BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Further Develop a Risk-Based Decision-Making Framework for Electric and Gas Utilities.	Rulemaking 20-07-013 (Filed on July 16, 2020)

(NOT CONSOLIDATED)

Application of Pacific Gas and Electric Company (U 39 M) to Submit Its 2020 Risk Assessment and Mitigation Phase Report. U 39 M)	A.20-06-012 (Filed on June 30, 2020)
Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2023. (U 39 M)	A.21-06-021 (Filed on June 30, 2021)

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

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Dated: April 1, 2022

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

Pacific Gas and Electric Company (PG&E) hereby submits this semi-annual Safety and Operational Metrics Report in compliance with California Public Utilities Commission Decision (D.) 21-11-009. This is PG&E's first such report. The report is provided as Attachment 1.

Separately, PG&E is concurrently filing and serving a "Notice of Availability of Pacific Gas and Electric Company's 'Safety and Operational Metrics Report: Supporting Documentation'" due to the size of the electronic files associated with the material supporting the attached report.

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Respectfully Submitted,

By: */s/ Steven W. Frank*
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Dated: April 1, 2022

ATTACHMENT 1

PACIFIC GAS AND ELECTRIC COMPANY

SAFETY AND OPERATIONAL METRICS REPORT

APRIL 1, 2022

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT
APRIL 1, 2022

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A. Introduction

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

At Pacific Gas and Electric Company (PG&E or the Company), nothing is more important than the safety of our customers, employees, contractors and communities. This SOMs Report demonstrates PG&E's commitment to overseeing safe operations and, where needed, driving progress to reduce risk and improve performance. SOMs are embedded in our internal processes to give Company leaders visibility into performance to identify negative trends and take swift corrective actions to prevent harm. These metrics are central to safety performance across the Company.

PG&E has approached each SOM on a metric-by-metric basis. More specifically, PG&E evaluated our historical and current year (2021) performance and available benchmarking data, and established objectives that align with our commitment to safety. For example, a metric where PG&E already performs in the first quartile may not demand dramatic improvement but could require consistent monitoring to ensure that performance remains at acceptable levels. For metrics that include Major Event Days (MED), PG&E will use the information to help ensure that our infrastructure is adaptable to an environment rapidly changing due to climate change. For some metrics, the Company has found opportunity to continue to drive safety performance through ongoing or future programs that are described in each chapter of this report.

B. Background and Requirements

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

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

> PG&E shall report its Safety and Operational Metrics as follows. PG&E shall, on a semi-annual basis, serve and file its SOMs Report in Rulemaking 20-07-013, any successor Safety Model Assessment Proceeding, and its most recent or current General Rate Case and Risk Assessment and Mitigation Phase proceedings starting March 31, 2022, and continuing annually at the end of September and March thereafter, with the March reports covering the 12 months of the previous calendar year (i.e., January through December) and the September reports providing data for January through June of the current year. PG&E shall concurrently send a copy of its semi-annual SOMs Reports to the Director of the Commission's Safety Policy Division and to RASA_Email@cpuc.ca.gov. PG&E shall:
>
> a) Report on each SOM, using data for the preceding 12 months and providing all available historical data[1];
> b) For each SOM, provide a proposed target for the year following the reporting period for each metric and a five-year target, with the proposed target represented as specific values, ranges of values, a rolling average, or another specified target value, except for our final adopted SOM #s 1.3, 2.3, 3.1, 3.3, 3.5, and 3.6 for which PG&E may provide directional targets;
> c) For each SOM, provide a narrative description of the rationale for selecting the target proposed and why a specific value, a range of values, a rolling average or another type of target is selected;
> d) For each SOM, provide a narrative description of progress towards the proposed annual and five-year targets;
> e) For each SOM, provide a narrative description of any substantial deviation from prior trends based on quantitative and qualitative analysis, as applicable;
> f) For each SOM, provide a brief description of current and future activities to meet the proposed targets; and,
> g) Provide the Commission's Safety and Policy Division with a copy of any report filed more frequently than semi-annually with the Commission that contains SOMs, at the same time the report is filed.[2]

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[1] An index of historical data files, provided by chapter, is included in PG&E's "Safety and Operational Metrics Report: Supporting Documentation."

[2] Reports that meet this requirement are provided in PG&E's "Safety and Operational Metrics Report: Supporting Documentation." PG&E understands this requirement to not include one-time event triggered reports (e.g., Electric Incident Reports). Note that PG&E provided quarterly reports as part of the Wildfire Mitigation Plan to the Commission through June 2021 but are now submitted to the Office of Energy Infrastructure Safety. These reports can be found online at [PG&E's Wildfire Mitigation Plan webpage].

This report outlines PG&E's performance from January 1, 2021, through December 31, 2021, and is organized into 32 individual metric chapters as defined in Attachment A of D.21-11-009. Each chapter provides discussion on performance and progress against one- and five-year targets. In future reports, PG&E will provide updates on progress towards targets and the internal or external factors that are driving performance.

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

Target Setting

For this first report, PG&E developed four pillars for developing targets that align with Commission's objective for this report:

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

With these criteria, PG&E sought to develop targets for each metric that generally maintain performance for well-performing metrics or drive performance improvement to satisfactory levels of safe and reliable service. As required by the decision, within each metric chapter PG&E provides the rationale behind the selection of the 1- and 5-year targets.

On their own, metrics can fail to tell a complete story and may not provide crucial detail or context that is necessary for a proper evaluation of performance or progress. Recognizing that, the Commission's decision requires PG&E to provide a narrative-driven report that gives the Commission further insight on how PG&E's safety and operational programs are progressing towards targets or if performance is deviating from target and trend, and to state current and future activities that will drive performance towards target.

D. Summary of Metric Performance Against Targets

Below is a summary of each metric and 2021 performance and targets. The details for each metric can be found in the metric report chapters that follow.

TABLE 1-1
SUMMARY OF METRIC PERFORMANCE AND TARGETS

#	Metric	2021 Performance	2022 Target	2026 Target
Safety				
1.1	Rate of Serious Injury or Fatality (SIF) Actual (Employee)	Rate: 0.042	Rate: 0.080	Rate: 0.080
1.2	Rate of SIF Actual (Contractor)	Rate: 0.063	Rate: 0.100	Rate: 0.100
1.3	SIF Actual (Public)	Confirmed: 3 Pending: 3	Decrease	Decrease
Reliability				
2.1	System Average Interruption Duration (Unplanned)	3.06 hrs.	5.67 – 6.8 hrs.	5.67 – 6.80 hrs.
2.2	System Average Interruption Frequency (Unplanned)	1.178 hrs.	1.681 – 2.017 hrs.	1.681 – 2.017 hrs.
2.3	System Average Outages due to Vegetation and Equipment Damage in High Fire Threat District (HFTD) Areas	643 CESO	Maintain	Maintain
2.4	System Average Outages due to Vegetation and Equipment Damage in HFTD Areas (Non-MEDs)	1,120 CESO	1,523 CESO	1,523 CESO
Electric				
3.1	Wires Down MED in HFTD Areas (Distribution)	10.96 WD events/1,000 mi.	Maintain	Maintain
3.2	Wires Down Non-MED in HFTD Areas (Distribution)	18.80 WD events/1,000 mi.	41.45	38.24
3.3	Wires Down MED in HFTD Areas (Transmission)	6.334 WD events/1,000 mi.	Maintain	Maintain
3.4	Wires Down Non-MED in HFTD Areas (Transmission)	1.991/WD events/1,000 mi.	≤4.456	≤4.456
3.5	Wires Down Red Flag Warning Days in HFTD Areas (Distribution)	.00011 WD event on RFWW/Circuit Mile-Days	Maintain	Maintain
3.6	Wires Down Red Flag Warning Days in HFTD Areas (Transmission)	.00000 WD event on RFWW/Circuit-Mile Days	Maintain	Maintain

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

#	Metric	2021 Performance	2022 Target	2026 Target
Patrols and Inspections				
3.7	Missed Overhead Distribution Patrols in HFTD Areas	0.86%	0.00% - 0.05%	0.00% - 0.02%
3.8	Missed Overhead Distribution Detailed Inspections in HFTD Areas	4.10%	0.00% - 0.05%	0.00% - 0.02%
3.9	Missed Overhead Transmission Patrols in HFTD Areas	0.07%	0.00% - 0.05%	0.00% - 0.02%
3.10	Missed Overhead Transmission Detailed Inspections in HFTD Areas	0.07%	0.00% - 0.05%	0.00% - 0.02%
3.11	GO-95 Corrective Actions in HFTDs	64.8%	70.0%	76.0%
3.12	Electric Emergency Response Time	Average: 31 min. Median: 30 min.	Average: 44min. Median: 43min.	Average: 44min. Median: 43min.
Ignitions and Wildfire				
3.13	Number of CPUC-Reportable Ignitions in HFTD Areas (Distribution)	126 ignitions	82-94 ignitions	82-94 ignitions
3.14	Percentage of CPUC-Reportable Ignitions in HFTD Areas (Distribution)	4.99 ignitions	3.24-3.72 ignitions	3.24-3.72 ignitions
3.15	Number of CPUC-Reportable Ignitions in HFTD Areas (Transmission)	4 ignitions	Range: 0 – 10 ignitions	Range: 0 – 10 ignitions
3.16	Percentage of CPUC-Reportable Ignitions in HFTD Areas (Transmission)	0.72 ignitions	Range: 0 – 1.75 ignitions	Range: 0 – 1.75 ignitions
Gas				
4.1	Number of Gas Dig-Ins per 1000 USA tickets on Transmission and Distribution pipelines	1.63	≤2.56	≤2.48
4.2	Number of Overpressure Events	5	≤11	≤9
4.3	Time to Respond On-Site to Emergency Notification	Average: 20.6 min. Median: 18.8 min.	Average: ≤21.6 min. Median: ≤19.8 min.	Average: ≤21.2 min. Median: ≤19.4 min.

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

#	Metric	2021 Performance	2022 Target	2026 Target
4.4	Gas Shut-In Times, Mains	79.1 min.	≤85.4 min.	≤83.4 min.
4.5	Gas Shut-In Times, Services	36.3 min.	≤40.4 min.	≤39.6 min.
4.6	Uncontrolled Release of Gas on Transmission Pipelines	2,821	≤3,545	≤3,405
4.7	Time to Resolve Hazardous Conditions	161.0 min.	≤183.5 min.	≤181.5 min.
Clean Energy				
5.1	Clean Energy Goals Compliance Metric	418	≥574	≥3,067
Quality of Service				
6.1	Quality of Service Metric	8 sec.	15 sec.	15 sec.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 1.1

SAFETY AND OPERATIONAL METRICS REPORT:

RATE OF SIF ACTUAL

(EMPLOYEE)

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A. Overview

1. Metric Definition

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

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

2. Introduction of Metric

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

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

The EEI OS&HC serious injury criteria are updated annually based on additional learnings from injury classification to provide further clarification or criteria for the following year. PG&E is using this year's (2022) criteria, which can be found on the EEI website.[1] The 2022 EEI OS&HC criteria define serious injuries as follows:

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[1] The criteria can be found on the EEI website: https://images.magnetmail.net/images/clients/EEI_//attach/Environment/hsif2022.pdf.

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

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

From 2017 to 2020, PG&E classified SIF-A incidents based on the job task and whether a life altering, life threatening injury or fatality occurred. In August of 2020, PG&E adopted Edison Electric International's Safety

Classification Learning (SCL)[2] model to classify its SIF incidents. The EEI SCL model classifies incidents into categories: High-Energy SIF (HSIF),[3] Low-Energy SIF (LSIF),[4] Potential SIF (PSIF),[5] Capacity,[6] Exposure,[7] Success,[8] and Low Severity.[9] The HSIF terminology is fairly new to the industry; however, it is equivalent to a SIF-A with regard to how serious life threatening, life-altering or fatalities are determined. Adopting the EEI SCL model has improved the SIF Program by bringing a consistent and objective approach to reviewing and classifying SIF incidents across the Company and industry. The SCL model allows the Company to focus its safety and risk mitigation efforts on the most serious outcomes and highest risk work where a high energy incident occurred. The EEI SCL model is also used for the Employee SIF-A Safety Performance Metric (SPM) and is aligned with other California utilities.

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

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2 EEI, SCL Model available here: https://esafetyline.net/eei/docs/eeiSCLmodel.pdf.

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

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

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

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

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

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

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

10 EEI Occupational Safety and Health Committee's Serious Injury Criteria.

B. Metric Performance

1. Historical Data (2017-2021)

PG&E is including five years of historical data representing 2017-2021. The dataset includes injury type, incident date, location, and EEI OS&HC injury classification. See PG&E's "Safety and Operational Metrics Report: Supporting Documentation" for a list of incidents.[11] The last five years of data is consistent with the start of the PG&E SIF Program.

Figure 1.1-1 illustrates the rate of employee injuries by year from 2017 to 2021. Between 2017 and 2021 there are a total of 44 injuries that met the EEI OS&HC serious injury criteria. 50 percent of the injuries met the criteria of bone fracture, including of the hands and feet. Four of the incidents were fatalities, one involved a violent act of a third party and three involved operations of motor vehicles.

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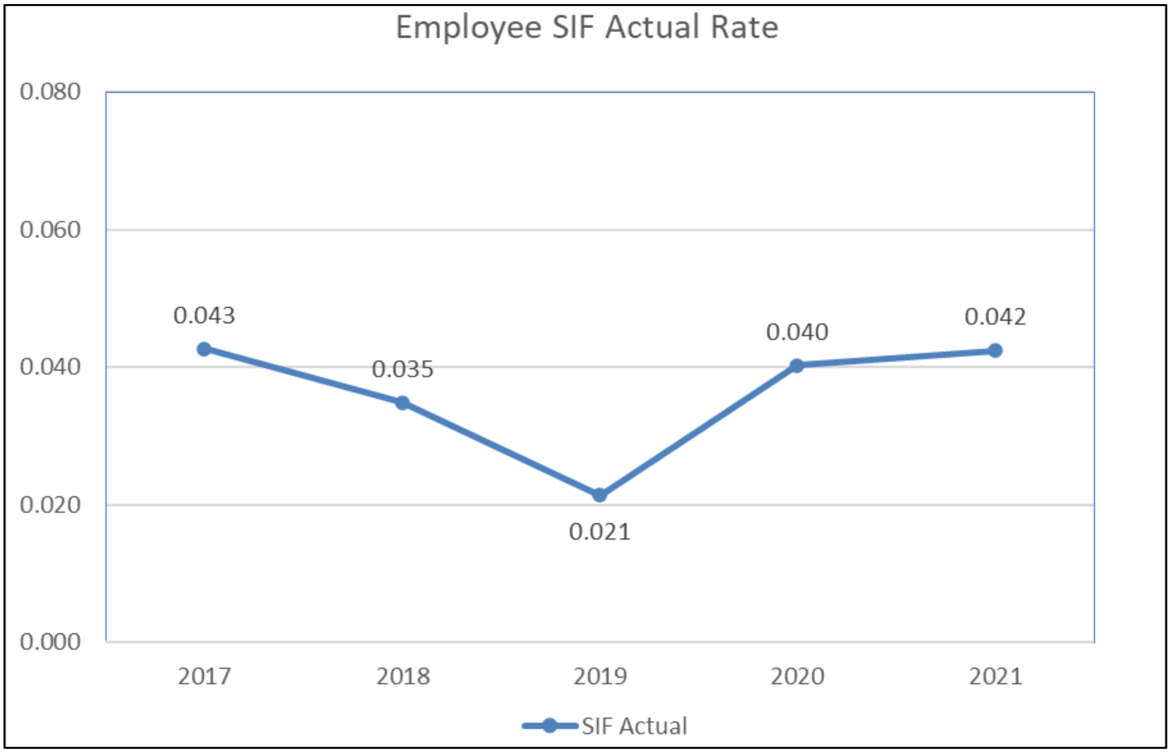
[11] PG&E is making this documentation available on its website pursuant to the instructions in the concurrently filed Notice of Availability for the "Safety and Operational Metrics Report: Supporting Documentation."

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



2. Data Collection Methodology

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

As mentioned above, the SIF-A (Employee) SOM as defined in D.21-11-009 is new in application to PG&E's existing injury and SIF dataset, and this report is the first year in which the data were analyzed and reported under this definition. To evaluate the SIF-A (Employee), PG&E reviewed all employee injury data from 2017-2021 to determine if any met the 14 EEI OS&HC serious injury criteria as summarized above. To establish historical performance, PG&E reviewed approximately 18,000-line items of injury data. A substantial portion of those were not OSHA-recordable (i.e., self-care), which do not meet the definition and were removed from the population. The remaining population that met the OSHA definition (i.e., work-related injury) was reviewed against the EEI OS&HC serious injury criteria for this report.

3. Metric Performance for 2021

In 2021, bone fractures were the leading cause of injuries at 72 percent (8 of 11). These included bone fractures of the fingers, wrist, arms, ribs and leg. The remaining three injuries including dislocation of a major tendon (2) and eye damage (1). Two of the bone fractures incidents involved a high-energy incident (working from heights). None of the incidents were considered life threatening or life altering injuries. There were no fatalities in 2021.

C. 1-Year Target and 5-Year Target

1. Target Methodology

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

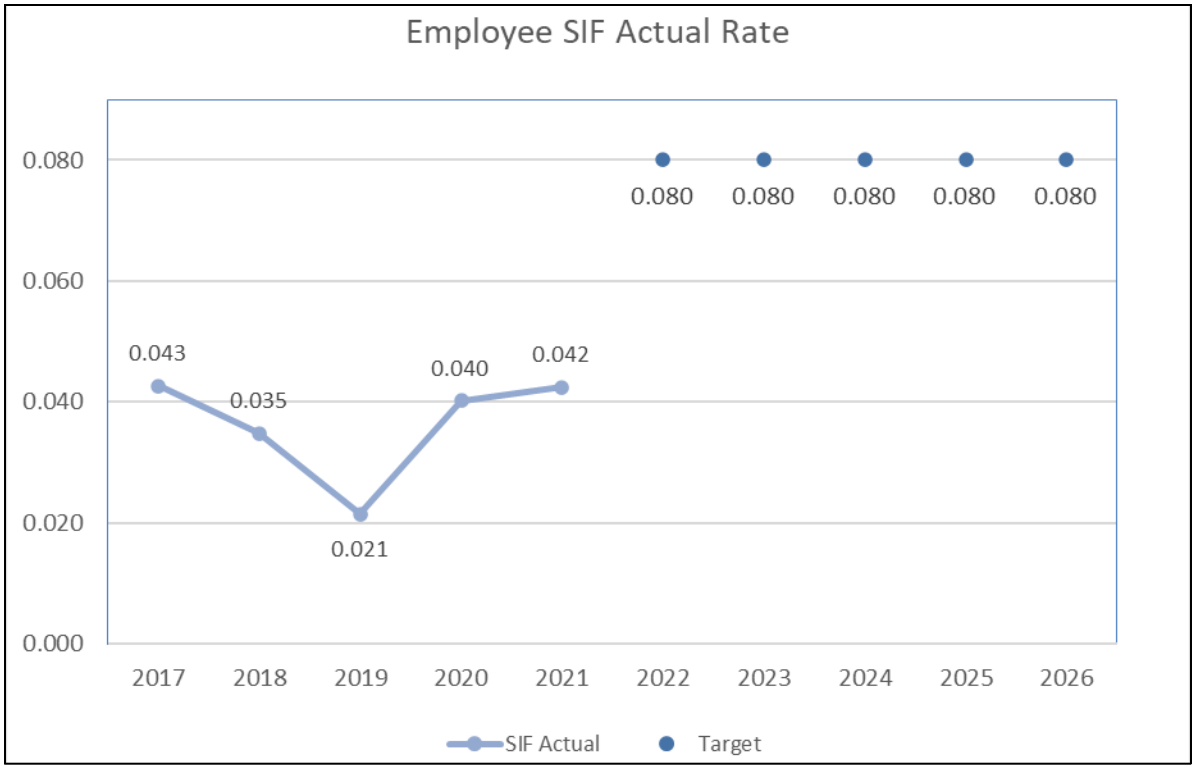
- Historical Data and Trends: PG&E pulled OSHA recorded injuries from 2017 to 2021 to review each injury against the EEI OS&HC serious injury criteria. This injury dataset was used because it aligns with the beginning of the PG&E SIF Program (est. in 2017). Over that historical data period, performance showed a consistent trend at or around 0.04 injury rate, with dip in 2019 and trend back up in 2020 and 2021;
- Benchmarking: Not available. This metric uses new methodology not used in the industry; therefore, benchmarking is not available. However, as noted in the Introduction section, PG&E follows the EEI SCL Model for SIF classification where benchmark data are available. For establishing the SOM 1.1: SIF-A (Employee) target threshold PG&E used that benchmark data as a proxy to establish approximate calculations. Doubling the historical rate with the benchmark data for EEI SCL Model would keep PG&E within top quartile. This guidance applies to the SOM 1.2: SIF-A (Contractor) calculation as well;

- Regulatory Requirements: None;
- Attainable Within Known Resources/Work Plan: Yes. The main focus for driving down injuries is noted below in planned/future work related to Days Away, Restricted and Transferred (DART) reduction;
- Appropriate/Sustainable Indicators: While the performance at or below the target threshold is a sustainable, the more appropriate metric is to focus on injuries resulting from a high energy incident, which is consistent with both industry SIF-A monitoring and the SPM; and
- Other Considerations: This target threshold approach was established to account for all job-related tasks with the potential to cause injury as defined by the EEI OS&HC criteria.

2. 2022 and 2026 Target

The 2022 and 2026 target thresholds are to maintain at a rate of less than 0.080. The target threshold rate for SIF-A (Employee)—using the EEI OS&HC serious injury criteria—allows for no more than an increase of 0.038, as compared to highest rate from 2017 to 2021. The targets for 2022 (1-year) and 2026 (5-year) use this same methodology. Rates are subject to change depending on number of employee hours worked in a given year. The target thresholds are set at the highest serious injury occurrence in one year that would be concerning if the rate was surpassed. Since this metric calculation is new to PG&E and this is the first year it is being reported, the threshold takes into consideration the past five years of historical data and allowance for understanding this calculation and its consequences. The threshold allows for an almost double the rate over 2021, which allows PG&E to refine expectations as this new metric is refined further. As mentioned above, this rate would keep us in the top quartile of our proxy benchmark data calculations. This is also the same methodology used for SOM 1.2: SIF-A (Contractor), which keeps target setting consistent for both metric calculations.

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



D. Current and Planned Work Activities

- PG&E One Plan: PG&E's safety strategy is continuing to evolve from the completion of the One PG&E Occupational Health and Safety Plan to the 2025 Workforce Safety Strategy including continued implementation of the Enterprise Safety Management System (ESMS), which provides governance over the Company's workforce and public safety. PG&E's Enterprise Health and Safety organization supports this metric through its health and safety professionals focusing on:
  - Safety Leadership Development and Safety Culture;
  - Preventing workforce illness and injuries;
  - Governance, oversight, analytics, and reporting functions—including field safety support to drive strategy, programs, and continuous improvement;
  - SIF prevention and life safety;
  - Safe operation of motor vehicles including regulatory compliance and governance;

- Workforce health programs;
- Field observations and inspections;
- Assessing safety program impact; and
- Incident investigations and human factor analyses.

- Regionalization: In 2021, PG&E regionalized its service territory to effectively and efficiently manage the workforce by balancing size, operational challenges such as wildfire risk, and complexity of issues. The regional field safety organization is led by five regional Safety Directors who work with the lines of business to advise on and support health and safety program implementation and sustainability including:
  - Safety Culture Improvements;
  - Hazards Identification with the goal of reducing risk exposures;
  - Workforce observations and inspections;
  - Incident investigations;
  - Safety tailboards and training; and
  - Emergency preparation and response.
- Injury Management: The SIF-A (Employee) SOM definition includes injuries that can occur during any work activity (including low or no energy tasks such as lifting, walking, managing tools like knives), which is broader than the high energy incidents that a mature SIF Program focuses on. Therefore, a significant driver for improvement is within our occupational health organization where our OSHA DART cases are managed. DART cases are employee OSHA-recordable injuries that involve Days Away from work and/or days on Restricted duty or a job Transfer because the employee is no longer able to perform his or her regular job. Since 2019, there has been a 50 percent decrease in the employee DART rate (number of DART cases per 100 fulltime employees divided by number of hours worked). The efforts supporting this reduction include the expansion of PG&E's on-site clinic services and increased Industrial Athlete Specialists for job site evaluation. A primary goal of the efforts is reduced injury severity through injury prevention and early intervention care for employees. In alignment with this, we are strengthening the identification of the highest risk work groups for vehicle ergonomic injuries and computer use and providing our people

leaders with additional injury management training. Additional efforts also include:

- – The use of predictive modeling to identify and provide targeted interventions on high-risk office employees;
- – Ergonomic solutions for high-risk tasks in the field;
- – Customized Stretch and Flex programs; and
- – Enhanced injury management on injuries at risk for escalation to DART.

- Safety Management System: The ESMS is a key tool for improving organizational safety, managing risks and opportunities, and developing and enhancing safety culture. It is an integral part of the Employee Safety Incident risk reduction program. The ESMS is based on a consistent and comprehensive enterprise safety controls framework reinforced with system assurance. Key components of the ESMS include:
  - – Leadership and Engagement: Leadership is the single most critical factor for success in the implementation of the ESMS. Leaders establish a vision and objectives, personally direct the process for continuous improvement, visibly demonstrate involvement and commitment, and build a strong safety culture;
  - – Workforce Safety: Hazards and risks are identified, associated work and work-related activities are planned, controlled, resourced, and supported, planning for emergencies and non-routine tasks is ongoing, and health and safety (H&S) related objectives are identified and managed;
  - – Management of Change (MOC): Hazards and risks associated with changes that impact H&S are identified, evaluated, and managed, and MOC is integrated into enterprise and line of business processes;
  - – Performance Improvement: H&S performance is reviewed daily, actions to achieve and sustain industry leading safety performance are identified and built into business plans and sharing of leading practices across the organization occurs; and
  - – Safety Assurance: Management and verification of critical H&S controls are established and functioning, conformance with applicable workforce H&S requirements is assured and risk to the enterprise is minimized.

- Safety Leadership Development: PG&E is continuing to improve Safety Leadership Development and supervisor coaching by developing an impactful, practical training course with refresher modules for front line leaders. The Safety Leadership development program provides training for crew leaders (i.e., those individuals who lead teams of front-line employees doing field operations and maintenance work) so they have the necessary safety skills to create trust, set expectations, remove barriers to safety and identify and mitigate at risk behaviors.
- Safety Observations: Safety Observations Program plays a critical role in helping to reduce employee and contractor injuries and fatalities by increasing awareness of hazards and exposures in the field, reinforcing positive work practices, and driving PG&E's Speak-Up culture. The Program includes the use of the SafetyNet observation tool, communications of top risks and barriers to senior leaders through the Safety Observations dashboards, promotion of continuous improvement, and communication of safety successes and improvement opportunities.
- Transportation Safety: PG&E Transportation Safety programs protect our employees and the public by establishing requirements and processes to control risks that can lead to motor vehicle accidents, improve safety performance, and increase awareness of all PG&E employees related to the operation of motor vehicles. This comprehensive program was established to reduce the number of motor vehicle incidents that have the potential for serious injury, including fatal injury, to PG&E's employees, staff augmentation employees operating vehicles on Company business, and the public. Driver performance data is used to identify specific risk drivers for targeted intervention, including driver training and implementing vehicle safety technology. Additional Motor Vehicle Safety Incident risk reduction programs including cell phone blocking and in-cab camera technologies currently being piloted are discussed in the PG&E 2020 Risk Assessment and Mitigation Phase (RAMP) Report.[12]

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[12] PG&E 2020 RAMP Report, Chapter 18, Risk Mitigation Plan: Motor Vehicle Safety Incident.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 1.2

SAFETY AND OPERATIONAL METRICS REPORT:

RATE OF SIF ACTUAL

(CONTRACTOR)

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1.2
INTRODUCTION

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1.2
INTRODUCTION

A. Overview

1. Metric Definition

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

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

2. Introduction of Metric

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

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

The EEI OS&HC serious injury criteria are updated annually based on additional learnings from injury classification to provide further clarification or criteria for the following year. PG&E is using this year's (2022) criteria, which can be found on the EEI website.[1] The 2022 OS&HC criteria define serious injuries as follows:

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[1] The criteria can be found on the EEI website: EEI Occupational Safety and Health Committee's Serious Injury Criteria.

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

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

From 2017 to 2020, PG&E classified SIF Actual (SIF-A) incidents based on the job task and whether a life altering, life threatening injury or fatality occurred. In August of 2020, PG&E adopted EEI Safety Classification Learning (SCL)[2] model to classify its SIF incidents. The EEI SCL model classifies incidents into categories: High-Energy SIF (HSIF),[3] Low-Energy

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[2] EEI, SCL Model available here: https://esafetyline.net/eei/docs/eeiSCLmodel.pdf.

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

SIF (LSIF),[4] Potential SIF (PSIF),[5] Capacity,[6] Exposure,[7] Success[8] and Low Severity.[9] The HSIF terminology is fairly new to the industry; however, it is equivalent to a SIF-A with regard to how serious life threatening, life-altering or fatalities are determined. Adopting the EEI SCL model has improved the SIF Program by bringing a consistent and objective approach to reviewing and classifying SIF incidents across the company and industry. The SCL model allows the Company to focus its safety and risk mitigation efforts on the most serious outcomes and highest risk work where a high energy incident occurred. The EEI SCL model is also used for the Employee SIF-A Safety Performance Metric (SPM) and is aligned with other California utilities. In addition, in June of 2020 PG&E modified the SIF Program to include internal classification and investigation of contractor SIF Potential (SIF-P) incidents.[10] This expanded requirement led to an increase in contractor injury data.

The rate of SIF-A (Contractor) SOM definition is based on the EEI OS&HC serious injury criteria[11] which is different than the EEI SCL Model. It is suggested by EEI to use the OS&HC criteria in conjunction with the EEI SCL model. Therefore, using only the OS&HC serious injury criteria creates a different result in SIF-A classification from the expectation of using the EEI SCL model that includes high energy incidents.

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

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

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

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

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

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

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

11 EEI OS&HC’s Serious Injury Criteria, which can be found at https://images.magnetmail.net/images/clients/EEI_//attach/Environment/hsif2022.pdf.

B. Metric Performance

1. Historical Data (2017-2021)

PG&E is including five years of historical data representing 2017-2021. The dataset includes injury type, incident date, location, and EEI OS&HC injury classification. See PG&E's "Safety and Operational Metrics Report: Supporting Documentation" for a list of incidents. Following the Kern Order Instituting Investigation (OII) Settlement Agreement,[12] PG&E deployed the SIF Program to investigate employee and contractor incidents resulting in life altering, life threatening or fatal injuries. Beginning in 2017, PG&E only tracked contractor incidents that were classified through the SIF Program[13] meeting those criteria. Prior to the implementation of the Kern OII requirements, contractors were not required to report SIF incidents. In June 2020, PG&E expanded the SIF Program to include investigating contractor incidents rising to SIF-P classification (focusing on incidents that meet the EEI SCL methodology as described above). This increased the number and types of injuries and incidents that contractors are required to report[14] in 2020 and 2021.[15]

Figure 1.2-1 illustrates the rate of contractor injuries by year from 2017-2021 based on historical data availability as discussed above. For 2020 and 2021, the dataset reflects the expanded SIF-P incident reporting requirements for contractors implemented in June of 2020.[16] There are a total of 41 injuries that met the EEI OS&HC serious injury criteria. Forty-nine percent of the injuries met the criteria of bone fracture, including of the hands and feet. Eleven were fatalities, where one helicopter crash in 2020 claimed the lives of three individuals; the other fatalities involved an

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

13 SAFE-1100S Rev. 00 (2017): SIF Program.

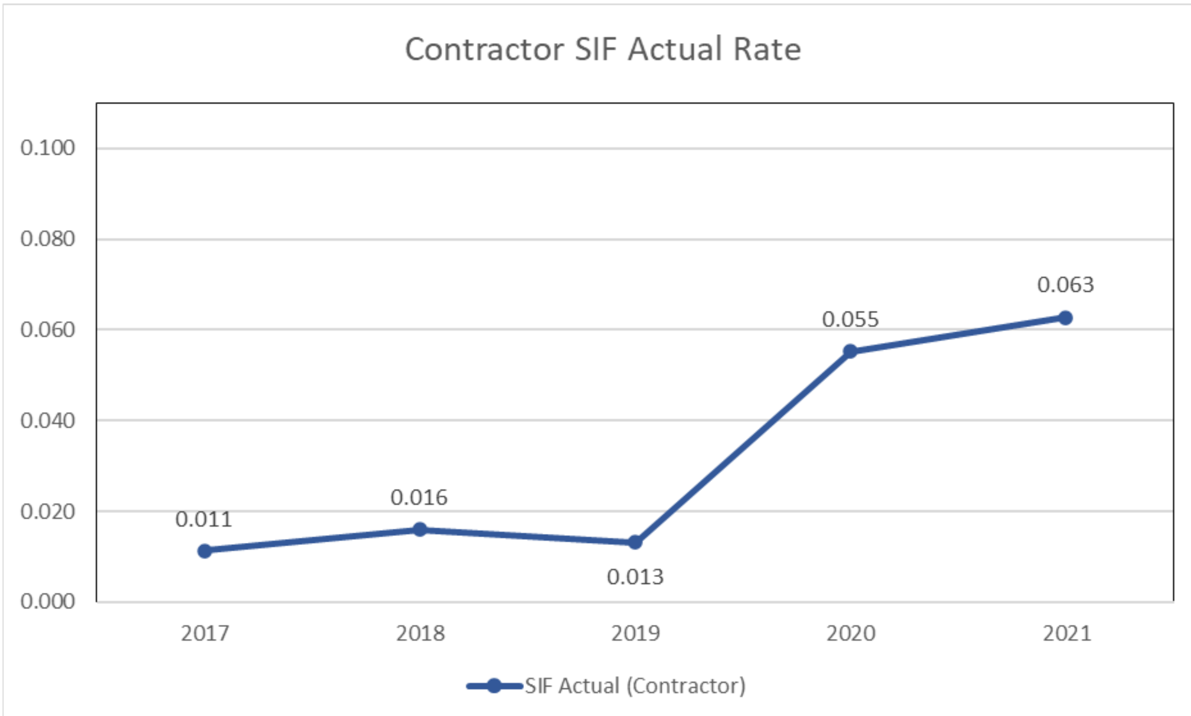
14 SAFE-1100S-B001.

