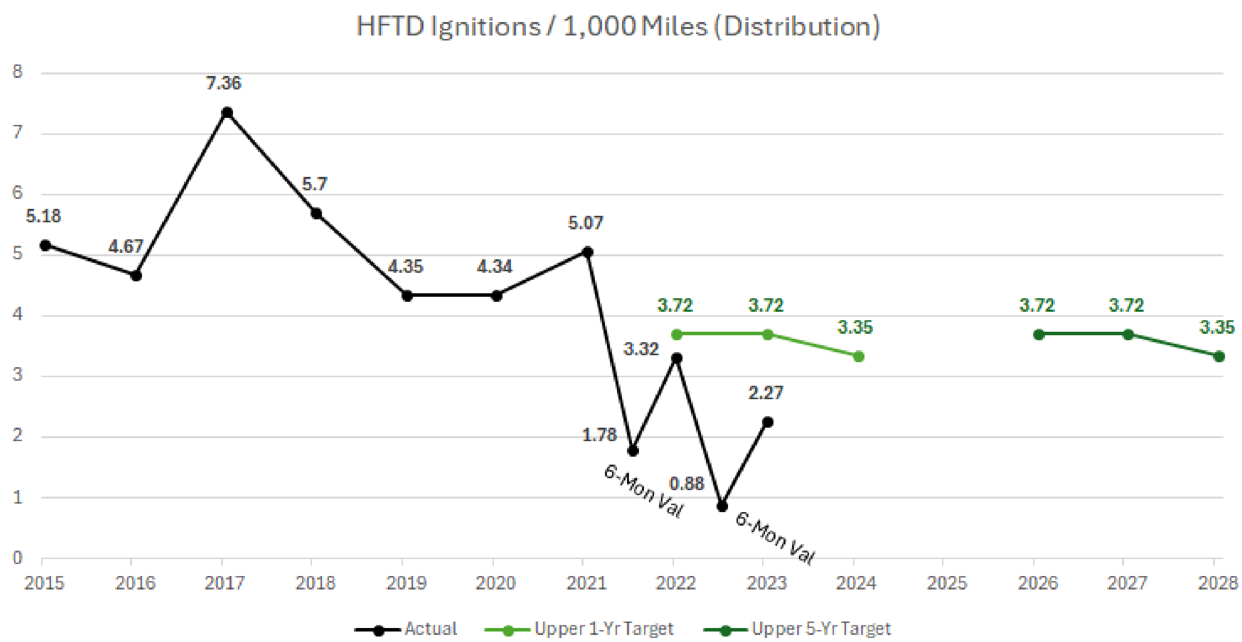
$$\frac{\#\ Reportable\ Ignitions\ Involving\ Distribution\ assets}{Total\ Distribution\ Line\ Miles\ in\ HFTDs}\ X\ 1000$$

The following chart shows Metric 3.14 results compared to targets for 2015 through 2028, including results from the 2022 and 2023 mid-year reports. All historical values reflect the most recent data available as of the 2023 report and may differ from previously reported figures. The mid-year values are

[42] Pacific Gas & Electric 2022 SOMs Report, p. 3.13-5. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/reports/r2007023-et-alpge-safety-and-operational-metrics-report040323s.pdf

substantially lower because they cover only six months of ignitions, whereas the annual values cover the full twelve months.

Figure 2-33: Metric 3.14 Summary Chart



2.21.1 Metric 3.14 Accuracy and Consistency

The data for Metric 3.14 is housed in the ignition database, called Foundry. The database was built in 2021. PG&E departments that need access to ignition data, like distribution, transmission, wildfire mitigation, vegetation and asset management have read access to the data. The Distribution Grid Operations team controls write access to ignition data. PG&E has documented procedures for editing, accessing and writing ignition data.

Prior to 2021, PG&E managed ignition data with an online tracker. A larger group of PG&E employees had the ability to view and edit the ignitions data, which led to errors such as accidentally deleted rows or changes to specific cells within the tracker. After 2021, the access was restricted such that even individuals with editor-level access don't have the ability to access all fields or delete data.

Most often, PG&E becomes aware of an ignition when field personnel are dispatched to an outage location and discovers evidence of an ignition. The field personnel access an app on their tablet and fill out information about the outage. This is the same app utilized for documenting outage events without evidence of an ignition. The personnel will indicate on that app that there is evidence of an ignition. The form offers ignition specific information if the box is checked, such as suspected cause. Once the form is complete, the data is transmitted to Foundry. PG&E uses EGIS to determine if the outage occurred in HTFDs.

The management of ignition data changed throughout the reporting period. PG&E was required by the CPUC to report ignition data starting in 2015. PG&E began utilizing ignition data to a greater degree in 2017 when it began data mining and conducting more in-depth data analysis exercises using ignition data.

PG&Es current practice of conducting in-depth investigations of every ignition began in 2020. At that stage, PG&E staff realized that ignition events were getting “missed”, meaning field personnel responded to asset outages but failed to indicate that there was an associated ignition. To resolve that problem, PG&E began conducting a daily audit on outage data looking for signs of associated ignitions.

The historical ignition data reported through the SOMs reports is the result of a post-processing audit of historical ignition records that PG&E conducted using trouble reports. PG&E reviewed historical outage information, looking for signs of ignitions events. PG&E searched through outage comments looking for words like, ignition, fire, or spark to identify outages which may have been CPUC-reportable ignitions.

Observations on Metric 3.14 Accuracy

To assess the accuracy of Metric 3.14, FEP evaluated PG&E’s process for determining if ignitions were reportable or non-reportable. Then, FEP summed the total reportable ignitions for each year. Lastly, FEP assessed PG&E’s process for determining the number of distribution line miles in HFTDs. Additionally, FEP verified the HFTD designations by plotting event coordinates in GIS. FEP found PG&E’s calculations for Metric 3.14 to be accurate.

Verification of Reportability

The first step in the accuracy verification process was to review the classification of whether ignitions are reportable or non-reportable. Ignitions are considered reportable if the ignition is associated with PG&E assets, if something other than PG&E facilities burned, and the resulting fire traveled more than one linear meter from the ignition point. There are fields in the dataset detailing the involvement of PG&E assets, the fire size, and ignited materials. Additionally, only ignitions in the HTFDs meeting the above criteria are included in Metric 3.14.

Verification of HFTD Designations

As previously described, FEP found discrepancies in PG&E’s outage HFTD designations. FEP requested that PG&E provide data on all outages which occurred in both the HFTD and non-HFTD areas. FEP used GIS software to plot the coordinates for the operating devices involved in the outages. FEP compared these plotted GIS locations to PG&E’s HFTD/non-HFTD designations. A spatial selection in GIS was used to identify outage points that intersected with the HFTDs. The intersecting points were then analyzed to assess the accuracy of PG&E’s HFTD/non-HFTD identification field. FEP found that many outages had latitude/longitude coordinates that fell within HFTD boundaries but were classified by PG&E as occurring in non-HFTD areas.

FEP undertook a similar assessment using the location of PG&E’s ignitions. PG&E’s 2021 – 2023 ignitions dataset included ignitions across PG&E’s full service territory (HFTD & non-HFTD) and both reportable and non-reportable ignitions. Of over 1,300 reportable ignitions, FEP found 4 labeled as non-HFTD that fell within HFTD boundaries when the coordinates were plotted. However, when FEP examined the notes and addresses associated with each ignition, it appeared that they were properly classified as non-HFTD and therefore excluded from the metric.

Verification of Ignition Counts

Once FEP verified the reportable classifications were accurate, FEP used a pivot table to sort the data by year and reportability. For Metric 3.14, FEP found 126 reportable ignitions in 2021, 84 reportable ignitions in 2022 and 57 reportable ignitions in 2023. These results match the values reported by PG&E for Metric 3.13, which is the numerator of the Metric 3.14 formula.

Ignitions per 1000 Line Miles

Metric 3.14 assessed normalized ignitions per 1000-line miles. The following table summarizes the line mile values provided in PG&E's SOMs report.

Table 2-43: Distribution Line Miles

Year	Reported Distribution Line Miles	Distribution Line Miles Used for Metric Result	FEP's Calculated Metric Result Using Reported Line Miles
2021	25,278.5	25,270	4.98
2022	25,270	25,270	3.34
2023	25,060	25,060	2.27

FEP was unable to replicate PG&E's Metric 3.14 result of 4.99 reportable distribution ignitions/distribution miles using the distribution line mile value that PG&E reported in the 2021 SOMs report (25,278.5). Using the line miles in PG&E's 2021 SOM report, FEP calculated the metric result to be 4.98. However, using the distribution line mile value provided in the 2022 SOMs report (25,270) yielded matching results to the metric value reported in 2021. In future SOMs reports, FEP recommends that PG&E use a consistent line mile value in the SOM reports and associated workpapers. Additionally, FEP recommends that PG&E document the mile line value and the date the value was calculated in the SOMs report. The line mile values should be recalculated at least yearly to represent current asset conditions.

2.21.2 Metric 3.14 Management

PG&E's ignition data is used by many internal departments. The data is continuously audited and scrubbed. Additionally, many other teams like distribution, transmission, vegetation, wildfire, and asset management review the data as they use and access it. Therefore, the ignition dataset is reviewed daily.

Once ignition data is collected in the field, it's added to the database daily. Daily ignition reports go out to a wide audience. The daily ignition reports show fire size, circuit, the closest city, suspected ignition event, and the type of conduct involved. Along with the daily reports, dispatchers send dispatch notices to departments involved in the investigations, such as dispatches for arborists or field investigators.

Prior to a completed ignition evaluation, the information included in the report and database is based off the troubleshooter's initial findings. Troubleshooters are trained to evaluate evidence and categorize data in a specific way that facilitates data analysis. However, the findings are subject to change pending a completed ignition evaluation.

All ignitions are reviewed at a "desktop level" by ignition specialists. This means that ignition specialists review the data and make an assessment to determine if a more in-depth evaluation is necessary. This is also an opportunity for PG&E ignitions specialists to conduct a quality control assessment of the data gathered by troubleshooters in the field. Evaluators gather information from fire agencies, first responders, and arborists to discover if vegetation may have been involved with the ignition. If the ignition is reportable, PG&E undertakes an enhanced ignition investigation which includes a forensic engineering exercise. Investigators collect material associated with the event and go onsite to assess the area. PG&E also conducts computer modeling to simulate the cause of the ignition and area of impact. Evaluators produce a preliminary investigation report and high-level findings are shared with regulatory agencies like the CPUC.

Whenever a troubleshooter or preliminary evaluator indicates that vegetation may have been involved with the ignition, the vegetation team receives notification of a new event. They proactively dispatch arborists to the ignition location but also receive dispatches from the daily ignition dispatch notifications. Onsite vegetation reviews for ignitions need to occur quickly to avoid condition changes, so the vegetation team typically assesses the ignition site within 48 business hours.

Throughout this process, ignition data receives many layers of review. Preliminary reviews are conducted every morning and the desktop quality control reviews by ignition specialists are completed shortly after. Preliminary investigation reports are produced and shared with the OEIS. Additionally, the Wildfire Management Team produces quarterly ignition reports. During the production of the quarterly reports, the Wildfire Management Team reviews ignitions data again. The final review of the quarterly data is conducted at the management level. Annual reports are compiled by the Communication Department. During the production of the annual report, staff review previous years of data in aggregate to assess ignition trends. Annual reports are dispersed by regulatory agencies like the CPUC and the telecommunication companies. Additionally, ignitions data for the SOMs are reviewed and summarized monthly. The data is certified internally every month.

Like other metrics, ignition SOMs data is reported to PG&E's CIC. PG&E discusses the status of the ignition metrics and makes catch back plans if the metrics are off track.

Observations on Metric 3.14 Management

PG&E's process for tracking and investigating ignitions appears to sufficiently capture ignitions data. PG&E conducts multiple levels of ignition investigations, including troubleshooter data collection, desktop reviews by ignitions specialists, enhanced investigations by specialists, and on-site reviews by vegetation and asset teams. Ignition data is widely dispersed to PG&E staff, and reports are produced daily, monthly, quarterly, and annually. Despite the wide dispersal of ignition data, write access is tightly controlled to prevent errors.

The accuracy of ignition SOMs reporting appeared to be impacted by circuit line mile calculations. This is the same phenomena that impacted some of the Wires Down metrics. PG&E could improve the accuracy of ignition SOMs reporting by including line mile values in the SOMs reports and instituting a process that allows the circuit mile values to be verified internally.

2.21.3 Metric 3.14 Performance and Targets

PG&E set the 2021 target by reducing the whole number of average ignitions from 2018 – 2021 by 25 percent, for a result of approximately 94 ignitions. This translates to a target of 3.72. PG&E developed this target by considering historical data trends, the regulatory requirements of D.14-02-015 and external factors. Decision 14-02-015 revised General Order 95 to include modified rules designed to reduce the fire risk associated with overhead power lines and required investor-owned utilities to report fire incidents. This decision relates to PG&E's target setting process because it defined a "reportable" ignition, which is measured by Metric 3.14. The external factor component means that PG&E considered indicators for EOE and the potential for an increase in severe weather due to climate change.

The following table displays PG&E's 2015 through 2023 metric results and the 1-year and 5-year metric targets.

Table 2-44: Metric 3-14 Results and Targets

Year	Metric Result	1-Year Target	5-Year Target
2015	5.18		
2016	4.67		
2017	7.40		
2018	5.10		
2019	4.31		
2020	5.38		
2021	4.99	3.72	3.72
2022	3.34	3.72	3.72
2023	2.27	3.35	3.35
[1] Targets reflect the target set in that report year (i.e. the 2021 1-year target reflects 2022 target).			

PG&E's average metric result from 2015 to 2023 was 4.75, and from 2021 to 2023, it was 3.53. PG&E's 2023 1- and 5-year targets of 3.35 are 29% below the nine-year average and 5% below the 2021–2023 average. PG&E's metric result in 2023 was 32% below the target. Overall, PG&E's Metric 3.14 result has trended downward.

PG&E stated that it did not use benchmarking from other utilities to set its targets for this metric. However, PG&E does engage in ignition benchmarking with other California utilities. PG&E stated that it works closely with other California utilities on its wildfire mitigation plans, which are filed with the Office of Energy Infrastructure Safety. Overall, PG&E staff felt that its ignition mitigation practices (i.e. tracking procedures, grid hardening treatments) were comparable to its peers, despite differing ignition drivers in northern and southern California.

Observations on Metric 3.14 Performance and Targets

PG&E provided the same targets in the 2021 and 2022 reports. In the 2022 report, PG&E stated that the target would continue to be challenging based on the variability of ignition factors like weather, migratory bird patterns, red flag warning days, and contact from external parties. [43]

PG&E's 2021 target setting strategy reflected a reduction to historical ignitions, and FEP would expect to see continued reduction for each subsequent yearly target, if the targets were meant to drive performance improvement. In addition to not reducing the target reported in 2022, PG&E uses the same value for the 5-year targets as the corresponding 1-year targets. FEP acknowledges that a 25% reduction of historical averages every year is likely unrealistic. However, some downward pressure seems appropriate. PG&E did reduce the targets in 2023 but still set the 5-year target to the 1- year target.

PG&E has, however, greatly reduced distribution ignitions since 2015. Ignition rates are a significant companywide focus. Reportable ignitions are an L1 metric as well as an SPM. PG&E's ignition rates are

[43] Portland General Electric 2022 SOMs Report, p. 3.13-5. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/reports/r2007023-et-alpge-safety-and-operational-metrics-report040323s.pdf

consistently higher than its utility peers in SPM 4. Downward pressure placed by these metrics will likely influence the performance of Metric 3.14 as well.

2.22 Metric 3.15: HFTD Ignitions (Transmission)

The CPUC defines Metric 3.15 as:

Number of CPUC-reportable ignitions involving overhead transmission circuits in High Fire Threat Districts (HFTDs).

Metric 3.15 assesses the number of CPUC-reportable ignitions on transmission circuits in PG&E's HFTDs. The CPUC defines reportable ignitions as fire incidents which meet the following criteria:

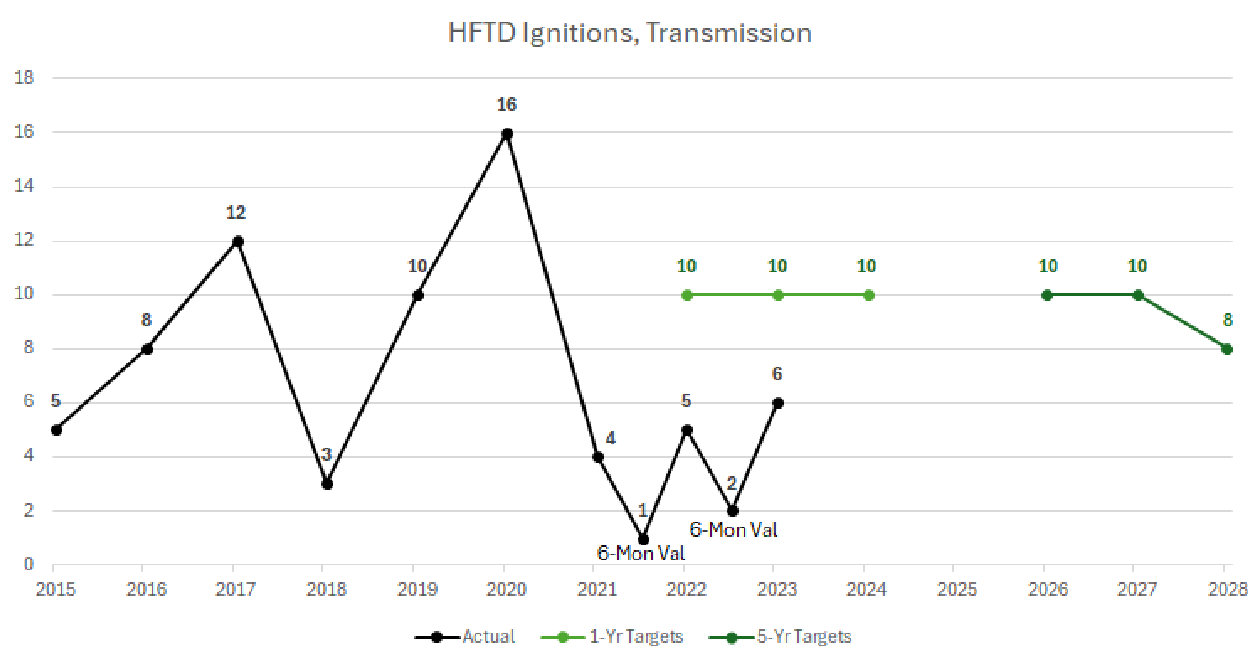
1) The ignition is associated with PG&E electric assets,

2) something other than PG&E facilities burned and

3) the resulting fire travelled more than one linear meter from the ignition point.

The following chart shows Metric 3.15 results compared to targets for 2015 through 2028, including results from the 2022 and 2023 mid-year reports. All historical values reflect the most recent data available as of the 2023 report and may differ from previously reported figures. The mid-year values are substantially lower because they cover only six months of ignitions, whereas the annual values cover the full twelve months.

Figure 2-34: Metric 3.15 Summary Chart



2.22.1 Metric 3.15 Accuracy and Consistency

The data for Metric 3.15 is housed in the ignition database, called Foundry. The database was built in 2021. PG&E departments that need access to ignition data, like distribution, transmission, wildfire mitigation, vegetation and asset management have read access to the data. The Grid Operations team controls write access to ignitions data. PG&E has documented procedures for editing, accessing and writing ignition data.

Prior to 2021, PG&E managed ignition data with an online tracker. A larger group of PG&E employees had the ability to view and edit the ignitions data, which led to errors such as accidentally deleted rows or changes to specific cells within the tracker. After 2021, the access was restricted such that even individuals with editor-level access don't have the ability to access all fields or delete data.

Most often, PG&E becomes aware of an ignition when field personnel are dispatched to an outage location and discovers evidence of an ignition. The field personnel access an app on their tablet and fill out information about the outage. This is the same app utilized for documenting outage events without evidence of an ignition. The personnel will indicate on that app that there is evidence of an ignition. The form offers ignition specific information if the box is checked, such as suspected cause. Once the form is complete, the data is transmitted to Foundry. PG&E uses its EGIS to determine if the outage occurred in HTFDs.

The management of ignition data changed throughout the reporting period. PG&E was required by the CPUC to report ignition data starting in 2015. PG&E began utilizing ignition data to a greater degree in 2017 when it began data mining and conducting more in-depth data analysis exercises using ignition data. PG&E's current practice of conducting in-depth investigations of every ignition began in 2020. At that stage, PG&E staff realized that ignition events were getting "missed", meaning field personnel responded to asset outages but failed to indicate that there was an associated ignition. To resolve that problem, PG&E began conducting a daily audit on outage data looking for signs of associated ignitions.

The historical ignition data reported through the SOMs reports is the result of a post-processing audit. PG&E reviewed historical outage information, looking for signs of ignitions events. PG&E searched through outage comments looking for words like, ignition, fire, or spark.

Observations on Metric 3.15 Accuracy

To assess the accuracy of Metric 3.15, FEP evaluated PG&E's process for determining if ignitions were reportable or non-reportable. Then, FEP summed the total reportable ignitions for each year. Additionally, FEP verified the HFTD designations by plotting event coordinates in GIS. FEP found PG&E's calculations for Metric 3.15 to be accurate.

Verification of Reportability

The first step in the accuracy verification process was to review the classification of whether ignitions are reportable or non-reportable. Ignitions are considered reportable if the ignition is associated with PG&E assets, if something other than PG&E facilities burned, and the resulting fire traveled more than one linear meter from the ignition point. There are fields in the dataset detailing the involvement of PG&E assets, the fire size, and ignited materials. Additionally, only ignitions in the HTFDs meeting the above criteria are included in Metric 3.15.

Since there were so few transmission ignitions included in Metric 3.15, FEP briefly reviewed the provided data for each ignition individually. From the data available to FEP, the designation of reportable ignitions appears to be accurate.

Verification of HFTD Designations

As previously described, FEP found discrepancies in PG&E's outage HFTD designations. FEP requested that PG&E provide data on all outages which occurred in both the HFTD and non-HFTD areas. FEP used GIS software to plot the coordinates for the operating devices involved in the outages. FEP compared these plotted GIS locations to PG&E's HFTD/non-HFTD designations. A spatial selection in GIS was used to identify outage points that intersected with the HFTDs. The intersecting points were then analyzed to assess the accuracy of PG&E's HFTD/non-HFTD identification field. FEP found that many outages had latitude/longitude coordinates that fell within HFTD boundaries but were classified by PG&E as occurring in non-HFTD areas.

FEP undertook a similar assessment using the location of PG&E's ignitions. PG&E's 2021 – 2023 ignitions dataset included ignitions across PG&E's full service territory (HFTD & non-HFTD) and both reportable and non-reportable ignitions. Of over 1,300 reportable ignitions, FEP found 4 labeled as non-HFTD that fell within HFTD boundaries when the coordinates were plotted. However, when FEP examined the notes and addresses associated with each ignition, it appeared that they were properly classified as non-HFTD and therefore excluded from the metric.

Verification of Ignition Counts

Once FEP verified the reportable classifications were accurate, FEP summed the total number of reportable ignitions by year. Both FEP and PG&E identified 4 reportable ignitions in 2021, 5 reportable ignitions in 2022 and 6 reportable ignitions in 2023.

2.22.2 Metric 3.15 Management

PG&E's ignition data is used by many internal departments. The data is continuously audited and scrubbed. Additionally, many other teams like distribution, transmission, vegetation, wildfire, and asset management review the data as they use and access it. Therefore, the ignition dataset is reviewed daily.

Once ignition data is collected in the field, it's added to the database daily. Daily ignition reports go out to a wide audience. The daily ignition reports show fire size, circuit, the closest city, suspected ignition event, and the type of conduct involved. Along with the daily reports, dispatchers send dispatch notices to departments involved in the investigations, such as dispatches for arborists or field investigators.

Prior to a completed ignition evaluation, the information included in the report and database is based off the troubleshooter's initial findings. Troubleshooters are trained to evaluate evidence and categorize data in a specific way that facilitates data analysis. However, the findings are subject to change pending a completed ignition evaluation.

All ignitions are reviewed at a "desktop level" by ignition specialists. This means that ignition specialists review the data and make an assessment to determine if a more in-depth evaluation is necessary. This is also an opportunity for PG&E ignitions specialists to conduct a quality control assessment of the data gathered by troubleshooters in the field. Evaluators gather information from fire agencies, first responders, and arborists to discover if vegetation may have been involved with the ignition. If the ignition is reportable, PG&E undertakes an enhanced ignitions investigation which includes a forensic engineering exercise. Investigators collect material associated with the event and go onsite to assess the area. PG&E also conducts computer modeling to simulate the cause of the ignition and area of impact. Evaluators produce a preliminary investigation report and high-level findings are shared with regulatory agencies like the CPUC.

Whenever a troubleshooter or preliminary evaluator indicates that vegetation may have been involved with the ignition, the vegetation team receives a notification of a new event. They proactively dispatch arborists to the ignition location but also receive dispatches from the daily ignition dispatch notifications. Onsite vegetation reviews for ignitions need to occur quickly to avoid condition changes, so the vegetation team typically assesses the ignition site within 48 business hours.

Throughout this process, ignition data receives many layers of review. Preliminary reviews are conducted every morning and the desktop quality control reviews by ignition specialists are completed shortly after. Preliminary investigation reports are produced and shared with OEIS. Additionally, the Wildfire Management Team produces quarterly ignition reports. During the production of the quarterly reports, the Wildfire Management Team reviews ignitions data again. The final review of the quarterly data is conducted at the management level. Annual reports are compiled by the Communication Department. During the production of the annual report, staff review previous years of data in aggregate to assess ignition trends. Annual reports are dispersed by regulatory agencies like the CPUC and the telecommunication companies. Additionally, ignitions data for the SOMs are reviewed and summarized monthly. The data is certified internally every month.

Like other metrics, ignition SOMs data is reported to PG&E's CIC. PG&E discusses the status of the ignition metrics and makes catch back plans if the metrics are off track.

Observations on Metric 3.15 Management

PG&E's process for tracking and investigating ignitions appears to sufficiently capture ignitions data. PG&E conducts multiple levels of ignition investigations, including troubleshooter data collection, desktop reviews by ignitions specialists, enhanced investigations by specialists, and on-site reviews by vegetation and asset teams. Ignition data is widely dispersed to PG&E staff, and reports are produced daily, monthly, quarterly, and annually. Despite the wide dispersal of ignition data, write access is tightly controlled to prevent errors.

The accuracy of ignition SOMs reporting appeared to be impacted by circuit line mile calculations. This is the same phenomena that impacted some of the Wires Down metrics. PG&E could improve the accuracy of ignition SOMs reporting by including line mile values in the SOMs reports and instituting a process that allows the circuit mile values to be verified internally.

2.22.3 Metric 3.15 Performance and Targets

The 2021 target for Metric 3.15 was based on average historical three-year performance. Unlike Metric 3.13 and Metric 3.14, PG&E did not include a 25% reduction in the target for transmission ignition metrics. PG&E stated that it did not include a reduction in the target for the transmission ignition metrics because the volume of transmission ignitions is low and year-to-year variability is high. However, PG&E does state in its 2021 report that the "lower end" of its target is zero to reflect its "stand that catastrophic wildfires shall stop."

The following table displays PG&E's 2015 through 2023 metric results and the 1-year and 5-year metric targets.

Table 2-45: Metric 3-15 Results and Targets

Year	Metric Result	1-Year Target	5-Year Target
2015	5		
2016	8		
2017	12		
2018	3		
2019	10		
2020	16		
2021	4	10	10
2022	5	10	10
2023	6	10	8
[1] Targets reflect the target set in that report year (i.e. the 2021 1-year target reflects 2022 target).			

PG&E's average metric result from 2015 - 2023 was 7.67 and 5.00 from 2021 - 2023. PG&E's 2021 target is 30% above the nine-year average and 100% above the 2021 – 2023 average. Due to the high degree of variability in the Metric 3.15 data, decerning a trend is challenging.

PG&E stated that it did not use benchmarking from other utilities to set its targets for this metric. However, PG&E does engage in ignition benchmarking with other California utilities. PG&E stated that it works closely with other California utilities on its wildfire mitigation plans, which are filed with the Office of Energy Infrastructure Safety. Overall, PG&E staff felt that its ignition programs and practices were comparable to its peers, despite differing ignition drivers in northern and southern California.

Observations on Metric 3.15 Performance and Targets

Like FEP observed with the transmission Wires Down data (Metric 3.4 & 3.6), the transmission ignition dataset is quite small, which makes statistical analysis of targets and trends challenging. It is more difficult to set targets for small and varied datasets that both place appropriate safety guardrails and leave room for variability that PG&E may not be able to completely control. While FEP understands PG&E forgoing a percentage reduction target to transmission ignitions like it did for distribution ignitions based on the challenging nature of the transmission dataset, incremental reductions to the yearly target would better reflect performance improvement goals. However, when considering transmission ignitions and the data limitations, reviewing the handling of individual events may be a clearer way to assess if PG&E's handling is in the best interests of public safety, rather than relying on counts.

2.23 Metric 3.16: HFTD Ignitions/1000 miles (Transmission)

The CPUC defines Metric 3.16 as:

Number of CPUC-reportable ignitions involving overhead transmission circuits divided by circuit-miles of transmission lines X 1000 in HFTDs.

Metric 3.16 assesses the number of CPUC-reportable ignitions on transmission circuits in PG&E's HFTDs. The CPUC defines reportable ignitions as fire incidents which meet the following criteria:

1) The ignition is associated with PG&E electric assets,

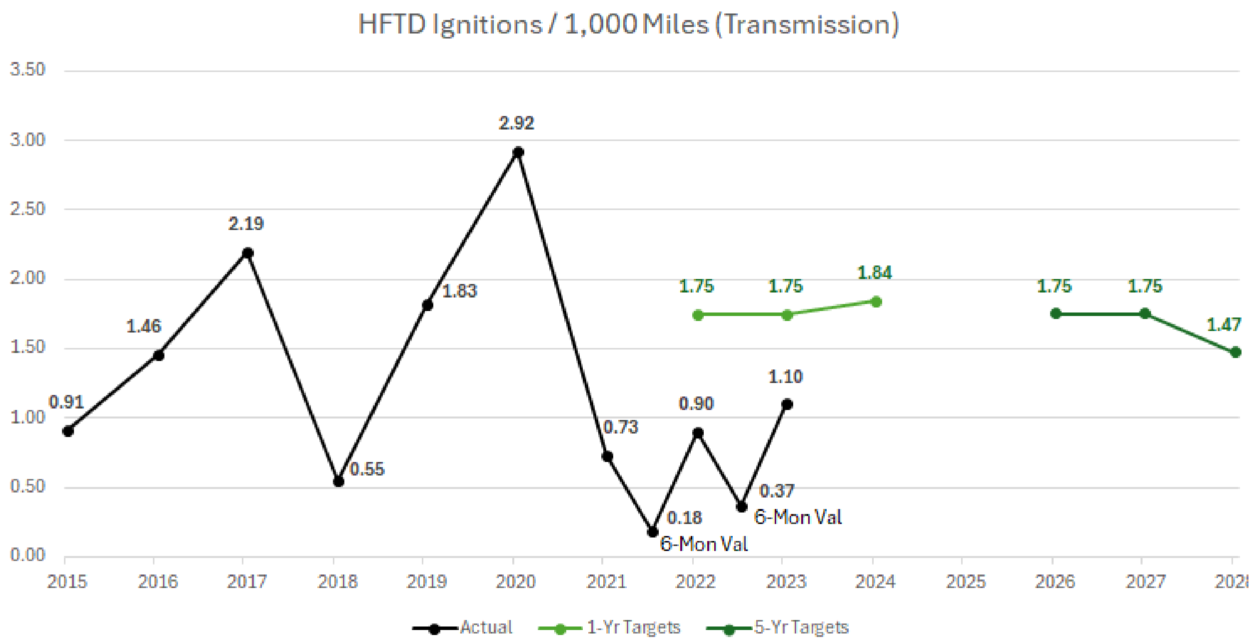
2) something other than PG&E facilities burned and

3) the resulting fire travelled more than one linear meter from the ignition point.

Number of ignitions is a useful measure of wildfire risk exposure from electric assets.

The following chart shows Metric 3.16 results compared to targets for 2015 through 2028, including results from the 2022 and 2023 mid-year reports. All historical values reflect the most recent data available as of the 2023 report and may differ from previously reported figures. The mid-year values are substantially lower because they cover only six months of ignitions, whereas the annual values cover the full twelve months.

Figure 2-35: Metric 3.16 Summary Chart



2.23.1 Metric 3.16 Accuracy and Consistency

The data for Metric 3.16 is housed in the ignition database, called Foundry. The database was built in 2021. PG&E departments that need access to ignition data, like distribution, transmission, wildfire mitigation, vegetation and asset management have read access to the data. The Grid Operations team controls write access to ignitions data. PG&E has documented procedures for editing, accessing and writing ignition data.

Prior to 2021, PG&E managed ignition data with an online tracker. A larger group of PG&E employees had the ability to view and edit the ignitions data, which led to errors such as accidentally deleted rows or changes to specific cells within the tracker. After 2021, the access was restricted such that even individuals with editor-level access don't have the ability to access all fields or delete data.

Most often, PG&E becomes aware of an ignition when field personnel are dispatched to an outage location and discovers evidence of an ignition. The field personnel access an app on their tablet and fill out information about the outage. This is the same app utilized for documenting outage events without evidence of an ignition. The personnel will indicate on that app that there is evidence of an ignition. The form offers ignition specific information if the box is checked, such as suspected cause. Once the form is complete, the data is transmitted to Foundry. PG&E uses its electric geographic information system (“EGIS”) to determine if the outage occurred in HTFDs.

The management of ignition data changed throughout the reporting period. PG&E was required by the CPUC to report ignition data starting in 2015. PG&E began utilizing ignition data to a greater degree in 2017 when it began data mining and conducting more in-depth data analysis exercises using ignition data. PG&E’s current practice of conducting in-depth investigations of every ignition began in 2020. At that stage, PG&E staff realized that ignition events were getting “missed,” meaning field personnel responded to asset outages but failed to indicate that there was an associated ignition. To resolve that problem, PG&E began conducting a daily audit on outage data looking for signs of associated ignitions.

The historical ignition data reported through the SOMs reports is the result of a post-processing audit. PG&E reviewed historical outage information, looking for signs of ignitions events. PG&E searched through outage comments looking for words like, ignition, fire, or spark.

Observations on Metric 3.16 Accuracy

To assess the accuracy of Metric 3.16, FEP evaluated PG&E’s process for determining if ignitions were reportable or non-reportable. Then, FEP summed the total reportable ignitions for each year. Additionally, FEP verified the HFTD designations by plotting event coordinates in GIS. Lastly, FEP assessed PG&E’s process for determining the number of distribution line miles in HFTDs. FEP found PG&E’s results to be accurate.

Verification of Reportability

The first step in the accuracy verification process was to review the classification of whether ignitions are reportable or non-reportable. Ignitions are considered reportable if the ignition is associated with PG&E assets, if something other than PG&E facilities burned, and the resulting fire traveled more than one linear meter from the ignition point. There are fields in the dataset detailing the involvement of PG&E assets, the fire size, and ignited materials. Additionally, only ignitions in the HTFDs meeting the above criteria are included in Metric 3.16.

Verification of HFTD Designations

As previously described, FEP found discrepancies in PG&E’s outage HFTD designations. FEP requested that PG&E provide data on all outages which occurred in both the HFTD and non-HFTD areas. FEP used GIS software to plot the coordinates for the operating devices involved in the outages. FEP compared these plotted GIS locations to PG&E’s HFTD/non-HFTD designations. A spatial selection in GIS was used to identify outage points that intersected with the HFTDs. The intersecting points were then analyzed to assess the accuracy of PG&E’s HFTD/non-HFTD identification field. FEP found that many outages had latitude/longitude coordinates that fell within HFTD boundaries but were classified by PG&E as occurring in non-HFTD areas.

FEP undertook a similar assessment using the location of PG&E’s ignitions. PG&E’s 2021 – 2023 ignitions dataset included ignitions across PG&E’s full service territory (HFTD & non-HFTD) and both reportable and non-reportable ignitions. Of over 1,300 reportable ignitions, FEP found 4 labeled as non-HFTD that fell within HFTD boundaries when the coordinates were plotted. However, when FEP examined the notes and addresses associated with each ignition, it appeared that they were properly classified as non-HFTD and therefore excluded from the metric.

Verification of Ignition Counts

Since there were so few transmission ignitions included in Metric 3.16, FEP briefly reviewed the provided data for each ignition individually. From the data available to FEP, the designation of reportable ignitions appears to be accurate. Once FEP verified the reportable classifications were accurate, FEP summed the total number of reportable ignitions by year. Both FEP and PG&E identified 4 reportable ignitions in 2021, 5 reportable ignitions in 2022 and 6 reportable ignitions in 2023. These results match the values reported by PG&E for Metric 3.15, which is the numerator of the Metric 3.16 formula.

Metric 3.14 assessed normalized ignitions per 1000-line miles. The following table summarizes the line mile values provided in PG&E's SOMs report.

Table 2-46: Transmission Line Miles

Year	Transmission Line Miles
2021	Not Provided
2022	Not Provided
2023	5,400

FEP observed that PG&E presented inconsistent transmission line mile values through the SOMs reports, workpapers, and RFIs. FEP recreated the 2021 and 2022 results using a value stated in the 2022 workpapers (5,478). FEP recommends that PG&E clearly document and retain the precise line mile calculations used to produce the SOMs metric results.

2.23.2 Metric 3.16 Management

PG&E's ignition data is used by many internal departments. The data is continuously audited and scrubbed. Additionally, many other teams like distribution, transmission, vegetation, wildfire, and asset management review the data as they use and access it. Therefore, the ignition dataset is reviewed daily.

Once ignition data is collected in the field, it's added to the database daily. Daily ignition reports go out to a wide audience. The daily ignition reports show fire size, circuit, the closest city, suspected ignition event, and the type of conduct involved. Along with the daily reports, dispatchers send dispatch notices to departments involved in the investigations, such as dispatches for arborists or field investigators.