15 Note, the expanded incident reporting requirement implemented in 2020 does not include the broader SOM SIF-A (Contractor) metric definition, which is discussed further in §III.b below.

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

act of a third party, falls from trees and electrical pole, gas pipe placement and operations of motor and powered vehicles.

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



2. Data Collection Methodology

Contractor related Serious Safety Incidents[17] or any SIF-A or SIF-P incidents are reported to the Safety Helpline at company number 223-8700, Option 1 and then entered into the Enterprise CAP program for SIF review and classification.[18] PG&E's SIF Program[19] is managed through the CAP.

As mentioned above, the SIF-A (Contractor) SOM as defined in D.21-11-009 SOM calculation is new in application to PG&E's existing injury and SIF dataset, and this report is the first year in which the data were analyzed and reported under this definition. To evaluate and establish

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

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

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

historical performance for the SOM SIF-A (Contractor) metric, PG&E pulled data from the CAP and reviewed 472 issues with the Issue Type of Contractor Safety. The list included both incidents or injuries reported to PG&E or entered in CAP between 2017-2021. 27 percent, or 128 incidents were related to gas dig-in by a third-party where no injuries occurred. The remaining issues were reviewed to determine if any met the 14 EEI OS&HC serious injury criteria as summarized above.

3. Metric Performance for 2021

In 2021, bone fractures were the leading type of injuries at 68 percent (13 of 19). These included bone fractures of the fingers, wrist, arms, ribs and legs.

Three of the 19 injuries were contractor fatalities:

- March 2021: Two Pre-inspectors were walking off the roadway in Watsonville when a third-party vehicle exited the roadway and hit one of the Pre-inspectors, which resulted in a fatality.
- May 2021: A two-man crew was tasked with installing ground rods as part of lightning arrestor work on a PG&E project work site in Humboldt County. The groundman was fatally injured while performing excavation work with a mini excavator on a dirt-sloped hill.
- June 2021: A contractor was fatally injured in a vehicle incident while performing electric transmission inspection-related work where the vehicle rolled down a steep hill.

The remaining three injuries (of the 19) include two concussions (one from a motor vehicle incident (MVI), and one from being hit in the head with a power tool) and one from trauma to internal organs from a tree split incident that pinned the contractor against the tree.

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

As mentioned above beginning in June of 2020, PG&E began requiring contractors to report all SIF-P incidents and injuries, which resulted in an increase in reported incidents in 2020 by 466-percent over 2019. In 2020, bone fractures were the leading cause of injuries at 50-percent (7 of 14). In addition, there were four contractor fatalities in 2020:

- Three fatalities resulted from a Helicopter incident involving contractors who were performing critical power line work; and
- One fatality resulted from the operation of an all-terrain vehicle.

C. 1-Year Target and 5-Year Target

1. Target Methodology

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

- Historical Data and Trends: The target threshold take into consideration the historical increase (from 0.013 to 0.063) between 2019, 2020 and 2021, after expanding the contractor reporting requirements in 2020. This increased the amount and rate of contractor serious injuries (as defined by the EEI OS&HC serious injury criteria) by over 466-percent. It also takes into consideration that in 2022 PG&E will have to expand contractor injury reporting requirements to meet the SOM SIF-A OS&HC criteria;
- Benchmarking: Not available. This metric uses new methodology not used in the industry; therefore, benchmarking is not available. However, as noted in the Introduction section, PG&E follows the EEI SCL Model for SIF classification where benchmark data are available. For establishing the SOM 1.2: SIF-A (Contractor) target threshold PG&E used that benchmark data as a proxy to establish approximate calculations. Doubling the historical rate with the benchmark data for EEI SCL Model would keep PG&E within top quartile. This guidance applies to the SOM 1.1: SIF-A (Employee) calculation as well;
- Regulatory Requirements: None;
- Attainable Within Known Resources/Work Plan: Yes. The main focus for driving down injuries is noted below in planned/future work related to Contractor Safety initiatives;
- Appropriate/Sustainable Indicators: While the performance at or below the target may be sustainable, the more appropriate metric is to focus on injuries resulting from a high energy incident, which is consistent with both industry SIF-A monitoring and the SPM; and

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

2. 2022 and 2026 Target

The 2022 (1-year) and 2026 (5-year) target thresholds are to maintain a rate of less than 0.10. This target rate takes into consideration the historical increase (from 0.013 to 0.063) between 2019, 2020 and 2021 after expanding the contractor reporting requirements in 2020. It also takes into consideration that in 2022 PG&E will have to expand contractor injury reporting requirements to meet the SOM SIF-A (Contractor) defined EEI OS&HC criteria. Rates are subject to change depending on number of contractors hours worked.

The target thresholds are set at the highest serious injury occurrence in one year that would be concerning if the rate was surpassed. Since this metric calculation is new to PG&E and this is the first year its being reported, the threshold takes into consideration the past two years of historical data and allowance for understanding this calculation and its consequences. The threshold allows for a 50-percent rate increase over 2021, which allows PG&E to refine expectations as this new metric is refined further. As mentioned above, this rate would keep us in the top quartile of our proxy benchmark data calculations. This is also the same methodology used for SOM 1.2: SIF-A (Employee), which keeps target setting consistent for both metric calculations.

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

D. Current and Planned Work Activities

- <u>PG&E's Contractor Safety Program</u>: Programs that support this metric include PG&E's Enterprise Health and Safety organization and the Contractor Safety Program. Beginning in 2016, PG&E implemented a formal Contractor Safety Program to help our contractor partners reduce illness and injuries when working with PG&E. The program was implemented as required by the CPUC, Kern OII Settlement Agreement. PG&E's Contractor Safety Program includes all contractors and subcontractors performing high and medium-risk work on behalf of PG&E, on either PG&E owned, or customer owned, sites and assets. The Contractor Safety Program consists of the following primary elements:
  - <u>Contractor Company Pre-Qualification</u>: PG&E leverages the capabilities of ISNetworld (ISN) to collect performance and safety compliance program information from all prime and subcontractors that conduct work classified as high or medium risk. Although PG&E remains responsible for the performance of its contractors, ISN, a third-party administrator, independently assesses contractors' historical safety data, safety, drug/alcohol, and disciplinary programs to evaluate whether contractors meet PG&E's minimum performance standards and have the necessary programs in place to manage compliance. A

variance to work for PG&E is required for contractors who do not meet the prequalification requirements. The variance process includes a review of the contractor's performance and improvement plans and the business need. The decision to award a variance requires Chief Executive Officer (CEO) approval, or CEO designee approval. PG&E is strengthening the requirements in the areas of fatalities and performance evaluation, including requiring a mitigation plan, and adding the requirement of a safety observation program.

– Enhanced Safety Contract Terms: PG&E Contract terms require that, following a serious public or worker safety incident, the contractor will conduct a cause evaluation, share the analysis with PG&E, and cooperate and assist with PG&E's cause evaluation analysis and corrective actions for the incident, and regulatory investigations and inquiries, including but not limited to Safety Enforcement Division's investigations and inquiries. Under the enhanced Safety Contract Terms, PG&E has the right to:
  1) Designate safety precautions in addition to those in use or proposed by the contractor;
  2) Stop work to ensure compliance with safe work practices and applicable federal, state and local laws, rules and regulations;
  3) Require the contractor to provide additional safeguards beyond what the contractor plans to utilize;
  4) Terminate the contractor for cause in the event of a serious incident or failure to comply with PG&E's safety precautions; and
  5) Review and approve criteria for work plans, which include safety plans.

- Contractor Job Safety Planning: Safety must be factored into every job plan from start to finish. Safety considerations include formal training, job site work controls, specialized equipment to reduce hazards, and personal protective equipment. Each of PG&E's Lines of Business have safety plan requirements unique to its operations. Prior to commencement of work, PG&E is required to review the adequacy of the safety plans, including contractor safety personnel qualifications where applicable, and perform a safety assessment to evaluate whether additional safety mitigations are required, including whether to assign PG&E onsite safety personnel. These reviews must be conducted by PG&E employees that are qualified to perform such work or PG&E engages third-party experts as appropriate to perform this safety analysis.

- Contractor Oversight: Work activities are governed by qualified PG&E oversight personnel to ensure work follows the PG&E reviewed and approved safety plan designed for the job. PG&E conducts field safety observations of the contractor. In 2021, approximately 97,000 contractor observations were conducted. High-risk findings are reviewed daily, and corrective actions are discussed. Collected by all observers (e.g., PG&E and contractors) is analyzed to support continuous improvement.
- Contractor Transportation Safety: In late 2021, the Motor Vehicle Safety team updated guidance for reviewing and classifying Contractor MVI SIF incidents for those who operate a vehicle when completing work for PG&E. In late 2021 and continuing into 2022, the Motor Vehicle Regulatory Team also hired a third-party expert to complete a systemwide review of the high and medium vendors in ISN who may operate trucks over 10,000 pounds Gross Vehicle Weight Rating, checking for a valid California motor carrier permit and USDOT number if required.
- Regionalization: See Chapter 1.1 of this report for the details of this activity.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 1.3

SAFETY AND OPERATIONAL METRICS REPORT:

SIF ACTUAL

(PUBLIC)

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1.3
INTRODUCTION

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1.3
INTRODUCTION

A. Overview

1. Metric Definition

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

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

2. Introduction of Metric

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

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

- First, the SOM requires a finding by an authority with jurisdiction (e.g., CAL FIRE, CPUC); and
- Second, that finding must determine that the Public SIF Actual was caused by incorrect operation, a malfunction, or failure to meet a Commission rule or standard.[1]

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

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

For the purposes of reporting, PG&E is including incidents where PG&E may have disputed the finding of an authority with jurisdiction that the Public SIF Actual was caused by incorrect operation, a malfunction, or failure to meet a commission rule or standard. For example, PG&E disputes that that the SIFs caused by the Kincade and Zogg Fires were caused by incorrect operation, a malfunction, or failure to meet a commission rule or standard, but is including the SIFs from those incidents in its reporting here because of CAL FIRE's determinations.

B. Metric Performance

1. Historical Data (2010-2021)

In this report, PG&E is providing 12 years of historical data from 2010-2021. The data include a description of the incident, type of injury, and the authority with jurisdiction that has determined that incorrect operations, malfunction, or failure to meet a standard was the cause of the injury. As mentioned above, the data collection and internal reporting

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

processes for public safety serious incidents were improved in 2012. Historical data for the Public SIF Actual metric are based on this timeframe and also include available data for the years of 2010 and 2011.

Since the metric definition requires a finding from an authority having jurisdiction, Public SIF Actual incidents in prior years may not appear in the historical data. PG&E will update the historical data in future SOMs Reports as appropriate and identify changes based on new information. See PG&E's "Safety and Operational Metrics Report: Supporting Documentation" for a detailed list of incidents.

2. Data Collection Methodology

PG&E's Public SIF Actual incident data largely come from the Enterprise Health and Safety Serious Incidents Reports, which includes a compilation of Law Department claims from PG&E's Riskmaster database, Electric Incident Reports, and other reportable incidents such as PG&E Federal Energy Regulatory Commission (FERC) license compliance reports. For the SOMs Report, the incidents included in the Public SIF Actual metric must be determined by an authority having jurisdiction to have resulted directly from: (1) incorrect operation of equipment, failure or malfunction of utility-owned equipment, or from (2) the failure to comply with any Commission rule or standard. PG&E interprets jurisdictional authorities to be those with enforcement authority, such as CAL FIRE, the CPUC, PG&E, or National Transportation Safety Board (NTSB).

3. Metric Performance

The graphs included in Figure 1.3-1 and Figure 1.3-2 below show the total number of incidents and the total number of serious injuries or fatalities for each identified incident. From 2010 through 2021, there were a total of 19 confirmed incidents where Public SIF Actuals occurred (Figure 1.3-1), which resulted in a total of 165 public SIFs (Figure 1.3-2). Eight incidents where Public SIF Actuals occurred are pending further investigation into the incident cause and a SOM determination.

FIGURE 1.3-1
NUMBER OF INCIDENTS WITH PUBLIC SIF ACTUALS 2010-2021
CONFIRMED AND PENDING INVESTIGATION

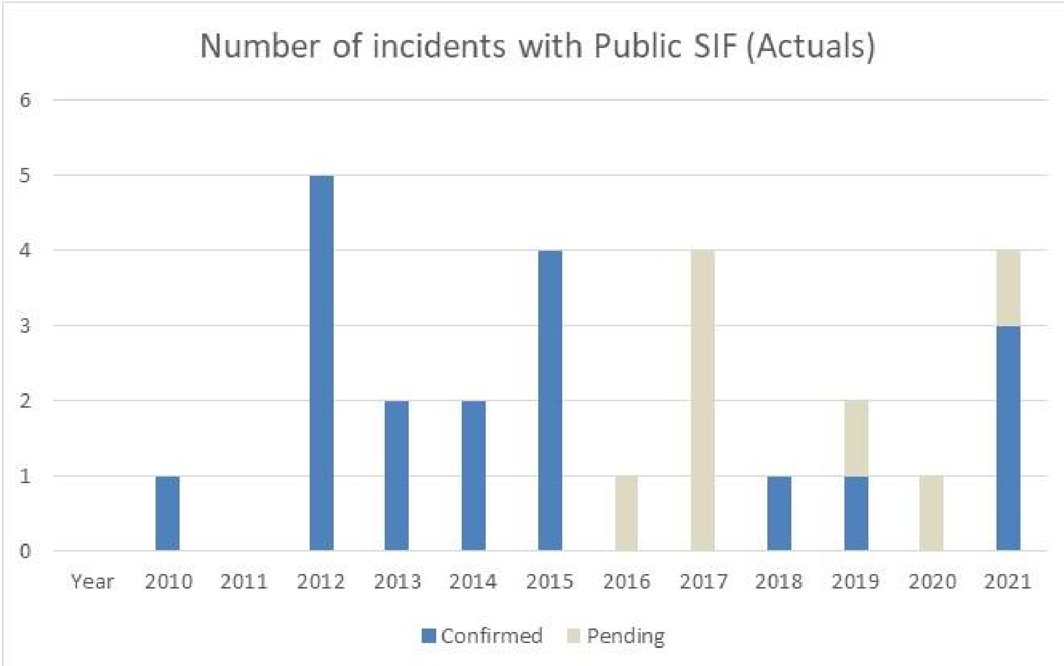
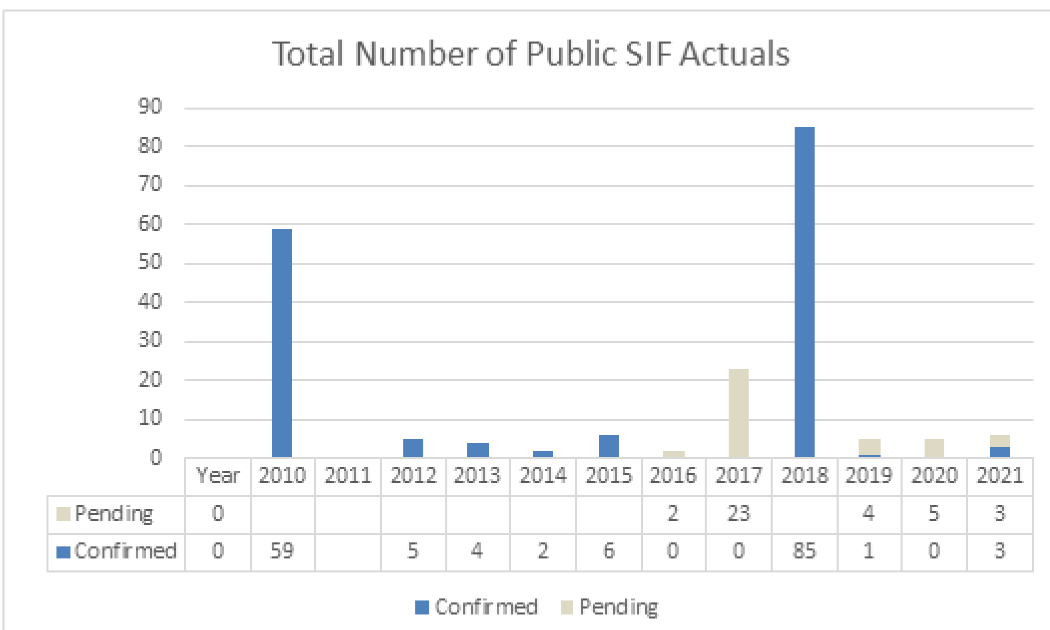


FIGURE 1.3-2
NUMBER OF PUBLIC SIF ACTUALS 2010-2021
CONFIRMED AND PENDING INVESTIGATION



	Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Pending	0							2	23		4	5	3
Confirmed	0	59		5	4	2	6	0	0	85	1	0	3

In 2021, there were three Public SIF Actual incidents that resulted in two fatalities and one serious injury as a result of an incorrect operation of equipment, failure or malfunction of utility-owned equipment, or failure to comply with any Commission rule or standard, as determined by an authority having jurisdiction. Two were the result of the failure of utility-owned equipment (wires down), and the third was the result of a contractor motor vehicle non-compliance. There is one incident (three injuries) pending investigation related to the Dixie fire.

TABLE 1.3-1
2021 PUBLIC SIF ACTUAL INCIDENTS

Line No.	Incident Date	Description	SIF
1	1/25/2021	Third-party contact with energized line (wires down) resulted in fatality.	1
2	6/5/2021	Unknown third party struck by Contractor employee resulting in fatality (motor vehicle safety violation).	1
3	9/30/2021	Third party contact with energized line (wires down) resulted in serious injury.	1

In 2022, PG&E is continuing to evaluate its Public Safety programs as discussed in the 2020 RAMP Report Third-Party Safety Incident Risk chapter and also in other chapters, and through further maturing its public SIF investigation process, including the advancement of Public SIF Actual metric definition requirements and learnings.

C. 1-Year Target and 5-Year Target

1. Target Methodology

In D.21-11-009, the Commission clarified that PG&E may propose "directional targets (i.e., that do not consist of numerical values) for the adopted SIF Actual (Public) SOM" and that the Safety metrics are "best used to monitor trends, not as a basis to initiate enforcement actions."

With our stand of Everyone and Everything is Always Safe, our goal is the elimination of Public SIF Actual incidents resulting directly from incorrect operation of PG&E equipment, failure or malfunction of PG&E-owned equipment, or from PG&E's failure to comply with any Commission rule or standard.

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

- Historical data and trends: From 2010 through 2021, there were a total of 19 confirmed incidents where Public SIF Actuals occurred (Figure 1.3-1), which resulted in a total of 165 public SIFs (Figure 1.3-2). Eight incidents where Public SIF Actuals occurred are pending further investigation into the incident cause and a SOM determination. Historical data will inform PG&E's plans and actions to achieve its goal of zero public safety incidents;
- Benchmarking: Not available. This is a new metric definition;
- Regulatory requirements: CPUC, FERC, and DOT, public safety reporting requirements;
- Attainable within known resources/work plan: Yes. PG&E's work and resource plan prioritizes public safety risk reduction. This includes minimizing the risk of catastrophic wildfires in alignment with the continued execution of the Wildfire Mitigation Plan (WMP) and maturation of key wildfire mitigation strategies. It also includes mitigation of other public safety risks related to the elimination of serious injuries and fatalities (zero Public SIF Actual incidents);
- Appropriate/Sustainable Indicators for Enhanced Oversight Enforcement: A goal of zero Public SIF Actuals, in 2022 (1 year) and on an ongoing basis into 2026 (5 year) reflects PG&E's intent to immediately and continuously operate without creating risk to the public; and
- Other Considerations: PG&E's approach is aligned to and anchored on PG&E's goal and commitment to "always" safe operations.

2. 2022 Target

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

3. 2026 Target

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

D. Current and Planned Work Activities

Many of the current and planned activities to eliminate public safety incidents are addressed by meeting key operations risks, which are discussed in other SOMs. The list here touches upon some of the key risk drivers and mitigation activities in place and references the specific SOMS chapters:

- Gas Distribution Public Safety Enhancements: We have made significant progress on the safety and reliability programs for our extensive gas storage, transmission, and distribution systems. The programs are designed to enhance public and coworker safety and the reliability of our natural gas system. Continued distribution system enhancements to public safety programs are forecasted through 2026 and include ongoing vintage gas pipeline replacement, corrosion detection and mitigation, leak surveys and repair, and locate and mark services so customers and workers will know where they can safely dig.
- Gas Transmission and Storage (GT&S) Safety Improvements: PG&E plans to increase the safety of our GT&S assets with increased in-line inspections, direct assessments, strength tests, over pressure protection, and gas storage well reworks and retrofits. Many of these programs are required by recent state and federal regulations designed to ensure that natural gas companies provide safe and reliable service to their customers. In addition to our own programs, federal and state regulations impacting natural gas infrastructure, including pipelines and storage facilities, continue to evolve and add new requirements for our operations.
- Gas Operations (GO) Public Awareness and Education Programs: GO public awareness programs reduce the threat of third-party damage to pipelines through educational outreach regarding safe excavation near pipelines. PG&E's gas safety communication efforts use a variety of media to effectively reach the greatest population possible within PG&E's service

territory. These efforts include sending bill inserts, e-mails, brochures or letters to communicate gas safety information, providing targeted agricultural excavation safety messaging, and hosting 811 "Call Before You Dig" workshops.

- GO Patrols: GO patrols help to identify third-party threats from construction and excavation activities.
- GO System Remediation: GO system remediation includes the retirement of gas gathering facilities, including idle pressurized pipe, and the replacement and remediation of exposed and shallow pipe to further reduce the likelihood of third-party contact.

For additional information regarding current and planned work activities for reducing the risk of gas transmission and distribution system equipment failure or malfunction, please see Chapters 4.1 through 4.7 of this report.

- Electric Operations (EO) manhole cover replacement: Programs that address asset-related safety risk also include continuing to replace manhole covers in areas of high pedestrian foot traffic with hinged venting manhole covers designed to stay in place in the event of a vault explosion.
- Electric Asset Inspections Improvements: The continuous improvement of detailed asset inspections to enable proactive identification of any potential equipment issues that may lead to failures.
- EO Public Awareness Programs: EO Public awareness programs to educate non-PG&E contractors and the public about power line safety and the hazards associated with wire down events and are intended to reduce the number of third-party electrical contacts. Outreach efforts include social media campaigns focused on increasing customer awareness of overhead lines, representation at local fire safe councils and community events and the automated customer notification system. Security improvements can include proactive equipment replacement, security measures and intrusion detection devices.

For additional information regarding current and planned work activities for reducing the risk of electric transmission and distribution system equipment failure or malfunction please see Chapters 2.1 through 2.4, Chapters 3.1 through 3.9, and Chapters 3.11 through 3.16 of this report. In addition, PG&E's

2022 Wildfire Mitigation Plan[2] also includes information regarding grid system hardening and enhancements to reduce the risk of wildfire.

- Power Generations Hydroelectric Programs: Hydroelectric programs include procedures for planning for unusual water releases, along with their associated safety warnings.
- Power Generation Compliance Programs: Public Safety Plans are published and routinely updated as required by PG&E hydroelectric facility FERC licenses. FERC required Emergency Action Plans exist for all significant and high hazards dams. The Plans are exercised annually with a seminar and phone drill.
- Hydro Facility Unusual Water Releases and Water Safety Warning Standard and accompanying procedure: Hydroelectric facility Unusual Water Releases and Water Safety Warning documentation establishes Hydro facility requirements for planning and making unusual water releases or high flow events and their associated safety warnings.
- PG&E Dam Safety Surveillance and Monitoring Program: This program establishes and defines PG&E's Dam Safety Surveillance and Monitoring Program for the continued long-term safe and reliable operation of PG&E's dams. Dam surveillance involves the collection of data by various means, including inspections and instrumentation, whereas monitoring involves the review of the collected data as obtained and over time for any adverse trends.
- Canals and Waterways Safety: From 2014 through 2021, Power Generation had installed approximately 150,000 linear feet of barrier fencing along PG&E's canal systems. Power Generation has also created and distributed safety information to property owners with canals that bisect their property. A canal entry emergency response plan has been published to guide efficient and timely communications between PG&E personnel and local first responders when responding to emergencies resulting from public entry into PG&E-owned water conveyance systems.
- Transportation Safety: PG&E Transportation Safety programs protect our employees and the public by establishing requirements and processes to

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2 PG&E's 2022 Wildfire Mitigation Plan.

control risks that can lead to motor vehicle accidents, improve safety performance, and increase awareness of all PG&E employees related to the operation of motor vehicles. This comprehensive program was established to reduce the number of motor vehicle incidents that have the potential for serious injury, including fatal injury, to PG&E's employees, staff augmentation employees operating vehicles on Company business, and the public. Driver performance data is used to identify specific risk drivers for targeted intervention, including driver training and implementing vehicle safety technology.

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

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

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2.1

SAFETY AND OPERATIONAL METRICS REPORT:

SYSTEM AVERAGE INTERRUPTION

DURATION INDEX (SAIDI)

(UNPLANNED)

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2.1
INTRODUCTION

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2.1
INTRODUCTION

A. Overview

1. Metric Definition

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

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

2. Introduction of Metric

The measurement of SAIDI unplanned represents the amount of time the average Pacific Gas and Electric Company (PG&E) customer experiences a sustained outage or outages, defined as being without power for more than five minutes, each year. The SAIDI measurement does not include planned outages, which occur when PG&E deactivates power to safely perform system work. This metric is associated with risk of Asset Failure, which is associated with both utility reliability and safety. The metric measures outages due to all causes including impacts of various external factors, but excludes MED. It is an important industry-standard measure of reliability performance as it is a direct measure of a customer's electric reliability experience.

B. Metric Performance

1. Historical Data (2013-2021)

PG&E has measured unplanned SAIDI for over 20 years, however this report uses 2013-2021 unplanned SAIDI values for target analysis to align with the same timeframe used for the wire down SOMs metrics. 2013 was the first full year PG&E uniformly began measuring wire down events.

The Cornerstone program investments in 2013 involved both capacity and reliability projects, and PG&E experienced its best reliability performance in 2015.

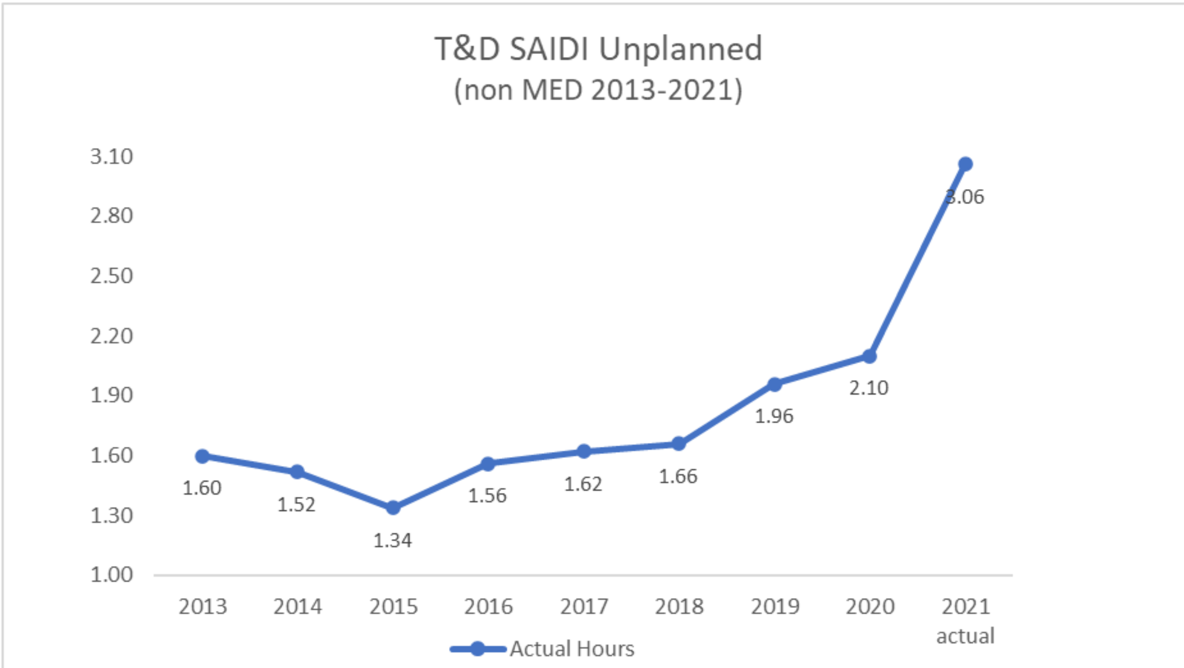
Much of the 2017-2020 reliability investment was on Fault Location Isolation and Restoration (FLISR), which automatically isolates faulted line sections and then restores all other non-faulted sections in less than five minutes typically in urban/suburban areas. Of note, FLISR does not prevent customer interruptions but rather reduces the number of customers that experience a sustained outage.

The targeted circuit program, distribution line fuse replacement, and installing reclosers in the worst performing areas are the initiatives that have had the biggest impact in improving system reliability at the lowest cost.

Other factors that contribute to reliability improvement include (but not limited to) reliability project investments and project execution, favorable weather conditions, outage response and repair times, asset lifecycle and health, vegetation management (VM) and switching device locations and function (including disablement of reclosers to mitigate fire risk).

Reliability performance has consistently degraded since 2017 as PG&E's focus pivoted to wildfire risk prevention and mitigation, with a 45 percent unplanned SAIDI increase occurring in 2021 from 2020.

FIGURE 2.1-1
TRANSMISSION AND DISTRIBUTION HISTORICAL UNPLANNED SAIDI PERFORMANCE
(2013-2021 NON-MED ONLY)



2. Data Collection Methodology

PG&E uses its outage database, typically referred to as its Integrated Logging Information System (ILIS) – Operations Database and its Customer Care and Billing database to obtain the customer count information to calculate these metric results. It should also be noted that PG&E's outage database includes distribution transformer level and above outages that impact both metered customers and a smaller number of unmetered customers. Outage information is entered into ILIS by distribution operators based on information from field personnel and devices such as Supervisory Control and Data Acquisition alarms and SmartMeters™. PG&E last upgraded its outage reporting tools in 2015 and integrated SmartMeter information to identify potential outage reporting errors and to initiate a subsequent review and correction.

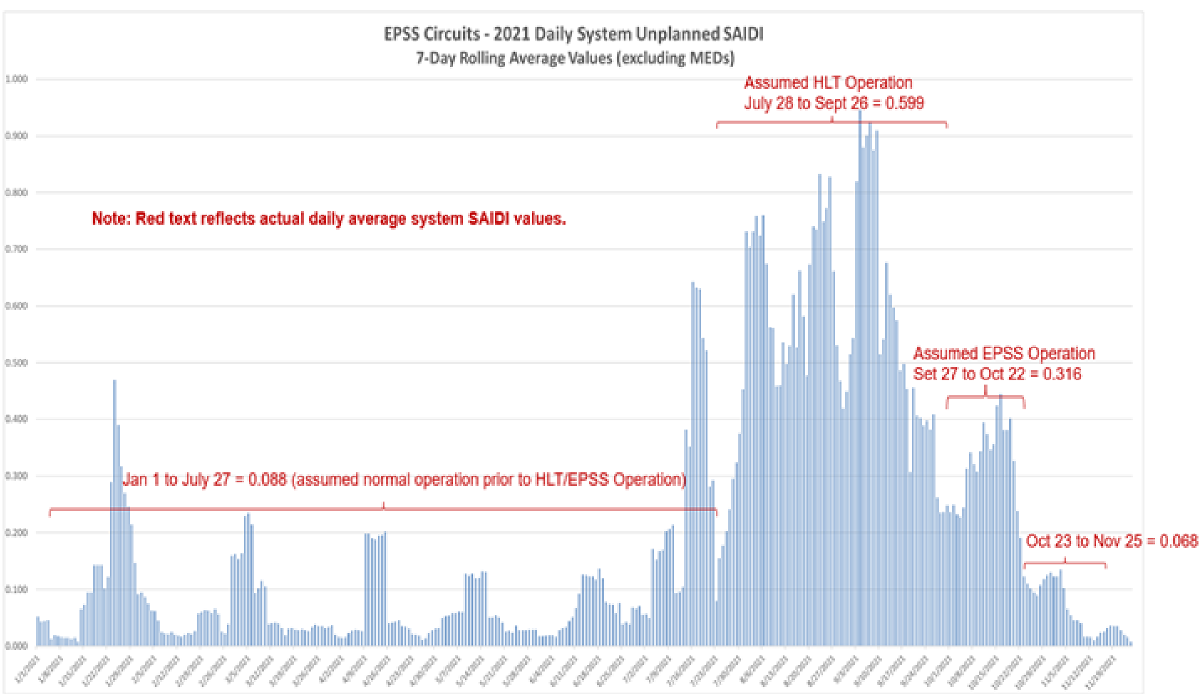
PG&E uses the Institute of Electrical and Electronics Engineers (IEEE) 1366 Standard titled IEEE Guide for Electric Power Distribution Reliability Indices to define and apply excludable MED to measure the performance of its electric system under normally expected operating conditions. Its purpose is to allow major events to be analyzed apart from daily operation and avoid allowing daily trends to be hidden by the large statistical effect of major events. Per the Standard, the MED classification is calculated from the natural log of the daily SAIDI values over the past five years. The SAIDI index is used as the basis since it leads to consistent results and is a good indicator of operational and design stress.