Prior to a completed ignition evaluation, the information included in the report and database is based off the troubleshooter's initial findings. Troubleshooters are trained to evaluate evidence and categorize data in a specific way that facilitates data analysis. However, the findings are subject to change pending a completed ignition evaluation.

All ignitions are reviewed at a "desktop level" by ignition specialists. This means that ignition specialists review the data and make an assessment to determine if a more in-depth evaluation is necessary. This is also an opportunity for PG&E ignitions specialists to conduct a quality control assessment of the data gathered by troubleshooters in the field. Evaluators gather information from fire agencies, first responders, and arborists to discover if vegetation may have been involved with the ignition. If the ignition is reportable, PG&E undertakes an enhanced ignitions investigation which includes a forensic engineering exercise. Investigators collect material associated with the event and go onsite to assess the area. PG&E also conducts computer modeling to simulate the cause of the ignition and area of impact. Evaluators produce a preliminary investigation report and high-level findings are shared with regulatory agencies like the CPUC.

Whenever a troubleshooter or preliminary evaluator indicates that vegetation may have been involved with the ignition, the vegetation team receives notification of a new event. They proactively dispatch arborists to the ignition location but also receive dispatches from the daily ignition dispatch notifications. Onsite vegetation reviews for ignitions need to occur quickly to avoid condition changes, so the vegetation team typically assesses the ignition site within 48 business hours.

Throughout this process, ignition data receives many layers of review. Preliminary reviews are conducted every morning and the desktop quality control reviews by ignition specialists are completed shortly after. Preliminary investigation reports are produced and shared with OEIS. Additionally, the Wildfire Management Team produces quarterly ignition reports. During the production of the quarterly reports, the Wildfire Management Team reviews ignitions data again. The final review of the quarterly data is conducted at the management level. Annual reports are compiled by the Communication Department. During the production of the annual report, staff review previous years of data in aggregate to assess ignition trends. Annual reports are dispersed by regulatory agencies like the CPUC and the telecommunication companies. Additionally, ignitions data for the SOMs are reviewed and summarized monthly. The data is certified internally every month.

Like other metrics, ignition SOMs data is reported to PG&E's CIC. PG&E discusses the status of the ignition metrics and makes catch back plans if the metrics are off track.

Observations on Metric 3.16 Management

PG&E's process for tracking and investigating ignitions appears to sufficiently capture ignitions data. PG&E conducts multiple levels of ignition investigations, including troubleshooter data collection, desktop reviews by ignitions specialists, enhanced investigations by specialists, and on-site reviews by vegetation and asset teams. Ignition data is widely dispersed to PG&E staff, and reports are produced daily, monthly, quarterly, and annually. Despite the wide dispersal of ignition data, write access is tightly controlled to prevent errors.

The accuracy of ignition SOMs reporting appeared to be impacted by circuit line mile calculations. This is the same phenomena that impacted some of the Wires Down metrics. PG&E could improve the accuracy of ignition SOMs reporting by including line mile values in the SOMs reports and instituting a process that allows the circuit mile values to be verified internally.

2.23.3 Metric 3.16 Performance and Targets

The 2021 target for Metric 3.16 was based on average historical three-year performance. Unlike Metric 3.13 and Metric 3.14, PG&E did not include a 25% reduction in the target for transmission ignition metrics. PG&E stated that it did not include a reduction in the target for transmission ignition metrics because the volume of transmission ignitions is low and year-to-year variability is high. However, PG&E does state in its 2021 report that the "lower end" of its target is zero to reflect its "stand that catastrophic wildfires shall stop."

The following table displays PG&E's 2015 through 2023 metric results and the 1-year and 5-year metric targets.

Table 2-47: Metric 3-16 Results and Targets

Year	Metric Result	1-Year Target	5-Year Target
2015	0.913		
2016	1.460		
2017	2.191		
2018	0.548		
2019	1.825		
2020	2.921		
2021	0.730	1.75	1.75
2022	0.913	1.75	1.75
2023	1.09	1.84	1.47
[1] Targets reflect the target set in that report year (i.e. the 2021 1-year target reflects 2022 target).			

PG&E's average metric result from 2015 through 2023 was 1.40 and 0.91 from 2021 - 2023. PG&E's target is 25% above the nine-year average and 92% above the 2021 – 2023 average. Due to the high degree of variability in the Metric 3.16 data, there is no discernable trend.

PG&E stated that it did not use benchmarking from other utilities to set its targets. However, PG&E does engage in ignition benchmarking with other California utilities. PG&E stated that it works closely with other California utilities on its wildfire mitigation plans, which are filed with the CPUC. Overall, PG&E staff felt that its ignition programs and practices were comparable to its peers, despite differing ignition drivers in northern and southern California.

Observations on Metric 3.16 Performance and Targets

Like FEP observed with the transmission Wires Down data (Metric 3.4 & 3.6), the transmission ignition dataset is quite small, which makes statistical analysis of targets and trends challenging. It is more difficult to set targets for small and varied datasets that both place appropriate safety guardrails and leave room for variability that PG&E may not be able to completely control. While FEP understands PG&E forgoing a percentage reduction target to transmission ignitions like it did for distribution ignitions based on the challenging nature of the transmission dataset, incremental reductions to the yearly target would better reflect performance improvement goals. However, when considering transmission ignitions and the data limitations, reviewing the handling of individual events may be a clearer way to assess if PG&E's handling is in the best interests of public safety, rather than relying on counts, based on the data limitations.

2.24 Metric 4.1: Gas Dig-Ins Rate

The CPUC defines Metric 4.1 as:

The number of gas dig-ins per 1,000 Underground Service Alert (USA) tickets received for gas.

Underground Service Alert ("USA") is an organization which provides information to excavators about underground facility locations. The law requires excavators to contact USA two days prior to excavation activities to avoid damaging underground facilities. USA generates tickets when individuals or organizations call USA to request location services.[44]

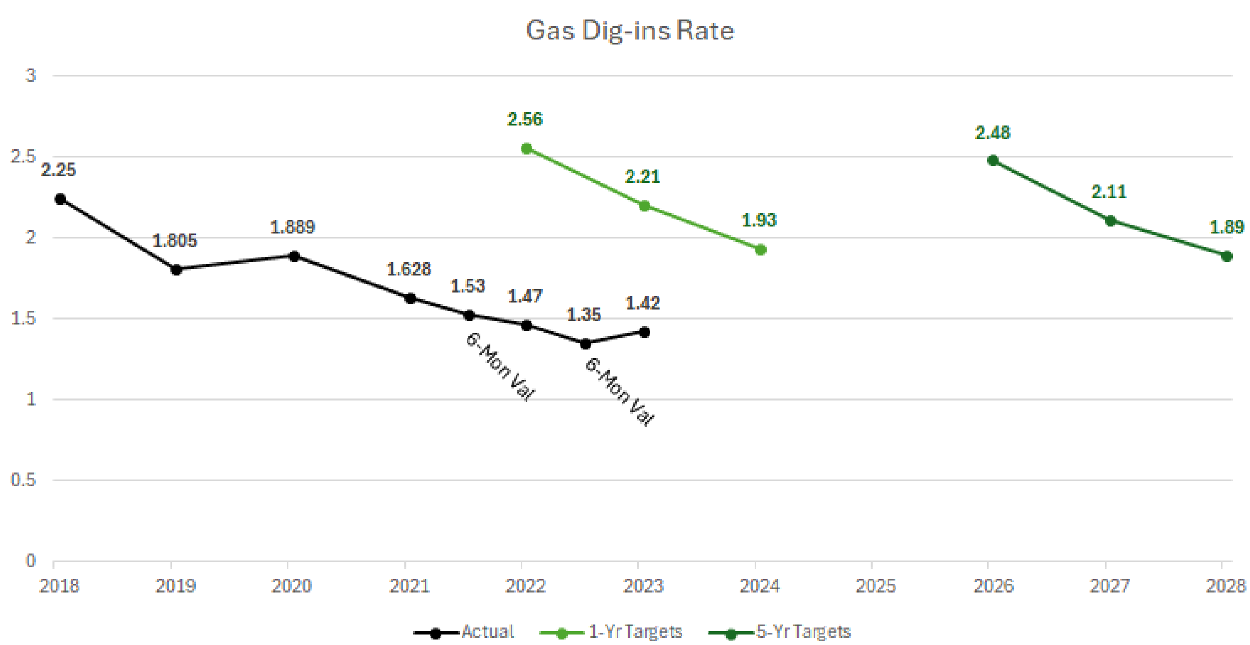
A gas dig-in refers to damage (impact or exposure) which occurs during excavation activities and results in the repair or replacement of an underground gas facility. This metric excludes fiber and electric tickets. This metric also excludes tickets originated by the utility itself (1st party) or by utility contractors (2nd party).

Metric 4.1 evaluates the effectiveness of PG&E's program to inform the public and excavators to call 811 (USA) before they dig, and PG&E's accuracy in locating and marking its buried gas facilities. The formula for calculating Metric 4.1 is:

$$= \frac{(\# \ of \ damages \ to \ underground \ facilities \ cased \ by \ excavation)}{(Total \ 3rd \ Party \ Underground \ Service \ Alert \ Tickets)/1000}$$

The following chart shows Metric 4.1 results compared to targets for 2018 through 2028, including results from the 2022 and 2023 mid-year reports. All historical values reflect the most recent data available as of the 2023 report and may differ from previously reported figures.

Figure 2-36: Metric 4.1 Summary Chart



2.24.1 Metric 4.1 Accuracy and Consistency

Information for Metric 4.1 is compiled into the Master Dig-in File (master file) and managed by the Damage Prevention Organization. The master file is a compilation and comparison of data collected from

[44] Digalert.org, https://www.digalert.org/

three source databases. The three data sources for Metric 4.1 are the Gas Dispatch Event Management Tool ("EMT"), PRONTO, and SAP.

Gas Dispatch receives notification of a gas dig-in and dispatches a PG&E Gas Service Representative ("GSR") and/or a construction crew, depending on the information received. When receiving the notification of the gas dig-in, Gas Dispatch enters the related information into the Gas Dispatch Event Management Tool.

Additionally, the Dig-in Reduction Team ("DiRT")is notified of the incident and is dispatched to investigate the cause of the dig-in. Investigators produce reports for all dig-ins. DiRT investigation results are entered into a DiRT PRONTO Record and the narrative of the incident is created on SharePoint as a Word document. GSR and gas construction crew document their work related to the incident in SAP.

PG&E has used the same process since 2015 when PG&E made minor modifications to the previous process. PG&E created an investigatory team for incidents involving third-party contractors. This team evolved into DiRT over the course of a year and expanded its investigations to include all dig-ins, rather than focusing exclusively on third party dig-ins. The team now has sixteen full-time employees with two supervisors and is supported by contractors.

Daily and weekly dig-in data is shared among front-line workers, as those statistics are the ones most relevant to their operations. PG&E staff conduct weekly working sessions around "at-fault" dig-ins that were caused by PG&E crews. They meet with the entire team involved with the dig-in to determine the dig-in cause and how it might be prevented in the future. The information from these working sessions is compiled and shared every two weeks throughout the broader gas team.

The three databases create redundancy and allow for comparison which generally confirms completeness and accuracy of the master file. The master file is updated monthly. While the updates occur only once a month, the data going into the update is maintained continuously to ensure the information going in is correct. This process is facilitated with a daily gas dig-in report that catalogs the known dig-ins which need to be addressed. The daily data is unverified data which is used as an internal metric to assess progress and workloads. To verify the data, the metric owner completes a monthly scrub of the data for accuracy and completeness. In addition, the team performs a quarterly review of the monthly results to verify accuracy.

Observations on Metric 4.1 Accuracy

To assess the accuracy of this metric, FEP reviewed the total number of USA tickets by year and the number of gas-dig ins. Overall, FEP found PG&E's calculation of Metric 4.1 to be accurate.

Dig In Party & Count

First, FEP verified that the ticket counts were filtered to only include work done by third parties. Then, FEP verified the number of dig-ins reported for each year. The results of this count match the values reported by PG&E for 2021, 2022 and 2023.

Ticket Count

FEP then verified the number of tickets by month and year. FEP then calculated the monthly and yearly dig-in rates using the formula above. The results for 2021 - 2024 match PGE's both on the monthly level and on the yearly level presented in the SOM report.

2.24.2 Metric 4.1 Management

The Damage Prevention and Compliance Department is responsible for managing, tracking and setting targets for Metric 4.1. The DiRT team reviews all reported Dig-Ins daily. All "at fault" dig-ins by PG&E are reviewed in a working session and assessed for cause with the entire group. All the information compiled weekly is shared during Operational Reviews on a bi-weekly basis.

There are weekly, monthly and quarterly accuracy reviews of dig-in data. PG&E considers gas dig-in rates to be a critical performance indicator, so statistics related to dig-ins are shared all the way up to upper management. However, the dig-in values broadly distributed are general dig-in rates and are not segmented based on SOM delimitations.

The metric results are reported to the CIC, where PG&E discusses whether the metrics are on target for their end of the year and five-year goals. If Metric 4.1 is off track, catch-back plans are developed to address the issues that are preventing the team from achieving its goals. The team reviews controls and mitigations that are currently in place and recommends adjustments.

PG&E takes the following actions to manage general dig-in rates:

- DiRT & Ground Patrol team respond to immediate threats identified by aerial patrol or other PG&E Groups to intervene in unsafe digging activities, to prevent dig-ins.
- PG&E's Damage Prevention Program was implemented to inform the public to prevent dig-ins.
- PG&E participates in the Common Ground Alliance, an alliance of stakeholders (utilities and contractors).
- Working sessions on all PG&E "at fault" dig-ins to determine the cause and prevent future dig-ins.

While the actions above outline PG&E's overall strategy for managing dig-ins, Metric 4.1 includes only third-party dig-in rates. PG&E staff note that impacting the number of third-party dig-ins is challenging. While PG&E has control over the actions of its staff and contractors, it has very little control over the actions of third parties. PG&E attempts to reduce dig-ins through activities like public awareness campaigns and community outreach, but these methods are indirect compared to the safety policies it can enact for its own employees. Public awareness and education campaigns are examples of proactive work. However, it takes time for these types of activities to impact Metric 4.1 performance.

Observations on Metric 4.1 Management

Overall, PG&E's process for tracking and managing dig-ins sufficiently captures data relevant to Metric 4.1. Metric 4.1 includes both data derived from PG&E's operations, and 811 data. PG&E's management of first, second- and third-party dig-ins captures relevant information, such as location, asset type and the parties involved. PG&E obtains the 811 data from an outside organization and does not have control over the collection of ticket data.

2.24.3 Metric 4.1 Performance and Targets

PG&E set targets for Metric 4.1 based on factors including historical performance, available benchmarking, and resource availability. PG&E stated that it used benchmarking of total dig in rates (including 1st, 2nd, and 3rd party) and subtracted the 1st and 2nd party tickets and dig-ins to derive the target for 3rd party tickets. This value was used to inform Metric 4.1 target setting. PG&E sets its target as at the cut-off boundary between the first and second quartile of industry benchmarking performance of total dig-ins.

The Damage Prevention and Compliance Department team meets with leadership to review and approve targets. PG&E staff noted that, since its Gas Dig-in performance is in the top quartile of gas utilities in the nation, it balances a desire for continuous improvement overall with existing resources. To benchmark Gas Dig-ins, PG&E participates in the American Gas Association (AGA) Best Practices and Peer Review programs. AGA's reporting process includes specific formulas and questions that all participating utilities answer. AGA compiles the results annually. PG&E uses its own industry benchmarking results for total Dig-in rates (including 1st, 2nd, and 3rd party) and subtracts the 1st and 2nd party tickets and dig-ins to derive its Metric 4.1 target for just 3rd party tickets. Since Metric 4.1 includes only 3rd party dig-ins, the AGA data is not a directly applicable benchmark for Metric 4.1.

In addition to participating in AGA, PG&E maintains close relationships with the other nearby utilities which provide gas services. These utilities include San Diego Gas and Electric, Southern California Gas and Southwest Gas.

Gas Dig-in benchmarking data is shared with company leadership. Leadership focuses closely on general Gas Dig-in benchmarking data and internal targets. However, SOMs targets are a lesser focus compared with general Dig-in benchmarking data and not shared as broadly.

The following table displays PG&E's 2018 through 2023 metric results and the 1-year and 5-year metric targets. PG&E's metric results were significantly lower than the metric targets throughout the reporting period.

Table 2-48: Metric 4.1 Results and Target

Year	Metric Result	1-Year Target[1]	5-Year Target[1]
2018	2.25		
2019	1.805		
2020	1.889		
2021	1.628	2.56	2.48
2022	1.470	2.21	2.11
2023	1.420	1.93	1.89

[1] Targets reflect the target set in that report year (i.e. the 2021 1-year target reflects 2022 target).

Overall, PG&E's Metric 4.1 results have shown a downward trend. PG&E's average metric result from 2018 to 2023 was 1.74, and from 2021 to 2023, it was 1.51. PG&E's 1-year target set in 2023 was 11% above the 6-year average and 28% above the 2021 – 2023 average.

Observations on Metric 4.1 Performance and Targets

Based on FEP's discussions with PG&E on Dig-In performance drivers, it appears that Metric 4.1 is not a major contributor to company behavior. As previously mentioned, dig-ins generally are closely monitored by PG&E leadership but the SOM targets are not set at levels that would drive performance improvement. Although PG&E participates in AGA benchmarking for dig-ins, the AGA metric includes all tickets while Metric 4.1 excludes PG&E and its contractor-initiated tickets.

PG&E has a vested interest in managing dig-ins and remaining in “top quartile” performance of general dig-in rates. PG&E’s L1 metric related to gas dig-ins is the “Total Gas Dig-In Rate”, which is defined as the number of gas dig-ins per 1,000 tickets from 811. The targets for L1s are aspirational and put more emphasis on performance improvement.

2.25 Metric 4.2: Gas Over Pressure Events

The CPUC defines Metric 4.2 as:

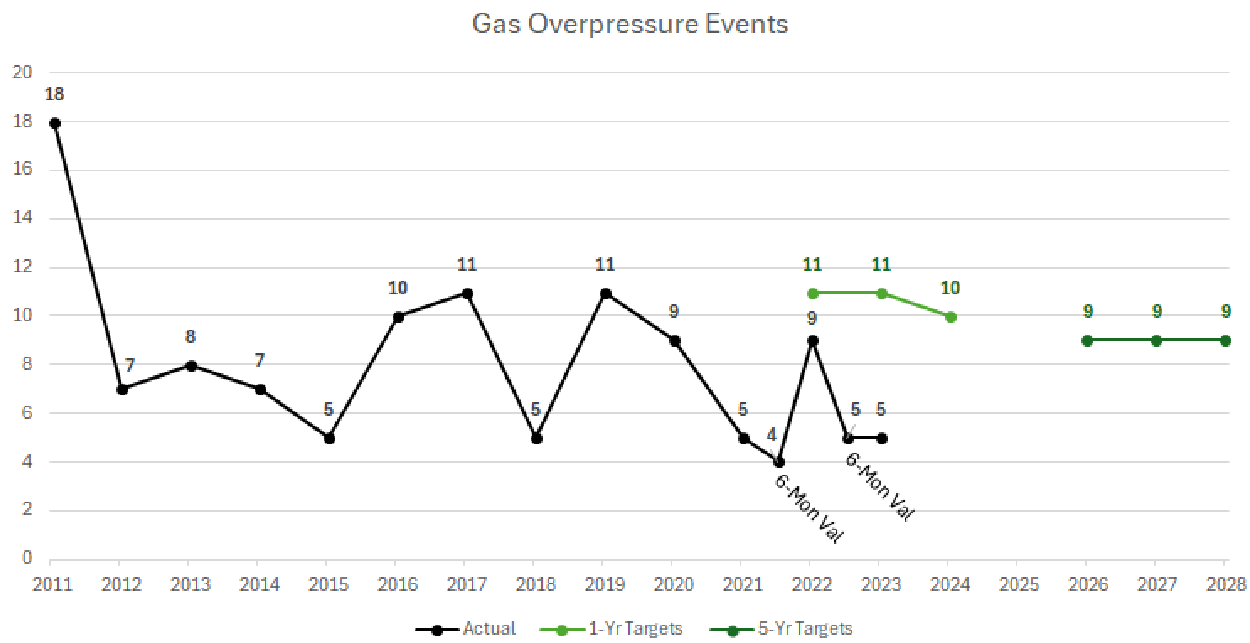
Over Pressure (OP) events as reportable under General Order (GO) 112-F 122.2 (d)(5). For Over Pressure (OP) events, the following are reportable: e *“Incidents where the failure of a pressure relieving and limiting stations, or any other unplanned event, results in pipeline system pressure exceeding its established Maximum Allowable Operating Pressure (MAOP) plus the allowable build up set forth in 49 CFR 192.201”.*

This metric includes all OP events which are reportable according to GO 112-F. Metric 4.2 assesses the accuracy and completeness of facility design, installation, and maintenance of devices which limit gas pressure on downstream facilities to no more than the system maximum allowable operating pressure (MAOP) plus the allowable build-up. When any of these three items are not properly performed, the pressure in a pipeline could exceed the MAOP and an OP event can occur. Improper equipment selection including sizing (design), equipment failure and operator error are the primary causes of OP events. An outside force such as a vehicle impact, or naturally occurring events such as earthquakes or landslides, can also result in OP events if pressure regulation equipment is damaged. The Gas Pipeline Safety Code, 49 CFR Part 192 requires proper design and annual inspection, maintenance and testing to ensure pressure limiting equipment is in good condition and operating correctly to protect the pipeline system. The Code also requires periodic verification that relief valves have adequate capacities to protect the system.

The main criteria for reportable overpressure events are distribution events greater than 50 percent above the MAOP in pipes with 12 pounds per square inch gauge (“psig”) or less, or greater than 6 psig above the MAOP for pipes between 12 and 60 psig. For lines with MAOPs greater than 60 psig, including Transmission, OP events greater than 10 percent above the MAOP are also considered large reportable events. OP events are also reportable if they occur on transmission infrastructure and produce a hoop stress of greater than or equal to 75% of the specified minimum yield strength of the piping involved.

The following chart shows Metric 4.2 results compared to targets for 2011 through 2028, including results from the 2022 and 2023 mid-year reports. All historical values reflect the most recent data available as of the 2023 report and may differ from previously reported figures.

Figure 2-37: Metric 4.2 Summary Chart



2.25.1 Metric 4.2 Accuracy and Consistency

Tracking Metric 4.2 includes several automated and employee-managed functions. PG&E's System Control and Data Acquisition (SCADA) systems monitor gas assets for pressure anomalies and alert the Gas Control team of potential OP events. Additionally, field personnel gauge pressure while performing maintenance on assets and report overpressure or other potential problems to Gas Control as they perform routine job functions.

Information about each event is collected and entered manually into PG&E's work management system, CAP. PG&E investigates each OP event and distributes the resulting information to a broad internal stakeholder audience. All the data entered into SAP is reviewed by the Facility Integrity Management Program Team for accuracy and completeness.

The Gas Regulation Services team compiles a list of all OP events. This master list is viewable by all PG&E Employees. Data on every OP event is distributed to employees involved with the management of gas pipelines. OP events are monitored closely within the organization, and PG&E leadership is briefed on each event during Daily Operations Briefings. While a broad stakeholder audience has READ access to PG&E's OP data, write access is limited to the Gas Regulation Services team.

OP event reports are entered into the CAP system and are tracked on the SharePoint site. The SharePoint site is visible to all employees. Changes or revisions to the data are automatically tracked to avoid accidental alterations or deletions of data.

In addition to daily reviews of OP events, OP event data is tracked monthly. Due to the small number of OP events, PG&E can track and fully investigate all occurrences. The tracking and investigation process for OP events has not changed in the last 10 years. Since the methodology which identifies OP events stayed the same, the metric data provided to the CPUC is comparable year-to-year.

Observations on Metric 4.2 Accuracy

To assess the accuracy of Metric 4.2, FEP reviewed the OP data to verify PG&E's determination of what events were included and excluded from the count based on reportability. FEP then summed the included datapoints to produce yearly values. Overall, FEP found PG&E's calculation of Metric 4.2 to be accurate.

Verification of Reportability

PG&E provided data on each OP event. The data included the maximum pressure value, the MAOP value, and the percentage over MAOP for the event. PG&E also designated whether events were classified as reportable. FEP verified the reportability designation. Due to the relatively small number of reportable overpressure events, FEP was able to manually review the reportable OP event records. Overall, FEP agrees with PG&E's reportability designations and the total reportable OP events for each year.

Exclusion of Over Pressure Events on Low Pressure Systems

PG&E stated that LP systems are excluded from this metric because LP OP events are not defined in federal code 49 CFR 192.201.[45] While the federal code does not specify OP standards on LP systems, it is PG&E's responsibility to determine safe pressures for those systems to operate under. The Metric 4.2 definition does not specifically exclude low pressure events.

PG&E operates under the CPUC's G.O. 58-A, "Standards for Gas Service in The State of California". This code specifies the minimum and maximum pressures of gas pipelines, including LP systems. However, PG&E defines LP systems differently than G.O 58-A. PG&E defines LP systems as those operating below 1 psig, which is equal to 27.7" w.c. Meanwhile, GO-58-A states that the upper limit of a low pressure system is 12" w.c.

PG&E uses other internal metrics to track large LP system OP events but excludes them from this metric. All LP OP events where the pressure exceeds PG&E's stated maximum safe pressure of 16" w.c. are reportable, so PG&E monitors and tracks OP events on LP systems. PG&E stated it hasn't had a large LP OP event since it performed extensive mitigations in 2015. Therefore, no unreported LP OP events occurred since this Metric 4.2 was initiated.

When the exclusion of LP events was discussed with PG&E, PG&E stated that excluding the LP system events made their rates more comparable to the other California utilities that do not have LP distribution systems, such as Sempra. From a safety and operations perspective, there is no difference between HP and LP OP events. LP OP events can be just as serious as HP OP events and have the same causes listed above. Even though the pressure limiting equipment may be slightly different for LP gas systems, the operating principles are the same.

2.25.2 Metric 4.2 Management

PG&E's Gas Regulation Services team is responsible for managing, tracking and setting targets for Metric 4.2. The Gas Regulation Services team reviews Metric performance for OP events and reports to management of the Gas Facilities and Storage Department monthly.

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[45] PG&E's 2021 SOMs Report, p. 4.2-1. https://www.cpuc.ca.gov/-/media/cpuc-website/industries-and-topics/reports/r2007013som-report412022.pdf

OP events are typically caused by oversized regulation equipment, undersized pressure relief equipment, equipment failure or operator error. Therefore, a detailed review is conducted for each event. This review determines the contributing factors, and a combination of gas stakeholders determines the main cause of the event. To maintain consistency in interactions with regulatory agencies, the regulatory department is also involved with OP event reviews.

The CIC meets monthly to discuss the metrics that are not on target to meet the 1-year and 5-year targets. If any metric is off track, catch back plans are developed to address the issues which are preventing the team from achieving the target. For example, management may ask the metric owner if more resources are needed to improve performance to meet the target. The most important factor for achieving the target for Metric 4.2 is ensuring annual inspections and maintenance on pressure reduction and limiting equipment are performed as required by the pipeline safety regulations. Root cause analyses of failures are performed to determine if any trends indicate that specific types of equipment need to be replaced, or design and construction standards should be changed.

Observations on Metric 4.2 Management

The CIC conducts a monthly meeting of metric owners and upper management to review any metrics not meeting SOMs Targets. FEP observed a portion of the February 2025 CIC meeting which involved one SOM Metric that was projected to miss its target. The catch-back plan was discussed. The metrics projected to not meet targets are visible to all CIC meeting attendees.

PG&E implemented several programs to reduce OP events. In 2011, PG&E reviewed its customer gas usage and the associated system capacities. As a result, PG&E lowered the normal Maximum Operating Pressures ("MOP") below MAOPs as appropriate, to create an operating cushion so minor pressure increases did not exceed MAOP plus the allowable build up. The result reduced the number of OP events by almost half.

PG&E also started retrofitting Pilot Operated regulator stations and Large Volume Customer Regulator ("LVCR") sets and rebuilding Large Volume Customer Meter ("LVCM") sets to eliminate Common Failure mode stations to reduce OP events. Common Failure Mode means both the working regulator (pressure-reducing) and the monitoring regulator (over-pressure prevention backing up the working regulator) are similar and have the same failure mode. If both pressure limiting regulators (the working pressure regulator and the monitoring (back-up) regulator) have the same failure mode, a single incident that damages one regulator would be likely to damage both regulators. An OP event will occur if both the pressure-limiting regulator and the monitor regulator fail.

The highest pressure on any system is usually at the outlet of the pressure limiting regulator station that supplies each system unless the supply station is at a significantly higher elevation than a portion of the system, an extremely rare situation. PG&E installed pressure recording equipment at most, if not all, of its regulator stations many years ago. Therefore, PG&E has data on every OP event, but in the past the pressures were not all reported in real time as they are by a SCADA system.

PG&E initiated installation of additional SCADA points on its system so Gas Control is informed in real time when a pressure upset occurs. Gas Dispatch can dispatch personnel more quickly when notified of a pressure increase, possibly preventing an OP event. PG&E is also utilizing its billing system for LVCM's with existing transmitted pressure compensation for additional system pressure points. PG&E could not answer what the direct impact of the additional system pressure data collected from the newly installed equipment was on reduced OP events.

2.25.3 Metric 4.2 Performance and Targets

Metric 4.2 targets are set by the Gas Regulation Services team, with input from various stakeholders like the Facilities Integrity Management team. PG&E used the highest metric result over the previous seven years of 11 to set the 1-year target in the 2021 and 2022 reports. years. In its 2021 report, PG&E stated its intention of decreasing the target for number of events by one every two years. PG&E reduced the 1-year target set in 2023 to 10, in line with this intention. However, PG&E did not reduce the 5-year target set in 2023.

The following table displays PG&E's 2013 through 2023 metric results and the 1-year and 5-year metric targets.

Table 2-49: Metric 4.2 Results and Targets

Year	Metric Result	1-Year Target	5-Year Target
2013	8		
2014	7		
2015	5		
2016	10		
2017	11		
2018	5		
2019	11		
2020	9		
2021	5	11	9
2022	9	11	9
2023	5	10	9
[1] Targets reflect the target set in that report year (i.e. the 2021 1-year target reflects 2022 target).			

PG&E's average metric result from 2013 to 2023 was 7.73, and from 2021 to 2023, it was 6.33. PG&E's 2023 target of 11 is 42% above the 11-year average and 74% above the 2021–2023 average. In 2023, PG&E's metric result of 5 was 55% below the target.

Since so few OP events occur per year, small shifts in OP rates can dramatically change metric results. PG&E staff stated that the small dataset makes discerning trends in OP data challenging. Additionally, pushing for a yearly incremental decrease of OP event rates becomes increasingly difficult after a certain point.

Various sources of benchmarking data are available to help guide target setting for Metric 4.2. Unlike many of the other SOMs, PG&E employees stated that the range of types of OP events included in Metric 4.2 is quite broad, capturing a broader range of events than is typically assessed industry wide. PG&E has conducted research and participated in benchmarking exercises with both national and international gas providers. These exercises are not directly comparable to Metric 4.2 and focus primarily on qualitative assessments of technology, management techniques, and company practices related to OP events. It considered what devices were used by outside organizations, and what its management philosophies were.

Observations on Metric 4.2 Performance and Targets

As OP events have become an area of greater concern in the natural gas industry in the last 15 years, there has been much discussion about benchmarking. So far, there is limited gas industry benchmarking available for OP Events. A major reason for the lack of robust benchmarking on OP events is that each incident is a failure of equipment and possibly a compliance issue, so there is reluctance to voluntarily report failures.

PG&E contracted for International & North American industry evaluations for techniques to improve OP performance. PG&E looked at what philosophies drive policies and the types of over-pressure protection equipment used by the various gas utilities, such as slam shut devices to shut off the flow of gas, remote operated valves, etc.

Natural gas utility operators share techniques and ideas to prevent OP events through membership in industry organizations, such as the American Gas Association (AGA), Southern Gas Association (SGA), Interstate Natural Gas Association of America (INGAA) and state and regional gas associations. The AGA has a program called SOS where gas utilities ask questions to other members about how they're addressing various issues and receive their responses.

Taken as guard rails, rather than aspirational goals, the targets set by PG&E are reasonable to maintain consistent results with slight long-term downward pressure. However, the nature of the target setting methodology, which views SOMs targets as "not to exceed" values, is unlikely to drive company performance and behavior related to OP event management.

2.26 Metric 4.3: Gas Emergency Average and Median Response Time

The California Public Utilities Commission (CPUC) defines Metric 4.3 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.

Metric 4.3 assesses the speed at which PG&E can respond to emergency situations involving natural gas pipelines. This metric signals PG&E's ability to provide efficient service while protecting public safety and infrastructure. GSRs are members of PG&E's staff qualified to assess and address potential issues with the gas pipeline system. This metric tracks PG&E's responses to customer reports of gas odors, which PG&E classifies as needing an "Immediate Response" (IR).[46] The formula for calculating Metric 4.3 (average) is:

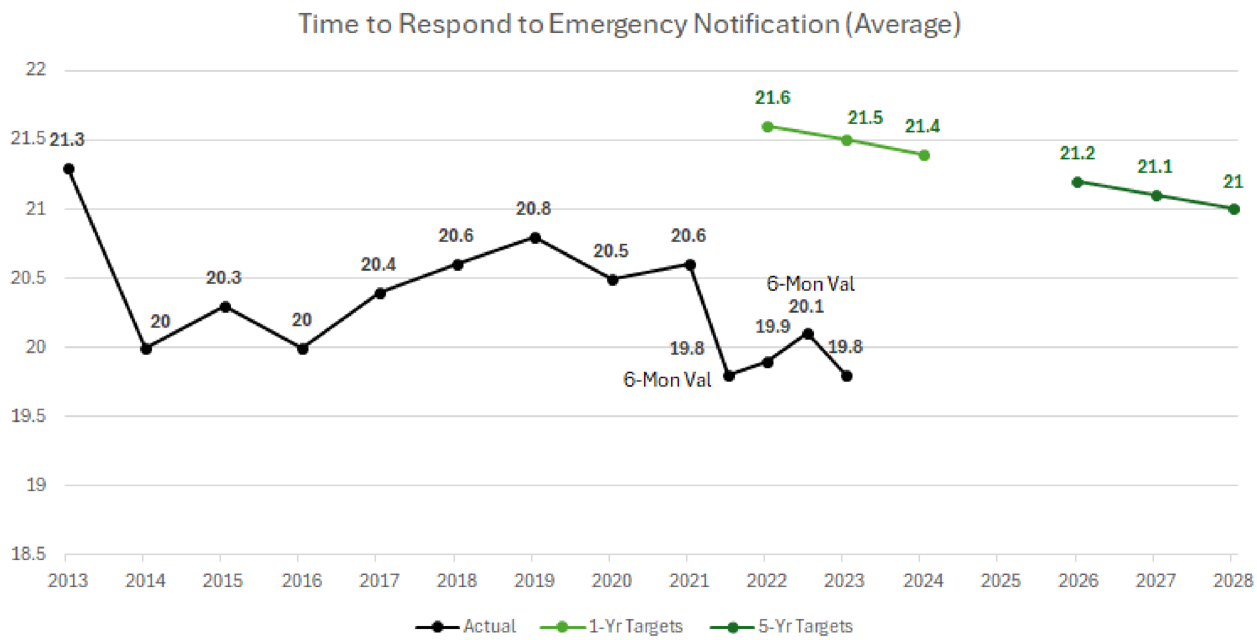
$$= \frac{Total\ Time\ to\ Repond\ Onsite\ to\ Gas\ IRs}{\#\ of\ Gas\ IRs}$$

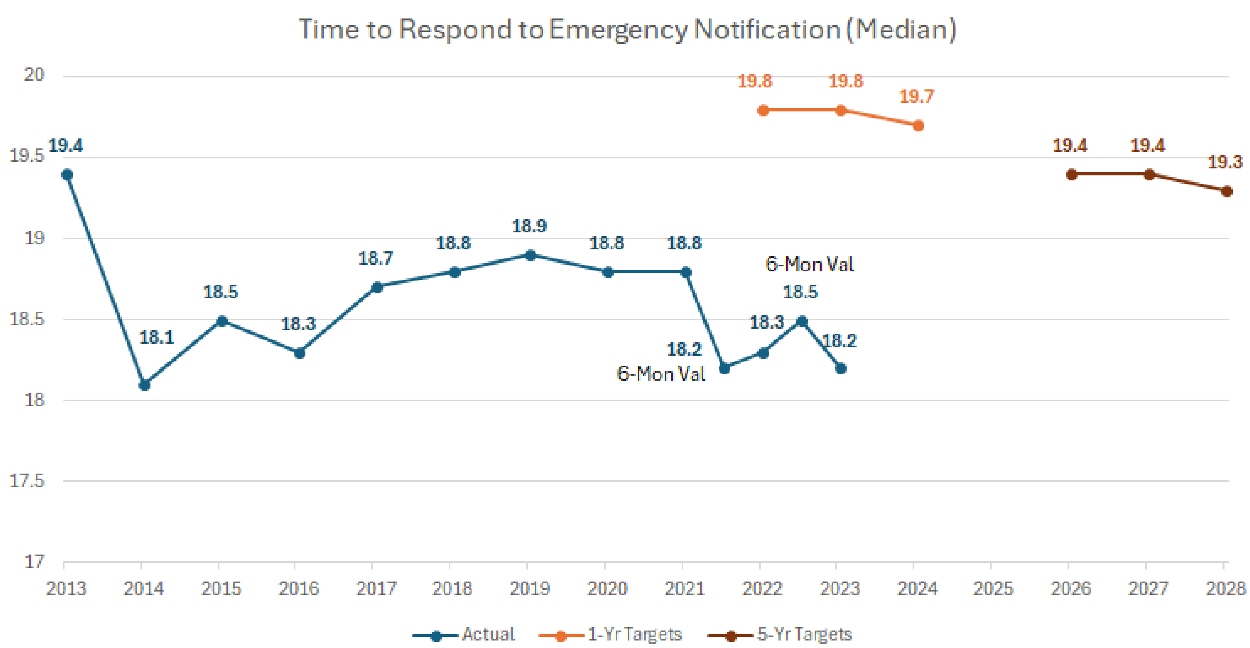
The median is calculated using statistical tools, like Microsoft Excel, and the formula depends on if the dataset has an odd or even number of values.