3. Metric Performance

In 2021, the unplanned SAIDI metric performance was 3.05 hours, which is approximately 45 percent higher than the 2020 result of 2.10 hours. This was largely due to the following factors:

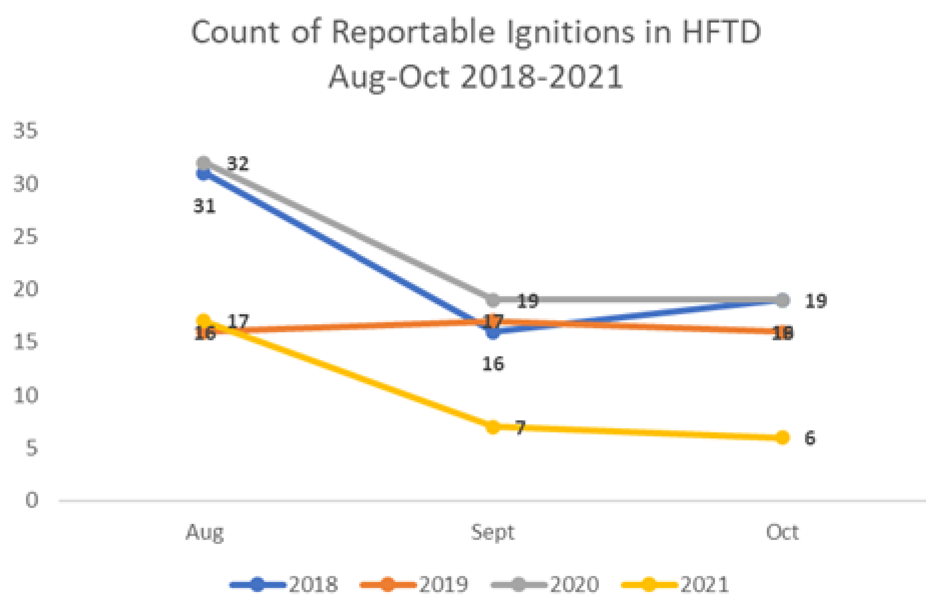
- To reduce ignition risk, PG&E implemented the Enhanced Powerline Safety Shutoff (EPSS) program in July 2021. This program enabled higher sensitivity settings on targeted circuits in High Fire Threat Districts (HFTD) to deenergize when tripped. As illustrated below, unplanned SAIDI performance was significantly impacted during the period these settings were activated (July 28-October 22, 2021).

FIGURE 2.1-2
2021 DAILY TRANSMISSION AND DISTRIBUTION SAIDI EPSS CIRCUIT PERFORMANCE



- In 2021, PG&E observed a 46 percent reduction in ignitions across HFTD compared to 3-year averages during the time that EPSS was enabled in limited locations from July 28-October 20.

FIGURE 2.1-3
2018-2021 COUNT OF CPUC-REPORTABLE TRANSMISSION AND DISTRIBUTION IGNITIONS AUG-OCT



- In addition to EPSS, the unplanned SAIDI metric has been impacted as PG&E shifted away from traditional system reliability improvement work and toward other wildfire risk reduction efforts, with reclose disablement beginning in 2018. As such, 2021 performance is not directly comparable to prior years as the operating conditions have changed significantly and resulted in large year-over-year changes.

C. 1-Year Target and 5-Year Target

1. Target Methodology

For 1-year and 5-year targets, PG&E is proposing a range for the SAIDI unplanned metric of 5.67 hours-6.80 hours, primarily due to the vast expansion of the EPSS Program in 2022 to reduce wildfire risk and the increase to PG&E's MED threshold.

- EPSS settings will be added to an additional 848 circuits in 2022 (compared to 170 in 2021) for a total of 1,018 [1] circuits.
- Settings to be deployed for the entire anticipated fire season (June through November), whereas in 2021 EPSS settings were active July 28 through October 22.
- The MED threshold has increased from a daily SAIDI value of 3.50 minutes in 2021 to 5.04 minutes in 2022. This new threshold would have equated to 7 more MED exclusions in 2022 (these days having occurred in the range of 3.50 minutes and 5.04 minutes, which exceeded last year's threshold but would not exceed this year's).

The following factors were also considered in establishing targets:

- Historical Data and Trends: As 2021 was the first year of EPSS deployment and given the expansion of the program in 2022, there is no historical data to help guide in target setting. PG&E has undertaken an effort to re-baseline 2021 results to the 2022 anticipated EPSS/MED threshold environment and illustrates an informational datapoint for future performance and target setting (the unplanned portion of the measure marked in red, note these SAIDI times are in minutes):

[1] As of March 10, 2022, the 2022 scope for EPSS has increased to 1,018 enabled circuits. Further changes may occur as the program is implemented throughout 2022.

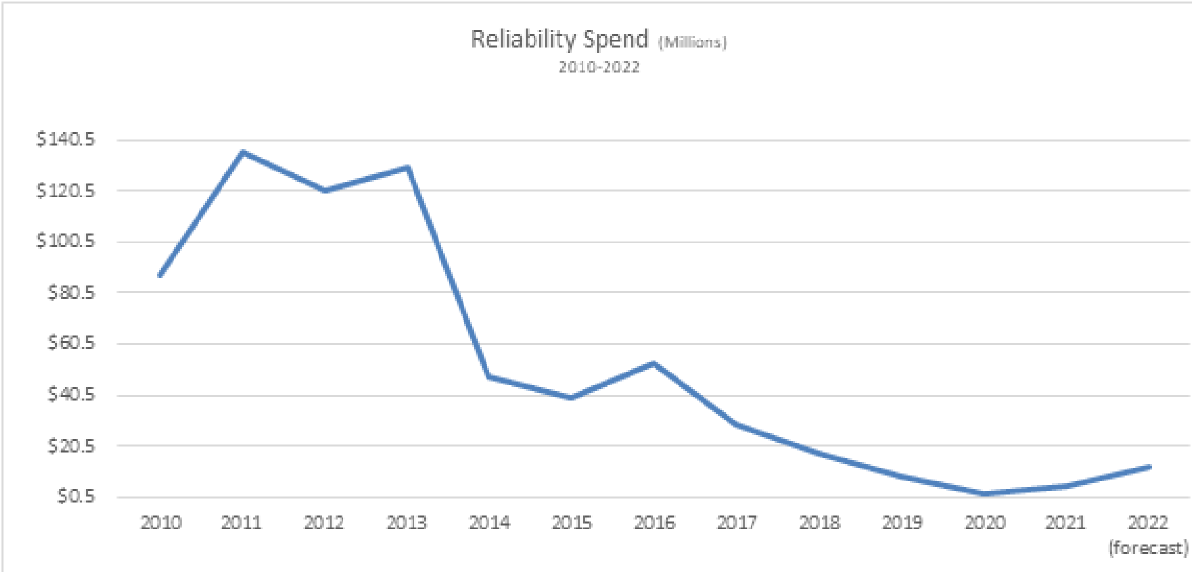
TABLE 2.1-1
SAIDI AND SAIFI ADJUSTED 2021 PERFORMANCE

	T&D - Unplanned & Planned Outages		T&D - Unplanned Outages		T&D - Planned Outages	
	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI
2021 EOY Results	218.7	1.320	183.3	1.180	35.4	0.140
Adjustment For Increased T_{MED} Threshold (2)	31.0	0.049	29.3	0.049	1.7	0.0003
Non EPSS Trendline adjustments (6)	14.4	0.049	6.3	0.029	8.1	0.021
Adjustment for current EPSS Ckts (3) (previsously HLT operated in 2021)	-14.3	-0.053	-14.3	-0.053	0.0	0.000
2021 EPSS Circuit Adjustment #1 (4)	28.1	0.101	28.1	0.101	0.0	0.000
EPSS Adjustment #2 for new EPSS circuits planned for 2022 (5)	118.7	0.428	118.7	0.428	0.0	0.000
Adjusted 2021 EOY Forecast (7)	**396.5**	**1.895**	**351.3**	**1.734**	**45.2**	**0.161**

Notes:
Red text indicates the recent updates from the previsous December estimates.
(1) **EOY 2021 actual values as of January 22, 2022.**
(2) Assumes 7 additional non-MEDs (daily SAIDI values between 3.5 and 5.0 based on the actual 2021 MEDs of Jan 25, July 18, July 22, August 1, August 12, December 25, and December 28).
(3) **HLT to EPSS Adjustment** - This adjustment replaces the temporary HLT operation values with an equivalent EPSS performance value.
Based on the actual daily outage rates of 161 circuits (days operated as HLT vs days operated as EPSS)
(4) **EPSS Adjustment #1**
Adjustment for full 172 days of EPSS (161 circuits implemented in 2021 and 6 to be implemented in 2022).
(5) **EPSS Adjustment #2**
Assumes 827 new circuits planned for 2022 EPSS (6 carry-over from 2021, 615 HFRA & HFTD, 27 HRFA, 23 HFTD) assumed to be operated from June to November and 156 Tier 1 Buffer circuits assumed to be operated for 30 days. Each group is forecasted based on its respective average number of EPSS devices per circuit and relative to the EPSS impacts measured in 2021.
(6) **Non-EPSS Related Trendline Adjustments** - These adjustments are based on the trendlines of the past five years for; (a) all unplanned non-EPSS outages and (b) all planned outages. The prior 3.0 planned outage adjustment was updated 12/16/21 to reflect the increase in work volume (+3.3) and to account for the estimated decrease in Hot work due in the HFTD areas (+1.8).
(7) **Adjusted 2021 EOY Forecast** - This forecast reflects the estimated 2021 SAIDI value if the electric T&D system is operated as that planned for 2022 (without improvement initiaves).

- Benchmarking: At this time, targets are set based on operational and risk factors, although current performance is acknowledged as an indicator of PG&E's opportunity to improve for our customers over the long-run as risk reduction allows;
- Regulatory Requirements: None;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: The target range for this metric is suitable for EOE as it accounts for our current work plan and the unknowns of EPSS;
- Attainable With Known Resources/Work Plan: Based on 2021 results and 2022 work plan, PG&E expects performance to fall within proposed target range. The bottom portion of PG&E's proposed SOMs target (5.67 hours) reflects a 3 percent improvement from our adjusted 2021 result (5.86 hours), ~11 minutes:
  - PG&E's top work plan and resource priority of minimizing the risk of catastrophic wildfires is the driving factor of reliability performance. This risk prioritized work plan does not support an improvement of the unplanned SAIDI metric;

FIGURE 2.1-4
HISTORICAL RELIABILITY SPEND (2010-2022)



- The GRC in 2017-20 allocated budget for reliability, but the work was re-prioritized to focus on wildfire mitigation, compliance, pole replacement and tags;
- The most significant driver of reliability performance is Equipment Failure, specifically Overhead (OH) Conductor;
- Current replacement rates from 2017-2021 have been on average 32 miles/year. This is significantly below the OH Conductor Asset Management Plan, which cites third-party recommendations for replacement rates at approximately 1200 miles per year to sustain 2016 levels of reliability performance;
- Current investment profile in the GRC for OH Conductor is ~70 miles/year. Alternative funding scenarios or internal prioritization would be needed to increase replacement miles per year;
- Conductor replacement under the System Hardening program for wildfire risk reduction is forecasted through the GRC period, but provides limited additional benefit, at approximately 1 percent (due to rural HFTD geography in which this work takes place);
- Current allocated 2022 GRC spending amount for targeted Reliability improvements (MAT code 49x) is $9 million, which

equates to an approximate unplanned SAIDI reduction of 0.72 minutes;

- Prior to the implementation of EPSS in July 2021, current levels of investment and assuming the GRC forecast through 2026, SAIDI/System Average Interruption Frequency Index (SAIFI) performance was expected to remain flat and sustained improvement trending not expected until 2023. However, with the EPSS implementation, performance fell.

- Other Considerations: PG&E expanded their 2022 EPSS Program (as described earlier in this chapter) and began enablement on high-risk circuits in January-representing and expanded fire season duration—all of which significantly impact expected SAIDI and SAIFI performance and targets.

2. 2022 Target

Range: 5.67 hours-6.80 hours.

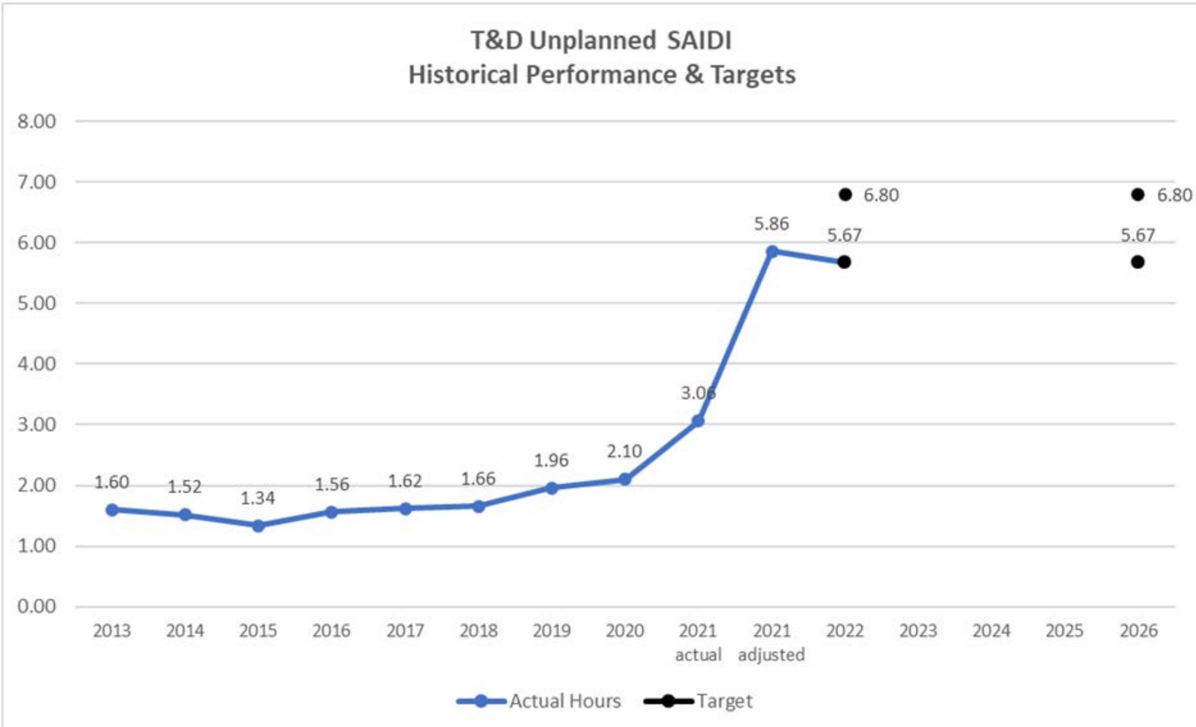
The 2022 target reflects a range of a 3 percent improvement to a 20 percent increased unplanned SAIDI performance from 2021 adjusted result (5.86 hours) to account for the factors listed above.

3. 2026 Target

Range: 5.67 hours-6.80 hours.

Given the uncertainty of the EPSS environments, 2026 target range mirrors 2022 and will be adjusted once the 2022 impacts are actualized and further data is available to leverage for updating the target strategy.

FIGURE 2.1-4
TRANSMISSION AND DISTRIBUTION UNPLANNED SAIDI HISTORICAL PERFORMANCE AND TARGETS



D. Current and Planned Work Activities

Existing Programs that could improve Reliability Metric Performance and historical trend data for SAIDI are listed below. Further work to quantify exact benefits is being undertaken in Q1 in 2022:

- <u>Enhanced Vegetation Management (EVM)</u>: Program is targeted at OH distribution lines in Tier 2 and 3 HFTD areas and supplements PG&Es annual routine VM work with CPUC mandated clearances. PG&E's VM program, components of which exceed regulatory requirements, is critical to mitigating wildfire risk. Our VM team inspects and identifies needed vegetation maintenance on all distribution and transmission circuit miles in PG&E's service area on a recurring cycle through Routine and Tree Mortality Patrols, as well as Pole Clearing. Our EVM program goes above and beyond regulatory requirements for distribution lines by expanding minimum clearances and removing overhang in HFTD areas. In 2022 PG&E will complete 1800 miles of EVM work.

  Please see Section 7.3.5, Vegetation Management and Inspections in PG&E's WMP for additional details on 2022.

- Asset Replacement (Overhead/Underground): Overhead asset replacement addresses deteriorated overhead conductor and switches, while underground asset replacement primarily focuses on replacing underground cable and switches.

  Please see Chapter 11 Overhead and Underground Distribution Maintenance in the 2023 GRC for additional details.
- Grid Design and System Hardening: PG&E's broader grid design program covers a number of significant programs, called out in detail in PG&E's 2022 WMP. The largest of these programs is the System Hardening Program which focuses on the mitigation of potential catastrophic wildfire risk caused by distribution overhead assets. In 2022, we are rapidly expanding our system hardening efforts by: completing 470 circuit miles of system hardening work which includes overhead system hardening, undergrounding and removal of overhead lines in HFTD or buffer zone areas; completing at least 175 circuit miles of undergrounding work, including Butte County Rebuild efforts and other distribution system hardening work; replacing equipment in HFTD areas that creates ignition risks, such as non-exempt fuses (3,000) and surge arresters (~4,500, all known, remaining in HFTD areas). As we look beyond 2022, PG&E is targeting 3600 miles of Undergrounding to be completed between 2023 and 2026 as part of the 10,000 Mile Undergrounding program. This system hardening work done at scale is expected to have limited reliability benefit due rural HFTD geography, and is prioritized to mitigate wildfire risk rather than reliability risk at this time,

  Please see Section 7.3.3, Grid Design and System Hardening Mitigations in PG&E's WMP for additional details on 2022.
- Animal Abatement: The installation of new equipment or retrofitting of existing equipment with protection measures intended to reduce animal contacts. This includes avian protection on distribution and transmission poles such as jumper covers, perch guards, or perching platforms

  Please see Chapter 11 Overhead and Underground Distribution Maintenance in the 2023 GRC for additional details.
- Overhead/Underground Critical Operating Equipment (COE) Replacement Work: The Overhead COE Program is comprised of corrective maintenance

of certain defined equipment—including Protective Devices (Reclosers, Cutouts, Sectionalizers), Voltage Devices (Regulators, Boosters), Switches (Switches, Disconnects), Capacitors, and Conductors—that plays an important role in preventing customer interruptions and is critical for restoring power after an outage.

The Underground COE Program is comprised of corrective maintenance of certain defined equipment—including Protective Devices (Reclosers, Interrupters, Sectionalizers), Voltage Devices (Regulators, Stepdowns/Autobanks), Switches (Switches, Auto-Transfer Switches), Capacitors, and Cable (Mainline (only), Loop (UG only))

Please see Chapter 11 Overhead and Underground Distribution Maintenance in the 2023 GRC for additional details.

TABLE 2.1-2
TRANSMISSION AND DISTRIBUTION SAIDI UNPLANNED PERFORMANCE DRIVER SUMMARY

SAIDI SUMMARY	2016	2017	2018	2019	2020	2021	5-Yr Ave	%
SYSTEM	93.9	97.5	99.6	117.6	125.8	183.3	106.9	-72%
3rd Party	18.9	16.5	20.6	22.9	26.4	29.0	21.1	-38%
Animal	3.8	4.2	6.5	6.2	7.0	10.5	5.5	-90%
Company Initiated	1.1	1.5	1.2	2.1	2.7	4.0	1.7	-133%
Environmental	1.7	3.0	3.7	2.7	4.0	8.8	3.0	-191%
Equipment Failure	43.2	45.9	43.2	48.0	54.8	73.6	47.0	-57%
Unknown Cause	7.6	7.7	9.8	12.9	14.4	33.1	10.5	-216%
Vegetation	17.3	18.8	14.5	22.4	15.4	23.8	17.7	-35%
Wildfire Mitigation	0.0	0.0	0.0	0.4	1.0	0.4	0.3	-43%

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2.2

SAFETY AND OPERATIONAL METRICS REPORT:

SYSTEM AVERAGE INTERRUPTION FREQUENCY (SAIFI)

(UNPLANNED)

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2.2
INTRODUCTION

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2.2
INTRODUCTION

A. Overview

1. Metric Definition

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

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

2. Introduction of Metric

The measurement of SAIFI unplanned represents the number of instances the average Pacific Gas and Electric Company (PG&E) customer experiences a sustained outage or outages, defined as being without power for more than five minutes,) each year. The SAIFI measurement does not include planned outages, which occur when PG&E deactivates power to safely perform system work. This metric is associated with the risk of Asset Failure, which is associated with both utility reliability and safety. The metric measures outages of all causes but excludes MEDs. It is an important industry-standard measure of reliability performance as it is a direct measure of the frequency of outages customers experience.

B. Metric Performance

1. Historical Data (2013-2021)

PG&E has measured unplanned SAIFI for over 20 years, however this report uses 2013 to 2021 unplanned SAIFI values for target analysis to align with the same timeframe used for the wire down SOMs metrics. 2013 was the first full year PG&E uniformly began measuring wire down events.

The Cornerstone program investments in 2013 involved both capacity and reliability projects, and PG&E experienced its best reliability performance in 2015.

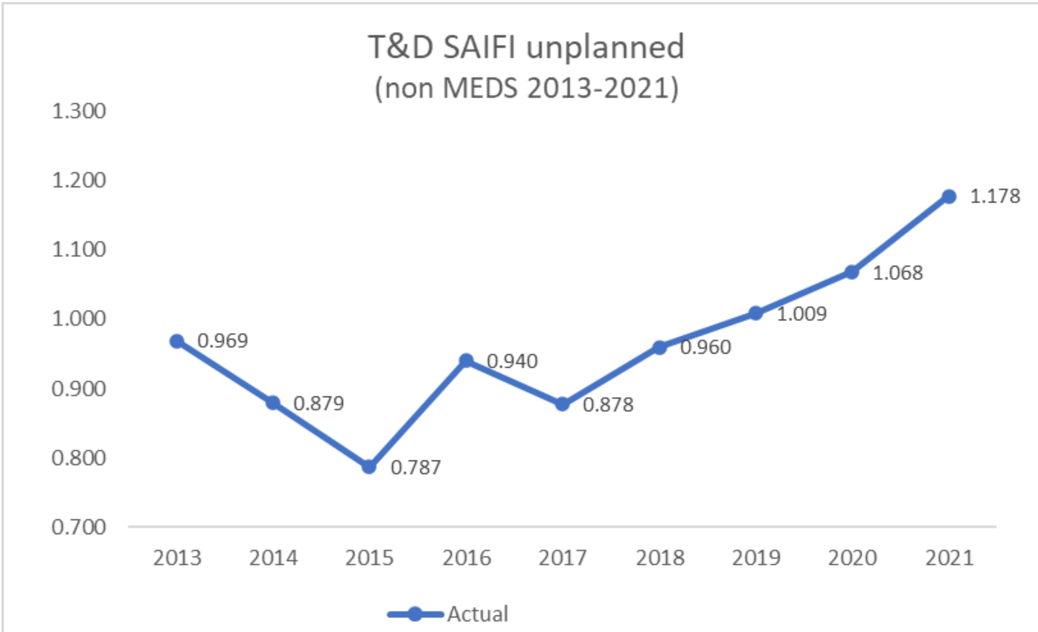
Most of the 2017-20 reliability investment was on Fault Location Isolation and Service Restoration (FLISR), which automatically isolates faulted line sections and then restores all other non-faulted sections in less than five minutes) typically in urban/suburban areas. Of note, FLISR does not prevent customer interruptions but rather reduces the number of customers that experience a sustained (greater than five minutes) outage.

The targeted circuit program, distribution line fuse replacements and installing reclosers in the worst performing areas are initiatives that have had the biggest impact in improving system reliability at the lowest cost.

Other factors that contribute to reliability improvement include (but not limited to) reliability project investments and project execution, favorable weather conditions, outage response and repair time, vegetation management (VM), asset lifecycle and health, and switching device locations and function (including disablement of reclosers to mitigate fire risk).

Reliability performance has consistently degraded since 2017 as PG&E’s focus pivoted to wildfire risk prevention and mitigation, with a 10 percent unplanned SAIFI increase occurring in 2021 from 2020.

FIGURE 2.2-1
TRANSMISSION AND DISTRIBUTION
SAIFI UNPLANNED HISTORICAL DATA
(2013-2021 NON-MEDS ONLY)



2. Data Collection Methodology

PG&E uses its outage database, typically referred to as its Integrated Logging Information System (ILIS) – Operations Database and its Customer Care & Billing database to obtain the customer count information to calculate these metric results. It should also be noted that PG&E's outage database includes distribution transformer level and above outages that impact both metered customers and a smaller number of unmetered customers. Outage information is entered into ILIS by distribution operators based on information from field personnel and devices such as Supervisory Control and Data Acquisition alarms and Smart meters. PG&E last upgraded its outage reporting tools in 2015 and integrated Smart meter information to identify potential outage reporting errors and to initiate a subsequent review and correction.

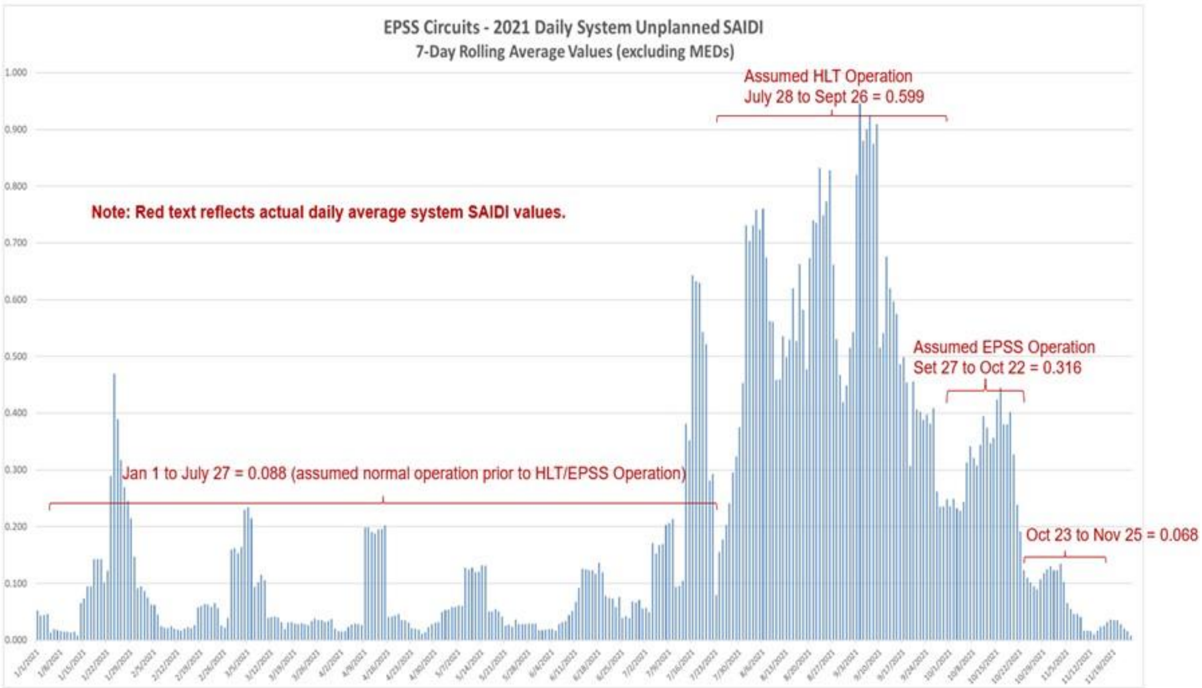
PG&E uses the Institute of Electrical and Electronics Engineers (IEEE) 1366 Standard titled IEEE Guide for Electric Power Distribution Reliability Indices to define and apply excludable MEDs to measure the performance of its electric system under normally expected operating conditions. Its purpose is to allow major events to be analyzed apart from daily operation and avoid allowing daily trends to be hidden by the large statistical effect of major events. Per the Standard, the MED classification is calculated from the natural log of the daily System Average Interruption Duration Index (SAIDI) values over the past five years by reliability specialists. The SAIDI index is used as the basis since it leads to consistent results and is a good indicator of operational and design stress.

3. Metric Performance

In 2021, the unplanned SAIFI metric performance was 1.178, which is approximately 10 percent higher than the 2020 result of 1.068. This was largely due to the following factors:

- To reduce ignition risk, PG&E implemented the Enhanced Powerline Safety Shutoff (EPSS) program in July 2021. This program enabled higher sensitivity settings on targeted circuits in High Fire Threat Districts (HFTD) to deenergize when tripped. As illustrated below by SAIDI unplanned 2021 performance, all reliability measures were significantly impacted during the period these settings were activated (July 28-October 22, 2021).
- In 2021, PG&E observed a 46 percent reduction in ignitions across HFTD, compared to 3-year averages during the time that EPSS was enabled in limited locations from July 28-October 20. In addition to EPSS, the unplanned SAIFI metric has been impacted as PG&E shifted away from traditional system reliability improvement work and more toward other wildfire risk reduction efforts, starting with recloser disablement in 2018. As such 2021 performance is not directly comparable to prior years as the operating conditions have changed significantly and resulted in large year-over-year changes.

FIGURE 2.2-2
2021 DAILY TRANSMISSION AND DISTRIBUTION
SAIDI UNPLANNED PERFORMANCE: EPSS CIRCUITS



C. 1-Year Target and 5-Year Target

1. Target Methodology

- For 1-year and 5-year targets, PG&E is proposing a range for the SAIFI unplanned metric of 1.681 to 2.017; primarily due to the vast expansion of the EPSS Program in 2022 and increase to MED threshold (and the unknowns that brings to the environment):
  - EPSS settings will be added to an additional 848 circuits in 2022 (compared to 170 in 2021) for a total of 1,018[1] circuits;
  - Settings to be deployed for the entire anticipated fire season (June through November), whereas in 2021 EPSS settings were active July 28 through October 22;
  - The MED threshold has increased from a daily SAIDI value of 3.50 in 2021 to 5.04 in 2022. This new threshold would equate to seven fewer MEDs in 2022, compared to that experienced in 2021;

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[1] As of March 10, 2022, the 2022 scope for EPSS has increased to 1,018 enabled circuits. Further changes may occur as the program is implemented throughout 2022.

- Historical Data and Trends: As 2021 was the first year of EPSS deployment and given the expansion of the program in 2022, there is no historical data to help guide in target setting. PG&E has undertaken the below effort to re-baseline 2021 results to the 2022 anticipated EPSS environment and illustrates an informational datapoint for future performance and target setting;

FIGURE 2.2-3
SAIDI AND SAIFI ADJUSTED 2021 PERFORMANCE

	T&D - Unplanned & Planned Outages		T&D - Unplanned Outages		T&D - Planned Outages	
	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI
2021 EOY Results	218.7	1.320	183.3	1.180	35.4	0.140
Adjustment For Increased T_{MED} Threshold (2)	31.0	0.049	29.3	0.049	1.7	0.0003
Non EPSS Trendline adjustments (6)	14.4	0.049	6.3	0.029	8.1	0.021
Adjustment for current EPSS Ckts (3) (previsously HLT operated in 2021)	-14.3	-0.053	-14.3	-0.053	0.0	0.000
2021 EPSS Circuit Adjustment #1 (4)	28.1	0.101	28.1	0.101	0.0	0.000
EPSS Adjustment #2 for new EPSS circuits planned for 2022 (5)	118.7	0.428	118.7	0.428	0.0	0.000
Adjusted 2021 EOY Forecast (7)	**396.5**	**1.895**	**351.3**	**1.734**	**45.2**	**0.161**

Notes:
Red text indicates the recent updates from the previous December estimates.
(1) **EOY 2021 actual values as of January 22, 2022.**
(2) Assumes 7 additional non-MEDs (daily SAIDI values between 3.5 and 5.0 based on the actual 2021 MEDs of Jan 25, July 18, July 22, August 1, August 12, December 25, and December 28).
(3) **HLT to EPSS Adjustment** - This adjustment replaces the temporary HLT operation values with an equivalent EPSS performance value.
Based on the actual daily outage rates of 161 circuits (days operated as HLT vs days operated as EPSS)
(4) **EPSS Adjustment #1**
Adjustment for full 172 days of EPSS (161 circuits implemented in 2021 and 6 to be implemented in 2022).
(5) **EPSS Adjustment #2**
Assumes 827 new circuits planned for 2022 EPSS (6 carry-over from 2021, 615 HFRA & HFTD, 27 HRFA, 23 HFTD) assumed to be operated from June to November and 156 Tier 1 Buffer circuits assumed to be operated for 30 days. Each group is forecasted based on its respective average number of EPSS devices per circuit and relative to the EPSS impacts measured in 2021.
(6) **Non-EPSS Related Trendline Adjustments** - These adjustments are based on the trendlines of the past five years for; (a) all unplanned non-EPSS outages and (b) all planned outages. The prior 3.0 planned outage adjustment was updated 12/16/21 to reflect the increase in work volume (+3.3) and to account for the estimated decrease in Hot work due in the HFTD areas (+1.8).
(7) **Adjusted 2021 EOY Forecast** - This forecast reflects the estimated 2021 SAIDI value if the electric T&D system is operated as that planned for 2022 (without improvement initiaves).

- Benchmarking: At this time, targets are set based on operational and risk factors, although current performance is acknowledged as an indicator of PG&E's opportunity to improve for our customers over the long-run as risk reduction allows;
- Regulatory Requirements: None;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: The target range for this metric is suitable for EOE as it accounts for our current work plan and the unknowns of EPSS;
- Attainable With Known Resources/Work Plan: Based on 2021 results and 2022 work plan, PG&E expects performance to fall within proposed

target range. The bottom portion of PG&E’s proposed SOMs target (1.681) reflects a 3 percent improvement from our adjusted 2021 result (1.734);

- PG&E’s top financial and resource priority of minimizing the risk of catastrophic wildfires has led to declining reliability performance and does not support an improvement of the unplanned SAIFI metric;

FIGURE 2.2-4
RELIABILITY SPEND 2010-2022

- The GRC in 2017-20 allocated budget for reliability, but the work was re-prioritized to focus on wildfire mitigation, compliance, pole replacement and tags;
- The most significant driver of reliability performance is Equipment Failure, specifically Overhead Conductor;
- Current replacement rates from 2017-2021 have been on average 32 miles/year. This is significantly below the Overhead Conductor Asset Management Plan, which cites 3rd party recommendations for replacement rates at approximately 1,200 miles per year to sustain 2016 levels of reliability performance;
- Current investment profile in the GRC for OH Conductor is ~70 miles/year. Alternative funding scenarios or internal

prioritization would be needed to increase replacement miles per year;

  - Conductor replacement under the System Hardening program for wildfire risk reduction is forecasted through the GRC period but provides limited additional benefit, at approximately 1 percent (due to the rural HFTD geography in which this work takes place);
  - Current assigned 2022 GRC spending amount for targeted Reliability improvements (MAT Code 49x) is $9 million, which equates to an approximate unplanned SAIFI reduction of 0.004 minutes;
  - Prior to the implementation of EPSS in July 2021, current levels of investment and assuming the GRC forecast through 2026, SAIDI/SAIFI performance was expected to remain flat and sustained improvement trending not expected until 2023. However, with the EPSS implementation, performance fell

- Other Considerations: PG&E expanded their EPSS Program in 2022 (as described earlier in this chapter) and began enablement on high-risk circuits in January-representing and expanded fire season—all of which significantly impact SAIDI and SAIFI performance.

2. 2022 Target

Range: 1.681-2.017

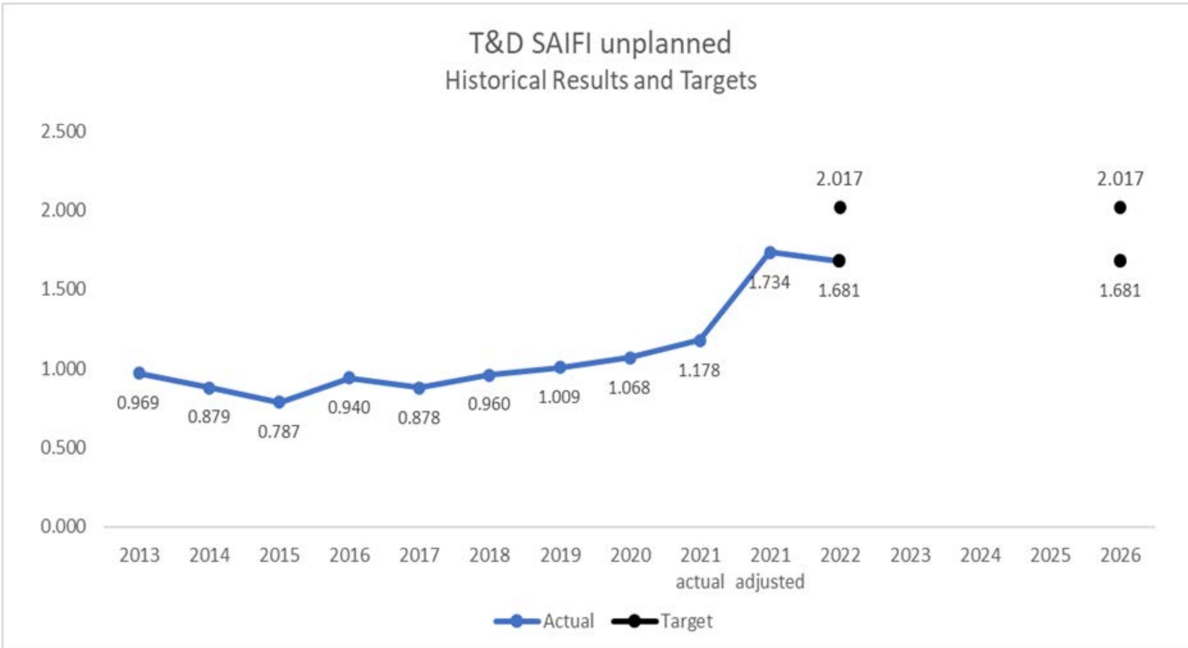
The 2022 target reflects a range of a 3 percent improvement to a 20 percent increased unplanned SAIFI performance from 2021 adjusted result to account for the factors listed above.

3. 2026 Target

Range: 1.681-2.017

Given the uncertainty of the EPSS environments, 2026 target range mirrors 2022 and will be adjusted once the 2022 impacts are actualized and further data is available to leverage for updating the target strategy.

FIGURE 2.2-5
TRANSMISSION AND DISTRIBUTION
SAIFI UNPLANNED HISTORICAL RESULTS AND TARGETS



4. Current and Planned Work Activities

Existing Programs that could improve Reliability Metric Performance and historical trend data for SAIFI are listed below. Further work to quantify exact benefits is being undertaken in Q1 in 2022:

- Enhanced Vegetation Management (EVM): Program is targeted at overhead distribution lines in Tier 2 and 3 HFTD areas and supplements PG&Es annual routine VM work with CPUC mandated clearances. PG&E's VM program, components of which exceed regulatory requirements, is critical to mitigating wildfire risk. Our VM team inspects and identifies needed vegetation maintenance on all distribution and transmission circuit miles in PG&E's service area on a recurring cycle through Routine and Tree Mortality Patrols, as well as Pole Clearing. Our EVM program goes above and beyond regulatory requirements for distribution lines by expanding minimum clearances and removing overhang in HFTD areas. In 2022 PG&E will complete 1,800 miles of EVM work.

  Please see Section 7.3.5, Vegetation Management and Inspections in PG&E's Wildfire Mitigation Plan (WMP) for additional details on 2022.

- Asset Replacement (Overhead, Underground): Overhead asset replacement addresses deteriorated overhead conductor and switches, while underground asset replacement primarily focuses on replacing underground cable and switches.

  Please see Chapter 11 Overhead and Underground Distribution Maintenance in the 2023 GRC for additional details.
- Grid Design and System Hardening: PG&E's broader grid design program covers a number of significant programs, called out in detail in PG&E's 2022 WMP. The largest of these programs is the System Hardening Program which focuses on the mitigation of potential catastrophic wildfire risk caused by distribution overhead assets. In 2022, we are rapidly expanding our system hardening efforts by: completing 470 circuit miles of system hardening work which includes overhead system hardening, undergrounding and removal of overhead lines in HFTD or buffer zone areas; completing at least 175 circuit miles of undergrounding work, including Butte County Rebuild efforts and other distribution system hardening work; replacing equipment in HFTD areas that creates ignition risks, such as non-exempt fuses (3,000) and surge arresters (~4,500, all known, remaining in HFTD areas). As we look beyond 2022, PG&E is targeting 3,600 miles of Undergrounding to be completed between 2023 and 2026 as part of the 10,000 Mile Undergrounding program. This system hardening work done at scale is expected to have limited reliability benefit due rural HFTD geography, and is prioritized to mitigate wildfire risk rather than reliability risk at this time,

  Please see Section 7.3.3, Grid Design and System Hardening Mitigations in PG&E's WMP for additional details on 2022.
- Animal Abatement: The installation of new equipment or retrofitting of existing equipment with protection measures intended to reduce animal contacts. This includes avian protection on distribution and transmission poles such as jumper covers, perch guards, or perching platforms

  Please see Chapter 11 Overhead and Underground Distribution Maintenance in the 2023 GRC for additional details,

- Overhead/Underground Critical Operating Equipment (COE) Replacement Work: The Overhead COE Program is comprised of corrective maintenance of certain defined equipment—including Protective Devices (Reclosers, Cutouts, Sectionalizers), Voltage Devices (Regulators, Boosters), Switches (Switches, Disconnects), Capacitors, and Conductors—that plays an important role in preventing customer interruptions and is critical for restoring power after an outage.

  The Underground COE Program is comprised of corrective 26 maintenance of certain defined equipment—including Protective 27 Devices (Reclosers, Interrupters, Sectionalizers), Voltage Devices 28 (Regulators, Stepdowns/Autobanks), Switches (Switches, Auto-Transfer 29 Switches), Capacitors, and Cable (Mainline (only), Loop (underground 30 only)).

  Please see Chapter 11 Overhead and Underground Distribution Maintenance in the 2023 GRC for additional details.

FIGURE 2.2-6
SAIFI UNPLANNED PERFORMANCE DRIVERS HISTORICAL DATA

SAIFI SUMMARY	2016	2017	2018	2019	2020	2021	5-Yr Ave	%
SYSTEM	0.940	0.877	0.877	0.960	1.068	1.181	0.968	-22%
3rd Party	0.199	0.169	0.216	0.201	0.220	0.234	0.201	-16%
Animal	0.051	0.057	0.071	0.069	0.075	0.078	0.065	-21%
Company Initiated	0.029	0.035	0.033	0.048	0.055	0.061	0.040	-53%
Environmental	0.022	0.017	0.028	0.022	0.020	0.026	0.022	-19%
Equipment Failure	0.413	0.413	0.398	0.405	0.436	0.485	0.413	-17%
Unknown Cause	0.098	0.088	0.117	0.136	0.172	0.200	0.122	-64%
Vegetation	0.127	0.104	0.101	0.129	0.087	0.098	0.110	11%
Wildfire Mitigation	0.000	0.000	0.000	0.002	0.002	0.001	0.001	-25%

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2.3

SAFETY AND OPERATIONAL METRICS REPORT:

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

(MAJOR EVENT DAYS)

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2.3
INTRODUCTION

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CHAPTER 2.3
INTRODUCTION

A. Overview

1. Metric Definition

Safety and Operational Metric (SOM) 2.3 – System Average Outages Due to Vegetation and Equipment Damage in HFTD (Major Event Days) is defined 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.

2. Introduction of Metric

The measurement of System Average Outages due to Vegetation and Equipment Damage in HFTD areas on MEDs is tied to the public safety risk of Asset Failure. While PG&E traditionally does not measure Customers Experiencing Sustained Outages (CESO) on MEDs only, CESO is an important industry-standard measure of reliability performance as it a direct measure of outage frequency.

B. Metric Performance

1. Historical Data (2013-2021)

PG&E has measured CESO for over 20 years, however this report used 2013 to 2021 CESO values for target analysis to align with the same timeframe used for the wire down SOMs metrics (2013 was the first full year PG&E uniformly began measuring wire down events).

The Cornerstone program investments in 2013 involved both capacity and reliability projects, and PG&E experienced its best reliability performance in 2015.

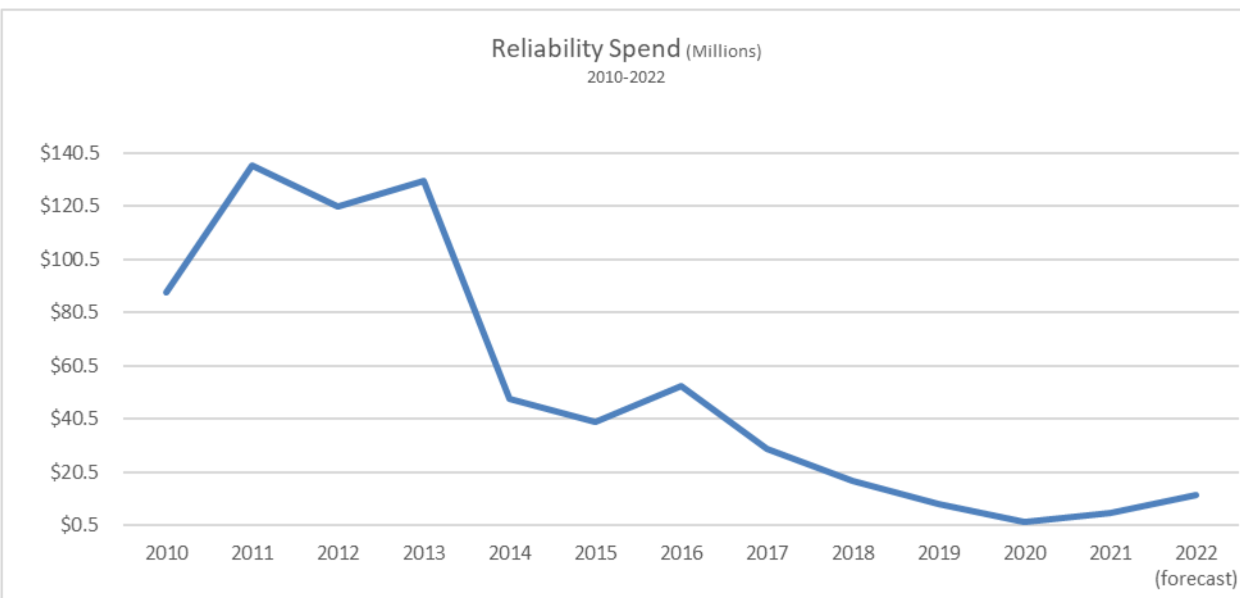
The majority of the 2017-2020 investment was on Fault Location Isolation and Restoration (FLISR), which automatically isolates faulted line sections and then restores all other non-faulted sections in less than five minutes) typically in urban/suburban areas. Of note, FLISR does not prevent customer interruptions but rather reduces the number of customers that experience a sustained outage.

The targeted circuit program, distribution line fuse replacement, and installing reclosers in the worst performing areas are initiatives that have had the biggest impact in improving system reliability at the lowest cost.

Other factors that contribute to reliability improvement include (but not limited to) project investments and project execution, favorable weather conditions, response to outages, asset lifecycle and health, vegetation management, switching device locations and function (including disablement of reclosers to mitigate fire risk).

The current investment/work plan is heavily weighted towards wildfire mitigation and is not weighted towards improving reliability performance. While the 2017 and 2020 General Rate Case (GRC) allocated budget for reliability, the work was re-prioritized to focus on wildfire mitigation, compliance, pole replacement and tags.

FIGURE 2.3-1
RELIABILITY SPEND HISTORICAL DATA 2010-2022



Reliability performance has consistently degraded since 2017 as PG&E's focus pivoted to wildfire risk prevention and mitigation.

FIGURE 2.3-2
TRANSMISSION AND DISTRIBUTION
VEGETATION AND EQUIPMENT FAILURE CESO HISTORICAL DATA
(MED ONLY, 2013-2021)

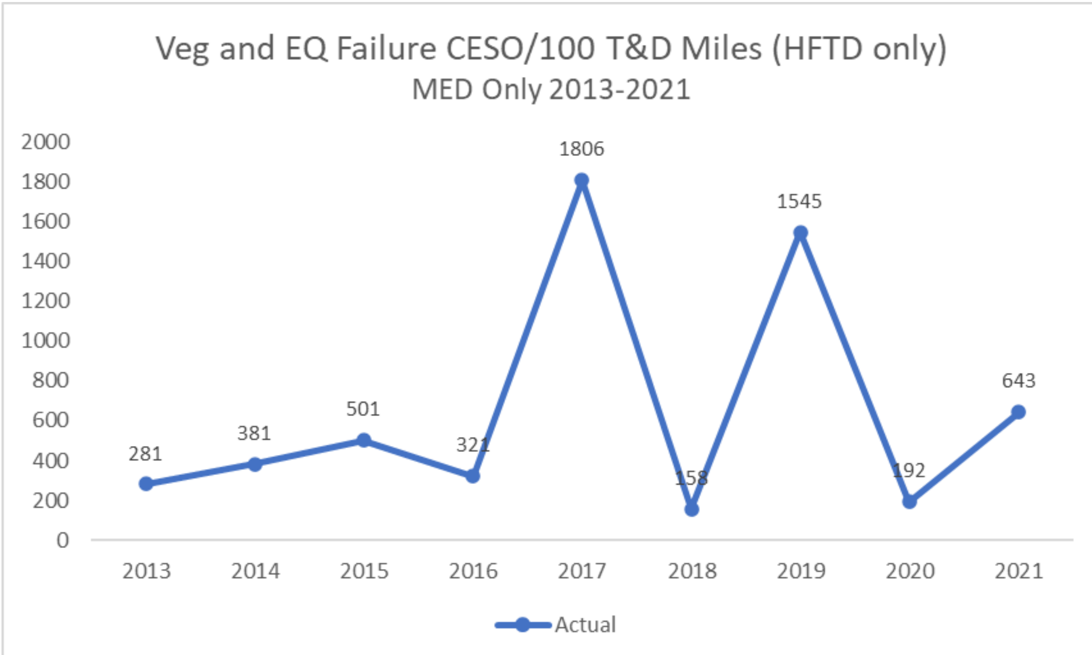


TABLE 2.3-3
TRANSMISSION AND DISTRIBUTION VEGETATION CESO HISTORICAL DATA
(MED ONLY 2013- 2021)

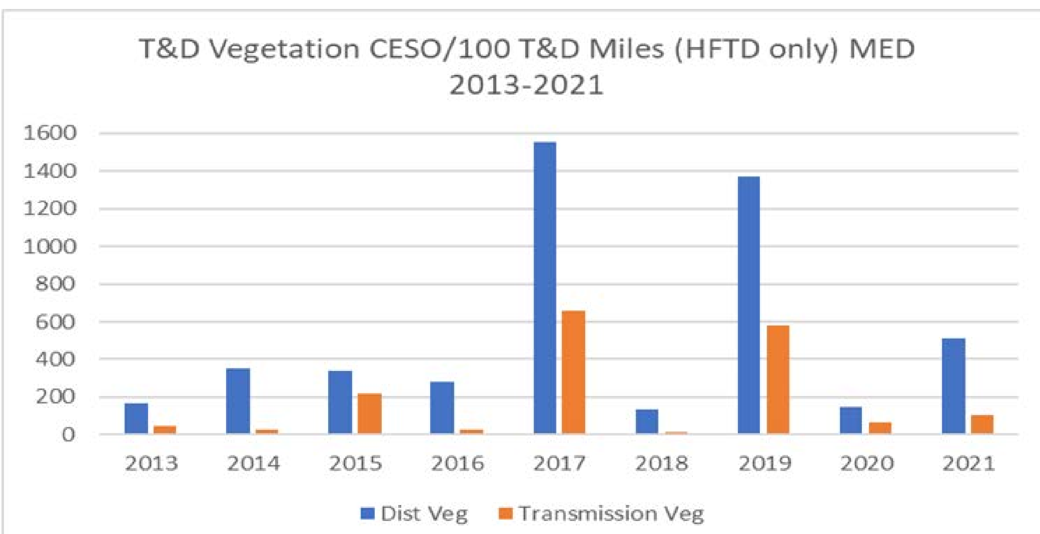


TABLE 2.3-4
TRANSMISSION AND DISTRIBUTION
OVERHEAD/UNDERGROUND EQUIPMENT FAILURE CESO HISTORICAL DATA
(MED ONLY, 2013-2021)

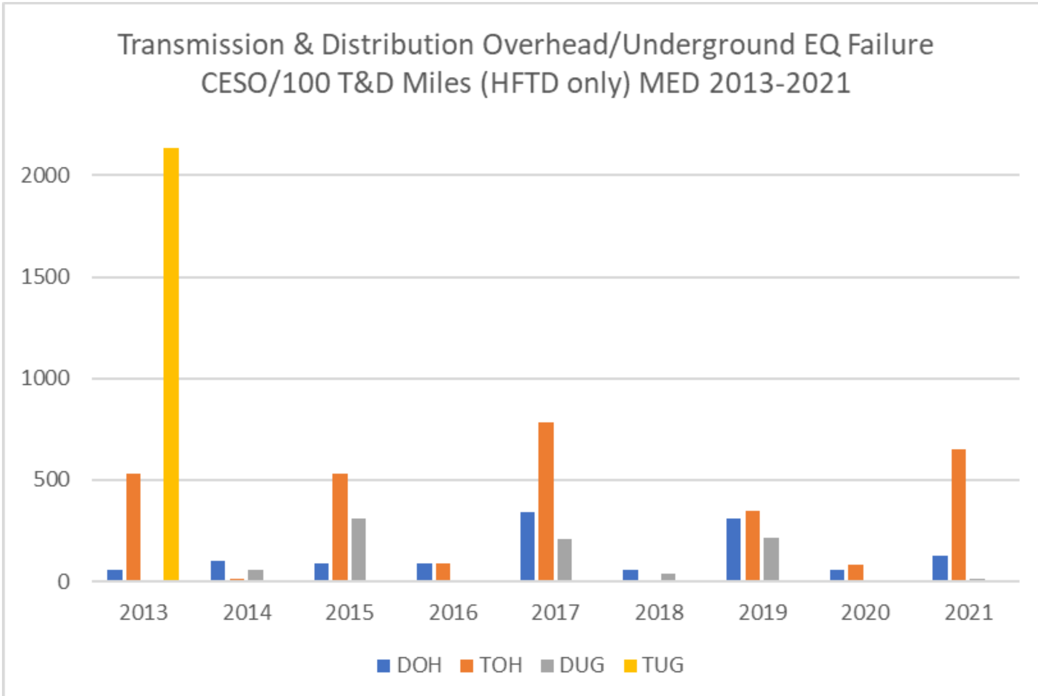


TABLE 2.3-5
ANNUAL MEDS (2013-2021)

Line No.	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	4	5	10	3	30	7	31	14	25

2. Data Collection Methodology

PG&E uses its outage database, typically referred to as its Integrated Logging Information System (ILIS) – Operations Database and its Customer Care & Billing database to obtain the customer count information to calculate these metric results. It should also be noted that PG&E's outage database includes distribution transformer level and above outages that impact both metered customers and a smaller number of unmetered customers. Outage information is entered into ILIS by distribution operators based on information from field personnel and devices such as SCADA alarms and Smart meters. PG&E last upgraded its outage reporting tools in

2015 and integrated Smart meter information to identify potential outage reporting errors and to initiate a subsequent review and correction.

PG&E traditionally excludes MEDs from Reliability measures per the Institute of Electrical and Electronics Engineers (IEEE) 1366 Standard titled IEEE Guide for Electric Power Distribution Reliability Indices to define and apply excludable MED to measure the performance of its electric system under normally expected operating conditions. Its purpose is to allow major events to be analyzed apart from daily operation and avoid allowing daily trends to be hidden by the large statistical effect of major events. Per the Standard, the MED classification is calculated from the natural log of the daily System Average Interruption Duration Index (SAIDI) values over the past five years by reliability specialists. The SAIDI index is used as the basis since it leads to consistent results and is a good indicator of operational and design stress.

There are a total of 33,599.5 transmission and distribution (overhead and underground) circuit miles located in the Tier 2 and Tier 3 HFTD areas. PG&E's data bases reflect the circuit miles that currently exist and do not maintain the historical values specifically in the Tier 2/3 HFTD areas. As such, PG&E has assumed these values have remained the same for all years from 2013 to 2021 and assuming annual variances due to the circuit miles are very small. On average (based on customer count data), PG&E's system is growing at ~0.6 percent per year. Therefore, assuming this is true for the OH miles in the Tier 2 and Tier 3 areas, the line miles would have grown roughly 5.4 percent over the past nine years. Consequently, the line mile adjustment would only represent a potential variance of around 5.4 percent, which is significantly smaller than the actual key metric driver of the number of equipment and vegetation caused outages and will also be significantly impacted by Enhanced Powerline Safety Shutoff (EPSS) in 2022.

Due to data limitations, PG&E uses the Lat/Long of the operating device as a proxy for determining the distribution outage events that occurred in the Tier 2/3 HFTD areas.

3. Metric Performance

The number of vegetation and equipment failure related customer outages per 100 transmission and distribution line miles during MEDs has varied each year and has been heavily driven by not just the number, but by the severity of the MED experienced in that specific year (refer to table above). 2021 performance increased by 235 percent from 2020, and experienced nine more MEDs-largely due to historic snowstorms that occurred in December. Other performance spikes were experienced in 2017 and 2019, with both years also experiencing a high number of MEDs. Given the randomness of weather patterns, no discernable trends can be learned from historical performance results.

C. 1-Year Target and 5-Year Target

1. Target Methodology

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

When normalized based on the number of MEDs per year, this metric shows improved performance. However, this metric measures the average number of customers impacted per 100 miles and will increase due the additional EPSS settings to be deployed in 2022 if EPSS contributes to more MEDs. Performance is expected to remain within historical range but would need to be reassessed after 2022 with more data available as to the impact of EPSS (refer to SAIDI and SAIFI reports).

In addition, the MED threshold has increased from a daily SAIDI value of 3.50 in 2021 to 5.04 in 2022. This new threshold would equate to seven fewer MEDs in 2022, compared to that experienced in 2021.

The following factors were also considered in establishing targets:

- Historical Data and Trends: No discernable trends can be learned from historical performance results given the randomness of weather patterns;
- Benchmarking: Not available;
- Regulatory Requirements: None;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: The directional target for this metric is suitable for EOE as

it states we are to remain within historical performance range while accounting for the randomness of weather patterns and impacts of climate change;

- Attainable With Known Resources/Work Plan: Based on 2021 results and variability in weather patterns, performance expected to be within historical range; and
- Other Considerations: Given the difficulty in predicting when PG&E areas will experience fire risk conditions, EPSS settings may be activated for a significantly longer period than the currently estimated fire season of June through November—leading to a greater than anticipated impact on reliability performance.

D. Current and Planned Work Activities

Existing Programs that could improve Reliability Metric Performance are listed below. Further work to quantify exact benefits is being undertaken in Q1 in 2022:

- Enhanced Vegetation Management: Program is targeted at overhead distribution lines in Tier 2 and 3 HFTD areas and supplements PG&Es annual routine vegetation management work with CPUC mandated clearances. PG&E's Vegetation Management program, components of which exceed regulatory requirements, is critical to mitigating wildfire risk. Our vegetation management team inspects and identifies needed vegetation maintenance on all distribution and transmission circuit miles in PG&E's service area on a recurring cycle through Routine and Tree Mortality Patrols, as well as Pole Clearing. Our EVM program goes above and beyond regulatory requirements for distribution lines by expanding minimum clearances and removing overhang in HFTD areas. In 2022 PG&E will complete 1,800 miles of EVM work.

  Please see Section 7.3.5, Vegetation Management and Inspections in PG&E's WMP for additional details on 2022.
- Asset Replacement (Overhead, Underground): Overhead asset replacement addresses deteriorated overhead conductor and switches, while underground asset replacement primarily focuses on replacing underground cable and switches.

Please see Chapter 11, Overhead and Underground Distribution Maintenance in the 2023 GRC for additional details.

- Grid Design and System Hardening: PG&E's broader grid design program covers a number of significant programs, called out in detail in PG&E's 2022 WMP. The largest of these programs is the System Hardening Program which focuses on the mitigation of potential catastrophic wildfire risk caused by distribution overhead assets. In 2022, we are rapidly expanding our system hardening efforts by: completing 470 circuit miles of system hardening work which includes overhead system hardening, undergrounding and removal of overhead lines in HFTD or buffer zone areas; completing at least 175 circuit miles of undergrounding work, including Butte County Rebuild efforts and other distribution system hardening work; replacing equipment in HFTD areas that creates ignition risks, such as non-exempt fuses (3,000) and surge arresters (~4,500, all known, remaining in HFTD areas). As we look beyond 2022, PG&E is targeting 3,600 miles of Undergrounding to be completed between 2023 and 2026 as part of the 10,000 Mile Undergrounding program. This system hardening work done at scale is expected to have limited reliability benefit due rural HFTD geography, and is prioritized to mitigate wildfire risk rather than reliability risk at this time,

  Please see Section 7.3.3, Grid Design and System Hardening Mitigations in PG&E's WMP for additional details on 2022.

- Animal Abatement: The installation of new equipment or retrofitting of existing equipment with protection measures intended to reduce animal contacts. This includes avian protection on distribution and transmission poles such as jumper covers, perch guards, or perching platforms.

  Please see Chapter 11 Overhead and Underground Distribution Maintenance in the 2023 GRC for additional details,

- Overhead/Underground Critical Operating Equipment (COE) Replacement Work: The Overhead COE Program is comprised of corrective maintenance of certain defined equipment—including Protective Devices (Reclosers, Cutouts, Sectionalizers), Voltage Devices (Regulators, Boosters), Switches (Switches, Disconnects), Capacitors, and Conductors—that plays an important role in preventing customer interruptions and is critical for restoring power after an outage.

The Underground COE Program is comprised of corrective maintenance of certain defined equipment—including Protective Devices (Reclosers, Interrupters, Sectionalizers), Voltage Devices (Regulators, Stepdowns/Autobanks), Switches (Switches, Auto-Transfer Switches), Capacitors, and Cable (Mainline (only), Loop (underground only))

Please see Chapter 11, Overhead and Underground Distribution Maintenance in the 2023 GRC for additional details.

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

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1. Metric Definition

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

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

2. Introduction of Metric

The measurement of System Average Outages due to Vegetation and Equipment Damage in HFTD areas is tied to the public safety risk of Asset Failure. Customers Experiencing Sustained Outages (CESO) is an important industry-standard measure of reliability performance as it a direct measure of outage frequency.

B. Metric Performance

1. Historical Data (2013-2021)

Pacific Gas and Electric Company (PG&E) has measured CESO for over 20 years, however this report used 2013-2021 CESO values for target analysis to align with the same timeframe used for the wire down SOMs (2013 was the first full year PG&E uniformly began measuring wire down events).

The Cornerstone program investments in 2013 involved both capacity and reliability projects, and PG&E experienced its best reliability performance in 2015.

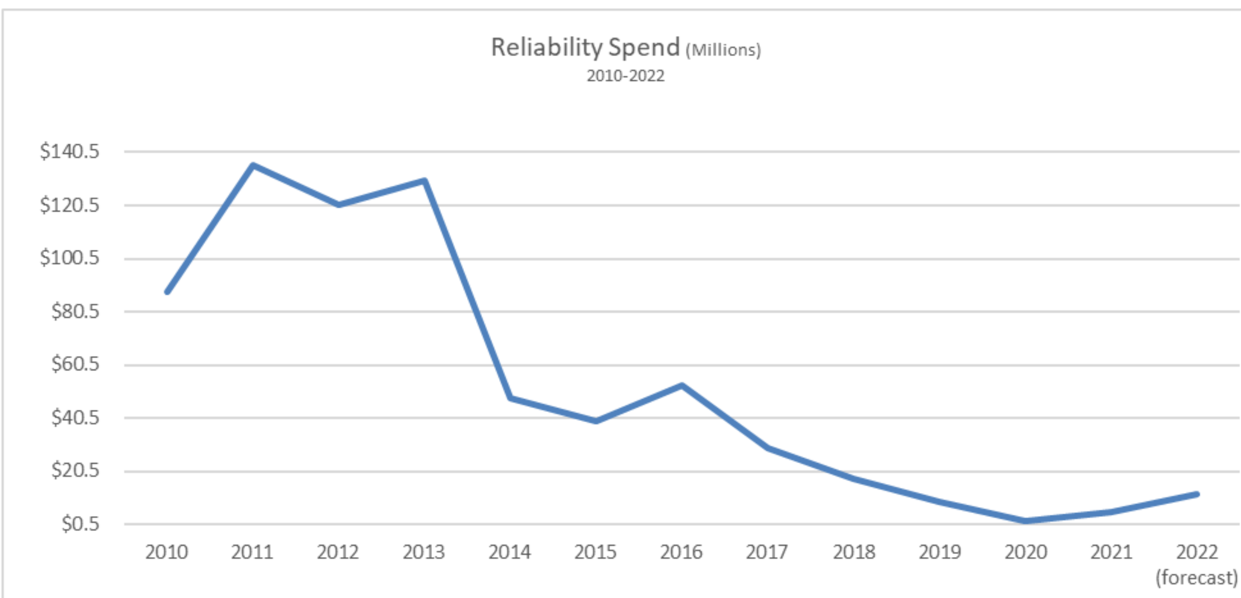
The majority of the 2017-2020 investment was on Fault Location Isolation and Restoration (FLISR), which automatically isolates faulted line sections and then restores all other non-faulted sections in less than five minutes) typically in urban/suburban areas. Of note, FLISR does not prevent customer interruptions but rather reduces the number of customers that experience a sustained (> 5 minutes) outage.

The targeted circuit program, distribution line fuses, and recloser installation in the worst performing areas have the biggest impact in improving system reliability at the lowest cost.

Many factors influence reliability performance, including (but not limited to) reliability project investments and project execution, favorable weather conditions, outage response time, asset lifecycle and health, switching device locations and function (including disablement of reclosers to mitigate fire risk).

The current investment/work plan is heavily weighted towards wildfire mitigation and is not targeted towards improving reliability performance.

FIGURE 2.4-1
HISTORICAL RELIABILITY SPEND: 2010-2022



Reliability performance has consistently degraded since 2017 as PG&E's focus pivoted to wildfire risk prevention and mitigation, with a 27 percent CESO increase occurring in 2021 from 2020.