[46] 2021 SOMs Report, 4.3.

The following chart shows Metric 4.3 results compared to targets for 2013 through 2028, including results from the 2022 and 2023 mid-year reports. All historical values reflect the most recent data available as of the 2023 report and may differ from previously reported figures.

Figure 2-38: Metric 4.3 Summary Chart





2.26.1 Metric 4.3 Accuracy and Consistency

Measurement of PG&E's gas emergency response time begins when the system utilized by Gas Dispatch timestamps the receipt of an emergency notification. The notifications measured by this metric include calls from emergency dispatchers or members of the public to PG&E's Emergency Hotline. The response time ends when the GSR arrives on site and indicates that they have arrived on their GPS-connected mobile data terminal. The start and end time for this metric is autogenerated through PG&E's tracking platform. The system calculates the response time as the difference between the timestamps.

Using GPS technology, Gas Dispatch is continually aware of the location of the crews and vehicles. When dispatching crews to potential gas emergency events, Gas Dispatch identifies the crew that is ideally close to the event and available to respond. When GSRs receive a new notification of an assigned event, they enter the new location into their GPS and provide an arrival estimate based on their location and availability. If Gas Dispatch determines another crew may be able to respond more quickly, they reassign the task.

Since 2014, PG&E has used the Customer Data Warehouse system, a database for Field Automated Systems (FAS) data. PG&E reviews all incoming data daily for accuracy and completeness. When inaccuracies in the incoming data are suspected by reviewers, PG&E compares the GPS location data and arrival time at the dispatched emergency location. The GPS data associated with crew mobile devices and vehicles is independent from the FAS data and serves as a duplicative record of response time. PG&E staff stated that the daily assessment of gas emergency data allows for easier identification of errors. If the Gas Dispatch team staff identify data entries where the FAS system and GPS tracking system recorded different results, the GPS tracking system is used to measure the response time. The FAS system begins when calls are received and ends when the GSR indicates they arrived on site by pressing a button on their tracking system.

PG&E's goal is to respond to all gas IRs within 60 minutes. To address IRs, PG&E uses techniques supported by the industry, such as mobile data terminals, Global Positioning Systems (GPS), back-up on-call technicians and shift coverage of 24 hours a day, seven days a week.

Metric 4.3 data is only collected when the automated Gas Dispatch system is operating. If there is an IT outage, the calls and dispatches are monitored and handled manually but are not included in the SOMs Metric data due to the inaccuracies in manual entry after the fact.

Data reports are checked and verified daily, weekly and monthly to confirm accuracy.

Certain IR gas emergency orders are excluded from the total gas emergency orders volume count. The exclusions include:

- Level 2 and above emergencies (region-wide emergency events that require 1-2 days for service restoration),
- Multiple calls from the same incident after the first call
- Calls resulting from planned gas releases.
- Duplicate orders, cancelled orders, calls from locations with no nearby gas facility, and
- When the FAS system is unavailable due to IT outages.

Metric 4.3 data collection and processing practices have remained largely consistent during the reporting period. The historical results are consistent and can be directly compared.

Observations on Metric 4.3 Accuracy

To assess the accuracy of the Metric 4.3 results, FEP calculated the time it took PG&E to respond to each emergency call and compared the results. Then, FEP calculated the average and median response times. Overall, FEP found PG&E's calculation of Metric 4.3 to be accurate.

Verification of Response Times & Metric Results

To verify the response time for each call, FEP recreated the value by subtracting the time and date of the emergency notification from the time and date a qualified PG&E employee arrived at the site. FEP then compared the calculated result to PG&E's reported result for each contact, to make sure they matched. This produced matching values for all three years after FEP requested updated data for 2021. FEP then calculated the mean and median response time for each year, to verify PG&E's reported results.

Comments on Metric Calculation Methodology

While reviewing the data, FEP noticed a substantial number of records with very short response times. In some instances, the response times were so short (i.e., 0.1 min) that they seemed to indicate that PG&E employees must have already been on site or arriving imminently. Logically, it seemed improbable that PG&E could receive a new contact about a gas situation for which it was previously unaware and arrive on scene in such a short timeframe. In response to an RFI, PG&E stated that, though they include the earliest emergency call received time, there were instances where a technician was already onsite when the call came in. Additionally, PG&E stated that they audit the data to remove duplicate emergency calls from the database. The following table summarizes 2023 response times.

Table 2-50: Response Times in Increments

Response Time Increments (Min)	Count of Responses	Percent of Total
0.1-10	11,623	10%
10.1-20	57,997	49%
20.1-30	34,210	29%
30.1-40	9,852	8%
40.1-50	2,637	2%
50.1-60	733	1%
> 60 minutes	366	0.31%
Total	117,418	100%

FEP agrees that response times by technicians who were nearby performing unrelated work should be included. However, if a technician is physically onsite performing work when the call comes in, it suggests that the work would likely be related to the call. From a safety perspective it is good that PG&E is proactive about addressing potential issues with their system, but including these calls does not appear to accurately represent the time it takes for PG&E to respond to emergency information of which they had no prior notice. Therefore,PG&E's response time to emergencies would be most accurately measured by removing calls from the database if staff were already onsite or headed to the site to perform work when the calls came in. Adding SCADA alarm notification times that result in an emergency dispatch could increase the accuracy of this metric.

2.26.2 Metric 4.3 Management

Metric 4.3 is tracked, managed and reported by Gas Distribution and Transmission in the Gas Distribution Operations Department. Performance is shared at daily, weekly, and monthly operations meetings. The Gas Distribution and Transmission team tracks the response time performance against PG&E's historical response time data to ensure consistent response time performance.

The metric results are reported to the CIC, where PG&E metric stakeholders discuss whether the metrics are on target for their end of the year and five-year goals. If Metric 4.3 is off track, a catch-back plan is developed to address the issues that are preventing the team from achieving its goals. The team reviews controls and mitigations which are currently in place and recommends adjustments.

Observations on Metric 4.3 Management

PG&E's processes for tracking median and average response times to gas emergencies are sufficient to capture the data required for this metric. PG&E relies on multiple tracking systems to manage the movements and operations of gas crews, which enhances the verifiability of response time data. Additionally, PG&E's policy of treating all customer contacts regarding suspected gas leaks as emergencies means customer concerns are being addressed. It is also less likely that calls intended to be captured by this metric are overlooked.

While PG&E's management of this metric is sufficient to collect the data needed to capture response time, the calculation methodologies may impact metric results. The automated time system generates a "start time" when a contact is submitted to the contact center. It is not guaranteed that this contact is alerting PG&E to a previously unknown issue, and there are instances where PG&E crews were very close by or already onsite when the contact was logged. These very short durations are included in the metric calculations, driving down the response time median and average. While these values may accurately represent the time it took PG&E to address an issue disclosed in a call, it doesn't represent the time it took PG&E to respond to a gas emergency due to an earlier notification.

2.26.3 Metric 4.3 Performance and Targets

PG&E uses AGA benchmarking to inform annual targets. The targets are set at the boundary between 1st and 2nd quartile of AGA results with a reduction of 0.1 minute year-over-year for five years. While PG&E reduced the average by 0.1 minutes each year, it only reduced the median by 0.1 minute in the 2023 report.

PG&E staff stated that additional considerations beyond resource constraints influenced its decision not to pursue a lower target for Metric 4.3. First, there is an intentional gap between internal company performance and metric targets with room for non-significant variability as PG&E perceives the targets as a threshold beyond which additional oversight may be warranted. Additionally, it considers the safety of crew members who respond to events. There is a minimum time it takes for a crew to safely travel between locations. Pursuing very low response times might inadvertently encourage crew members to drive unsafely. Crews respond to calls 365 days a year, at all times of day, and in adverse weather conditions.

The following table displays PG&E's 2013 through 2023 metric results and the 1-year and 5-year metric targets.

Table 2-51: Metric 4.3 Results and Targets

Year	Metric Result (average/median)	1-Year Target (average/median)	5-Year Target (average/median)
2013	21.3/19.4		
2014	20.0/18.1		
2015	20.3/18.5		
2016	20.0/18.3		
2017	20.4/18.7		
2018	20.6/18.8		
2019	20.8/18.9		
2020	20.5/18.8		
2021	20.6/18.8	21.6/19.8	21.2/19.4
2022	19.9/18.3	21.5/19.8	21.1/19.4
2023	19.8/18.2	21.4/19.7	21/19.3
[1] Targets reflect the target set in that report year (i.e. the 2021 1-year target reflects 2022 target).			

PG&E's average metric result from 2013 to 2023 was 20.38, and from 2021 to 2023, it was 20.10. PG&E's target of 21.4 is 5% above the 11-year average and 6% above the 2021-2023 average. Overall, PG&E's Metric 4.3 result has slightly trended downward.

Observations on Metric 4.3 Performance and Targets

PG&E participates in AGA benchmarking for emergency response times. No change in the definition for Metric 4.3 is needed for PG&E to obtain valid AGA benchmark data for this metric. PG&E desires to maintain first quartile performance for this metric. The data captured by Metric 4.3 is consistent with PG&E's L1 metric, suggesting consistency in the management of gas emergency response times. The target for Metric L1 in 2023 is an average Gas Emergency Response Time of 19.9 minutes. This is lower than the 4.3 Metric target, suggesting that the L1 target is representative of company aspirational goals, while the SOM target is a "not to exceed" threshold.

This metric avoids some of challenges associated with a lack of aspirational targets discussed in Section 1.4.3 The targets are set within a comparatively narrow margin of the results and were additionally set to reflect a 0.1-minute decrease compared to the year before. Additionally, this metric has a sufficiently large dataset to conduct robust analysis. There is consistency across company performance drivers and national benchmarking is available.

2.27 Metric 4.4: Gas Shut-In Time (Mains)

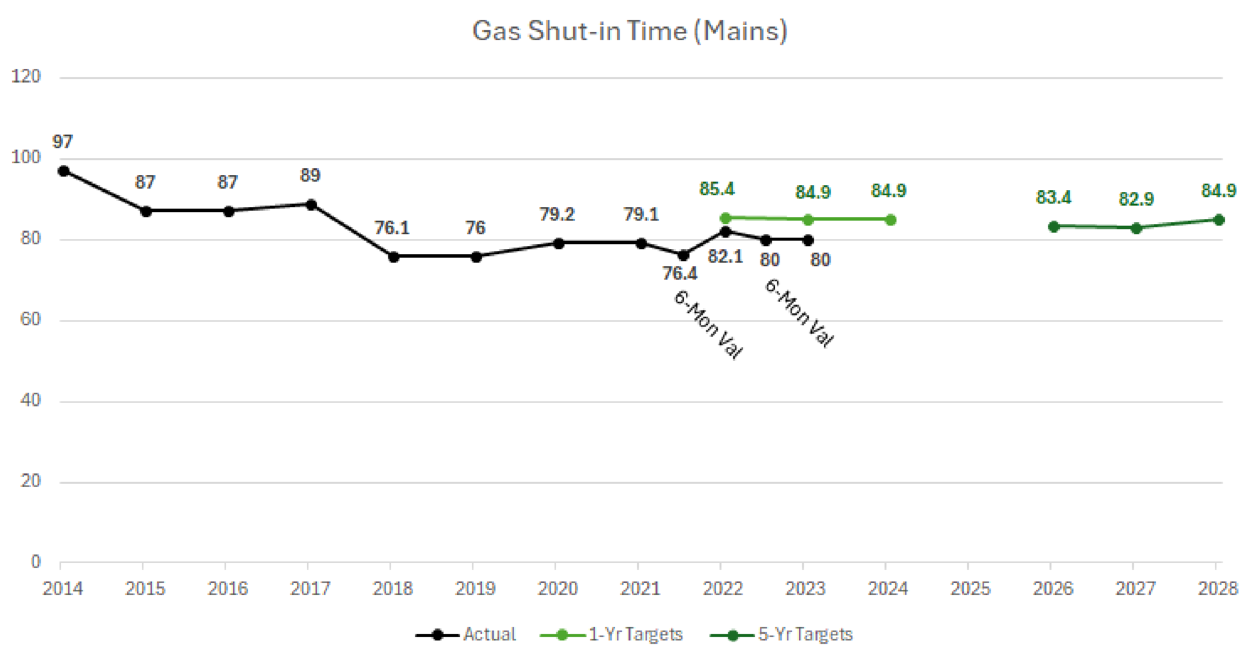
The California Public Utilities Commission (CPUC) defines Metric 4.4 as:

Median time to shut-in gas when an uncontrolled or unplanned gas release occurs on a main.

This metric highlights PG&E's median response time to resolve hazardous leak conditions on gas mains. A gas shut-in is when PG&E stops the flow of gas to perform work on the pipeline. Timely gas shut-ins reduce dangerous gas explosions or overpressure events which pose a risk to human health and safety. Generally, faster response and mitigation times are associated with less public hazard and disruption of normal gas services. The median is calculated using statistical tools, like Microsoft Excel, and the formula depends on if the dataset has an odd or even number of values.

The following chart shows Metric 4.4 results compared to targets for 2014 through 2028, including results from the 2022 and 2023 mid-year reports. All historical values reflect the most recent data available as of the 2023 report and may differ from previously reported figures.

Figure 2-39: Metric 4.4 Summary Chart



2.27.1 Metric 4.4 Accuracy and Consistency

The process for timing PG&E response begins when PG&E receives a report of a possibly hazardous leak. The measured time ends when a qualified representative determines that: 1) a leak does not exist, 2) the leak is not hazardous or 3) action to eliminate the hazardous leak is complete. Metric 4.4 includes response and mitigation times for existing hazardous leaks. PG&E tracks the time it takes to respond to all leak notifications, as it cannot know at first contact if a leak will be deemed hazardous or non-hazardous. Ultimately, Metric 4.4 excludes responses where the representative determines that the leak is non-existent or non-hazardous.

PG&E's process for managing emergency response and gas main shut-in times begins with its field automated system (FAS) that logs and timestamps incoming customer calls or 911 emergency calls. Calls regarding gas leaks are directed to Gas Dispatch, who then initiates an EMT. PG&E automatically logs the date/time that Dispatch creates a new EMT in response to an incident. If the FAS time exists, it serves as the beginning of the response time. Otherwise, the EMT creation time is the starting point. FEP used an Excel IF statement to identify the start time.

Gas Dispatch transfers the EMT to Gas Control, which documents the progress of the event. Gas Control enters data into the EMT as reported by GSRs and/or Maintenance & Construction (M&C) crews in the field. Gas Control closes out the emergency event in EMT when completed.

PG&E leverages electronic platforms, like Microsoft Teams, to capture data for some events. The EMT was created in 2018. PG&E has made some updates to the EMT, but they have been relatively minor.

PG&E produces reports using the EMT daily, weekly, and monthly data. Reports are produced and reviewed daily. At the start of each day, PG&E reviews the data from the previous 24 hours. Incidents opened and closed during the previous day are reviewed. In some instances, there are delays in closing out files due to the magnitude of the incident and additional incoming information. PG&E also reviews leak data on a weekly basis to capture instances which were unreported or changed since the daily reviews. Monthly reports are conducted to ensure that all the cases have been closed and that the reported data is finalized. The reports are accessible broadly throughout PG&E. The weekly reports are shared up through the Vice President level.

Due to the high visibility of the data, PG&E staff stated that errors in the data are easily identifiable. Individuals reviewing the daily, weekly and monthly data discuss potential errors with Gas Dispatch. Gas Dispatch has write access to the data, while other users have read-only access.

PG&E’s management of this metric has been largely consistent since 2014, though additional changes occurred in 2018. PG&E implemented its centralized process for managing gas emergency shut-ins in 2014, which allowed for greater efficiencies and effectiveness of distribution, transmission, dispatch, and planning personnel. The centralization of these groups allowed for the implementation of PG&E’s EMT for tracking incidents.

In 2018, PG&E implemented the existing automated tracking system. Prior to 2018, the metric was assessed beginning when the alert was sent to the crews that respond to gas emergencies. After the implementation of FAS and the existing database, the time started when Gas Dispatch was first notified.

Observations on Metric 4.4 Accuracy

To assess the accuracy of this metric, FEP recreated the resolution time for each incident using the time the incident was reported and the time the incident was resolved. Next, FEP calculated the median response time for the dataset to verify the metric results. Overall, FEP found PG&E’s calculation of Metric 4.4 to be accurate.

Service vs Main Designation

FEP first verified that all incidents PG&E included in this metric were gas shut-ins related to mains. FEP reviewed the data related to the assets involved to ensure that all included incidents related to mains.

Response Time Verification

To document response time, PG&E provided the date and time that an emergency notification of a potential gas leak was received and the date and time the shut-in was completed. FEP calculated the difference between those times to verify the shut-in time for each contact. Then, FEP calculated the median time it took to resolve the condition. FEP’s results matched the values reported by PG&E.

2.27.2 Metric 4.4 Management

The Gas Transmission and Distribution team in Gas Distribution Operations manages and tracks Metric 4.4. Teams involved with managing gas shut-ins review incidents daily. During each daily review, the team considers the data for the previous 24 hours. Daily data is reviewed for completeness and accuracy, then is assessed weekly by the larger stakeholder audience. During the weekly reviews, teams discuss what caused the leak, how the shut-in was managed, and any takeaways which are relevant to ensuring smooth operation of the system. At the end of the month the data is reviewed again then closed out. The final monthly numbers are then reported for the tracking of Metric 4.4 specifically. The metrics owner team reviews weekly and monthly performance and shares the results with management including upper leadership. Senior Executive management reviews metrics performance weekly.

A key stakeholder in managing the metric performance is PG&E's CIC which tracks all PG&E commitments. Metric owners report results to the CIC. The CIC meets monthly where PG&E management and metric owners discuss the metrics that are not on target to meet the end-of-the-year and five-year goals. If any metric is off track to achieve its goal, the metric owner develops catch-back plans addressing the issues that are preventing the team from achieving the goal and presents them to the CIC. For example, management may ask the metric owner if more resources are needed to improve performance to meet the target.

While the process for managing the metrics is similar when the metrics are either on or off target, there is heightened focus if the metric is off target. Monthly assessments take place regardless of whether the metric is on or off track, but the progress towards the catch back plan is reported frequently if the metric is off track.

PG&E implemented several efforts which improved metric performance:

- Purchased and implemented Emergency Trailers in every division allowing easier access to emergency equipment.
- Implemented Emergency Management Tool (EMT) to alert M&C of STIG events when notified by third-party emergency organizations.
- Established concurrent response protocol (dispatch M&C and Field Service resources) when notified by third-party emergency agencies (Utility Procedure TD-6100P-03 Major Gas Event Response).
- Implemented Incident Command 30-60-90-120+ communication protocols to ensure consistent and timely information updates to the Gas Distribution Control Center.
- Located crews in areas where incidents are more frequent than average to reduce travel time.
- Daily operating reviews to identify countermeasures for deviations.
- Live action drills simulating emergency scenarios with first responders, practicing isolation procedures and documentation of lessons learned.
- Weekly meetings to share best practices and lessons learned across the company.