FIGURE 2.4-2
TRANSMISSION AND DISTRIBUTION
VEGETATION AND EQUIPMENT FAILURE CESO HISTORICAL DATA
(HFTD ONLY, NON-MED 2013-2021)

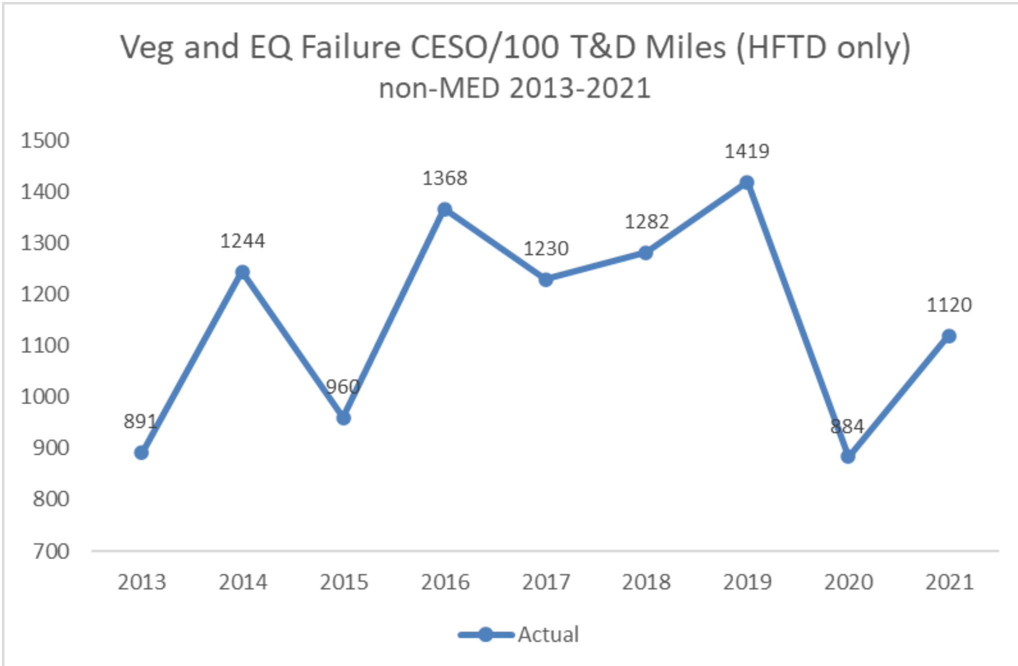


FIGURE 2.4-3
TRANSMISSION AND DISTRIBUTION
OVERHEAD/UNDERGROUND EQUIPMENT FAILURE CESO HISTORICAL DATA
(NON MED, 2013-2021)

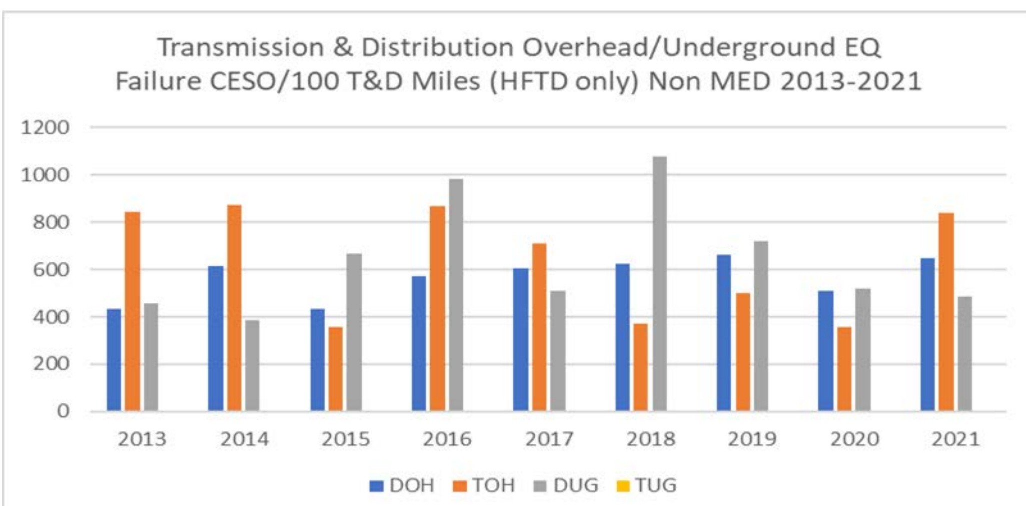
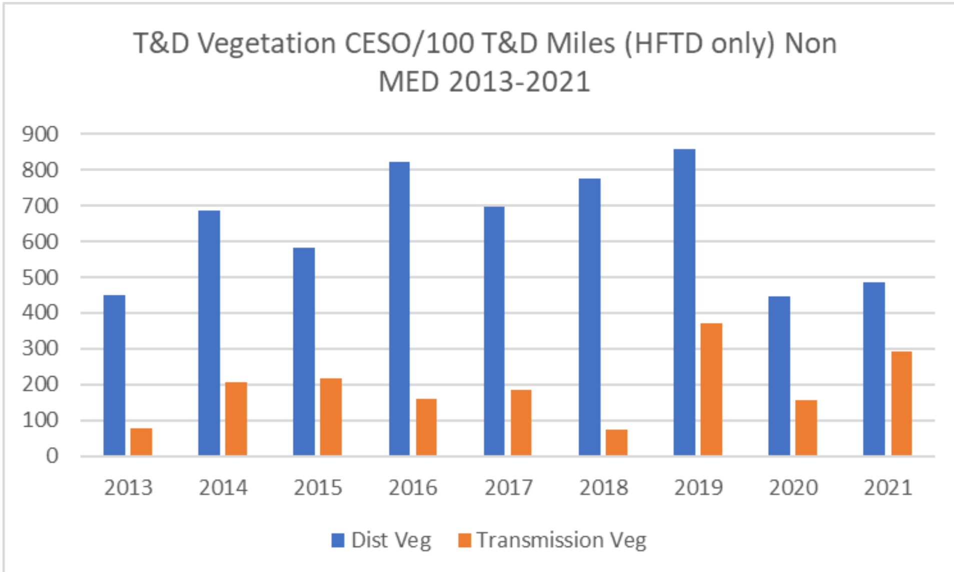


FIGURE 2.4-4
TRANSMISSION AND DISTRIBUTION
VEGETATION CESO HISTORICAL DATA
(NON MED 2013-2021)



2. Data Collection Methodology

PG&E uses its outage database, typically referred to as its Integrated Logging Information System (ILIS) – Operations Database and its Customer Care & Billing database to obtain the customer count information to calculate these metric results. It should also be noted that PG&E's outage database includes distribution transformer level and above outages that impact both metered customers and a smaller number of unmetered customers. Outage information is entered into ILIS by distribution operators based on information from field personnel and devices, such as SCADA alarms and SmartMeter™ devices. PG&E last upgraded its outage reporting tools in 2015 and integrated SmartMeter™ devices information to identify potential outage reporting errors and to initiate a subsequent review and correction.

PG&E excludes MEDs from Reliability measures per the Institute of Electrical and Electronics Engineers (IEEE) 1366 Standard titled IEEE Guide for Electric Power Distribution Reliability Indices to define and apply excludable MED to measure the performance of its electric system under normally expected operating conditions. Its purpose is to allow major events to be analyzed apart from daily operation and avoid allowing daily trends to be hidden by the large statistical effect of major events. Per the Standard, the MED classification is calculated from the natural log of the daily System Average Interruption Duration Index (SAIDI) values over the past five years by reliability specialists. The SAIDI index is used as the basis since it leads to consistent results and is a good indicator of operational and design stress.

There are a total of 33,599.5 transmission and distribution (overhead and underground) circuit miles located in the Tier 2 and Tier 3 HFTD areas. PG&E's data bases reflect the circuit miles that currently exist and do not maintain the historical values specifically in the Tier 2/3 HFTD areas. As such, PG&E has assumed these values have remained the same for all years from 2013 to 2021 and assuming annual variances due to the circuit miles are very small. On average (based on customer count data), PG&E's system is growing at ~0.6 percent per year. Therefore, assuming this is true for the OH miles in the Tier 2 and Tier 3 areas, the line miles would have grown roughly 5.4 percent over the past nine years. Consequently, the line mile adjustment would only represent a potential variance of around 5.4 percent, which is significantly smaller than the actual key metric driver of the number of equipment and vegetation caused outages and will also be significantly impacted by Enhanced Powerline Safety Shutoff (EPSS) in 2022.

Due to data limitations, PG&E uses the Lat/Long of the operating device as a proxy for determining the distribution outage events that occurred in the Tier 2/3 HFTD areas.

3. Metric Performance

The number of vegetation and equipment failure related customer outages occurring per 100 T&D line miles on Non-MEDs has varied each year but has generally been declining since 2016. 2021 performance was 27 percent worse than 2020, driven primarily by a 37 percent increase in Equipment Failure CESO. Performance drivers include the following:

- To reduce ignition risk, PG&E implemented the EPSS Program in July 2021. This program enabled higher sensitivity settings on targeted circuits in HFTD to deenergize when tripped. It should be noted that the number of California Public Utilities Commission (CPUC) reportable ignitions in HFTD decreased by 51 percent from the previous 3-year average upon deployment of EPSS; and

- In addition to the impact of EPSS, the metrics tied to CESO have been impacted as PG&E shifted away from traditional system reliability improvement work and more toward wildfire risk reduction, from reclose disablement in 2018 forward. As such, 2021 performance is not directly comparable to prior years as the operating conditions have changed significantly and resulted in large year-over-year changes.

C. 1-Year Target and 5-Year Target

1. Target Methodology

- For 1-year and 5-year targets, PG&E is proposing a CESO due to Vegetation and Equipment Failure in HFTD of 1,523. This number correlates to the anticipated ~36 percent increase to SAIFI performance in 2022 (2021 result of 1.320 compared to a projected SAIFI result of 1.801 in 2022, reflected in the illustration below). Increase is primarily due to the vast expansion of the EPSS Program in 2022 and increase to MED threshold (and the unknowns that brings to the environment):
  - EPSS settings will be added to an additional 848 circuits in 2022 (compared to 170 in 2021) for a total of 1,018[1] circuits;
  - Settings to be deployed for the entire anticipated fire season (June through November), whereas in 2021 EPSS settings were active July 28 through October 22; and
  - The MED threshold has increased from a daily SAIDI value of 3.50 in 2021 to 5.04 in 2022. This new threshold would equate to seven fewer MEDs in 2022 compared to that experienced in 2021.

The following factors were also considered in establishing targets:

- Historical Data and Trends: As 2021 was the first year of EPSS deployment and given the expansion of the program in 2022, there is no historical data to help guide in target setting. PG&E has undertaken an effort to re-baseline 2021 results to the 2022 anticipated EPSS/MED threshold environment and illustrates an informational datapoint for

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[1] As of March 10, 2022, the 2022 scope for EPSS has increased to 1,018 enabled circuits. Further changes may occur as the program is implemented throughout 2022.

future performance and target setting. In Figure 2.4-5 below, the unplanned portion of the measure is marked in red; SAIDI times are provided in minutes;

FIGURE 2.4-5
2021 AND 2022 SAIDI AND SAIFI ADJUSTED FORECASTS

	T&D - Unplanned & Planned Outages		T&D - Unplanned Outages		T&D - Planned Outages	
	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI
2021 EOY Results	218.7	1.320	183.3	1.180	35.4	0.140
Adjustment For Increased T_{MED} Threshold (2)	31.0	0.049	29.3	0.049	1.7	0.0003
Non EPSS Trendline adjustments (6)	14.4	0.049	6.3	0.029	8.1	0.021
Adjustment for current EPSS Ckts (3) (previously HLT operated in 2021)	-14.3	-0.053	-14.3	-0.053	0.0	0.000
2021 EPSS Circuit Adjustment #1 (4)	28.1	0.101	28.1	0.101	0.0	0.000
EPSS Adjustment #2 for new EPSS circuits planned for 2022 (5)	118.7	0.428	118.7	0.429	0.0	0.000
Adjusted 2021 EOY Forecast (7)	**396.5**	**1.895**	**351.3**	**1.734**	**45.2**	**0.161**

Notes:
Red text indicates the recent updates from the previous December estimates.
(1) **EOY 2021 actual values as of January 22, 2022.**
(2) Assumes 7 additional non-MEDs (daily SAIDI values between 3.5 and 5.0 based on the actual 2021 MEDs of Jan 25, July 18, July 22, August 1, August 12, December 25, and December 28).
(3) **HLT to EPSS Adjustment** - This adjustment replaces the temporary HLT operation values with an equivalent EPSS performance value.
Based on the actual daily outage rates of 161 circuits (days operated as HLT vs days operated as EPSS)
(4) **EPSS Adjustment #1**
Adjustment for full 172 days of EPSS (161 circuits implemented in 2021 and 6 to be implemented in 2022).
(5) **EPSS Adjustment #2**
Assumes 827 new circuits planned for 2022 EPSS (6 carry-over from 2021, 615 HFRA & HFTD, 27 HRFA, 23 HFTD) assumed to be operated from June to November and 156 Tier 1 Buffer circuits assumed to be operated for 30 days. Each group is forecasted based on its respective average number of EPSS devices per circuit and relative to the EPSS impacts measured in 2021.
(6) **Non-EPSS Related Trendline Adjustments** - These adjustments are based on the trendlines of the past five years for; (a) all unplanned non-EPSS outages and (b) all planned outages. The prior 3.0 planned outage adjustment was updated 12/16/21 to reflect the increase in work volume (+3.3) and to account for the estimated decrease in Hot work due in the HFTD areas (+1.8).
(7) **Adjusted 2021 EOY Forecast** - This forecast reflects the estimated 2021 SAIDI value if the electric T&D system is operated as that planned for 2022 (without improvement initiaves).

- <u>Benchmarking</u>: Not available;
- <u>Regulatory Requirements</u>: None;
- <u>Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement</u>: The target for this metric is suitable for EOE as it aligns with unplanned SAIFI target range and accounts for our current work plan and the unknowns of EPSS;
- <u>Attainable With Known Resources/Work Plan</u>: Based on 2021 results and 2022 work plan, PG&E does not expect degradation that would prevent us from meeting proposed target;
- PG&E's top financial and resource priority of minimizing the risk of catastrophic wildfires has led to declining reliability performance and does not support an improvement of outage performance:

- The General Rate Case (GRC) in 2017-20 allocated budget for reliability, but the work was re-prioritized to focus on wildfire mitigation, compliance, pole replacement and tags;
- The most significant driver of reliability performance is Equipment Failure, specifically Overhead Conductor;
- Current replacement rates from 2017-2021 have been on average 32 miles/year. This is significantly below the Overhead Conductor Asset Management Plan, which cites third-party recommendations for replacement rates at approximately 1200 miles per year to sustain 2016 levels of reliability performance;
- Current investment profile in the GRC for OH Conductor is ~70 miles/year. Alternative funding scenarios or internal prioritization would be needed to increase replacement miles per year;
- Conductor replacement under the System Hardening program for wildfire risk reduction is forecasted through the GRC period but provides limited additional benefit, at approximately 1 percent (due to the rural HFTD geography in which this work takes place);
- Current allocated 2022 GRC spending amount for targeted reliability improvements (MAT Code 49x) is $9 million;
- Prior to the implementation of EPSS in July 2021, current levels of investment and assuming the GRC forecast through 2026, SAIDI/SAIFI performance was expected to remain flat and sustained improvement trending not expected until 2023. However, with the EPSS implementation performance fell

• Other Considerations: PG&E expanded their EPSS Program (as described earlier in this chapter) and began enablement on high-risk circuits in January—representing and expanded fire season—all of which significantly impact SAIDI, SAIFI and CESO performance.

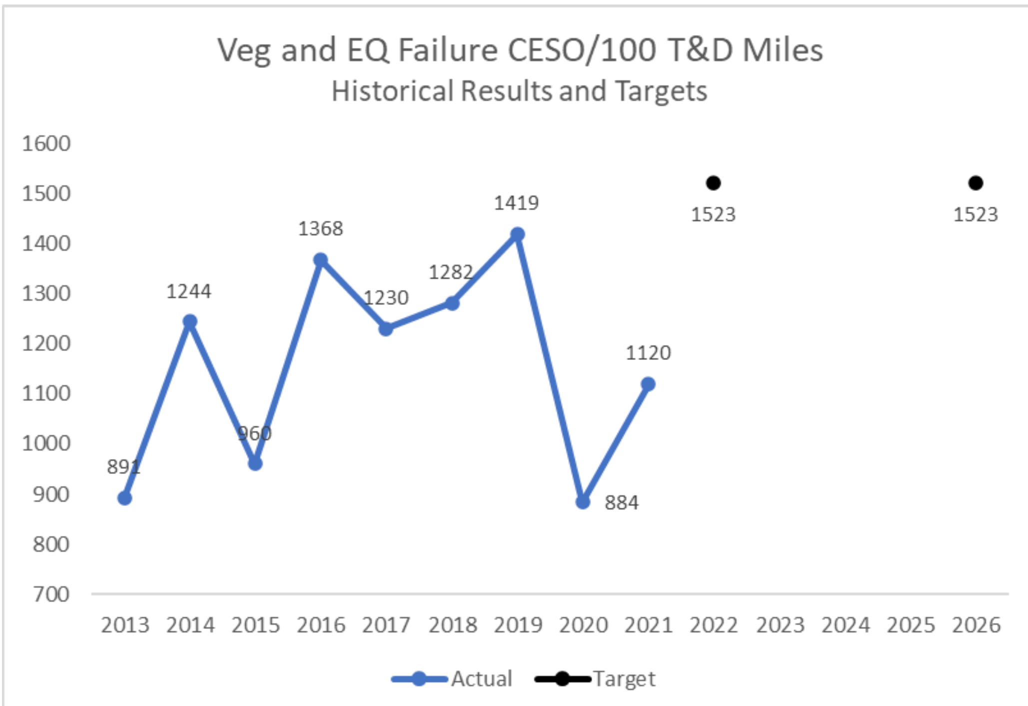
2. 2022 Target

The 2022 Target is 1,523, which aligns to the projected 2022 SAIFI (planned/unplanned) performance increase (1.320 to 1.801), primarily driven by anticipated EPSS impacts.

3. 2026 Target

The 2026 Target is 1,523, which mirrors the 2022 target given the uncertainty of the EPSS environments. The target will be adjusted once the 2022 impacts are actualized, and further data is available to leverage for updating the target strategy.

FIGURE 2.4-6
TRANSMISSION AND DISTRIBUTION
VEGETATION AND EQUIPMENT FAILURE CESO HISTORICAL RESULTS AND TARGETS



D. Current and Planned Work Activities

Existing Programs that could improve Reliability Outage Metric Performance are listed below. Further work to quantify exact benefits is being undertaken in Q1 in 2022:

- Enhanced Vegetation Management: Program is targeted at overhead distribution lines in Tier 2 and 3 HFTD areas and supplements PG&Es annual routine vegetation management work with CPUC mandated clearances. PG&E's Vegetation Management program, components of which exceed regulatory requirements, is critical to mitigating wildfire risk. Our vegetation management team inspects and identifies needed vegetation maintenance on all distribution and transmission circuit miles in PG&E's

service area on a recurring cycle through Routine and Tree Mortality Patrols, as well as Pole Clearing. Our EVM Program goes above and beyond regulatory requirements for distribution lines by expanding minimum clearances and removing overhang in HFTD areas. In 2022 PG&E will complete 1800 miles of EVM work.

Please see Section 7.3.5, Vegetation Management and Inspections in PG&E's Wildfire Mitigation Plan (WMP) for additional details on 2022.

- Asset Replacement (Overhead, Underground): Overhead asset replacement addresses deteriorated overhead conductor and switches, while underground asset replacement primarily focuses on replacing underground cable and switches.

  Please see Chapter 11, Overhead and Underground Distribution Maintenance in the 2023 GRC for additional details.

- Grid Design and System Hardening: PG&E's broader grid design program covers several significant programs, called out in detail in PG&E's 2022 WMP. The largest of these programs is the System Hardening Program which focuses on the mitigation of potential catastrophic wildfire risk caused by distribution overhead assets. In 2022, we are rapidly expanding our system hardening efforts by: completing 470 circuit miles of system hardening work which includes overhead system hardening, undergrounding and removal of overhead lines in HFTD or buffer zone areas; completing at least 175 circuit miles of undergrounding work, including Butte County Rebuild efforts and other distribution system hardening work; replacing equipment in HFTD areas that creates ignition risks, such as non-exempt fuses (3,000) and surge arresters (~4,500, all known, remaining in HFTD areas). As we look beyond 2022, PG&E is targeting 3,600 miles of Undergrounding to be completed between 2023 and 2026 as part of the 10,000 Mile Undergrounding program. This system hardening work done at scale is expected to have limited reliability benefit due rural HFTD geography, and is prioritized to mitigate wildfire risk rather than reliability risk at this time,

  Please see Section 7.3.3, Grid Design and System Hardening Mitigations in PG&E's WMP for additional details on 2022.

- Animal Abatement: The installation of new equipment or retrofitting of existing equipment with protection measures intended to reduce animal contacts. This includes avian protection on distribution and transmission poles such as jumper covers, perch guards, or perching platforms

  Please see Chapter 11 Overhead and Underground Distribution Maintenance in the 2023 GRC for additional details.

- Overhead/Underground Critical Operating Equipment (COE) Replacement Work: The Overhead COE Program is comprised of corrective maintenance of certain defined equipment—including Protective Devices (Reclosers, Cutouts, Sectionalizers), Voltage Devices (Regulators, Boosters), Switches (Switches, Disconnects), Capacitors, and Conductors—that plays an important role in preventing customer interruptions and is critical for restoring power after an outage.

  The Underground COE Program is comprised of: corrective maintenance of certain defined equipment—including Protective Devices (Reclosers, Interrupters, Sectionalizers); Voltage Devices (Regulators, Stepdowns/Autobanks); Switches (Switches, Auto-Transfer Switches); Capacitors, and Cable (Mainline (only); Loop (underground only))

  Please see Exhibit (PG&E-4), Chapter 11, Overhead and Underground Distribution Maintenance in the 2023 GRC for additional details.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3.1

SAFETY AND OPERATIONAL METRICS REPORT:

WIRES DOWN MAJOR EVENT DAYS IN HFTD AREAS

(DISTRIBUTION)

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3.1
INTRODUCTION

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3.1
INTRODUCTION

A. Overview

1. Metric Definition

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

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

2. Introduction of Metric

In 2012, PG&E initiated the Electric Wires Down Program, including introduction of the electric wires down metric, to address our increased focus on public safety by reducing the number of electric wire conductors that fail and result in contact with the ground, a vehicle, or other object.

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

B. Metric Performance

1. Historical Data (2013-2021)

We have nine years of historical data that includes the years 2013-2021. Although we started measuring distribution wire down incidents in 2012, 2013 was the first full year we uniformly measured the number of distribution wire down incidents. Over this historical reporting period, performance is largely influenced by external factors such as weather and third-party contact with our OH electric facilities. These historical results are plotted in Figure 3.1-1 below.

Our OH electric primary distribution system consists of approximately 81,000 circuit miles of OH conductor and associated assets that could contribute to a wires down incident. Approximately 25,280 miles of our OH electric primary distribution lines traverse in the HFTD areas.

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

- Investigating wire down incidents and implementing learnings and corrective actions;
- Performing infrared inspections of OH electric power lines to identify and repair hot spots;
- Clearing of vegetation hazards posing risks to our OH electric facilities
- Replacing deteriorated OH electric line conductors with newer line conductors; and
- Hardening of OH electric power systems with more resilient equipment.

In addition, our vegetation management (VM) teams conduct site visits of vegetation caused wires down incidents as part of its standard tree caused service interruption investigation process. The data obtained from site visits supports efforts to reduce future vegetation caused wires down incidents. The data collected from these investigations also helps identify failure patterns by tree species that are associated with wires down incidents.

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

FIGURE 3.1-1
DISTRIBUTION PRIMARY WIRES DOWN INCIDENTS PER 1,000 CIRCUIT MILES TIER 2/3, OCCURRING ON MEDS (2013-2021)

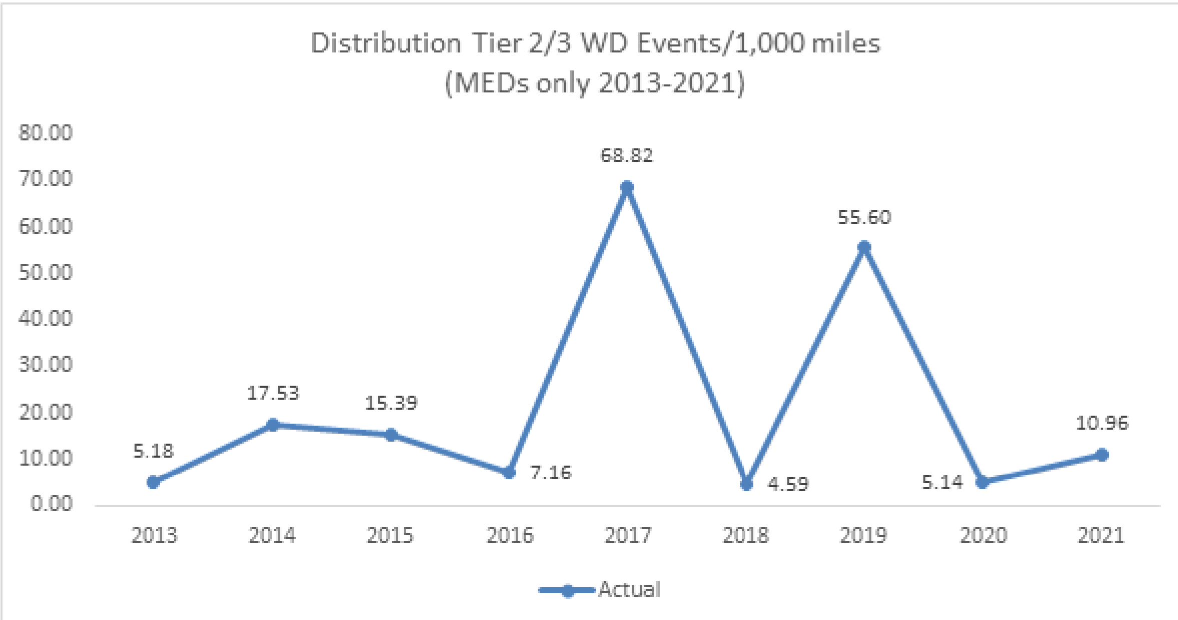

TABLE 3.1-1
NUMBER OF MEDS/YEAR

Line No.	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	4	5	10	3	30	7	31	14	25

2. Data Collection Methodology

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

PG&E uses the Institute of Electrical and Electronics Engineers (IEEE) 1366 Standard titled IEEE Guide for Electric Power Distribution Reliability Indices to define MED to measure the performance of its electric system under normally expected operating conditions. PG&E normally excludes MEDs to allow major events to be analyzed apart from daily operation and avoid allowing daily trends to be hidden by the large statistical effect of major events. Per the Standard, the MED classification is calculated from the natural log of the daily SAIDI values over the past five years by reliability specialists. The SAIDI index is used as the basis since it leads to consistent results and is a good indicator of operational and design stress.

3. Metric Performance

The number of Distribution Wire Down events during MEDs has varied each year and has been heavily driven by both the number and severity of the MED experienced in that specific year.

As can be seen from the 2013 to 2021 distribution down event and number of MEDs per year data, the number of Tier 2 and Tier 3 wire down events were significantly impacted by the number of MEDs experienced in 2017 and 2019. The average number of Tier 2 and Tier 3 HFTD distribution wire down events per 1,000 mile per MED was 0.438 in 2021, compared to 2.294 in 2017 and 1.794 in 2019.

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

C. 1-Year Target and 5-Year Target

1. Target Methodology

- Directional Only: Maintain (stay within historical range, and assumes response stays the same in events);
- Historical Data and Trends: This metric is expected to remain within the historical performance levels, but will vary based on the number of MEDs experienced in a year;
- Benchmarking: Not available;
- Regulatory Requirements: None;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: The directional target for this metric is suitable for EOE as it states performance will remain within historical range;
- Attainable Within Known Resources/Work Plan: Yes, this metric is attainable within known resources, however this metric is impacted by variability in conditions outside of PG&E's control, such as the severity of weather on MED; and
- Other Considerations: None.

2. 2022 Target

The 2022 target is to maintain within historical performance levels.

3. 2026 Target

The 2026 target is to maintain within historical performance levels.

D. Current and Planned Work Activities

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

- OH Conductor Replacement: PG&E's electric distribution system includes approximately 81,000 circuit miles of OH conductor on its distribution system that operates between 4 and 21 kilovolt, including bare and covered conductors. Approximately 55,000 circuit miles of this distribution conductor, including approximately 40,000 circuit miles of small conductor is in non-HFTD areas. PG&E's OH Conductor Replacement Program, recorded in MAT 08J, proactively replaces OH conductor in non-HFTD areas to address elevated rates of wires down and deteriorated/damaged conductors and to improve system safety, reliability, and integrity.

PG&E updated its prioritization process for OH conductor replacements to include consideration the RAMP risk tranches with Safety Consequence Zones and/or shared protection zones with critical customer(s). The three focused tranches are: (1) corrosive regions with specific materials (Aluminum Conductor Steel-Reinforced (ACSR)), (2) elevated wires down (small copper conductors), and (3) poor reliability performance. The final definition of 2 the Safety Consequence Zones is being developed, but currently takes 3 into consideration: Within buffer zones near Major Transportation 4 Infrastructure, Public Assembly Areas, and Public Safety Entities.

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

- Patrols and Inspections: PG&E monitors the condition of primary OH conductor through patrols and inspections consistent with GO 165, and targeted infrared inspections. Replacement plans are developed using failure rates obtained through wires down analysis and conductor-splice data. PG&E conducts post-event investigations of targeted equipment failure caused outages (i.e., wires down events involving conductor or splice failure). These investigations collect physical and environmental attributes to determine conductor replacement justification and priority as well as to determine failure trends. The information collected is entered into the "Engineer Investigation Wires Down Database." Analysis of this data has informed PG&E's strategy to focus replacement work on conductor types with elevated wires down rates, including small (#4 and #6 gauge) copper conductors and #4 ACSR conductors located in corrosion areas.

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

- Grid Design and System Hardening: PG&E's broader grid design program covers several significant programs, called out in detail in PG&E's 2022 WMP. The largest of these programs is the System Hardening Program which focuses on the mitigation of potential catastrophic wildfire risk caused by distribution OH assets. In 2022, we are rapidly expanding our system hardening efforts by: completing 470 circuit miles of system hardening work, which includes: OH system hardening, undergrounding, and removal of OH lines in HFTD or buffer zone areas; completing at least 175 circuit miles of undergrounding work, including Butte County Rebuild efforts and other distribution system hardening work; replacing equipment in HFTD areas that creates ignition risks, such as non-exempt fuses (3,000) and surge arresters (~4,500, all known, remaining in HFTD areas). As we look beyond 2022, PG&E is targeting 3,600 miles of Undergrounding to be completed between 2023 and 2026 as part of the 10,000 Mile Undergrounding Program. This system hardening work done at scale is expected to have limited reliability benefit due rural HFTD geography, and is currently prioritized to mitigate wildfire risk rather than reliability risk.

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

- Enhanced Vegetation Management (EVM): The EVM Program is targeted at OH distribution lines in Tier 2 and 3 HFTD areas and supplements PG&E's annual routine VM work with California Public Utilities Commission mandated clearances. PG&E's EVM Program, components of which exceed regulatory requirements, is critical to mitigating wildfire risk. Our EVM team inspects and identifies needed vegetation maintenance on all distribution and transmission circuit miles in PG&E's service area on a recurring cycle through Routine and Tree Mortality Patrols, as well as Pole Clearing. Our EVM Program goes above and beyond regulatory requirements for distribution lines by expanding minimum clearances and removing overhang in HFTD areas. In 2022 PG&E will complete 1,800 miles of EVM work.

  Please see Section 7.3.5, Vegetation Management and Inspections in PG&E's WMP.

- Other Advancements: There are several technologies that PG&E is piloting to better identify and/or prevent conductor to ground faults. This includes:
  - SmartMeter-based methods;
  - Distribution Falling Wire Detection Method;
  - Distribution Fault Anticipation;
  - Early Fault Detection; and
  - Rapid Earth Fault Current Limiter.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3.2

SAFETY AND OPERATIONAL METRICS REPORT:

WIRES DOWN NON-MAJOR EVENT DAYS IN HFTD AREAS

(DISTRIBUTION)

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3.2
INTRODUCTION

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3.2
INTRODUCTION

A. Overview

1. Metric Definition

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

Number of Wires Down incidents on Non-Major Event Days (Non-MED) involving Overhead (OH) electric primary distribution circuits divided by the total circuit miles of OH electric primary distribution lines multiplied by 1,000, in High Fire Threat District (HFTD) areas, in a calendar year.

2. Introduction to the Metric

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

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

B. Metric Performance

1. Historical Data (2013-2021)

There are nine years of historical data available from the years 2013-2021. Although PG&E started measuring distribution wire down incidents in 2012, 2013 was the first full year uniformly measuring the number of distribution wire down incidents.

Over this historical reporting period, performance is largely influenced by external factors such as weather and third-party contact with OH electric facilities.

PG&E's OH electric primary distribution system consists of approximately 81,000 circuit miles of OH conductor and associated assets that could contribute to a wires down incident. Approximately 25,280 miles of our OH electric primary distribution lines traverse in the HFTD areas.

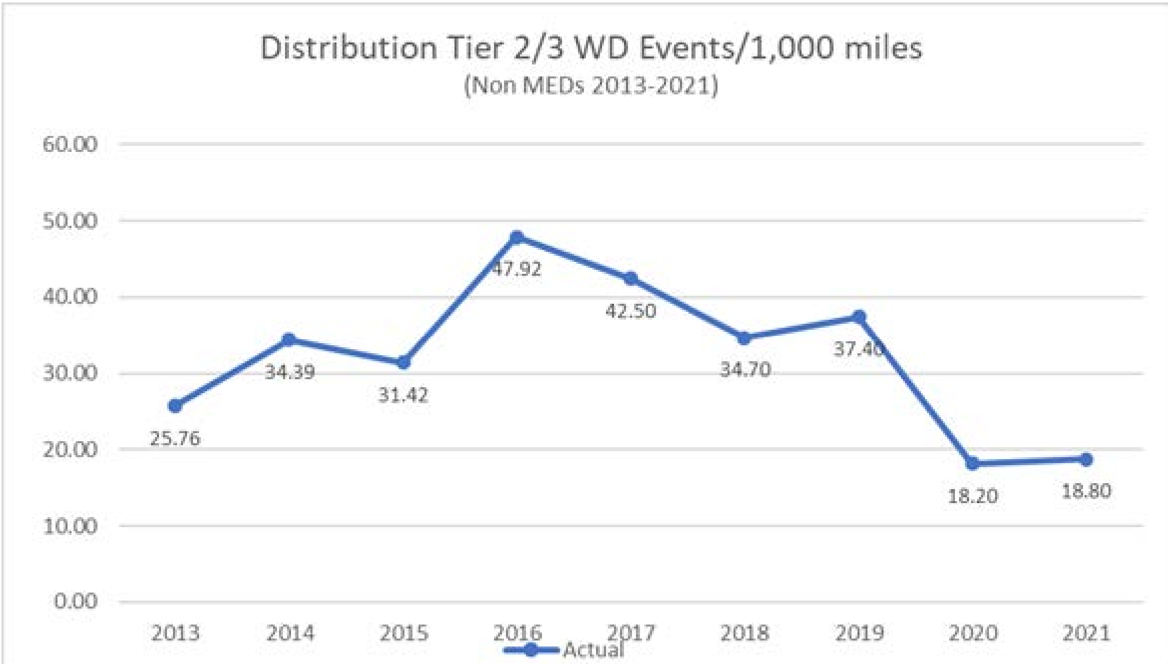
Over the last several years, we have completed significant work and launched various initiatives targeted at reducing wires down incidents, including:

- Investigating wire down incidents and implementing learnings and corrective actions;
- Performing infrared inspections of OH electric power lines to identify and repair hot spots;
- Clearing of vegetation hazards posing risks to our OH electric facilities;
- Replacing deteriorated OH electric line conductors with newer line conductors; and
- Hardening of OH electric power systems with more resilient equipment.