Observations on Metric 4.4 Management

PG&E's divisions review metric data for each local area. Any division that is not meeting any metric target individually implements catch-back plans for the areas off target. The incident data input form allows Field technicians to enter any barriers to or delays in their response. The divisions look at initiatives to address any feedback from the technicians. This process includes local problem-solving sessions to help understand key drivers. Performing this locally is effective because local conditions are better understood by a local team. These actions by each division contribute to improving the company-wide results. The system-wide metric owners use a similar process to address any projected shortfalls.

2.27.3 Metric 4.4 Performance and Targets

In 2021, the 1-year SOM target set for 2022 was based on the median of the four-year historical performance from 2018 to 2021 plus 10% to address non-significant variability. The targets for the subsequent years were set at a reduction of 0.5 minutes year-over-year. However, starting in 2023, PG&E did not apply the 0.5-minute reduction.

The following table displays PG&E's 2014 through 2023 metric results and the 1-year and 5-year metric targets.

Table 2-52: Metric 4.4 Results and Targets

Year	Metric Result	1-Year Target	5-Year Target
2014	97.0		
2015	87.0		
2016	87.0		
2017	89.0		
2018	76.1		
2019	76.0		
2020	79.2		
2021	79.1	85.4	83.4
2022	82.1	84.9	82.9
2023	80.0	84.9	84.9
[1] Targets reflect the target set in that report year (i.e. the 2021 1-year target reflects 2022 target).			

PG&E's average metric result from 2014 to 2023 was 83.25, and from 2021 to 2023, it was 80.40. PG&E's target of 84.9 is 2% above the 10-year average and 6% above the 2021-2023 average. Overall, PG&E's Metric 4.4 result has shown a downward trend.

Observations on Metric 4.4 Performance and Targets

PG&E has a relationship with Sempra and Southwest Gas and communicates with the other IOUs to review and compare results on this topic. PG&E stated that if this Metric 4.4 was combined with the portion of Metric 4.7 related to mains, it would align very closely with the way the other California IOUs measure their performance. PG&E's performance in mains shut-in time (combining Metric 4.4 with the mains portion of Metric 4.7) was 45% better than that of SoCal Gas and 47% better than that of SDG&E.

Between 2014 and 2018 PG&E's metric results showed a mostly consistent downward trend, coinciding with the centralization of the back-office support personnel. Since 2018 when FAS was introduced, metric results largely increased each year. FAS collects the Start Time when PG&E receives the emergency call, which is earlier than the dispatch time. In the 2023 report, PG&E increased its 5-year target from 82.9 to 84.9 and set it equal to the 1-year target. This is not aligned with performance improvement goals.

2.28 Metric 4.5: Gas Shut-In Times (Services)

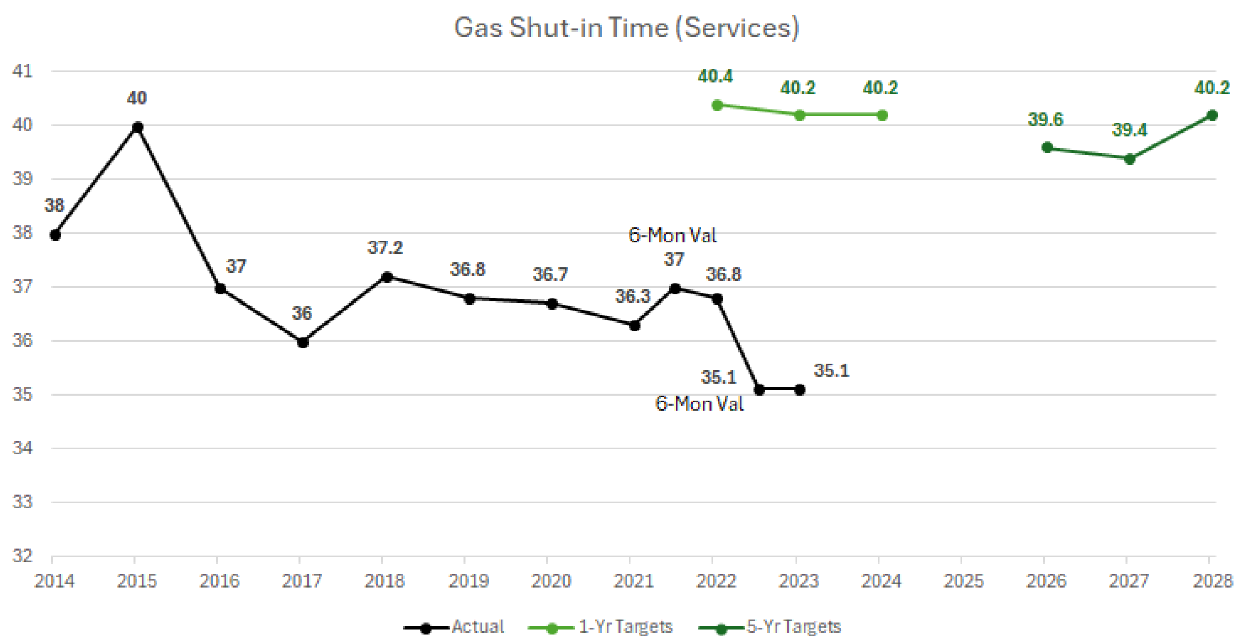
The California Public Utilities Commission (CPUC) defines Metric 4.5 as:

Median time to shut-in gas when an uncontrolled or unplanned gas release occurs on a service.

This metric highlights PG&E's median response time for hazardous leak conditions on gas services. A gas shut-in is when PG&E stops the flow of gas to perform work on the service. Timely gas shut-ins reduce dangerous gas explosions or overpressure events which pose a risk to human health and safety. Generally, faster response and mitigation times are associated with less public hazard and disruption of normal gas services. The median is calculated using statistical tools, like Microsoft Excel, and the formula depends on if the dataset has an odd or even number of values.

The following chart shows Metric 4.5 results compared to targets for 2014 through 2028, including results from the 2022 and 2023 mid-year reports. All historical values reflect the most recent data available as of the 2023 report and may differ from previously reported figures.

Figure 2-40: Metric 4.5 Summary Chart



2.28.1 Metric 4.5 Accuracy and Consistency

The process for timing PG&E response begins when PG&E receives a report of a possibly hazardous leak. The measured time ends when a qualified representative determines that: 1) a leak does not exist,

2) the leak is not hazardous or 3) action to eliminate the hazardous leak is complete. Metric 4.5 includes response and mitigation times for existing hazardous leaks. PG&E tracks the time it takes to respond to all leaks, as it cannot know at first contact if a leak will be deemed hazardous or non-hazardous. Ultimately, Metric 4.5 excludes responses where the representative determines that the leak is non-existent or non-hazardous.

PG&E's process for managing emergency response and gas service shut-in times begins with its field automated system (FAS) that logs and timestamps incoming customer calls or 911 emergency calls. Calls regarding gas leaks are directed to Gas Dispatch, who then initiates an EMT. PG&E automatically logs the date/time that Dispatch creates a new EMT in response to an incident. If the FAS time exists, it serves as the beginning of the response time. Otherwise, the EMT creation time is the starting point. FEP used an Excel IF statement to identify the start time.

Gas Dispatch transfers the EMT to Gas Control which documents the progress of the event. Gas Control enters data into the EMT as reported by GSRs and/or Maintenance & Construction (M&C) crews in the field. Gas Control closes out the emergency event in EMT when completed.

PG&E leverages electronic platforms, like Microsoft Teams, to capture data for some events. The EMT was created in 2018. PG&E has made some updates to the EMT, but they have been relatively minor.

PG&E produces reports using the EMT daily, weekly, and monthly data. Reports are produced and reviewed daily. At the start of each day, PG&E reviews the data from the previous 24 hours. Incidents opened and closed during the previous day are reviewed. In some instances, there are delays in closing files due to the magnitude of the incident and additional incoming information. PG&E also reviews leak data on a weekly basis to capture instances which were unreported or changed since the daily reviews. Monthly reports are conducted to ensure that all the cases have been closed and that the reported data is finalized. The reports are accessible broadly throughout PG&E. The weekly reports are shared up through the Vice President level.

Due to the high visibility of the data, PG&E staff stated that errors in the data are easily identifiable. Individuals reviewing the daily, weekly and monthly data discuss potential errors with Gas Dispatch. Gas Dispatch has write access to the data, while other users have read-only access.

PG&E's management of this metric has been largely consistent since 2014, though additional changes occurred in 2018. PG&E implemented its centralized process for managing gas emergency shut-ins in 2014, which allowed for greater efficiencies and effectiveness of distribution, transmission, dispatch, and planning personnel. The centralization of these groups allowed for the implementation of PG&E's EMT for tracking incidents.

In 2018, PG&E implemented the existing automated tracking system. Prior to 2018, the metric was assessed beginning when the alert was sent to the crews who respond to gas emergencies. After the implementation of FAS and the existing database, the time started when dispatch was first notified.

Observations on Metric 4.5 Accuracy

To assess the accuracy of this metric, FEP recreated the resolution time for each incident using the time the incident was reported and the time the incident was resolved. Next, FEP calculated the median response time for the dataset to verify the metric results. FEP's results matched PG&E's for this metric.

Service vs Main Designation

FEP first verified that all incidents PG&E included in this metric were gas shut-ins related to services. FEP reviewed the data related to assets involved to ensure that all included incidents related to services.

Response Time Designation

To document response time, PG&E provided the date and time that an emergency notification of a potential gas leak was received and the date and time the shut-in was completed. FEP calculated the difference between those times to verify the shut-in time for each contact. Then, FEP calculated the median time it took to resolve the condition. FEP's results matched the values reported by PG&E.

2.28.2 Metric 4.5 Management

The Gas Transmission and Distribution team in Gas Distribution Operations manages and tracks Metric 4.5. Teams involved with managing gas shut-ins review incidents daily. During each daily review, they consider the data for the previous 24 hours. Daily data is reviewed for completeness and accuracy, then is assessed weekly by the larger stakeholder audience. During the weekly reviews, teams discuss what caused the shut-in, how the shut-in was managed, and any takeaways which are relevant to ensuring smooth operation of the system. At the end of the month the data is reviewed again then closed out. The final monthly numbers are then reported for the tracking of Metric 4.5 specifically. The metrics owner team reviews weekly and monthly performance and shares the results with management including upper leadership. Senior Executive management reviews metrics performance weekly.

The CIC meets monthly where PG&E management and metric owners discuss the metrics that are not on target to meet end of the year and five-year goals. If any metric is off track to achieve the goal, the metric owner develops catch-back plans addressing the issues that are preventing the team from achieving the goal and presents them to the CIC. For example, management may ask the metric owner if more resources are needed to improve performance to meet the target.

PG&E implemented several efforts which improved metric performance:

- Enhanced plastic squeeze-off capabilities to ~50% of Gas Service Representatives for sizes up to 1.5" plastic pipe and annual plastic squeeze training for all Field Service employees (OQ Refresher).
- Purchased and implemented Emergency Trailers in every division allowing easier access to emergency equipment.
- Implemented Emergency Management Tool (EMT) to alert M&C of STIG events when notified by third-party emergency organizations.
- Established concurrent response protocol (dispatch M&C and Field Service resources) when notified by third-party emergency agencies (Utility Procedure TD-6100P-03 Major Gas Event Response).
- Implemented Incident Command 30-60-90-120+ minute communication protocols to ensure consistent and timely information updates.
- Located crews in areas where incidents are more frequent than average to reduce travel time.
- Daily operating reviews to identify countermeasures for deviations.
- Live action drills simulating emergency scenarios with first responders, practicing isolation procedures and documentation of lessons learned.
- Tier 3 incident Review weekly meetings to share best practices and lessons learned across the company.

Observations on Metric 4.5 Management

PG&E reviews the status and progress of all SOMs metrics. Any metric that is not meeting any metric target individually implements catch-back plans for the areas off target. The incident data input form allows field technicians to enter any barriers to or delays in their response. The metric owners look at initiatives to address any feedback from the technicians. This process includes local problem-solving sessions to help understand key drivers. Performing this locally is effective because local conditions are better understood by a local team. These actions by each division contribute to improving the company-wide results.

2.28.3 Metric 4.5 Performance and Targets

In 2021, the SOM 1-year target set for 2022 was based on the average of the four-year historical performance from 2018 to 2021 plus 10% to address non-significant variability. The targets for the subsequent years were set at a reduction of 0.2 minutes forecasted year-over-year. For the 5-year target, PG&E reduced the 1-year target by 0.2 per year for 4 additional years (for a total of 0.8 minute reduction). The 5-year target set in 2022 reduced the 2021 5-year target by an additional 0.2 minutes. However, PG&E did not apply the 0.2-minute reduction to the 1-year target set in 2023 and raised the five-year target to match the 1-year target.

The following table displays PG&E's 2013 through 2023 metric results and the 1-year and 5- year metric targets.

Table 2-53: Metric 4.5 Results and Targets

Year	Metric Result	1-Year Target	5-Year Target
2014	38.0		
2015	40.0		
2016	37.0		
2017	36.0		
2018	37.2		
2019	36.8		
2020	36.7		
2021	36.3	40.4	39.6
2022	36.8	40.2	39.4
2023	35.1	40.2	40.2
[1] Targets reflect the target set in that report year (i.e. the 2021 1-year target reflects 2022 target).			

PG&E's average metric result from 2014 -2023 was 36.99 and 36.07 from 2021-2023. PG&E's target is 9% above the 10-year average and 11% above the 2021-2023 average. Overall, PG&E's metric result has trended downward.

Observations on Metric 4.5 Performance and Targets

PG&E has a relationship with Sempra and communicates with the other IOUs to review and compare results on this topic. PG&E stated that if this Metric 4.5 was combined with the portion of Metric 4.7 related to services, it would very closely compare to the way the other California IOUs measure performance. PG&E's performance in service shut-in time (combining Metric 4.5 with the services portion of Metric 4.7) was 46% better than that of SoCal Gas, but SDG&E's was 5.6% better than PG&E's.

PG&E raised the 5-year target for Metric 4.5 to match the 1-year target, despite a downward trend in the data. Raising targets is not conducive to performance improvement. It seems especially counterproductive considering PG&E performed well below previous targets.

2.29 Metric 4.6: Uncontrolled Gas Release

The CPUC defines Metric 4.6 as:

Number of leaks, ruptures, or other loss of containment of transmission lines for the reporting period, including gas releases reported under Title 49 Code of Federal Regulations (CFR) Part 191.3.

Metric 4.6 considers Grade 1, 2 and 3 gas leaks, in addition to ruptures or loss of containment events that occur on gas transmission pipelines. Tracking these events is important because an uncontrolled gas loss of containment poses health and safety issues to the surrounding population and can result in disruptions to gas service. Additionally, PG&E tracks gas leaks because they are an important indicator of where other events may occur due to a similarity of conditions relating to the pipelines. This metric is also an indicator of the efficacy of PG&E's Gas Transmission Integrity Program (TIMP) and PG&E's progress in eliminating its pipeline segments constructed with legacy materials and methods inferior to current standards.

California and many other states categorize gas leaks by grade, depending on their hazard level. Grade 1 leaks pose an existing or probable hazard to property and the public and require immediate, continuous action until repaired or made non-hazardous. Grade 2 leaks are non-hazardous at the time of event discovery but have the potential to become hazardous. Meanwhile, Grade 3 leaks are non-hazardous at the time of discovery and are expected to remain that way. [47]

All gas transmission line operators are required by law to leak survey all gas transmission pipelines at least twice per year. The California Air Resources Board Oil and Gas Greenhouse Gas (GHG) Rule became effective in 2018. As a result, PG&E is required to leak survey underground gas storage facilities and gas transmission compressor stations four times per year. Because of this change in leak survey requirements, the leak count increased significantly in 2018 above previous levels. There is considerable vibration of the gas piping in a compressor station, so small leaks were found earlier than they would have been found previously.

Leak surveys are conducted using both hand-held and vehicle-mounted gas detection instruments for ground leak surveys, or gas detection instruments mounted on airplanes or helicopters for more efficient surveys when feasible.

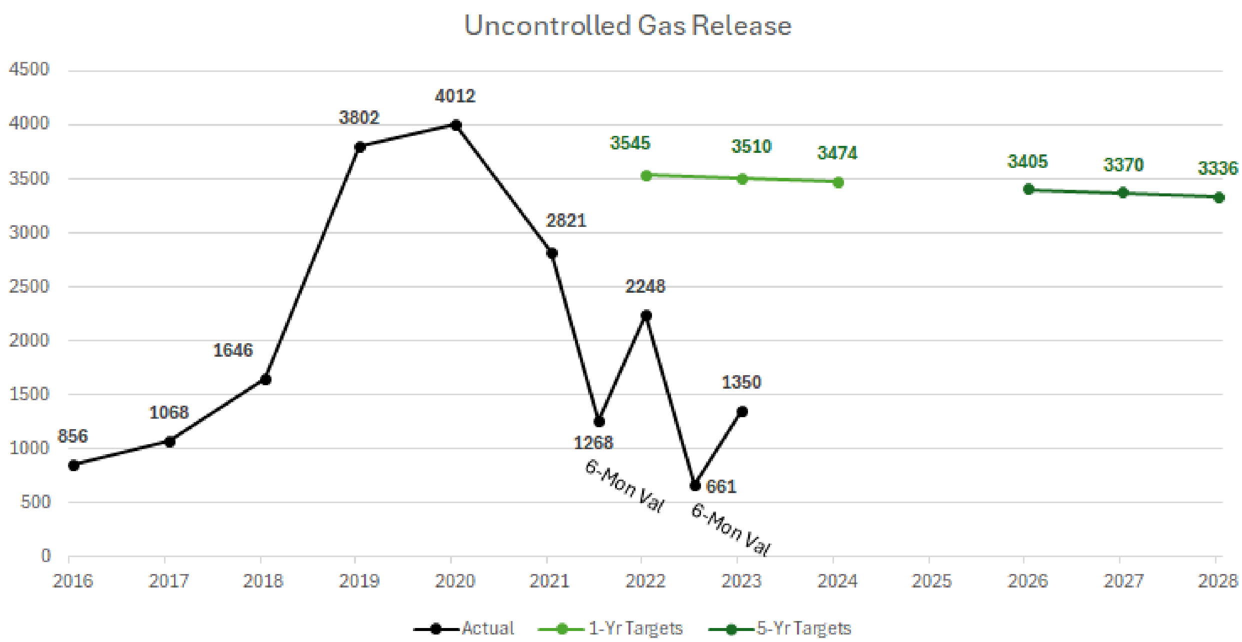
The formula for calculating Metric 4.6 is:

$$= \#\, Grade\ 1\ leaks + \#\, Grade\ 2\ leaks + \#\, Grade\ 3\ leaks$$

The following chart shows Metric 4.6 results compared to targets for 2016 through 2028, including results from the 2022 and 2023 mid-year reports. All historical values reflect the most recent data available as of the 2023 report and may differ from previously reported figures. The mid-year values are substantially lower because they cover only six months of leaks, whereas the annual values cover the full twelve months.