In addition, our vegetation management (VM) teams conduct site visits of vegetation caused wires down incidents as part of its standard tree caused service interruption investigation process. The data obtained from site visits supports efforts to reduce future vegetation caused wires down incidents. The data collected from these investigations also helps identify failure patterns by tree species that are associated with wires down incidents.

PG&E’s asset data base reflects the circuit miles that currently exist, and it does not specifically maintain line miles by HFTD in prior years. As such, all wire down rates are based on a total of 25,278.5 overhead distribution circuit line miles and assumes annual variances due to the circuit miles are considered to be negligible.

FIGURE 3.2-1
DISTRIBUTION PRIMARY WIRES DOWN INCIDENTS PER 1,000 CIRCUIT MILES
(TIER 2/3, NON-MED ONLY 2013-2021)



2. Data Collection Methodology

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

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

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

PG&E uses the IEEE 1366 Standard titled IEEE Guide for Electric Power Distribution Reliability Indices to define and apply excludable Major Event Days (MED) to measure the performance of its electric system under normally expected operating conditions. Its purpose is to allow major events to be analyzed apart from daily operation and avoid allowing daily trends to be hidden by the large statistical effect of major events. Per the Standard, the MED classification is calculated from the natural log of the daily System Average Interruption Duration Index (SAIDI) values over the past five years by reliability specialists. The SAIDI index is used as the basis since it leads to consistent results and is a good indicator of operational and design stress.

3. Metric Performance

In 2021 there were 15 more distribution wires down events in HFTD than had occurred in 2020. The number of distribution wire down events occurring on non-MED has varied each year. The significant variance in this metric is driven by several factors including weather conditions, third party influence and the number of MED days per year. Furthermore, PG&E's approach to wildfire mitigations in the HFTD locations is based on a risk informed prioritization of work in the areas where wildfire risk is evaluated as highest, as opposed to where wires down incidents have a high likelihood of occurrence if they are in areas where wildfire risk is relatively lower within the HFTD.

C. 1-Year Target and 5-Year Target

1. Target Methodology

To establish the 1-year and 5-year targets, the following factors were considered:

- Historical Data and Trends:
  - The past five years were used in PG&E's target setting methodology. These five years (2017-2021), as opposed to the 9 years of historical data available, were used because of their comparability to the current state of wildfire mitigation activity, which

began at significant scale in 2017. Not only do these years more comparability reflect the current environment but also the current state of performance. Between 2017 and 2021, there was a 55 percent decrease in distribution wire down events.

  - Target methodology leverages a 5-year average + 1 Standard deviation approach, so that targeted performance maintains the improvement achieved over the past five years while accounting for the normal variability observed in the results of this metric, typically caused by weather;
  - Target methodology also accounts for PG&E's wildfire mitigation strategies, with work in HFTD areas being targeted for wildfire risk reduction, which is not fully consistent with a work prioritization approach targeting wires down count reduction only;

- <u>Benchmarking:</u> Not available;
- <u>Regulatory Requirements:</u> None;
- <u>Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement:</u> The targets for this metric are suitable for EOE as they account for the variability experienced by this metric;
- <u>Attainable Within Known Resources/Work Plan:</u> Targets are attainable within known resources, however this metric is impacted by the variability in conditions outside of PG&E's control, such as weather conditions that may not be excluded as an MED; and
- <u>Other Considerations:</u>
  - Longer term (5-year) target setting includes a 2 percent year-over-year improvement methodology which accounts for weather variability and the increase in MED threshold (less days will be excluded) in 2022, as well as the improvements expected in HFTD from System Hardening and Enhanced Vegetation Management (EVM).

2. 2022 Target

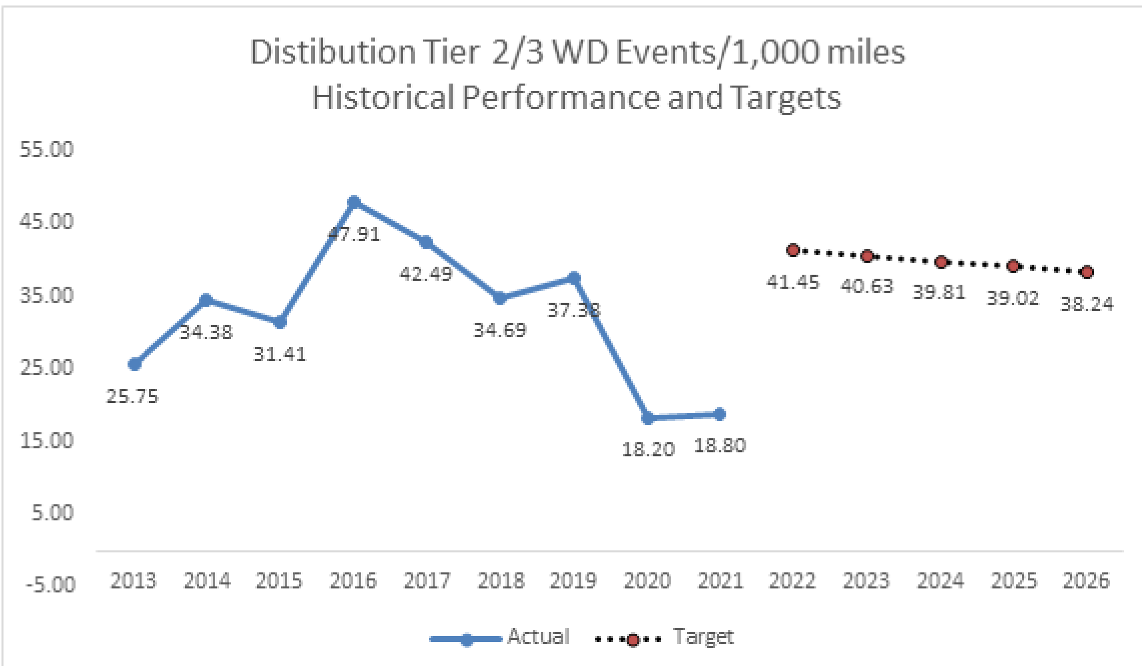
The 2022 target leverages a 5-year average + 1 Standard deviation approach.

3. 2026 Target

The 2026 target is set to a 10 percent improvement from the 2017 result (assumes a continued year-over-year 2 percent improvement from the 2022 Target) based on the considerations described above.

The following figure plots our historical and projected performance for Distribution Wires Down during Non-MED in the HFTD.

FIGURE 3.2-2
HISTORICAL AND PROJECTED ELECTRIC DISTRIBUTION PRIMARY WIRES DOWN INCIDENTS PER 1,000 CIRCUIT MILES



D. Current and Planned Work Activities

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

- Overhead Conductor Replacement: PG&E's electric distribution system includes approximately 81,000 circuit miles of OH conductor on its distribution system that operates between 4 and 21 kilovolt, including bare and covered conductors. Approximately 55,000 circuit miles of this distribution conductor, including approximately 40,000 circuit miles of small conductor is in non-HFTD areas. PG&E's OH Conductor Replacement Program, recorded in MAT 08J, proactively replaces OH conductor in non-HFTD areas to address elevated rates of wires down and deteriorated/damaged conductors and to improve system safety, reliability, and integrity.

PG&E updated its prioritization process for OH conductor replacements to include consideration the RAMP risk tranches with Safety Consequence Zones and/or shared protection zones with critical customer(s). The three focused tranches are: (1) corrosive regions with specific materials (Aluminum Conductor Steel-Reinforced (ACSR)), (2) elevated wires down (small copper conductors), and (3) poor reliability performance. The final definition of two the Safety Consequence Zones is being developed, but currently takes three into consideration: Within buffer zones near Major Transportation 4 Infrastructure, Public Assembly Areas, and Public Safety Entities.

Please see Chapter 13, Overhead and Underground Asset Management in the 2023 GRC for additional details.

- Patrols and Inspections: PG&E monitors the condition of primary OH conductor 4 through patrols and inspections consistent with GO 165 and targeted 5 infrared inspections. Replacement plans are developed using failure 6 rates obtained through wires down analysis and conductor-splice data. Seven PG&E conducts post-event investigations of targeted equipment failure eight caused outages (i.e., wires down events involving conductor or splice failure). These investigations collect physical and environmental attributes to determine conductor replacement justification and priority as well as to determine failure trends. The information collected is entered into the "Engineer Investigation Wires Down Database." Analysis of this data has informed PG&E's strategy to focus replacement work on conductor types with elevated wires down rates, including small (#4 and #6 gauge) copper conductors and #4 ACSR conductors located in corrosion areas.

  Please see Chapter 13, Overhead and Underground Asset Management in the 2023 GRC for additional details.

- Grid Design and System Hardening: PG&E's broader grid design program covers a number of significant programs, called out in detail in PG&E's 2022 WMP. The largest of these programs is the System Hardening Program which focuses on the mitigation of potential catastrophic wildfire risk caused by distribution OH assets. In 2022, we are rapidly expanding our system hardening efforts by: completing 470 circuit miles of system hardening work which includes OH system hardening, undergrounding and removal of OH lines in HFTD or buffer zone areas; completing at least 175 circuit miles of undergrounding work, including Butte County Rebuild efforts and other distribution system hardening work; replacing equipment in HFTD areas that creates ignition risks, such as non-exempt fuses (3,000) and surge arresters (~4,500, all known, remaining in HFTD areas). As we look beyond 2022, PG&E is targeting 3,600 miles of Undergrounding to be completed between 2023 and 2026 as part of the 10,000 Mile Undergrounding Program. This system hardening work done at scale is expected to have limited reliability benefit due to rural HFTD geography, and is prioritized to mitigate wildfire risk rather than reliability risk at this time.

Please see Section 7.3.3, Grid Design and System Hardening Mitigations in PG&E's WMP for additional details on 2022.

- Enhanced Vegetation Management: The EVM program is targeted at OH distribution lines in Tier 2 and 3 HFTD areas and supplements PG&Es annual routine VM work with CPUC mandated clearances. PG&E's VM program, components of which exceed regulatory requirements, is critical to mitigating wildfire risk. PG&E's VM team inspects and identifies needed vegetation maintenance on all distribution and transmission circuit miles in PG&E's service area on a recurring cycle through Routine and Tree Mortality Patrols, as well as Pole Clearing. Our EVM program goes above and beyond regulatory requirements for distribution lines by expanding minimum clearances and removing overhang in HFTD areas. In 2022 PG&E will complete 1,800 miles of EVM work.

  Please see Section 7.3.5, Vegetation Management and Inspections in PG&E's WMP for additional details.

- Other Advancements: In addition, there are several technologies that PG&E is piloting to better identify and/or prevent conductor to ground faults. This includes:
  - SmartMeter-based methods;
  - Distribution Falling Wire Detection Method;
  - Distribution Fault Anticipation;

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

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3.3

SAFETY AND OPERATIONAL METRICS REPORT: WIRES DOWN MAJOR EVENT DAYS IN HFTD AREAS (TRANSMISSION)

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3.3
INTRODUCTION

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3.3
INTRODUCTION

A. Overview

1. Metric Definition

Safety and Operational Metrics (SOM) 3.3 – Wires Down Major Event Days in HFTD Areas (Transmission) is defined as:

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

2. Introduction of Metric

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

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

B. Metric Performance

1. Data Collection

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

2. Historical Data

PG&E initiated the electric wires down events metric in 2012 to support public safety. To help develop targets for 2012, outages in 2011 were reviewed for a count of wire down events. See PG&E's "Safety and Operational Metrics Report: Supporting Documentation" for details of all the ET wire down events since 2011. The workbook allows users to filter for events that occurred on MEDs, were within a particular HFTD (either Tier 2 or Tier 3), or were due to specific cause (e.g., equipment failure, external contacts such as Mylar balloons or vehicles, lightning, and tree failures).

Electric Transmission reports its wire down events by precise points of failure including circuit name and pole location. When multiple spans are involved, the spreadsheet shows only one of those spans, but the column under the "Comments" header provides more details about the event including if multiple spans were involved. There are also columns that were populated for latitude and longitude from PG&E's ET Geographical Interface System coinciding with the pole location. This view is available by request.

This metric is normalized by the transmission circuit miles within Tier 2 and Tier 3 HFTDs. The HFTD boundaries are recent development and were not defined for several years as shown in Figure 3.3-1 below. Hence, for all years prior to and including 2021 performance PG&E uses 5,525.9 overhead transmission circuit miles in Tier 2/3 HFTD areas and assumes any variances in prior years are negligible.

3. Historical Performance

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

The probability that a point falls above the upper control limit (for most control chart designs, usually an indicator of significant process degradation) or below the lower control limit (an indicator, usually, of significant process improvement) if only common causes are operating is approximately

0.00135. It is therefore unlikely to have measures fall beyond the control limits when no special cause is operating. False alarms are possible, but the placement of the control limits at 3 standard deviations (+/-) from the process average is thought to control the number of false alarms adequately in most situations. The simplest rule for detecting presence of a special cause is one or more points that fall beyond upper or lower limits of the chart.

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

Figure 3.3-1 below is a control chart showing historical annual performances since 2011 for ET wire down events excluding those that occurred on a declared MED. Similarly, Figure 3.3-2 is a control chart showing all wire down events including MEDs.

FIGURE 3.3-1
ELECTRIC TRANSMISSION PRIMARY WIRES DOWN EVENTS, EXCLUDING MEDS (2013-2021)

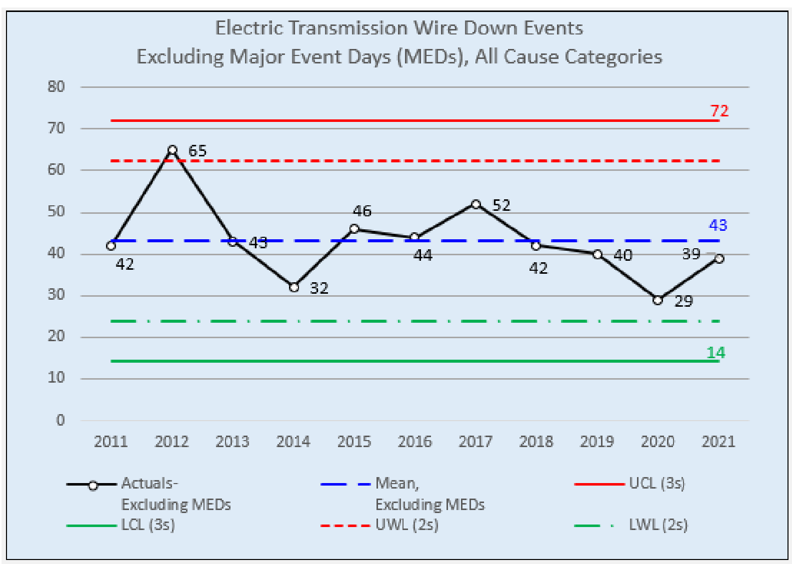
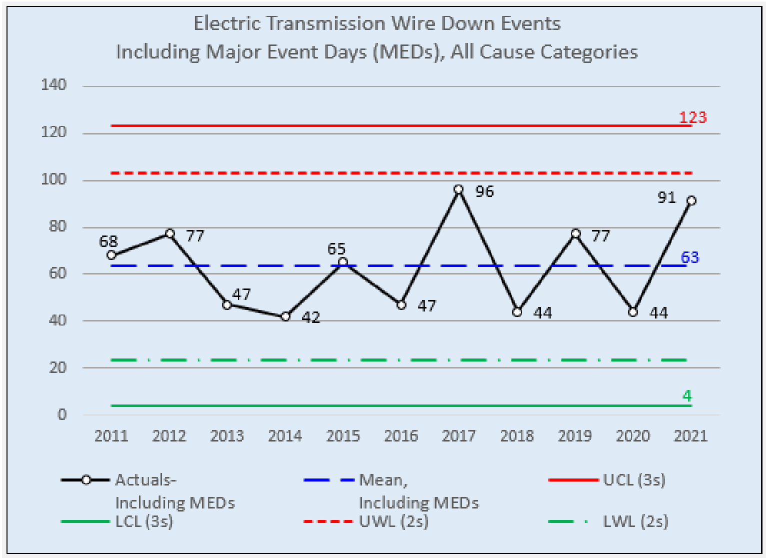


FIGURE 3.3-2
ELECTRIC TRANSMISSION PRIMARY WIRES DOWN EVENTS, INCLUDING MEDS (2013-2021)



Comparing the two figures above, one can conclude that on average we can expect 20 more transmission wire down events when MEDs are included. More importantly, there are no instances in either chart where the upper chart limit set at three standard deviations was exceeded, and there's only one instance (performance year 2012) where the upper warning limit (UWL) set at two standard deviations was exceeded. It appears we have a stable performing process in the count of transmission wire down events, whether MEDs are included in the count or not.

Figure 3.3-3 below is analogous to Figure 3.3-2 above but restricts the count of transmission wire down events to those occurring within Tier 2 or Tier 3 HFTDs. All categories related to cause are included. The bars in the chart show congruence between the number of MEDs in a performance year vs. the count of transmission wire down. It's also apparent that we have a stable system as all annual performance results fall within the two standard deviation lines for UWL and lower warning limit.

FIGURE 3.3-3
ELECTRIC TRANSMISSION PRIMARY WIRES DOWN EVENTS, INCLUDING MEDS, TIER 2/3 (2013-2021)

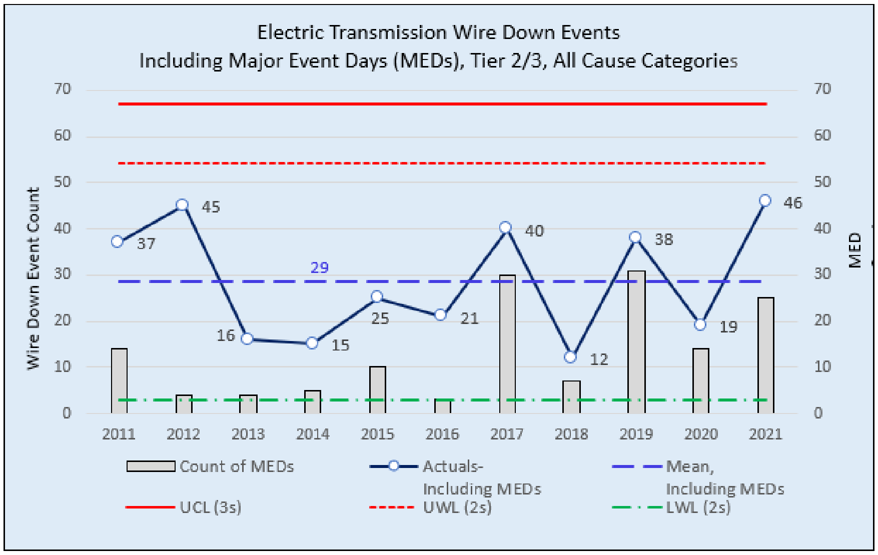
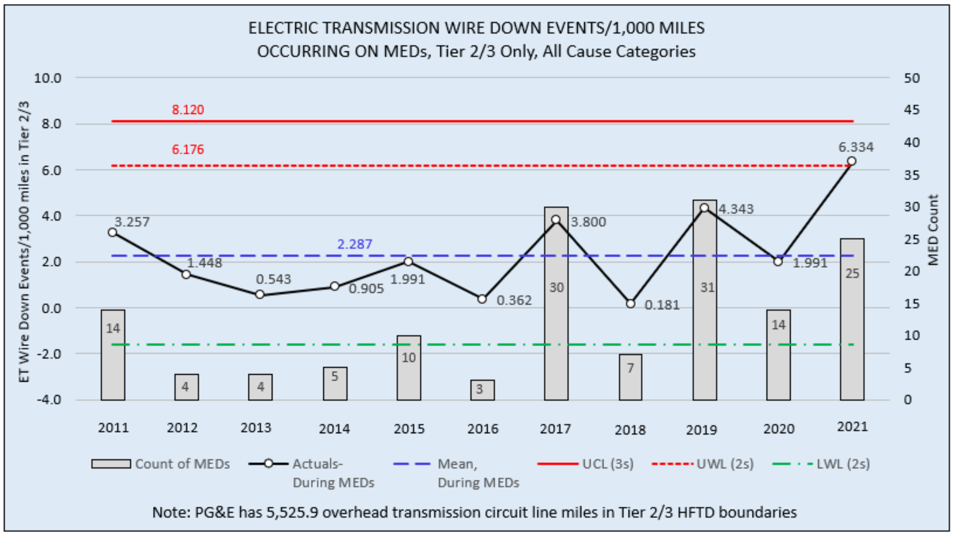


Figure 3.3-4 below is analogous to Figure 3.3-3 above but further restricts the count of transmission wire down events to those that occurred only during a declared MED. These counts are normalized by dividing by the circuit mileage associated circuits located in Tier 2 and Tier 3 boundaries x 1,000. Again, there is congruence between the normalized counts of transmission wire down events and the number of MEDs. There is one instance (2021) where the actual count slightly exceeds the UWL set at two standard deviations. Nevertheless, it appears we have a stable performance.

FIGURE 3.3-4
ELECTRIC TRANSMISSION PRIMARY WIRES DOWN EVENTS
OCCURRING ON MEDS, TIER 2/3 (2013-2021)



C. 1-Year Target and 5-Year Target

1. Target Methodology

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

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

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

- Other Considerations: None.

D. Current and Planned Work Activities

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

- Asset Inspection: Enhanced detailed inspections (i.e., enhanced inspections) of overhead transmission assets seek to proactively identify and treat pending failures of asset components which could create future wire down, outage, and/or safety events if left unresolved or allowed to "run to failure." Enhanced inspections for transmission assets involve at least two detailed inspection methods per structure: ground and aerial. In addition to the ground and aerial inspections, climbing inspections are also required for 500 kilovolt structures or as triggered. All these inspection methods involve detailed, visual examinations of the assets with use of inspection checklists that are in accordance with the ET Preventive Maintenance (TD-1001M) as well as the Failure Modes and Effects Analysis. Aerial inspections may be completed either by drone, helicopter, or aerial lift.
- Asset Repair and Replacement: Completing repair, replacement, and life extension to transmission assets provides the benefit of reduced probability of failure for components that could potentially result in a wire down event. Most corrective maintenance notifications are identified as a result of transmission asset inspections and patrols.

  Prioritization of maintenance tags are based on severity of the issues found, fire ignition potential (i.e., asset-conditions impacting issues associated with HFTD areas and High Fire Risk Area), probability of failure and the Wildfire Consequence Model. As conditions are identified, they are given a time-based priority based on guidance in PG&E's ET Preventative Maintenance Manual. For certain tags (E and F priority tags), additional prioritization occurs based on the damage found. Time dependent conditions (meaning that the damage can worsen with time) with ignition potential are typically prioritized before other non-time dependent, non-ignition potential tags. Execution of the prioritized work plan would also have to address other factors such as clearance availability, access, work efficiency, etc.

Additionally, replacement of assets in HFTD areas also may reduce wire down event risk. This reduction can be a combination of replacing aged, degraded assets, as well as providing more robust, up-to-standard designs. Asset removal eliminates wire-down event risk by removing the energized electrical components.

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

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

- Routine NERC: The Routine NERC Program includes Light Detection and Ranging (LiDAR) inspection, visual verification of findings, and mitigation of vegetation encroachments, as well as other vegetation conditions on approximately 6,800 miles of NERC Critical lines.100 percent inspection and work plan completion are required by NERC Standard FAC-003-4. Work is prioritized based on aerial LiDAR detection. This program recurs annually.

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

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3.4

SAFETY AND OPERATIONAL METRICS REPORT:

WIRES DOWN NON-MAJOR EVENT DAYS IN HFTD AREAS

(TRANSMISSION)

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3
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INTRODUCTION

A. Introduction

1. Metric Definition

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

Count of electric transmission wire down events on non-Major Event Days (MED) (as defined in IEEE (Institute of Electronic and Electrical Engineers) Standard 1366) divided by the total circuit miles of overhead transmission lines (divided by 1,000) in high fire threat district (HFTD) Areas.

2. Introduction of Metric

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

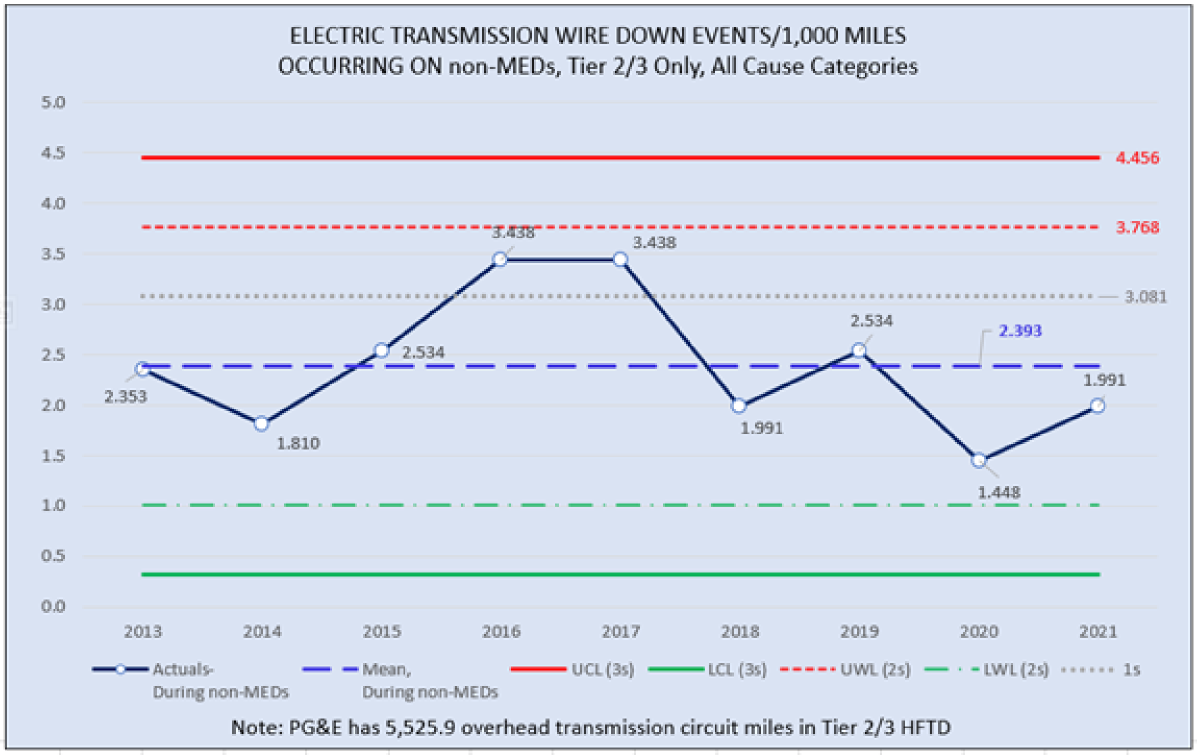
This metric is associated with PG&E's Failure of Electric Transmission Overhead Asset Risk and Wildfire Risk, which are part of the Company's 2020 Risk Assessment and Mitigation Phase Report (RAMP) filing.

B. Metric Performance

1. Historical Data (2013-2021)

There are nine years of historical data available from the years 2013-2021. Although PG&E started measuring wire down incidents in the 2012, 2013 was the first full year uniformly measuring the number of transmission wire down incidents. This metric is normalized by the transmission circuit miles within Tier 2 and Tier 3 HFTDs. The HFTD boundaries are a recent development and were not defined for several years within the historical data timeframe. Hence, for all years prior to and including performance year 2021 PG&E uses 5,525.9 overhead transmission circuit miles in Tier 2/3 HFTD areas and assumes any variances in prior years are negligible.

FIGURE 3.4-1
ELECTRIC TRANSMISSION PRIMARY WIRES DOWN EVENTS OCCURRING ON NON-MEDS PER 1,000 CIRCUIT MILES (2013-2021)



2. Data Collection Methodology

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

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

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

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

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

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

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

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

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

There is precedent internally for using control charts to set targets.

Figure 3.4-1 above is a control chart showing historical annual performances since 2013 for electric transmission wire down events excluding those that occurred on a declared major event day (MED).

C. 1-Year Target and 5-Year Target

1. Target Methodology

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

- Historical Data and Trends: 1-year and 5-year Targets are set to maintain performance within a 3 standard deviation range using the available historical data. As discussed above in the interpretations of control charts related to this metric—and absent any “special” cause(s) that would result in deviation above the current 3 standard deviations—it is reasonable to expect that future transmission wire down results would remain within the historical performance levels. Such results will vary based on the number of MEDs experienced in a year; however, end of year actuals should remain centered around the mean and below the UWL shown in Figure 3.4-3;
- Benchmarking: Not available;
- Regulatory Requirements: None;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: The target for this metric is suitable for EOE as it suggests that future results will remain within the historic performance levels;
- Attainable Within Known Resources/Work Plan: Metric targets are attainable within known resources, however this metric is impacted by the variability in conditions outside of PG&E's control, such as the severity of inclement weather on days that don’t register as Major Event Days; and

- Other Considerations: None.

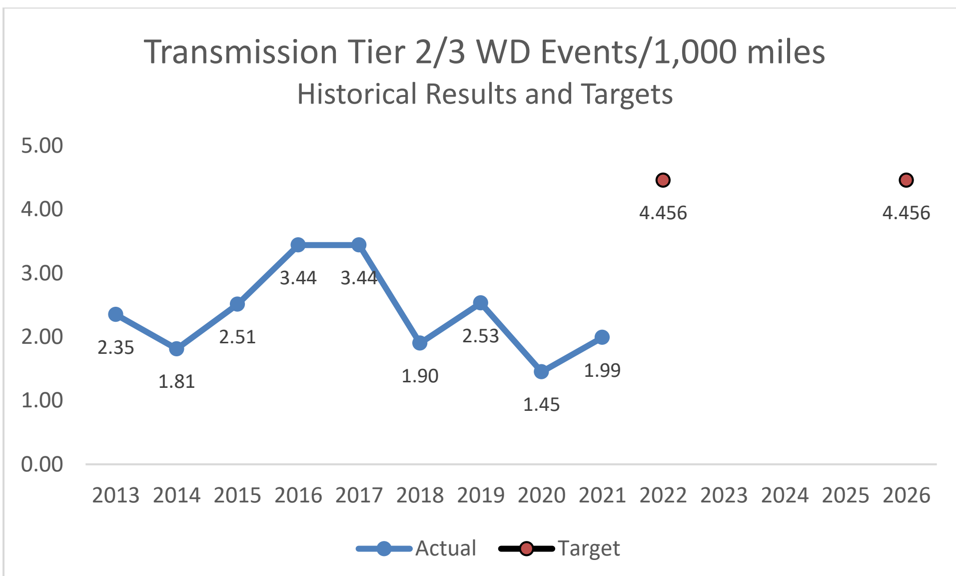
2. 2022 Target

Not to exceed 4.456, which represents maintaining a 3 standard deviation range.

3. 2026 Target

Not to exceed 4.456, which represents Maintaining a 3 standard deviation range.

FIGURE 3.4-3
ELECTRIC TRANSMISSION PRIMARY WIRES DOWN EVENTS OCCURRING ON NON-MEDS PER 1,000 CIRCUIT MILES (2013-2021)



4. Current and Planned Work Activities

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

- Asset Inspection: Enhanced detailed inspections (i.e., enhanced inspections) of overhead transmission assets seek to proactively identify and treat pending failures of asset components which could create future wire down, outage, and/or safety events if left unresolved or allowed to "run to failure." Enhanced inspections for transmission assets involve at least two detailed inspection methods per structure: ground and aerial. In addition to the ground and aerial inspections, climbing inspections are also required for 500 kilovolt (kV) structures or as triggered. All these inspection methods involve detailed, visual examinations of the assets with use of inspection checklists that are in accordance with the Electric Transmission Preventive Maintenance (TD-1001M), as well as the Failure Modes and Effects Analysis. Aerial inspections may be completed either by drone, helicopter, or aerial lift.

- Asset Repair and Replacement: Completing repair, replacement, and life extension to transmission assets provides the benefit of reduced probability of failure for components that could potentially result in a wire down event. Most corrective maintenance notifications are identified as a result of transmission asset inspections and patrols.

  Prioritization of maintenance tags are based on severity of the issues found, fire ignition potential (i.e., asset-conditions impacting issues associated with HFTD areas and High Fire Risk Area), probability of failure and the Wildfire Consequence Model. As conditions are identified, they are given a time-based priority based on guidance in PG&E's Electric Transmission Preventative Maintenance Manual. For certain tags (E and F priority tags), additional prioritization occurs based on the damage found. Time dependent conditions (meaning that the damage can worsen with time) with ignition potential are typically prioritized before other non-time dependent, non-ignition potential tags. Execution of the prioritized work plan would also have to address other factors such as clearance availability, access, work efficiency, etc.

  Additionally, replacement of assets in HFTD areas also may reduce wire down event risk. This reduction can be a combination of replacing aged, degraded assets, as well as providing more robust, up-to-standard designs. Asset removal eliminates wire-down event risk by removing the energized electrical components.

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

PG&E operates our lines in ET corridors that are home to vast amounts of vegetation. This vegetation ranges from sparse to extremely dense. Our transmission lines also pass through urban, agricultural, and forested settings. The corridor environment is dynamic and requires focused attention to ensure vegetation stays clear of energized conductors and other equipment. Vegetation inspection is a required operational step in an overall Vegetation Management (VM) Program. Accordingly, PG&E has developed an annual inspection cycle program as part of our overall Transmission VM Program to respond to the diverse and dynamic environment of our service territory. The Routine North American Electric Reliability Corporation (NERC) and Routine Non-NERC Programs are annually recurring. The Integrated Vegetation Management (IVM) Program maintains cleared ROWs on a recurs every 3- to 5-year cycles. The frequency and prioritization for each of these programs is described in more detail below.

- <u>Routine NERC</u>: The Routine NERC Program includes Light Detection and Ranging (LiDAR) inspection, visual verification of findings, and mitigation of vegetation encroachments, as well as other vegetation conditions on approximately 6,800 miles of NERC Critical lines.100 percent inspection and work plan completion are required by NERC Standard FAC-003-4. Work is prioritized based on aerial LiDAR detection. This program recurs annually.
- <u>Routine Non-NERC</u>: The Non-Routine NERC Program includes LiDAR inspection, visual verification of findings, and mitigation of vegetation encroachments, as well as other vegetation conditions on approximately 11,400 miles of transmission lines not designated as critical by NERC. Work is prioritized based on aerial LiDAR detection. This program recurs annually.

- Integrated Vegetation Management: The IVM Program is an ongoing maintenance program designed to maintain cleared ROWs in a sustainable and compatible condition by eliminating tall-growing and fire-prone vegetation and promoting low-growing, compatible vegetation. Prioritization is based on aging of work cycles and evaluation of vegetation re-growth. After initial work is performed, the ROWs are reassessed every two to five years.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3.5

SAFETY AND OPERATIONAL METRICS REPORT:

WIRES DOWN RED FLAG WARNING DAYS IN HFTD AREAS

(DISTRIBUTION)

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3.5
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CHAPTER 3.5
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A. Overview

1. Metric Definition

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

Number of Wires Down events in High Fire Threat District (HFTD) Areas on Red Flag Warning (RFW) Days involving overhead primary distribution circuits divided by RFW Distribution Circuit-Mile Days in HFTD Areas, in a calendar year.

2. Introduction of Metric

This metric measures the number of distribution wire down events located in the Tier 2 and Tier 3 HFTD areas that occurred on RFW Days and is divided by sum of days and line miles (of the Tier 2 and Tier 3 HFTD overhead distribution line miles involved on each RFW Day). In 2012, Pacific Gas and Electric Company (PG&E or the Company) initiated the Wires Down Program, including introduction of the wires down metric, to advance the Company's focus on public safety by reducing the number of conductors that fail and result in a contact with the ground, a vehicle, or other object.

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

B. Metric Performance

1. Historical Data (2013-2021)

There are nine years of historical data available from 2013 to 2021. Although PG&E started measuring distribution wire down incidents in the 2012, 2013 was the first full year uniformly measuring the number of distribution wire down incidents.

Over this historical reporting period, performance is largely influenced by external factors such as weather and third-party contact with our overhead electric facilities.

PG&E's overhead electric primary distribution system consists of approximately 81,000 circuit miles of overhead conductor and associated assets that could contribute to a wires down incident. Approximately 25,280 miles of our overhead electric primary distribution lines traverse in the HFTD areas.

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

- Investigating wire down incidents and implementing learnings and corrective actions;
- Performing infrared inspections of overhead electric power lines to identify and repair hot spots;
- Clearing of vegetation hazards posing risks to our overhead electric facilities;
- Replacing deteriorated overhead electric line conductors with newer line conductors; and
- Hardening of overhead electric power systems with more resilient equipment.

In addition, our vegetation management teams conduct site visits of vegetation caused wires down incidents as part of its standard tree caused service interruption investigation process. The data obtained from site visits supports efforts to reduce future vegetation caused wires down incidents. The data collected from these investigations also helps identify failure patterns by tree species that are associated with wires down incidents.

PG&E's asset data base reflects the circuit miles that currently exist, and it does not specifically maintain line miles by HFTD in prior years. As such, all wire down rates are based on a total of 25,278.5 overhead distribution circuit line miles and assumes annual variances due to the circuit miles are considered to be negligible.

For the calculation of this metric, both the HFTD overhead line miles and number of wires down events are measured based on the area subjected by each specific RFW Day event and summed for each specific year.

FIGURE 3.5-1
ELECTRIC DISTRIBUTION
PRIMARY WIRES DOWN INCIDENTS PER RFW/CIRCUIT MILE-DAYS (2013-2021)

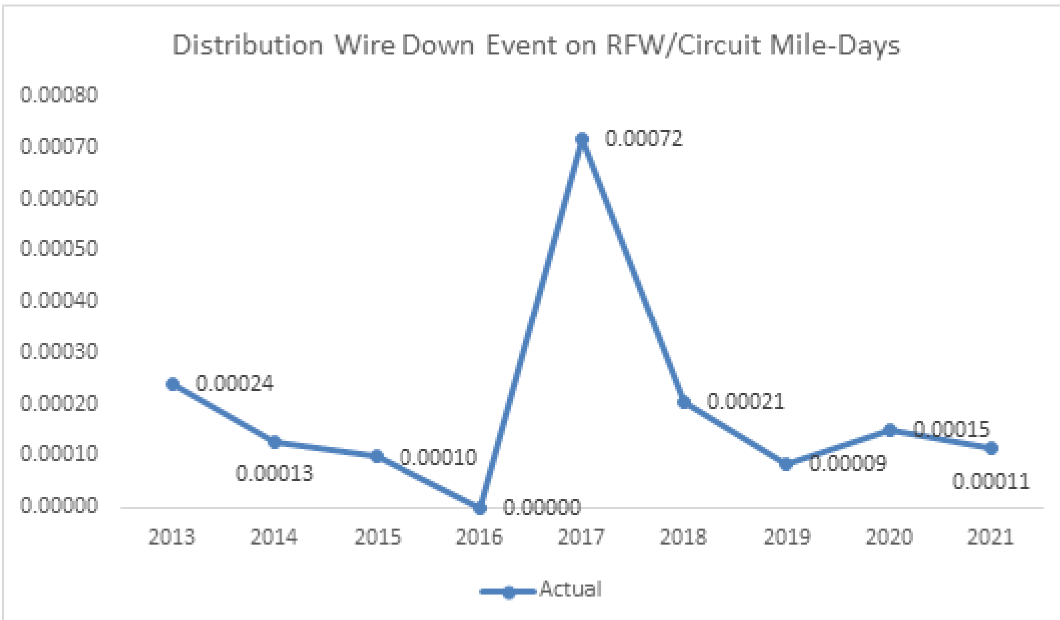

TABLE 3.5-1
ELECTRIC DISTRIBUTION
HISTORICAL RED FLAG CIRCUIT MILE DAYS (2013-2021)

Line No.	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	79,789	70,275	30,780	50,173	187,089	179,612	140,160	224,994	114,122

2. Data Collection Methodology

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

PG&E's meteorology group maintains a data base tracking RFW dates, time, and involved areas and determines RFW Circuit Miles Days as follows:

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

3. Metric Performance

As shown in Figure 3.5-1 above, the distribution wire down events on RFW days per circuit mile day has varied each year but has generally declined since 2017. 2021 experienced 13 wires down events on RFWs compared to 34 in 2020. Improved performance is attributed to ongoing efforts in reducing wires down events, in particular vegetation management and hardening.

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

C. 1-Year Target and 5-Year Target

1. Target Methodology

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

To establish the directional 1-year and 5-year targets, the following factors were considered:

- Historical Data and Trends: This metric is expected to remain within the historical performance levels, but will vary based on the number of RFWs and severity of weather experienced in a year;
- Benchmarking: Not available;
- Regulatory Requirements: None;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: The directional target for this metric is suitable for EOE, as it suggests performance will remain within the historical range, which accounts for unknown factors which may vary—such as the frequency and severity of weather;
- Attainable Within Known Resources/Work Plan: The directional target to maintain performance is attainable within known resources; however, this metric is impacted by the variability in conditions outside of PG&E's controls, such as the severity of weather on RFWs;
- Other Considerations: None.

2. 2022 Target

The 2022 target is to maintain within historical performance levels.

3. 2026 Target

The 2026 target is to maintain within historical performance levels.

D. Current and Planned Work Activities

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

- Overhead Conductor Replacement: PG&E's electric distribution system includes approximately 81,000 circuit miles of overhead conductor on its distribution system that operates between 4 and 21 kilovolts, including bare and covered conductors. Approximately 55,000 circuit miles of this distribution conductor, including approximately 40,000 circuit miles of small conductor is in non-HFTD areas. PG&E's Overhead Conductor Replacement Program, recorded in MAT 08J, proactively replaces overhead conductor in non-HFTD areas to address elevated rates of wires down and deteriorated/damaged conductors and to improve system safety, reliability, and integrity.

PG&E updated its prioritization process for overhead conductor replacements to include consideration the RAMP risk tranches with Safety Consequence Zones and/or shared protection zones with critical customer(s). The three focused tranches are: (1) corrosive regions with specific materials (ACSR), (2) elevated wires down (small copper conductors), and (3) poor reliability performance. The final definition of the Safety Consequence Zones is being developed, but currently takes into consideration: Within buffer zones near Major Transportation Infrastructure, Public Assembly Areas, and Public Safety Entities.

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

- Patrols and Inspections: PG&E monitors the condition of primary overhead conductor through patrols and inspections consistent with General Office 165 and targeted infrared inspections. Replacement plans are developed using failure rates obtained through wires down analysis and conductor-splice data. PG&E conducts post-event investigations of targeted equipment failure caused outages (i.e., wires down events involving conductor or splice failure). These investigations collect physical and environmental attributes to determine conductor replacement justification and priority as well as to determine failure trends. The information collected is entered into the "Engineer Investigation Wires Down Database." Analysis of this data has informed PG&E's strategy to focus replacement work on conductor types with elevated wires down rates, including small (#4 and #6 gauge) copper conductors and #4 ACSR conductors located in corrosion areas.

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

- Grid Design and System Hardening: PG&E's broader grid design program covers a number of significant programs, called out in detail in PG&E's 2022

Wildfire Mitigation Plan (WMP). The largest of these programs is the System Hardening Program which focuses on the mitigation of potential catastrophic wildfire risk caused by distribution overhead assets. In 2022, we are rapidly expanding our system hardening efforts by: completing 470 circuit miles of system hardening work which includes overhead system hardening, undergrounding and removal of overhead lines in HFTD or buffer zone areas; completing at least 175 circuit miles of undergrounding work, including Butte County Rebuild efforts and other distribution system hardening work; replacing equipment in HFTD areas that creates ignition risks, such as non-exempt fuses (3,000) and surge arresters (~4,500, all known, remaining in HFTD areas). As we look beyond 2022, PG&E is targeting 3,600 miles of Undergrounding to be completed between 2023 and 2026 as part of the 10,000 Mile Undergrounding program. This system hardening work done at scale is expected to have limited reliability benefit due rural HFTD geography, and is prioritized to mitigate wildfire risk, rather than reliability risk at this time. Please see Section 7.3.3, Grid Design and System Hardening Mitigations in PG&E's WMP for additional details.

- Enhanced Vegetation Management (EVM): The EVM Program is targeted at OH lines in Tier 2 and 3 HFTD areas and supplements PG&Es annual routine VM work with California Public Utilities Commission-mandated clearances. PG&E's VM Program, components of which exceed regulatory requirements, is critical to mitigating wildfire risk. PG&E's VM team inspects and identifies needed vegetation maintenance on all distribution and transmission circuit miles in PG&E's service area on a recurring cycle through Routine and Tree Mortality Patrols, as well as Pole Clearing. Our EVM Program goes above and beyond regulatory requirements for distribution lines by expanding minimum clearances and removing overhang in HFTD areas. In 2022 PG&E will complete 1,800 miles of EVM work.

  Please see Section 7.3.5, Vegetation Management and Inspections in PG&E's WMP for additional details.
- Other Advancements: In addition, there are several technologies that PG&E is piloting to better identify and/or prevent conductor to ground faults. This includes:
  - SmartMeter-based methods;

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

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3.6

SAFETY AND OPERATIONAL METRICS REPORT:

WIRES DOWN RED FLAG WARNING DAYS IN HFTD AREAS

(TRANSMISSION)

PACIFIC GAS AND ELECTRIC COMPANY
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A. Overview

1. Metric Definition

Safety and Operational Metric (SOM) 3.6 – Wires Down Red Flag Warning Days in HFTD Areas (Transmission) is defined as:

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

2. Introduction of Metric

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

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

B. Metric Performance

1. Historical Data (2013-2021)

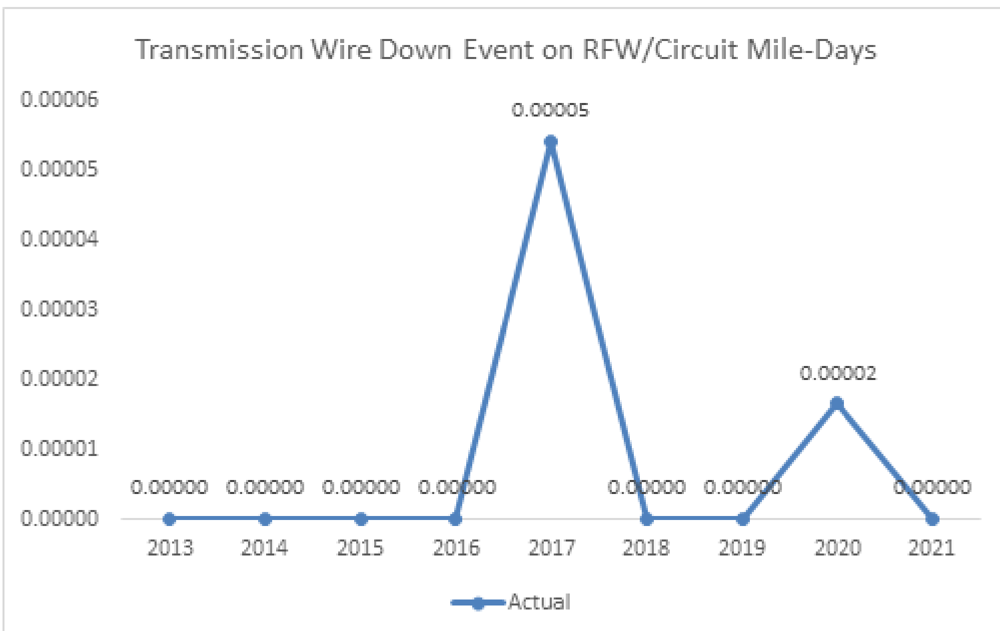
PG&E used nine years of historical data that includes the years 2013-2021 for target analysis. In 2012, PG&E initiated the Electric Wires Down Program, including introduction of the electric wires down metric, to address increased focus on public safety by reducing the number of electric wire conductors that fail and result in contact with the ground, a vehicle, or other object.

Initially the internal definition focused on wires down on the ground and in 2014 the definition was augmented to include wires down on foreign objects.

PG&E started measuring wire down incidents in the 2012, however, 2013 was the first full year we uniformly measured the number of transmission wire down events. Actual results over time have confirmed that PG&E experiences more wire down events on days where storms are prevalent.

It should also be noted that when calculating this metric, both the HFTD overhead line miles and number of wires down events are measured based on the area subjected by each specific RFW Day event and summed for each specific year.

FIGURE 3.6-1
ELECTRIC TRANSMISSION
PRIMARY WIRES DOWN INCIDENTS PER RFW/CIRCUIT MILE-DAYS (2013-2021)



2. Transmission RFW Circuit Mile Days

TABLE 3.6-1
ELECTRIC TRANSMISSION
HISTORICAL RED FLAG CIRCUIT MILE DAYS (2013-2021)

Line No.	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	24,220	22,115	8,576	17,316	55,362	44,291	36,238	60,675	27,335

3. Data Collection Methodology

PG&E used its transmission outage database, typically referred to as Transmission Operations Tracking & Logging to count the number of these events. Although PG&E's outage database does not specifically identify the precise location of the downed wire, PG&E uses the Lat/Long of the device used to operate/isolate the involved line section as a proxy and then uses its Electric Distribution Geographic Information System application to determine if that point is in a Tier 2 or Tier 3 HFTD area. Although PG&E maintains historical line miles of its entire transmission system, it does not have the ability to identify the line miles specifically located within Tier 2 and Tier 3 HFTD in prior years. As such, these annual metrics all use the same current transmission and distribution Tier 2 and Tier 3 HFTD line miles as of the end of 2021.

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

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

4. Metric Performance

As shown in Figure 3.6-1, the transmission wire down events on RFW days per circuit mile day is a very small subset of wire down events, making it difficult to identify any trending information. Zero events occurred in 2021, whereas 2020 experienced one. Since 2013, only two years have experienced any Transmission Wire Down events on RFWs; 2017 (3) and 2020 (1), respectively.

C. 1-Year Target and 5-Year Target

1. Target Methodology

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

Note that there has not been enough historic electric transmission wire down events on RFW days to establish a target based on prior performance.

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

D. Current and Planned Work Activities

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

- Asset Inspection: Enhanced detailed inspections (i.e., enhanced inspections) of overhead transmission assets seek to proactively identify and treat pending failures of asset components which could create future wire down, outage, and/or safety events if left unresolved or allowed to “run to failure.” Enhanced inspections for transmission assets involve at least two detailed inspection methods per structure: ground and aerial. In addition to the ground and aerial inspections, climbing inspections are also required for 500 kilovolt structures or as triggered. All these inspection methods involve detailed, visual examinations of the assets with use of inspection checklists that are in accordance with the Electric Transmission Preventive Maintenance (TD-1001M), as well as the Failure Modes and Effects Analysis. Aerial inspections may be completed either by drone, helicopter, or aerial lift.

- Asset Repair and Replacement: Completing repair, replacement, and life extension to transmission assets provides the benefit of reduced probability of failure for components that could potentially result in a wire down event. Most corrective maintenance notifications are identified as a result of transmission asset inspections and patrols.

  Prioritization of maintenance tags are based on severity of the issues found, fire ignition potential (i.e., asset-conditions impacting issues associated with HFTD areas and High Fire Risk Area), probability of failure and the Wildfire Consequence Model. As conditions are identified, they are given a time-based priority based on guidance in PG&E's Electric Transmission Preventative Maintenance Manual. For certain tags (E and F priority tags), additional prioritization occurs based on the damage found. Time dependent conditions (meaning that the damage can worsen with time) with ignition potential are typically prioritized before other non-time dependent, non-ignition potential tags. Execution of the prioritized work plan would also have to address other factors such as clearance availability, access, work efficiency, etc.

  Additionally, replacement of assets in HFTD areas also may reduce wire down event risk. This reduction can be a combination of replacing aged, degraded assets, as well as providing more robust, up-to-standard designs. Asset removal eliminates wire-down event risk by removing the energized electrical components.

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

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

- Routine NERC: The Routine NERC Program includes Light Detection and Ranging (LiDAR) inspection, visual verification of findings, and mitigation of vegetation encroachments, as well as other vegetation conditions on approximately 6,800 miles of NERC Critical lines.100 percent inspection and work plan completion are required by NERC Standard FAC-003-4. Work is prioritized based on aerial LiDAR detection. This program recurs annually.
- Routine Non-NERC: The Non-Routine NERC Program includes LiDAR inspection, visual verification of findings, and mitigation of vegetation encroachments, as well as other vegetation conditions on approximately 11,400 miles of transmission lines not designated as critical by NERC. Work is prioritized based on aerial LiDAR detection. This program recurs annually.
- Integrated Vegetation Management: The IVM Program is an ongoing maintenance program designed to maintain cleared ROWs in a sustainable and compatible condition by eliminating tall-growing and fire-prone vegetation and promoting low-growing, compatible vegetation. Prioritization is based on aging of work cycles and evaluation of vegetation re-growth. After initial work is performed, the ROWs are reassessed every two to five years.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3.7

SAFETY AND OPERATIONAL METRICS REPORT:

MISSED OVERHEAD DISTRIBUTION PATROLS IN HFTD AREAS

PACIFIC GAS AND ELECTRIC COMPANY
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1. Metric Definition

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

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

2. Introduction of Metric

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

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

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

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

- The due date for each map is based on the date the map was last inspected or patrolled;

- Inspections or patrols may not exceed three additional months past the previous inspection or patrol date (maximum 15 months);
- Inspections or patrols may be performed before the due date;
- Under a due date of 12 months (maximum 15 months) since the last patrol or inspection, at least one patrol or inspection should occur each calendar year; and
- The start of an inspection or a patrol starts a new inspection or patrol interval that must be completed within the prescribed timeframe.

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

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

B. Metric Performance

1. Historical Data

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

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

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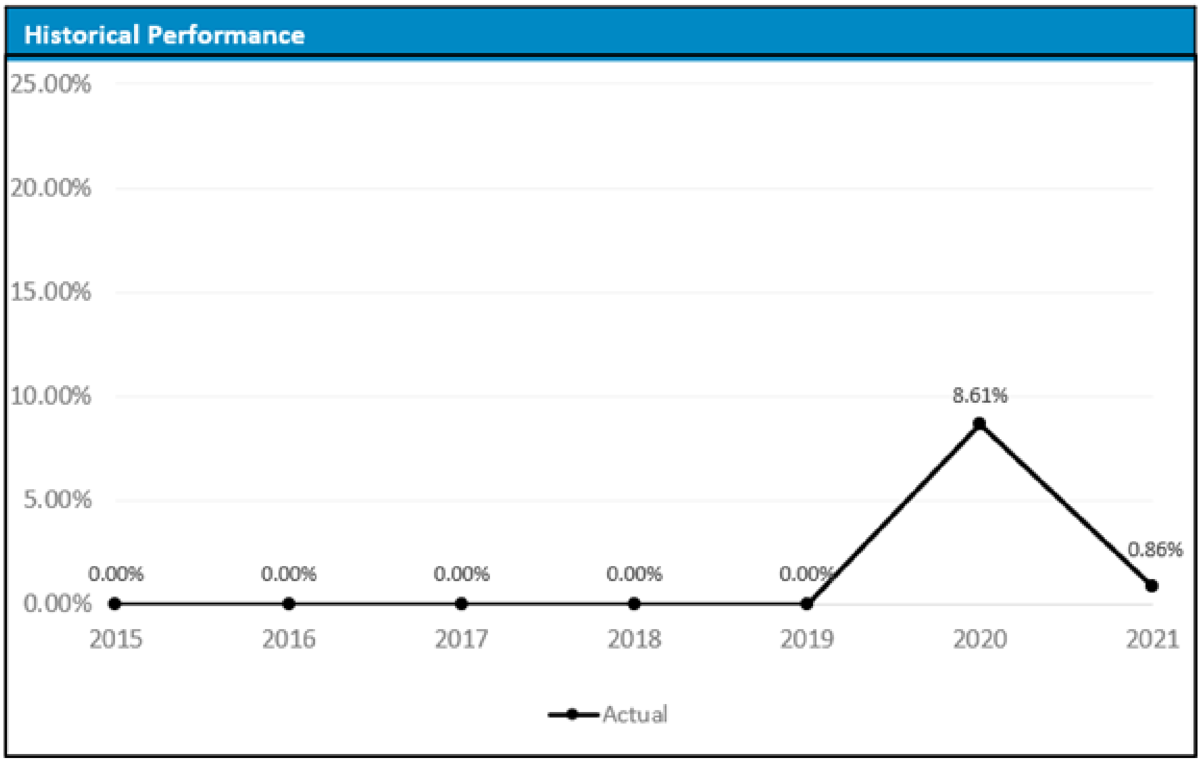
[1] Historical patrol data is at plat map level vs. structure level. We are further validating plat based results for HFTD vs. NHFTD units, we may see slight changes to volumes completed late vs. on time, or vice-versa.

performance for completing patrols in these years was 0.01 percent completed late.

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

FIGURE 3.7-1
HISTORICAL PERFORMANCE (2015-2021)



Note: Actual performance as follows between 2015-2019: 2015: 0.0003%, 2016: 0.0003%, 2017: 0.0000%, 2018: 0.0002%, 2019: 0.0015%.

2. Data Collection Methodology

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

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

3. Metric Performance

Between 2015-2019, PG&E's annual performance for completing patrols by the CPUC "12+3" due date was 0.01 percent completed late. These results demonstrate our commitment to meet GO 165 CPUC "12+3" due dates.

For the years 2020 and 2021, performance was impacted by the shift to the described wildfire risk reduction-focused approach, and away from completing overhead patrols by the "12+3" calculated due date.

C. 1-Year and 5-Year Target

1. Target Methodology

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

- Historical data and trends: Based on historical performance of 0.01 percent completed late (2015-2019) and the results of the more recently used wildfire risk reduction approach (2020-2021). In 2022 PG&E intends to improve performance by completing overhead patrols to (1) be in compliance with GO 165, with a target range of 0.00 percent-0.05 percent completed late, and (2) incorporate Asset Strategy risk models.
- Benchmarking: Not available;
- Regulatory Requirements: GO 165;
- Attainable Within Known Resources/Work Plan: Targeted performance is attainable within PG&E's currently known resource plan;
- Appropriate/Sustainable Indicators for Enhanced Oversight Enforcement: The target range is a suitable indicator for EOE as it intends to return PG&E to historical levels of near-zero percent non-compliances while also incorporating reasonable impacts resulting from prioritizing wildfire risk reduction, and therefore avoiding potential unintended consequence of conformance to risk reduction.

- Other Considerations: None.

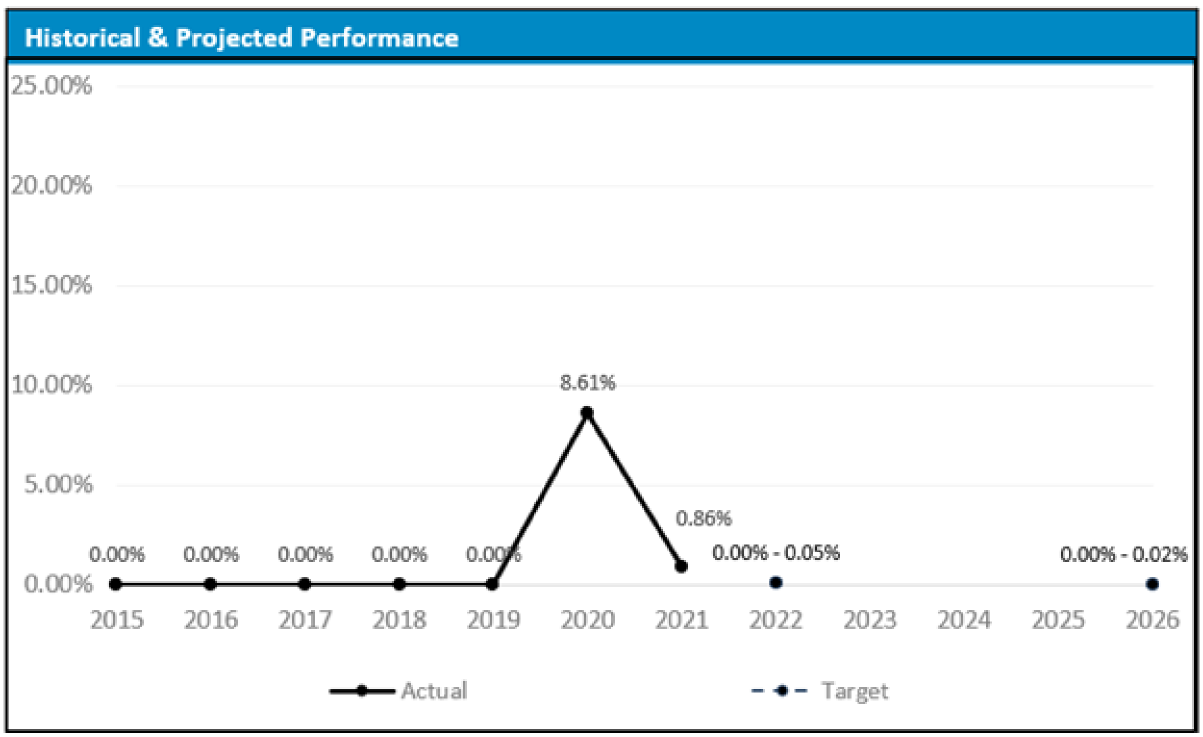
2. 2022 Target

The 2022 target is 0.00 percent-0.05 percent to improve performance compared to 2021 based on the factors described above.

3. 2026 Target

The 2026 target is 0.00 percent-0.02 percent to improve performance compared to 2022, based on the factors described above, and the commitment to continuously improve performance.

FIGURE 3.7-2
HISTORICAL PERFORMANCE (2015-2021) AND TARGETS (2022 AND 2026)



D. Current and Planned Work Activities

- Visibility and Compliance: Beginning in 2022, Supervisors and Inspectors will see the CPUC due dates for each patrol package to ensure understanding as to the due date of the overhead patrol.
- Tracking:

- System Inspections will track progress and completion of overhead patrols on a continuous basis, using detailed excel tracking spreadsheets and SAP data.
- System Inspections will track and report-out on any “late” overhead patrols, including identifying mitigating factors and implementing process improvements or changes to the program.
- System Inspections will track timeliness of patrols being completed on their weekly scorecard.

- Training: System Inspections will conduct refresher training to ensure understanding of the importance of patrols in identifying obvious structural problems and hazards in years where an inspection is not required.
- Maintenance Plan Management Tool: System Inspections Maintenance Planners will complete timely review and completion of changes to structures and maintenance plans by way of the “maintenance plan management tool.”

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3.8

SAFETY AND OPERATIONAL METRICS REPORT: MISSED OVERHEAD DISTRIBUTION DETAILED INSPECTIONS IN HFTD AREAS

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A. Overview

1. Metric Definition

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

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

2. Introduction of Metric

Detailed inspections are performed to identify non-conformances affecting safety or reliability. Within 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.

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

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

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

- The due date for each map is based on the date the map was last inspected or patrolled;
- Inspections or patrols may not exceed three additional months past the previous inspection or patrol date (maximum 15 months);
- Inspections or patrols may be performed before the due date;
- Under a due date of 12 months (maximum 15 months) since the last patrol or inspection, at least one patrol or inspection should occur each calendar year; and
- The start of an inspection or a patrol starts a new inspection or patrol interval that must be completed within the prescribed timeframe.

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

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

B. Metric Performance

1. Historical Data

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

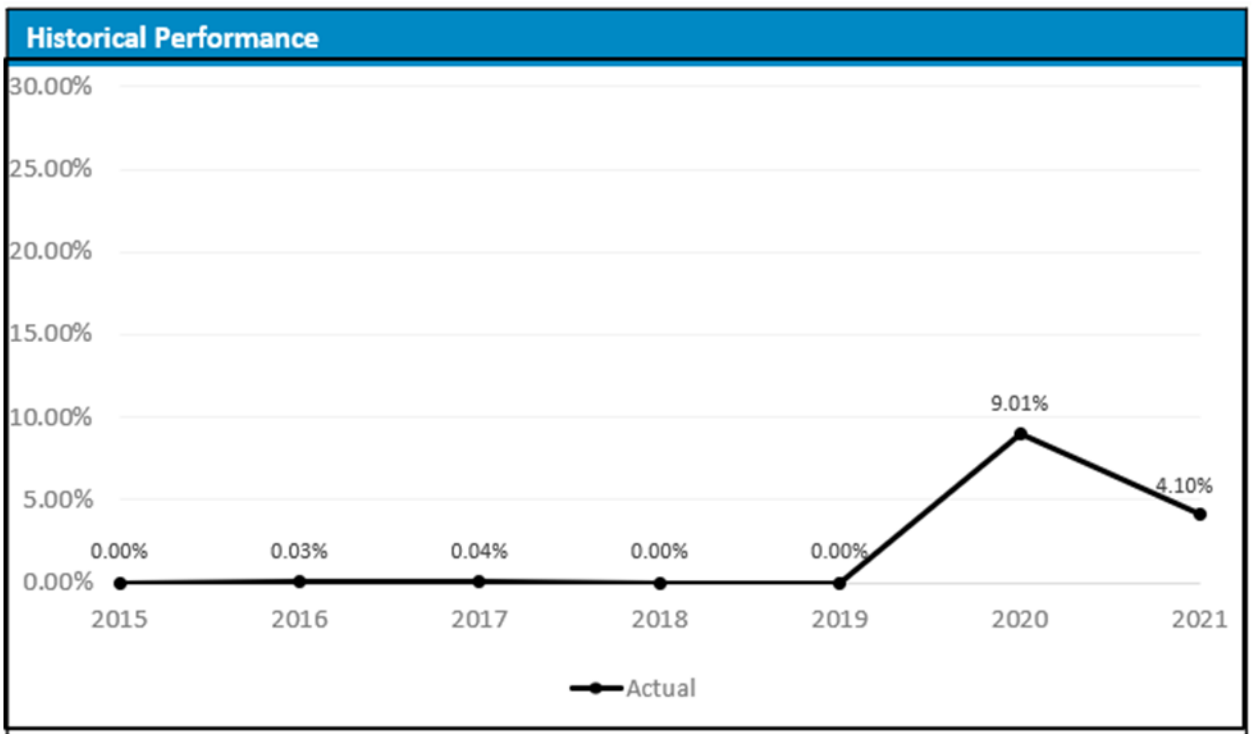
Prior to 2020, PG&E completed inspections on paper by plat map. Each plat map had a calculated "12+3" due date based on the start date of the last patrol or inspection for that plat map. For the years 2015 – 2019, PG&E tracked and measured performance of inspections based on the "12+3" calculated due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

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

and end dates for each plat map, as well as actual units and PG&E LAN ID (login ID) of the Inspector who completed the work. PG&E's annual performance for completion and inspections in these years was 0.01-0.04 percent completed late.

For the years 2020 and 2021, PG&E's performance was impacted by the shift to the described wildfire risk reduction focused approach and away from completing overhead inspection by the "12+3" calculated due date.

FIGURE 3.8-1
HISTORICAL PERFORMANCE (2015-2021)



2. Data Collection Methodology

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

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

3. Metric Performance

Between 2015-2019, PG&E's annual performance for completing inspections by the CPUC "12+3" due date was 0.01-0.04 percent completed late. These results demonstrate our commitment to meet GO 165 CPUC "12+3" due dates.

For the years 2020 and 2021, performance was impacted by the shift to a wildfire risk reduction focused approach and away from completing overhead inspections by the "12+3" calculated due date.

C. 1-Year and 5-Year Target

1. Target Methodology

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

- Historical Data and Trends: Based on historical performance of 0.01-0.04 percent completed late (2015-2019) and the results of the more recently used wildfire risk reduction approach (2020-2021), in 2022 PG&E intends to improve performance by completing overhead inspections to: (1) be in compliance with GO 165, with a target range of 0.00 percent-0.05 percent completed late, and (2) incorporate Asset Strategy risk models;
- Benchmarking: Not available;
- Regulatory Requirements: GO 165;
- Attainable Within Known Resources/Work Plan: Targeted performance is attainable within PG&E's currently known resource plan;
- Appropriate/Sustainable Indicators for Enhanced Oversight Enforcement: The target range is a suitable indicator for EOE as it intends to return PG&E to historical levels of near-zero percent non-compliances while also incorporating reasonable impacts resulting from prioritizing wildfire risk reduction, and therefore avoiding potential unintended consequence of conformance to risk reduction; and
- Other Considerations: None.