[47] CPUC, p. 57, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/reports/2024-ngla-joint-report_122424.pdf

Figure 2-41: Metric 4.6 Summary Chart



2.29.1 Metric 4.6 Accuracy and Consistency

PG&E's Leak Survey Process team ("LSP") manages data for Metric 4.6. The primary data source for Metric 4.6 is SAP. The SAP data contains all the leaks found during the reporting period and includes information on leak location, line type, and grade. Data enters SAP through the same methodology described in Metric 4.1, Section II. When a leak is reported to PG&E by a third party, GSRs are dispatched to the leak location. Depending on the reported severity or type of leak, a gas construction crew or a pipeline mechanic could be dispatched immediately as well. The GSRs would likely arrive on the scene first and begin documenting the characteristics of the leak. After the leak is repaired, the repairing party documents the type of work done to eliminate the leak. This data also includes a narrative description of the event. The GSR or repairing crew compiles the reports, which are uploaded to SAP. Most minor leaks on gas transmission pipeline facilities are found and documented by the gas leak detection surveyor. Leaks are located, graded and reported immediately if the leak is significant, i.e., graded as a 1 or 2 leak. The leak surveyor reports all leaks found daily by location, (usually with Geospatial Positioning System (GPS) enabled equipment), leak grade and facility type and size if known.

The LSP team compiles monthly reports, known as GCM13. This report is compiled with input from the Regulatory Compliance and Reporting group. Once data is entered into SAP, the LSP team can view the data but does not make changes. PG&E relies on the GSRs' original leak grade to categorize leaks and does not alter the leak grade to reflect changing conditions at the site. LSP develops the report by downloading raw data from SAP and filtering it to include only the applicable reporting period.

PG&E audits the data monthly and semi-annually to find problems within the reporting process. For example, PG&E found an issue with the 2022 and 2023 data which stemmed from the data being pulled on the last day or next-to-last day of the month. When the data was pulled early, PG&E noticed that it failed to capture leaks which occurred on the last two days in the month. The process was adjusted to require that the data be pulled after the close of the month, and PG&E updated its last reports to reflect the change.

When errors are found, they are reported to the CRM repository. If the discovery occurs before the data is used in official reports, the change is made immediately. If the error impacted reports which went out to an external audience, PG&E develops a white paper outlining the discovery and changes. The white papers are shared with impacted agencies, such as the CPUC.

In 2018, The California Air Resources Board Oil and Gas Greenhouse Gas (“GHG”) Rule became effective. As a result, PG&E is required to leak survey underground gas storage facilities and gas transmission compressor stations four times per year.

Observations on Metric 4.6 Accuracy

Metric 4.6 summed the number of grades 1, 2 and 3 leaks which occurred on PG&E’s transmission pipelines during the reporting period. The dataset for Metric 4.6 included the date the leak occurred, leak grade, and the type of assets involved. To assess the accuracy of this metric, for each year, FEP first assessed the leak characteristics to verify that the leak occurred on transmission pipelines. FEP then summed grades 1, 2 and 3 leaks for each year.

When FEP first summed the number of transmission leaks included in the 2022 and 2023 datasets, the values did not match those reported by PG&E. When FEP requested more information about the discrepancy, PG&E staff stated that the data for some of the months in 2022 and 2023 was captured before the month was completed, resulting in leak omissions. These omissions were identified in the following months and included in the SOMs reports. When PG&E transmitted new data, the values were verifiable.

To increase the transparency of Metric 4.6 reporting, FEP recommends that PG&E end the practice of pulling data before the month is complete. While some omissions may be uncovered through data auditing, the number of leaks omitted from the monthly snapshots is significant. For example, in 2023 1276 leaks were identified when the data was originally pulled for each month. This data was compiled and transmitted to FEP. In subsequent months, PG&E identified another 74 leaks, to put the reported total at 1350. This means that approximately 6% of the data was omitted due to untimely data pulls.

2.29.2 Metric 4.6 Management

Metric 4.6 is managed by PG&E’s Gas Transmission Engineering and Planning Department with the Leak Survey Process team (LSP). Monthly leak reports generated from SAP are reviewed and analyzed by department leadership for emerging issues or trends. PG&E considers overall leak rates, as well as leak rates in specific locations or with specific types of pipelines. This monthly review also serves as a second quality control check. It reviews the year-to-date leak statistics and ensures they’re under the Metric 4.6 target. Corrective actions are managed through the CAP system and are reviewed on a weekly basis to ensure there are timely responses. Leadership has visibility to all corrective activities.

PG&E is actively engaged in several programs to reduce the number of leaks on its gas transmission system. PG&E’s TIMP program assesses threats on every segment of transmission pipeline covered by the program, evaluates the associated risks and acts to prevent or mitigate these risks. PG&E initiated several TIMP related activities to mitigate threats and reduce risks. Examples are strength testing, inline inspections, direct assessment, and pipeline replacement. Reassessment is required at a minimum of every seven years. PG&E’s Leak Management program locates leaks and repairs them to reduce Loss of

Containment (LOC). PG&E conducts leak surveys two times per year on the gas transmission system, and four times a year on compressor and gas storage facilities to find leaks. PG&E is also replacing high bleed pneumatic devices at its compressor stations and storage facilities.

Observations on Metric 4.6 Management

The Metric 4.6 Team meets with leadership to discuss Metric performance. Leak survey requirements had not changed for many years until 2018. Since the leak survey requirements changed in 2018, significantly more leaks were found at compressor stations and storage fields. This required more scrutiny of the leaks found at these facilities and required additional management of the process. Additionally, leak detection equipment has become more sensitive since 2018, which increased the number of leaks found in 2018, 2019 and 2020 as well. Leak numbers have dropped significantly since 2020. Small leaks were found and repaired earlier than would have been the case before the new tools were implemented. The result is that leak numbers have improved at a faster rate compared to Metric 4.6 Targets.

2.29.3 Metric 4.6 Performance and Targets

PG&E's Gas Transmission Engineering and Planning Department establishes the Targets for Metric 4.6. In the 2021 report, the target was based on the average of the past three years of historical data (2019 – 2021). In the report, PG&E staff set the target for 2026 (5-year target) to represent a 1% reduction in leaks per year. Therefore, PG&E set the 2026 target to be 96% of the 1-year target. To set the target for subsequent years, PG&E reduced the previous target by 1%.

The following table displays PG&E's 2016 through 2023 metric results and the 1-year and 5-year metric targets.

Table 2-54: Metric 4.6 Results and Targets

Year	Metric Result	1-Year Target	5-Year Target
2016	856		
2017	1,068		
2018	1,646		
2019	3,802		
2020	4,012		
2021	2,821	3,545	3,405
2022	2,248	3,510	3,370
2023	1,350	3,474	3,336
[1] Targets reflect the target set in that report year (i.e. the 2021 1-year target reflects 2022 target).			

PG&E's average metric result from 2016 -2023 was 2225.38 and 2139.67 from 2021-2023. PG&E's target is 56% above the 8-year average and 62% above the 2021-2023 average.

Observations on Metric 4.6 Performance and Targets

Metric 4.6 targets are not aligned with performance improvement measures given the significant buffer from actual performance. PG&E states in its 2023 Annual Report for Metric 4.6, "Even though the target (for 2024) is set at a performance level worse than 2023 performance, it should not be interpreted as intention to worsen performance." PG&E established future year targets with only 1% improvement per year from the three-year average performance from 2019 through 2021 and continues to do so even though actual performance has been improving at an average rate of approximately 30% per year since 2020.

There are no existing gas industry benchmarks for gas transmission leaks. The Pipeline and Hazardous Materials Safety Administration (PHMSA) Annual Report requires reporting the number of transmission line leaks repaired, excluding all leaks that can be eliminated by minor tightening of flange bolts or pipe threads or greasing valves. The Annual report also requires reporting existing known leaks as of December 31 each year. Since the PHMSA Annual reports are public records, benchmarking could be done using metrics such as reported repaired leaks per mile of transmission line and known existing leaks per mile of gas transmission line. The definition of Metric 4.6 would have to be changed to be identical to the PHMSA Annual Report definition for reported leaks to use a benchmark like this. Because the definition for Metric 4.6 requires PG&E to report every minor leak on gas transmission facilities, even those eliminated by greasing a valve, PG&E reports ten times as many leaks to the CPUC as it reports in its annual report to PHMSA.

2.30 Metric 4.7: Hazard Resolution Time

The California Public Utilities Commission (CPUC) defines Metric 4.7 as:

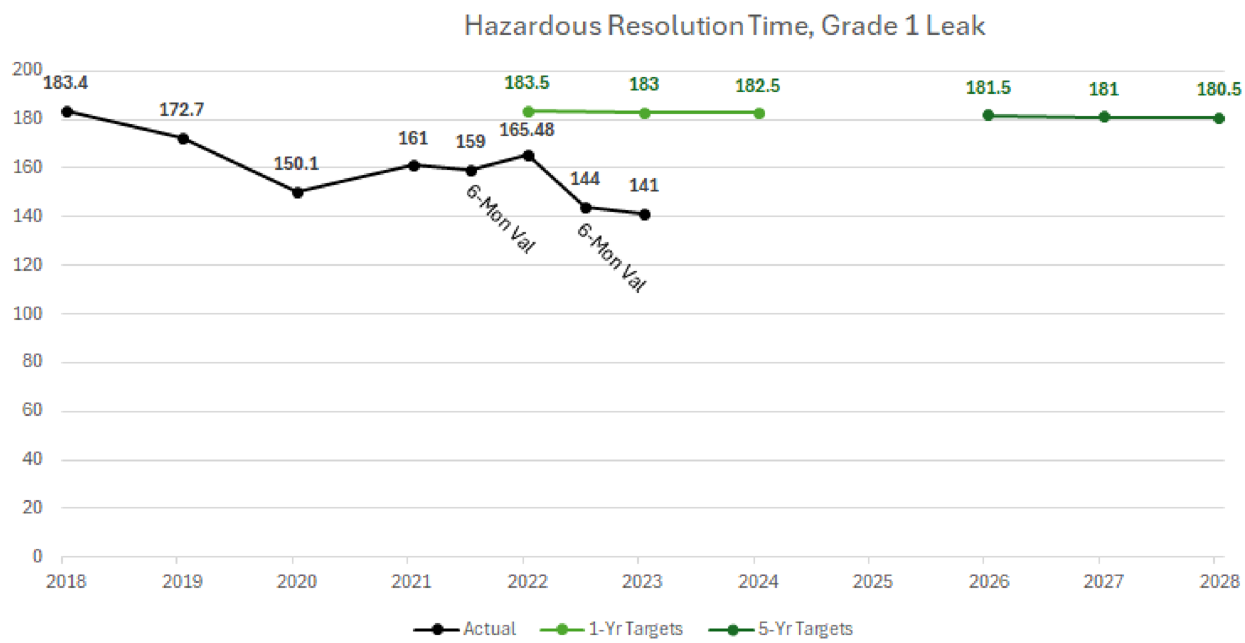
Median response time to resolve Grade 1 leaks. Time starts when the utility first receives the report and ends when a utility's qualified representative determines, per the utility's emergency standards, that the reported leak is not hazardous or the utility's representative completes actions to mitigate 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.

This metric highlights PG&E's median resolution time for grade 1 leaks. California and many other states categorize gas leaks by grade, depending on their hazard level. Grade 1 leaks pose an existing or probable hazard to property and the public and require immediate, continuous action until repaired or made non-hazardous. PG&E initially treats every leak reported by third parties (customers and first responders) as Grade 1 leaks or as Immediate Response (IR) leaks and responds accordingly.

The median response time is calculated using statistical tools, like Microsoft Excel, and the formula depends on if the dataset has an odd or even number of values.

The following chart shows Metric 4.7 results compared to targets for 2018 through 2028, including results from the 2022 and 2023 mid-year reports. All historical values reflect the most recent data available as of the 2023 report and may differ from previously reported figures.

Figure 2-42: Metric 4.7 Summary Chart



2.30.1 Metric 4.7 Accuracy and Consistency

The process for timing PG&E's response begins when PG&E receives a report of a possibly hazardous leak. Metrics 4.4, 4.5 and 4.7 all measure PG&E's response time to shut-in gas leaks though they focus on different service or leak types. PG&E manages the three metrics using the same processes. Metrics 4.4 and 4.5 focus on leaks on mains and services, respectively. Meanwhile, Metric 4.7 considers only Grade 1 leaks, which pose an existing or probable hazard to public safety.

The measured time ends when a qualified representative determines that: 1) a leak does not exist, 2) the leak is not hazardous or 3) actions to eliminate the hazardous leak are complete. Metric 4.7 includes response and mitigation times for Grade 1 leaks. PG&E tracks the time it takes to respond to and repair all leaks, and the data is later filtered to only include applicable leaks.

PG&E's process for managing emergency response and Grade 1 Leaks begins with its field automated system ("FAS") that logs and timestamps incoming customer calls or 911 emergency calls. Calls regarding gas leaks are directed to Gas Dispatch, who then initiates an EMT. PG&E automatically logs the date/time that Dispatch creates a new EMT in response to an incident. If the FAS time exists, it serves as the beginning of the response time. Otherwise, the EMT creation time is the starting point. FEP used an Excel IF statement to identify the start time.

Gas Dispatch documents the progress of the event by entering data into the EMT as reported by GSRs and/or Maintenance & Construction (M&C) crews in the field. Gas Dispatch closes out the emergency event in EMT when completed.

PG&E leverages electronic platforms, like Microsoft Teams, to capture data for some events. The EMT was created in 2018. PG&E has made some updates to the EMT, but they have been relatively minor.

PG&E produces reports using EMT daily, weekly, and monthly data. Reports are produced and reviewed daily. At the start of each day, PG&E reviews the previous 24 hours of data. Incidents opened and closed during the previous day are reviewed. In some instances, there are delays in closing files due to the magnitude of the incident and additional incoming information. PG&E also reviews leak data on a weekly basis to capture instances which were unreported or changed since the daily reviews. Monthly reports are conducted to ensure that all the cases have been closed and that the reported data is finalized. The reports are accessible broadly throughout PG&E. The weekly reports are shared up through the Vice President level.

Due to the high visibility of the data, PG&E staff stated that errors in the data are easily identifiable. Individuals reviewing the daily, weekly and monthly data discuss potential errors with Gas Control. Gas Control has write access to the data, while other users have read-only access.

PG&E's management of Grade 1 Leaks has been largely consistent since 2014, though changes to the management process occurred in 2018. PG&E implemented its centralized process for managing gas emergency shut-ins in 2014, which allowed for greater efficiencies and effectiveness of distribution, transmission, dispatch, and planning personnel. The centralization of these groups allowed for the implementation of PG&E's EMT for tracking incidents.

In 2018, PG&E implemented the existing automated tracking system. Prior to 2018, the data for this metric was assessed beginning when the alert was sent to the crews who respond to gas emergencies. After the implementation of FAS and the existing database, the time started when dispatch was first notified.

Observations on Metric 4.7 Accuracy

To assess the accuracy of this metric, FEP recreated the resolution time for each incident using the time the incident was reported and the time the incident was resolved. Next, FEP calculated the median response time for the dataset to verify the metric results. FEP's results matched PG&E's for this metric.

Grade 1 Designation

FEP first verified that all incidents PG&E included in this metric were gas shut-ins of Grade 1 leaks. FEP reviewed the data related to involved assets to ensure that all included incidents related only to leaks which PG&E designated as Grade 1.

Response Time Verification

To document response time, PG&E provided the date and time that an emergency notification of a potential gas leak was received and the date and time the shut-in was completed. FEP calculated the difference between those times to verify the shut-in time for each contact. Then, FEP calculated the median time it took to resolve the condition. FEP's results matched the values reported by PG&E.

2.30.2 Metric 4.7 Management

The Gas Transmission and Distribution team in Gas Distribution Operations manages and tracks Metric 4.7. Teams involved with managing gas shut-ins review incidents daily. During each daily review, they consider the data from the previous 24 hours. Daily data is reviewed for completeness and accuracy, then is assessed weekly by the larger stakeholder audience. During the weekly reviews, teams discuss what caused the leak, how the shut-in was managed, and any takeaways which are relevant to ensuring smooth operation of the system. At the end of the month, the data is reviewed again then closed out. The final monthly numbers are then reported for the tracking of Metric 4.7 specifically. The metrics owner team reviews weekly and monthly performance and shares the results with management including upper leadership. Senior Executive management reviews metrics performance weekly.

The CIC meets monthly where PG&E management and metric owners discuss the metrics that are not on target to meet the end of the year and five-year goals. If any metric is off track to achieve the goal, the metric owner develops catch-back plans addressing the issues that are preventing the team from achieving the goal and presents them to the CIC. For example, management may ask the metric owner if more resources are needed to improve performance to meet the target.

While the process for managing the metrics is similar when the metrics are either on or off target, there is heightened focus if the metric is off target. Even when the metric is on track, there are monthly reviews. These assessments take place regardless of whether the metric is on or off track, but the progress towards the catch back plan is reported frequently if the metric is off track.

PG&E implemented several efforts which improved metric performance:

- Enhanced plastic squeeze-off capabilities to ~50% of Gas Service Representatives for sizes up to 1.5" plastic pipe.
- Purchased and implemented Emergency Trailers in every division allowing easier access to emergency equipment.
- Implemented Incident Command communication protocols to ensure consistent and timely information updates.
- Located crews in areas where incidents are more frequent than average to reduce travel time.
- Daily operating reviews to identify countermeasures for deviations.
- Live action drills simulating emergency scenarios with first responders, practicing isolation procedures and documentation of lessons learned.
- Weekly meetings to share best practices and lessons learned across the company.

Observations on Metric 4.7 Management

PG&E's divisions review metric data for each individual area. Any division that is not meeting any metric target individually implements catch-back plans for the areas off target. The incident data input form allows Field technicians to enter any barriers to or delays in their response. The divisions look at initiatives to address any feedback from the technicians. This process includes local problem-solving sessions to help understand key drivers. Performing this locally is effective because local conditions are better understood by a local team. These actions by each division contribute to improving the company-wide results.

2.30.3 Metric 4.7 Performance and Targets

In 2021 the 1- year target set for 2022 set based on the average of the four-year historical performance from 2018 to 2021 plus 10% to address non-significant variability. The targets for the subsequent years were set at a reduction of 0.5 minutes year-over-year. 5-year targets reduced the 1-year target by 2 minutes.

The following table displays PG&E's 2018 through 2023 metric results and the 1-year and 5-year metric targets.

Table 2-55: Metric 4.7 Results and Targets

Year	Metric Result	1-Year Target	5-Year Target
2018	183.40		
2019	172.70		
2020	150.10		
2021	161.00	183.50	181.50
2022	165.48	183.00	181.00
2023	141.00	182.50	180.50
[1] Targets reflect the target set in that report year (i.e. the 2021 1-year target reflects 2022 target).			

PG&E's average metric result from 2018 to 2023 was 162.28, and from 2021 to 2023, it was 155.83. PG&E's 2023 target of 182.5 is 12% above the 6-year average and 17% above the 2021-2022 average. Overall, PG&E's metric result has shown a downward trend.

Observations on Metric 4.7 Performance and Targets

PG&E participates in American Gas Association's (AGA) Best Practices program to improve performance across all member gas utilities. The AGA benchmarking on the emergency response topic aligns most closely with Metric 4.3, which doesn't include the time to shut-in blowing gas.

PG&E has a relationship with Sempra and communicates with other IOUs to review and compare results on this topic. PG&E stated if Metrics 4.4 and the main portion of Metric 4.7 were combined, and Metric 4.5 and the service portion of Metric 4.7 were combined, the results would closely compare to the way SoCal Gas and SDG&E measure their performance. PG&E reports that its performance in main shut-ins is approximately 47% better than that of SoCal Gas and 45% better than that of SDG&E. PG&E's performance in service shut-ins is approximately 48% better than that SoCal Gas, but about 5% worse than SDG&E's.

PG&E's response time for Grade 1 leaks has largely decreased since 2018. While PG&E's target is significantly above metric performance, it has decreased by half a minute each year since 2021. From conversations with PG&E, FEP understands that Metrics 4.4, 4.5 and 4.7 are managed by the same team using the same protocols. Despite management consistency, these three metrics have different results trends. Metric 4.5 (services) and Metric 4.7 (Grade 1 Leaks) both trend downward, while Metric 4.4 (mains) trends slightly upward since 2018. The nature of the leak and asset types might contribute to this. Mains are more difficult to shut-in than services, overall. Meanwhile, Grade 1 leaks are the most hazardous type of leak. They take the longest to resolve on average but may have a greater performance improvement focus.

2.31 Metric 5.1: Clean Energy Goals Compliance

The CPUC defines Metric 5.1 as:

Progress towards meeting the procurement obligations in the following California Public Utilities Commission (Commission) decisions: 21 (1) D.19-11-016, (2) D.21-06-035, and (3) D.23-02-040 (together, the Integrated Resource Planning (IRP) Decisions).

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). 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.

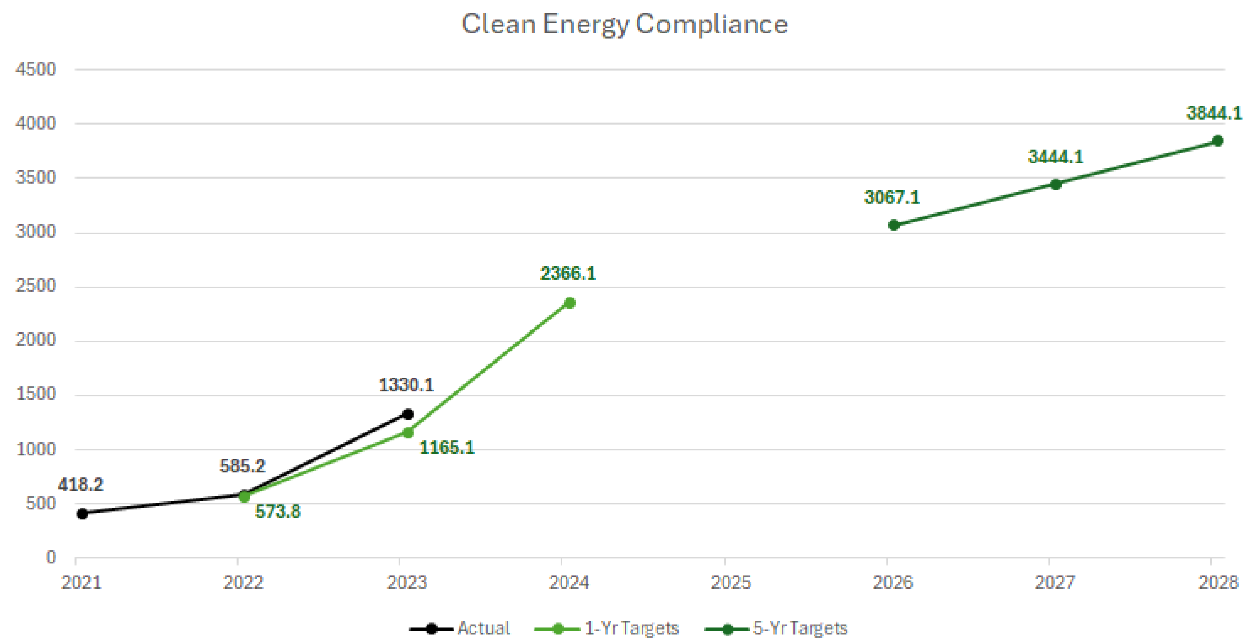
In June 2021, the Commission issued D.21-06-035 to address the mid-term (period of 2023-2026) reliability needs of the electric grid and to help achieve the state's greenhouse gas (GHG) emissions reduction targets. In the decision, the Commission ordered 11,500 MW of incremental resource procurement exclusively from zero-emitting resources, unless the resource otherwise qualifies under California's Renewables Portfolio Standard eligibility requirements. 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.

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.

There's no formula for this metric. The reporting is based on the total amount of capacity procured by PG&E to meet the clean energy requirements. PG&E does have a formula that it must apply to the capacity to determine the net capacity that will be acceptable to count toward the generation requirements. That process is described below in metric accuracy.

The following chart shows Metric 5.1 results compared to targets for 2021 through 2028. All historical values reflect the most recent data available as of the 2023 report and may differ from previously reported figures.

Figure 2-43: Metric 5.1 Summary Chart



2.31.1 Metric 5.1 Accuracy and Consistency

Information for Metric 5.1 is maintained in the company contract management database. As new contracts are approved and executed the information for that contract is entered into the database and then included in subsequent reporting. This has been the same process since the inception of the requirement in 2021.

The procurement and contracts management organizations along with the Energy Policy organization are responsible for negotiating and executing the contracts. They require approval from PG&E management and then from the CPUC before the final contract is awarded. They must also ensure that the capacity reported is an agreement with the capacity counting rules established by the CPUC.

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. 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 Net Qualifying Capacity ("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.

Observations on Metric 5.1 Accuracy

To assess the accuracy of Metric 5.1 results, FEP reviewed PG&E's procurement data to determine the total procured capacity for each year. First, FEP verified PG&E's conversion of nameplate capacity to actual capacity. Then FEP summed up the procured capacity.

Nameplate Capacity Conversion

PG&E provided data on each of the procured resources including type, capacity, and the year it comes online. For resources contracted through Decision 21-06-035, PG&E was required to reduce the nameplate capacity by a certain percentage based on the technology type. FEP verified the conversions and agree with PG&E's converted capacity values. FEP's results matched PG&Es.

Total Capacity Procurement

Next, FEP summed up the available capacity each year. During the evaluation process, PG&E noted that the values presented in the 2023 full-year SOM report represented the amount provided at the time of contract execution. Since filing the report and contract completion, there were delays which resulted in projects not coming online as expected. Through requests for information, FEP received updated procurement totals in September of 2024. FEP's calculations match the updated values provided by PG&E.

2.31.2 Metric 5.1 Management

The Energy Policy and Procurement department has overall responsibility for this metric. The procurement and contract management teams run reports on a weekly basis to monitor the status of the contracted capacity vs the requirements from the CPUC. They also run reports when new contracts are approved to ensure the new capacity has been added and is being tracked for the metric. PG&E also meets, and reports on contracted capacity, with the Energy Division of the CPUC every other week. This process keeps the CPUC updated on where PG&E stands on their generating capacity requirements as it relates to the Clean Energy initiative and the targets established by the CPUC.

Because contract changes can happen (such as test capacity, commercial online date, etc.), even up to the expected online date, there can be unforeseen impacts to the available capacity. When that happens PG&E can fall out of compliance. In order to attempt to address this, PG&E will over-procure what is required based on an analysis of the history of delays. If there are still concerns that they may be short during a period of time PG&E will use "bridge procurement", which is a mechanism determined by the CPUC to address the delays and shortfalls. There are two types: short term import energy bridge and energy bridge for a long term. These products can only be used as a bridge and do not meet the qualifications of a project used to meet the standard. There is a finite amount of capacity that can be transported across and imported into CA, given the transmission constraints and several companies competing for volumes, making it difficult to procure bridge capacity. PG&E works closely with the energy division of the CPUC to discuss procurement issues and impacts on the metric.

Observations on Metric 5.1 Management

The work to achieve the requirements for the metric is very dynamic considering the market volatility and the competition amongst California utilities to meet Clean Energy requirements. PG&E appears to have a good process in place to manage this metric and maintain consistent communication with the CPUC regarding the status of the metric. As of the end of 2023 PG&E has actually exceeded the amount of capacity required by the commission's decisions.

2.31.3 Metric 5.1 Performance and Targets

Metric 5.1 targets are set by the CPUC. The work done by PG&E is based solely on meeting these targets. As noted in the graph in section 1, the yearly targets increase as the required generation by the CPUC increases.

PG&E staff stated that no benchmarking was used to set the targets for Metric 5.1 because they were set by the CPUC. Each operator has their own specific requirements so there is no comparison for performance.

The following table shows Metric 5.1 performance versus the 1-year and 5-year metric target for 2021-2023.

Table 2-56: Metric 5-1 Results and Targets

Year	Metric Result	1-Year Target	5-Year Target
2021	418.2	573.8	3,054.1
2022	585.2	1,165.1	3,444.1
2023	1,330.1	2,366.1	3,844.1
[1] Targets reflect the target set in that report year (i.e. the 2021 1-year target reflects 2022 target).			

Observations on Metric 5.1 Performance and Targets

While PG&E has been successful thus far in acquiring the capacity needed to meet the CPUC mandated targets, it continues to face challenges as it looks to future targets. Some of those challenges include increases in component prices, continued supply chain constraints, and industry-wide inflation on total project costs that have hindered developers' ability to bring projects online by their contractual online dates. In recognition of these challenges, the Commission has provided mitigation tools in D.23-02-040 and D.24-02-047 for LSEs to continue making progress towards their procurement obligations to ensure system reliability in the mid-term. PG&E will continue to use those tools to meet its targets.

2.32 Metric 6.1: Emergency Call Quality of Service

The California Public Utilities Commission (CPUC) defines Metric 6.1 as:

Average Speed of Answer (ASA) in seconds for Emergency calls handled in Contact Center Operations (CCO).

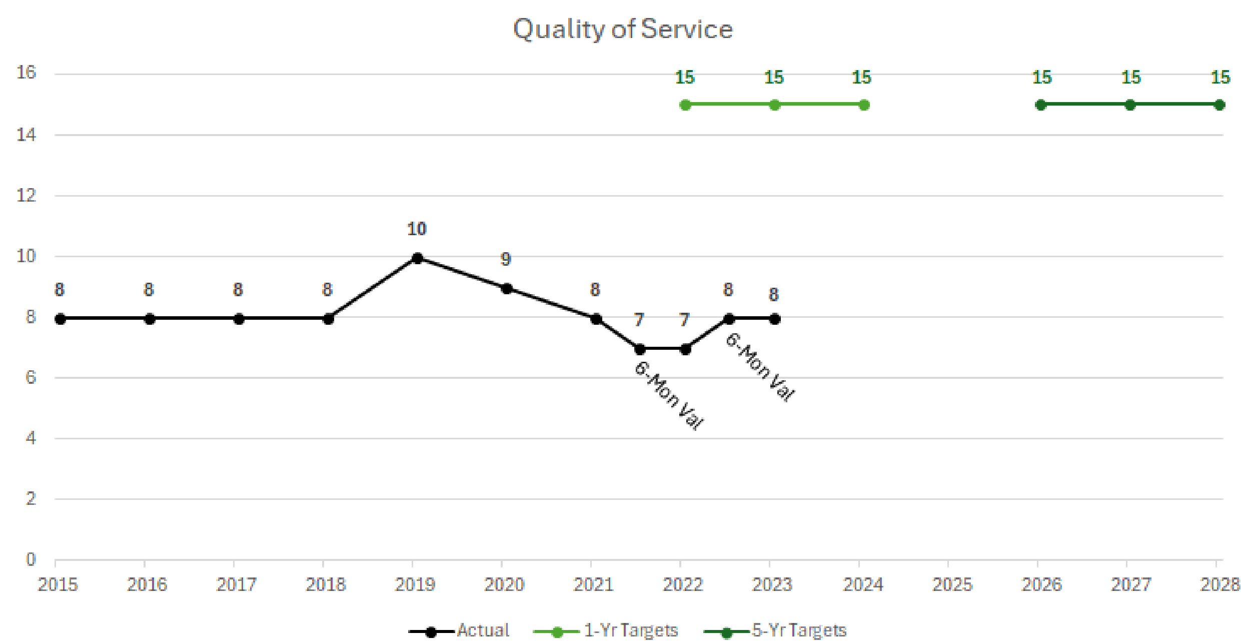
Metric 6.1 calculates the average amount of time it takes to connect customers to a service representative for calls reporting hazardous or emergency situations such as suspected natural gas leaks or downed power lines. PG&E's telephone system uses Interactive Voice Response (IVR), which is an automated platform that provides customers with a list of options and directs the call based on their responses. The IVR speeds up the time to connect to the correct personnel. Not only is Emergency ASA a quality measurement of how efficiently PG&E is able to answer customers calling to report an emergency, but it is also a safety measurement. Answering the call is the first step in ensuring the customer is safe.

The formula for calculating Metric 6.1 is:

$$= \frac{Total\ Time\ in\ Seconds\ to\ Answer\ All\ Emergency\ Calls}{Total\ Number\ of\ Emergecy\ Calls}$$

The following chart shows Metric 6.1 results compared to targets for 2015 through 2028, including results from the 2022 and 2023 mid-year reports. All historical values reflect the most recent data available as of the 2023 report and may differ from previously reported figures.

Figure 2-44: Metric 6.1 Summary Chart



2.32.1 Metric 6.1 Accuracy and Consistency

Information for Metric 6.1 is verified during the daily reporting process. The call data from the previous day is extracted from the telephone system (Cisco Unified Contact Center Enterprise). The dates are reviewed to ensure all data is current and that there are no duplicates being reported. The results are then compared back to the data in the system of record. The data analysis is performed daily so that when the monthly reports are prepared all information will be accurate.

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.

The oversight and management process for this metric has been consistent for the past decade. The policies around data gathering, input, and extraction have been consistent throughout the reporting period with minimal changes to the reporting standard. The primary change involved downloading the call information into excel to manage the data and prepare for reporting. This was due to the fact that the telephone system report function was found to be rounding down on the numbers being extracted for reporting purposes.

Observations on Metric 6.1 Accuracy

Metric 6.1 assessed the average answer speed by a customer representative for a call identified as an emergency by the customer, using the interactive voice recording system. PG&E's automated telephone system is the primary tracking methodology for this metric. To assess the accuracy of Metric 6.1, FEP first evaluated PG&E's calculation methodology through interviews. Then, FEP verified the average answering speed calculation.

Methodology Verification

Metric 6.1 is calculated by logging the total number of calls received, filtering the calls by those identified as emergencies, then taking the total answering time for those calls. To produce an average, the total answering time (in seconds) is divided by the total number of emergency calls received. FEP discussed the functionality of the telephone system with PG&E and evaluated the calculation methodologies at a high level. PG&E's process for tracking call response time is in keeping with industry standards.

Average Answering Time

FEP then verified the average answering speed based on the total calls received and the total answering time, in seconds. PG&E queries the total call data and answering time from their phone system database, which is keeping with industry practices.

The following table displays the total number of emergency calls PG&E reported for 2021 through 2023, as well as the time it took to answer the calls, in seconds. The third column displays FEP's calculated average answering speed. The value FEP calculated matches the value PG&E reported for each year. FEP was not able to independently verify the answering speed for each call, due to the very high number of total calls received.

Table 2-57: Emergency Call Answering Time

Year	Total Calls	Total Answering Time	Avg. Ans. Speed (sec)
2021	531,513	4,219,875	8
2022	448,952	3,106,378	7
2023	528,337	3,988,610	8

2.32.2 Metric 6.1 Management

PG&E's Customer and Enterprise Solutions department is responsible for managing, tracking, and setting targets for Metric 6.1. Reports are run daily to extract results from the prior day. Those results are analyzed by metric owners and the department vice president. If there are any spikes in call answering time, they will first review any outages that may have occurred on the prior day and any other activity that could have driven an increase in call volumes. Those results are then reviewed monthly to create the SOMs report. This report is approved by the VP and then sent to the CIC for review. If this metric is off track from the target, an explanation of the cause is required to be submitted with the SOM report to the CIC. It must also include a plan to get the results back on target.

This metric is heavily impacted by the Contact Center resourcing and staffing levels. Staffing is based on forecasted volumes due to weather, PSPS events, etc. PG&E implements mandatory overtime and voluntary overtime to prepare for these events. These actions are all in an effort to maintain the target response time. The metric is not used to drive employee performance within the call centers. Those employees are instructed to take all calls in the order they were received. Information provided by the customer then determines if the call is deemed an emergency. While the metric targets are not used to improve employee performance, they are used to drive improvements to the processes used to handle calls so that response times remain under the 15 second target. As upcoming events such as PSPS (Public

Safety Power Shutoff), weather, storm and temperature outages impact required staffing, alternate plans are in place to have additional staffing in place. These include mandatory overtime and emergency overtime policies. This allows PG&E to maintain their current staffing levels and still meet those unexpected events as they occur.

Observations on Metric 6.1 Management

This metric is managed on a daily basis. Any variations from the target are reviewed and root causes are established. The forecasting of weather has also helped to improve the management of the metric target. While performance has continually been under the 15 second target, the company has not reduced the target to below 15 seconds to be more in line with actual response times of 8 – 10 seconds. The justification has been stated as the uncertainty of weather, available staffing and unforeseen events that impact call volumes.

2.32.3 Metric 6.1 Performance and Targets

PG&E's Customer and Enterprise Solutions department is responsible for managing, tracking, and setting targets for Metric 6.1. In the 2021 report, PG&E stated that it sets the target "based on the average of the past four years of historical data."[48]. However, the average of 2018 – 2021 data is 8.75 rather than 15. In a response to an RFI regarding this target PG&E indicated it took the 4-year average and added a margin to it to account for the potential volatility of this metric, which in this case was approximately 71% PG&E stated that one major event could impact the metric for an entire year as it relates to the SOM reporting. The following table displays PG&E's 2015 through 2023 metric results and the 1-year and 5-year metric target.

Table 2-58: Metric 6-1 Results and Targets

Year	Metric Result	1-Year Target	5-Year Target
2015	8		
2016	8		
2017	8		
2018	8		
2019	10		
2020	9	15	15
2021	8	15	15
2022	7	15	15
2023	8	15	15
[1] Targets reflect the target set in that report year (i.e. the 2021 1-year target reflects 2022 target).			

PG&E's average metric result from 2015 to 2023 was 8.22, and from 2021 to 2023, it was 7.67. PG&E's target of 15 in 2023 was 82% above the 9-year average and 96% above the 2021-2023 average. Overall, PG&E's metric result has remained consistently below target levels.

PG&E staff stated that no benchmarking was used to set the target for Metric 6.1. Staff stated that they use a company called DataSource to compare results with other industry participants. However, PG&E

[48] 2021 PG&E SOMs Report, p 6-1.4.

stated this company does not currently have a metric in its database that matches metric 6.1 to use for comparisons.

Observations on Metric 6.1 Performance and Targets

FEP did note one specific standard set by the National Emergency Number Association which is NENA-STA-020.1-2020, formerly 56-005.

Following is a summary of the standard:

1. NENA Standard:
   - **90% of 9-1-1 calls** should be answered within **15 seconds**.
   - **95% of 9-1-1 calls** should be answered within **20 seconds**.
2. Other benchmarks: In some cases, particularly in high-demand centers, local standards may set a stricter target, such as answering **95% of calls within 10 seconds** during peak hours.

Utilizing these benchmarks would require PG&E to change its method of calculation from measuring average answering speed to calculating the percentage of calls answered within a target time.