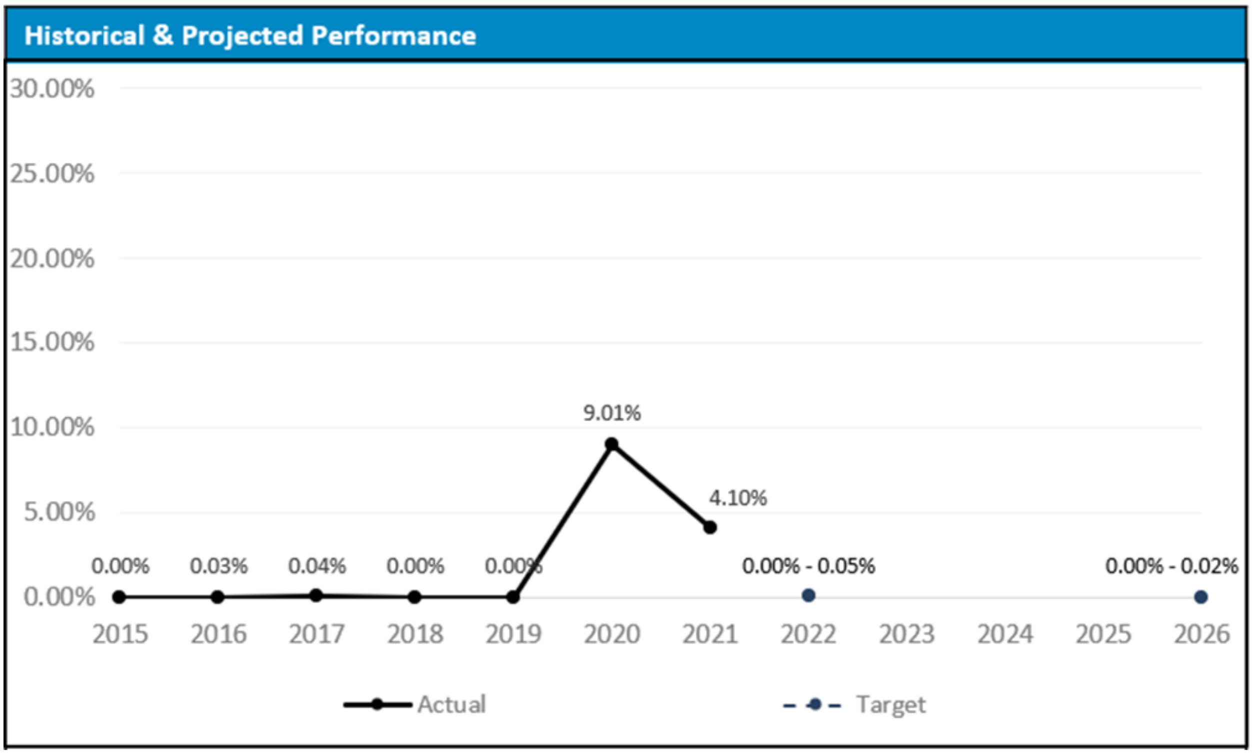
2. 2022 Target

The 2022 target is 0.00 percent-0.05 percent to improve performance compared to 2021 based on the factors described above.

3. 2026 Target

The 2026 target is 0.00 percent-0.02 percent to improve performance compared to 2022 based on the factors described above and the commitment to continuously improve performance.

FIGURE 3.8-2
HISTORICAL PERFORMANCE (2015-2021) AND TARGETS (2022 AND 2026)



D. Current and Planned Work Activities

- Visibility and Compliance: Beginning in 2022, Supervisors and Inspectors will see the CPUC due dates for each inspection that is due to ensure understanding as to the due date of the overhead inspection.
- Tracking:
  - System Inspections will track progress and completion of overhead inspections on a continuous basis, using detailed SAP data reports and excel tracking spreadsheets.
  - System Inspections will track and report-out on any “late” overhead inspections, including identifying mitigating factors and implementing process improvements or changes to address gaps.

- System Inspections will track timeliness of inspections being completed on their weekly scorecard.

- Training: System Inspections conducts annual "Refresher" training on overhead inspections, which includes focus on anything that has changed since the previous year (guidance, standards, procedures), including updates to the INSPECT application, inspection checklists, and associated Inspector job aids.
- Asset Strategy – Monthly Inspection Validations: Monthly inspection validations will continue to identify required additions to the original plan arising from additions or changes to the asset registry.
- Asset Strategy – Ad Hoc Inspections: Asset Strategy will continue to evaluate the asset registry and may identify additional "ad hoc" structures to be inspected each year, based on analysis related to ignition risk, etc.
- Maintenance Plan Management Tool: System Inspections Maintenance Planners will complete timely review and completion of changes to structures and maintenance plans by way of the "maintenance plan management tool."
- Desktop Quality Control: System Inspections conducts desktop work verification activities on a valid sample size of completed inspections to evaluate the completeness and quality of inspections.
- Quality Control Field Work Verification: System Inspections conducts "blind" field work verification activities on a valid sample size of completed inspections to evaluate the completeness and quality of inspections.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3.9

SAFETY AND OPERATIONAL METRICS REPORT:

MISSED OVERHEAD TRANSMISSION PATROLS IN HFTD AREAS

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A. Overview

1. Metric Definition

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

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

2. Introduction of Metric

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

All assets require either a detailed inspection or a patrol each year. While detailed inspections have shifted from circuit-based cycles to an inspection frequency that depends on HFTD and structure-level risk considerations, patrols are performed by circuit. Therefore, any line that does not receive a detailed inspection from end-to-end will require a patrol and it is possible for some structures to receive both an inspection and a patrol in the same year. Patrols may be performed either by air (helicopter) or ground (walking or driving). Compared to transmission detailed inspections, the transmission OH patrol program has not undergone significant changes over the reporting period from 2015-present. Starting in 2021, Pacific Gas and Electric Company (PG&E) imposed an in-year deadline of July 31 for patrols on circuits containing HFTD or High Fire Risk

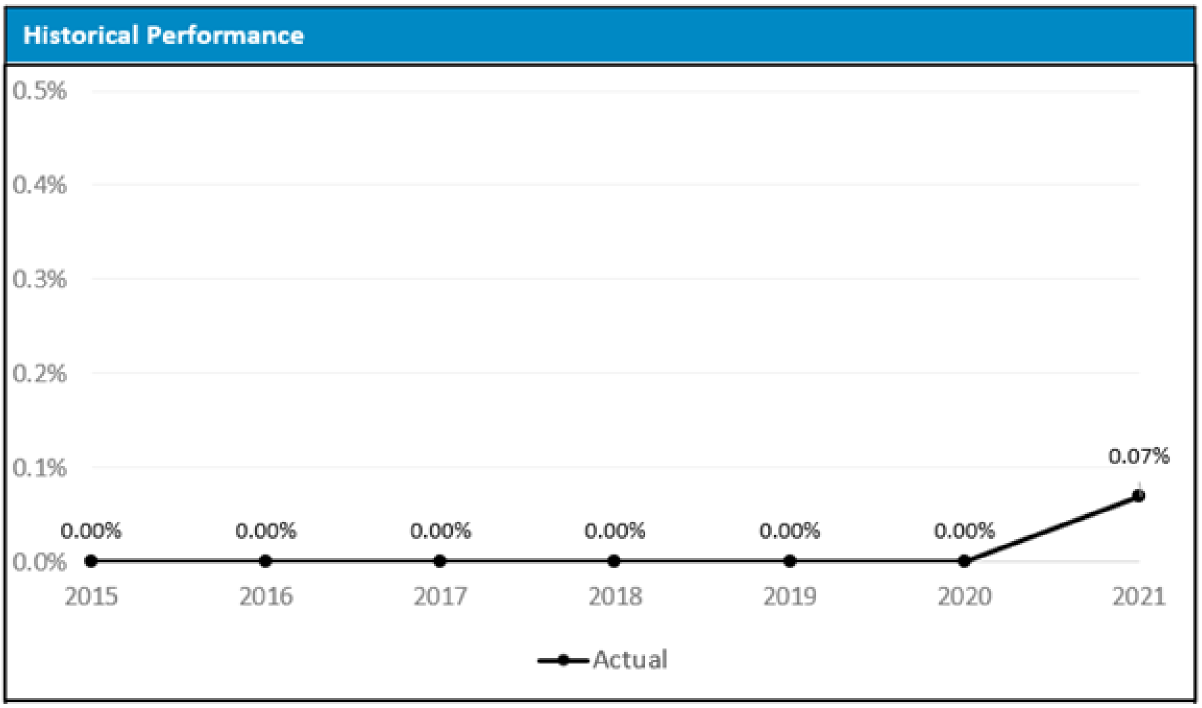
Area structures. Monthly validations of the inspection plan were started in June 2021 to ensure that all assets were either inspected or patrolled each year, including assets that were newly added to the asset registry. The in-year deadline of July 31 introduced in 2021 for inspections and patrols in HFTD will continue to be used in 2022. Beginning in 2022, assets added to the registry after July 31 or whose HFTD changes after July 31 will not be considered late as in 2021, provided that they are inspected or patrolled within 90 days of the addition to the registry or the HFTD change.

B. Metric Performance

1. Historical Data (2015-2021)

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

FIGURE 3.9-1
HISTORICAL PERFORMANCE (2015-2021)



2. Data Collection Methodology

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

3. Metric Performance

Very few patrols were missed through 2020, rounding to 0.00 percent each year. The increase in missed patrols in 2021 to 0.07 percent was driven by the implementation of a July 31 deadline, rather than only requiring the patrols to occur within the calendar year. The majority of late 2021 patrols involved assets added to the registry after July 31 or where the asset location was corrected from non-HFTD to HFTD after July 31. The remaining late patrols were on a set of double-circuit towers in which a patrol prior to July 31 was only confirmed on one circuit.

C. 1-Year Target and 5-Year Target

1. Target Methodology

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

- Historical Data and Trends: The July 31 deadline for HFTD patrols was first applied in 2021 and is still in practice. Therefore targets use 2021 performance as a baseline with incremental improvement for the reasons described below;
- Benchmarking: Not available;
- Regulatory Requirements: Relevant items include: (1) General Order 165 requirements to follow internal maintenance procedures, and (2) Wildfire Mitigation Plan targets to perform HFTD inspections and patrols by July 31;
- Attainable Within known Resources/Work Plan: Targets are attainable within currently known resources;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: Targets are suitable indicators for EOE as historical driver of worsening performance (asset registry changes after July 31) will have an allowance to be counted as on time if inspected within 90 days of the addition to the registry or HFTD change beginning in 2022. This update ensures that the metric is an appropriate indicator of performance by focusing the measure on timely action to complete inspections as opposed to asset registry completeness; and
- Other Considerations: The issue of patrols on both sides of double-circuit structures was considered in the development of the 2022 Inspection and Patrol plan. If an inspection validation in 2022 concludes that a structure needs to have a patrol added, the validation will call for a patrol on all circuits on the structure (alternately, the structure may receive a detailed inspection, which includes inspection of all circuits on the structure).

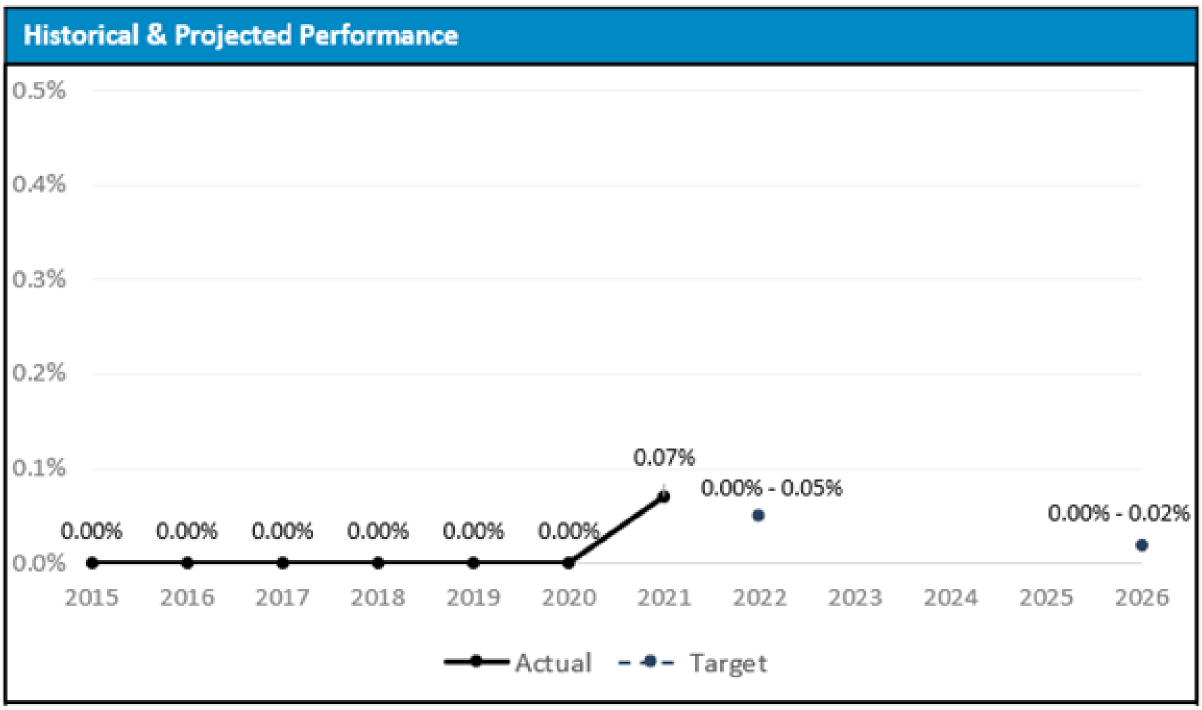
2. 2022 Target

The 2022 target is to improve performance to 0.00 percent-0.05 percent, based on the 90 day allowance for asset registry changes and consideration of double circuits described in the methodology above.

3. 2026 Target

The 2026 target is to improve performance to 0.00 percent-0.02 percent, based on the 90 day allowance for asset registry changes and consideration of double circuits described in the methodology above, as well as a reduction over time in the number of asset registry additions from assets being discovered in the field.

FIGURE 3.9-2
HISTORICAL PERFORMANCE (2015-2021) AND TARGETS (2022 AND 2026)



D. Current and Planned Work Activities

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

- <u>2022 Inspection and Patrol Plan</u>: The 2022 Inspection and Patrol plan has been created, which defines the initial scope of the HFTD patrols that fall under this metric. The plan contains approximately 200 circuits running through HFTD areas that will be patrolled.
- <u>Monthly Inspection Validations</u>: Monthly inspection validations, which also consider required patrols, will continue to identify required additions to the original plan arising from additions or changes to the asset registry. Changes in HFTD affect the scope of patrols covered by this metric.
- <u>In-Year Deadline Requirements</u>: The in-year deadline of July 31 introduced in 2021 for patrols in HFTD will continue to be used in 2022, with the same provisions for access issues as in 2021 and the addition of the 90-day

requirement described above for additions and changes to the asset registry. The deadline is tracked with the patrol orders so that each HFTD patrol is identified as having the July 31 compliance requirement.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3.10

SAFETY AND OPERATIONAL METRICS REPORT:

MISSED OVERHEAD TRANSMISSION DETAILED INSPECTIONS

IN HFTD AREAS

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A. Overview

1. Metric Definition

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

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

2. Introduction of Metric

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

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

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

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

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

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

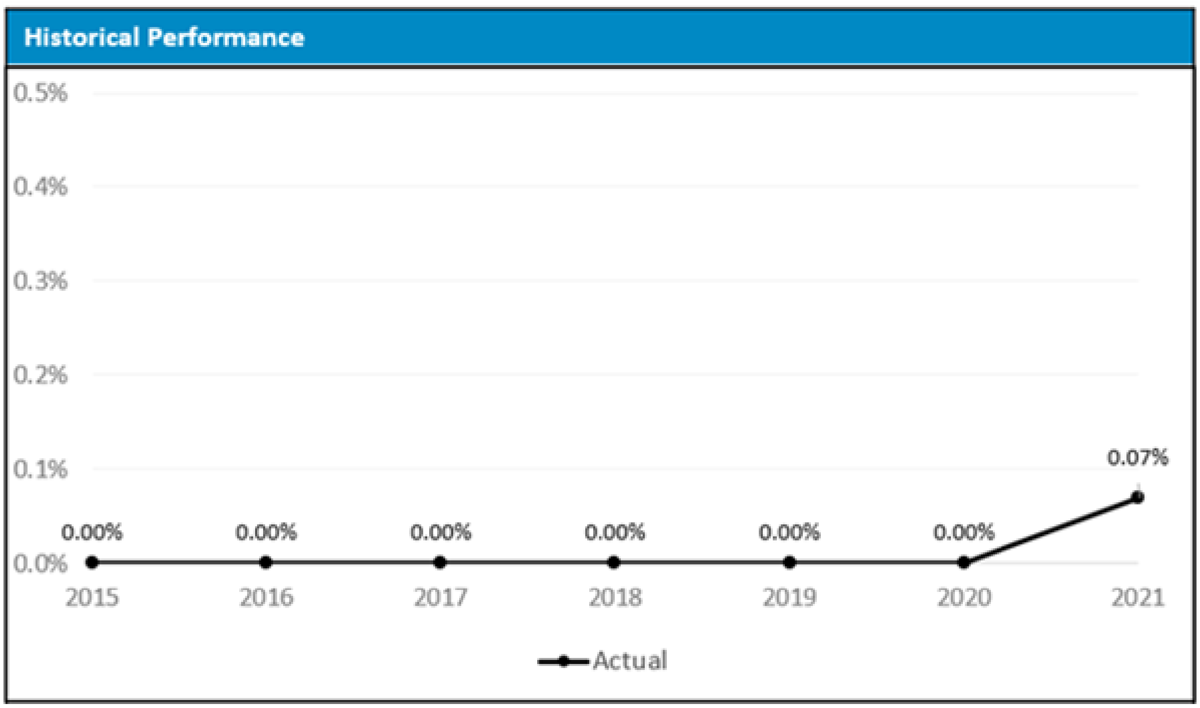
B. Metric Performance

1. Historical Data (2015-2021)

Historical data is provided from 2015-2021. Data provided for 2015-2019 reflects systemwide performance. HFTD-specific performance is not available prior to 2020. The percentage of missed inspections is calculated as the number of inspections not performed by the required deadline divided by the total number of inspections performed for that year.

Through 2020, there was not a specific in-year deadline for inspections, so the deadline was considered December 31. The July 31 deadline for HFTD inspections in 2021 allowed exceptions due to access issues, landowner refusal, or site-specific worker safety situations (i.e., Cannot Get In (CGI)) where an unsuccessful inspection attempt was made prior to the deadline. In 2021, HFTD structures added to the asset registry after July 31 and inspected after the July 31 deadline were counted as missed inspections, as well as instances where the asset location was corrected from non-HFTD to HFTD after July 31.

FIGURE 3.10-1
HISTORICAL PERFORMANCE | PERCENT LATE (2015-2021)



2. Data Collection Methodology

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

3. Metric Performance

Very few inspections were missed through 2020, rounding to 0.00 percent each year. The increase in missed inspections in 2021 to

0.07 percent was driven by the implementation of a July 31 deadline rather than only requiring the inspections to occur within the calendar year. All late 2021 inspections involved assets added to the registry after July 31, 2021, or where the asset location was corrected from non-HFTD to HFTD after July 31. All HFTD assets in the asset registry prior to July 31 were either inspected by the July 31 deadline or had a CGI.

C. 1-Year Target and 5-Year Target

1. Target Methodology

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

- Historical Data and Trends: The July 31 deadline for HFTD patrols was first applied in 2021 and is still in practice. Therefore targets use 2021 performance as a baseline with incremental improvement for the reasons described below;
- Benchmarking: Not available;
- Regulatory Requirements: Relevant items include: (1) General Order 165 requirements to follow internal maintenance procedures, and (2) Wildfire Mitigation Plan (WMP) targets to perform certain HFTD inspections and patrols by July 31;
- Attainable Within Known Resources/Work Plan: Targets are attainable within currently known resources;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: Targets are suitable indicators for EOE as historical driver of worsening performance (asset registry changes after July 31) will have an allowance to be counted as on time if inspected within 90 days of the addition to the registry or HFTD change beginning in 2022. This update ensures that the metric is an appropriate indicator of performance by focusing the measure on timely action to complete inspections as opposed to asset registry completeness; and
- Other Considerations: None.

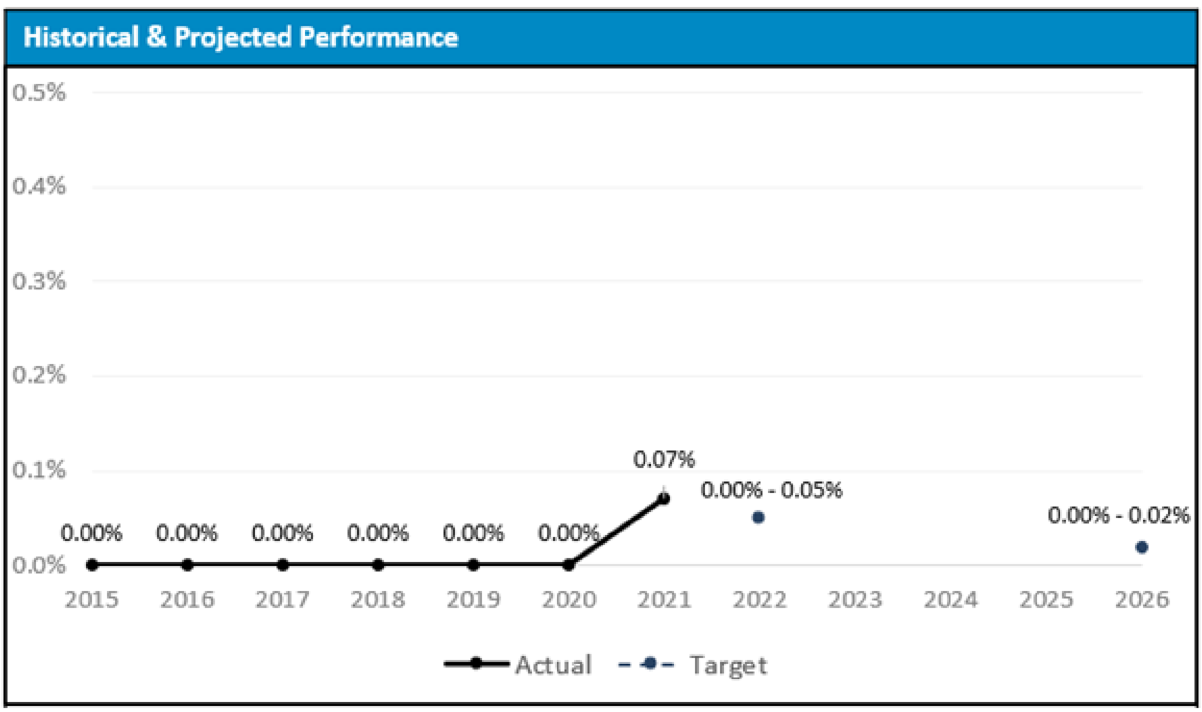
2. 2022 Target

The 2022 target is to improve performance to 0.00 percent-0.05 percent, based on the 90 day allowance for asset registry changes described in the methodology above.

3. 2026 Target

The 2026 target is to improve performance to 0.00 percent-0.02 percent, based on the 90-day allowance for asset registry changes described in the methodology above, as well as a reduction over time in the number of asset registry additions from assets being discovered in the field.

FIGURE 3.10-2
HISTORICAL PERFORMANCE (2015-2021) AND TARGETS (2022 & 2026)



D. Current and Planned Work Activities

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

- <u>2022 Inspection and Patrol Plan</u>: The 2022 inspection plan has been created and contains approximately 39,000 Tier 3 and Tier 2 structures receiving ground and aerial inspections and approximately 1,800 structures that also will receive a climbing inspection. These numbers were reported in the WMP, which includes some Zone 1 and HFRA structures that do not fall under the scope of this metric (Tier 3 and Tier 2 only). Additional evolution of the scope may occur through the inspection validation process described below.

- Monthly Inspection Validations: Monthly inspection validations will continue to identify required additions to the original plan arising from additions or changes to the asset registry. Changes in HFTD may affect the scope of inspections covered by this metric.
- In-Year Deadline Requirements: The in-year deadline of July 31 introduced in 2021 for inspections in HFTD will continue to be used in 2022, with the same provisions for CGI access issues as in 2021 and the addition of the 90 day requirement described above for additions and changes to the asset registry. The deadline is tracked with the inspection and patrol orders so that each HFTD inspection is identified as having the July 31 compliance requirement.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3.11

SAFETY AND OPERATIONAL METRICS REPORT:

GO-95 CORRECTIVE ACTIONS IN HFTDS

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1. Metric Definition

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

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

GO 95, Rule 18, Priority Level 2 has four relevant timeframes for corrective action: (1) six months for potential violations that create a fire risk in Tier 3 of HFTD; (2) 12 months for potential violations that create a fire risk in Tier 2 of HFTD; (3) 12 months for potential violations that compromise worker safety; and (4) 36 months for all other Level 2 potential violations.[2]

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

2. Introduction to the Metric

The GO 95 Corrective Actions in HFTD metric measures the number of Priority Level 2 corrective notifications (tags) in HFTD that are completed in accordance with the GO 95 Rule 18 timelines. This metric is associated with our Failure of Electric Distribution Overhead Asset Risk and our Wildfire Risk, which are part of our 2020 Risk Assessment and Mitigation Phase Report filing. Vegetation Management (VM) work generally follows wildfire risk priorities. Priority notifications are tracked to completion against procedural timelines that are consistent with the underlying risk of the work.

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

2 GO 95 Rule 18, B1ai-aiii.

3. Background

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

- Corrective Notifications Identified from Inspections: PG&E routinely inspects our electric assets using a variety of methods, including observations when performing work in the area, periodic patrols and inspections, and targeted condition-based and/or diagnostic testing and monitoring. These inspections of our overhead and underground electric assets are designed to meet GO 95, 165, and 174 requirements. Regarding our equipment inspections process, when an inspector identifies a maintenance condition, the inspector either immediately corrects (e.g., performs minor repair work) the condition and records the correction or records the uncorrected condition, which is also reviewed by a Centralized Inspection Review (CIRT) team. 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).

  In addition, the inspector fills out the initial corrective notification tag. The centralized review team approves and prioritizes the corrective notification tag in our Work Management system. These tags are prioritized based on the risk posed by the condition and urgency of repairs. We also inspect vegetation in the vicinity of our facilities and apply a similar process, described below.

  In regard to Priority Level 2 electric notifications pertaining to our equipment inspections, we have subdivided Priority Level 2 into two categories: Priority "B" and Priority "E". Priority "B" notifications are scheduled to be addressed within 3 months for Tiers 2 and 3. Priority "E" are scheduled to be completed within 6 months for Tier 3 and 12 months for Tier 2.

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

  When an inspector identifies a clearance condition or a potential tree hazard, they record an abatement prescription (tree work) within VM's data systems. This tree work is assigned to tree crews unless there are constraints that require prior resolution (e.g., customer access, city or agency permits). Tree crews confirm the completion of tree work within the VM data systems. VM tree work identified in this way does not follow the EC or LC notification tag priority assignments. Our VM timeline to complete this tree work generally aligns with the risk presented by the vegetation and the risk reduction objectives of the VM Program.
- Priority Classifications and Timelines for Completion: We manage our corrective actions in HFTDs with a risk-informed prioritization of our work plans. Our strategy focuses on reducing wildfire risk associated with open corrective notifications. To accomplish this, we first address the highest risk Level 2 corrective notifications first (e.g., Level 1 and Level 2 Priority "B"). After that, we manage the inventory of Level 2 Priority "E" corrective notifications in a risk informed manner, where the highest risk Level 2 Priority "E" corrective notifications are targeted first, while deploying safety controls to manage the lower risk Level 2 Priority "E" corrective notifications. This approach allows strategic and targeted wildfire risk reductions, informed by risk spend efficiencies, to continue to be our primary focus.

We recognize that our electric Priority “B” notifications, which we consider having a higher likelihood of creating an equipment failure than other Level 2 Priority notifications, have a more aggressive timeline to address than GO 95 Rule 18 Priority Level 2. We will be revisiting this difference in the near future as we aim to take steps to further align our electric corrective action Priority levels with that of GO 95 Rule 18. However, consistent with Decision 21-11-009, we are reporting our performance against the timelines set forth in GO 95 Rule 18 and can provide, upon request, additional information as to how we are performing against our more aggressive internal timelines for our electric Priority “B” notifications. Furthermore, we are including all Electric Corrective (EC for Distribution) and Line Corrective (LC for Transmission) notifications, as well as all inspection-identified vegetation safety hazards that meet the definition of GO 95 Rule 18 Level 2.

The following table summarizes the priority classifications we use to comply with GO 95 Rule 18.

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

Line No.	GO 95 Rule 18	PG&E Priority	Description	GO 95 Rule 18 Timeline for Corrective Action	PG&E Internal Timeline for Corrective Action (Electric Notifications)	PG&E Internal Timeline for Corrective Action (Vegetation Tree Work)
1	Level 1	A (Electric) Priority 1 (Vegetation)	An immediate risk of high potential impact to safety or reliability	Take corrective action immediately, either by fully repairing or by temporarily repairing and reclassifying to a lower priority	Consistent with GO 95 Rule 18	Within 24 hrs. after identification
2	Level 2	B (Electric) Priority 2 or Dead & Dying (Vegetation)	Any other risk of at least moderate potential impact to safety or reliability: Take corrective action within specified time period (either by fully repair or by temporarily repairing and reclassifying to Level 3 priority).	Time period for corrective action to be determined at the time of identification by a qualified company representative, but not to exceed: 1. Six months for potential violations that create a fire risk located in Tier 3 of the HFTD. 2. 12 months for potential violations that create a fire risk located in Tier 2 of the HFTD.	Corrective action within 3 months from date condition identified for electric equipment	1. Within 20 business days from identification Priority 2 Tag. 2. Dead & Dying tree: a. Six months within Tier 3 & Tier 2 of the HFTD; and b. 12 months outside Tier 3 & Tier 2 of the HFTD.
3		E (Electric)	Any other risk of at least moderate potential impact to safety or reliability: Take corrective action within specified time period (either by fully repair or by temporarily repairing and reclassifying to Level 3 priority).	Time period for corrective action to be determined at the time of identification by a qualified company representative, but not to exceed: 1. Six months for potential violations that create a fire risk located in Tier 3 of the HFTD. 2. 12 months for potential violations that create a fire risk located in Tier 2 of the HFTD. 3. 12 months for potential violations that compromise worker safety; and 4. 36 months for all other Level 2 potential violations.	Corrective action within: 1. Six months for conditions that create a fire risk located in HFTD Tier 3 2. 12 months for conditions that create a fire risk located in HFTD Tier 2 Field Safety Re-assessment performed annually on time dependent tags to confirm Priority “E” Notification has not escalated to Priority A or B. If notification has escalated to Priority A or B, address according to timelines above.	N/A
4		H (Electric)	These are PG&E Priority “E” Notifications that are planned to be addressed by a planned System Hardening Project	Same as above	Field Safety Re-assessment performed annually on time dependent tags to confirm Priority “E” Notification has not escalated to a Priority A or B. If notification has escalated to Priority A or B, address according to timelines above.	N/A
5	Level 3	F (Electric)	Any risk of low potential impact to safety or reliability	Take corrective action within 60 months subject to the specific exceptions.[a]	1. Corrective actions for distribution assets to be addressed within five years from date condition identified. 2. Corrective actions for transmission assets to be addressed within two years from date condition identified.	N/A

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

B. Metric Performance

1. Historical Data

We are reporting historical data from the years 2020 and 2021.

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

Reported timelines generally align with VM adoption of updated internal timelines for Priority Tag mitigation and additional 'Dead & Dying' tree abatement identified through the implementation of PG&E Enhanced VM Program in 2019. The VM Program's work management system tracking these corrective actions is tracked in two separate databases. The Vegetation Management System (VMS) tracks work identified through its annual inspection programs. Tree work identified on its Enhanced Vegetation Management (EVM) Program is maintained in a geospatial platform named ArcGIS Online.

2. Data Collection Methodology

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

We are including all EC (Distribution) and LC (Transmission) notifications, as well as all inspection-identified vegetation safety hazards that meet the definition of GO 95 Rule 18 Level 2. Furthermore, we have included our corrective notification tags related to locations where we are unable to access for inspections (e.g., Can't Get In or CGI) in this population. We will re-visit in the future if these CGIs can be excluded from this reporting.

3. Metric Performance

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

As described in earlier sections, we are reporting and setting targets against the timeframes identified in GO 95 Rule 18 rather than the timelines articulated in our internal electric Priority “B” and “E” notifications, and internal VM Priority 2 and Dead and Dying Tree abatement corrective notifications. However, there may be some limited instances where PG&E is using more aggressive timelines than GO 95 Rule 18’s timelines.

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

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

Our approach for managing the inventory of Level 2 Priority “E” is to: (1) group high concentrations of individual capital intensive rebuild corrective notifications into new, more comprehensive, System Hardening projects, and (2) permanently remove electric lines out of service that have multiple corrective notifications and serve small numbers of customers, where service can be provided via alternate line interconnections or remote grid solutions, as well as individual corrective work execution for those Level 2 Priority “E” notifications that were of high wildfire risk informed priority.

Our recent 2021 experience in managing our Level 2 Priority “E” corrective notifications in this manner resulted in a 62 percent relative risk reduction of open corrective notifications on electric distribution facilities located in HFTD Tiers 2 and 3.

For those electric corrective Level 2 Priority “E” notifications that were going to remain open past their original due date, and that had the potential to degrade over time, we performed Field Safety Reassessments (FSR) of those open Level 2 Priority “E” electric notifications to determine if the conditions of the electric asset had degraded. If they had, we would accelerate those corrective notifications for repair.

We are also currently completing available vegetation priority corrective notifications within our internal timelines, limiting inventory to corrective notifications where we have access issues, such as customer property access issues or related permitting concerns, which are worked as dependencies are resolved. This is consistent with our Dead and Dying Tree Abatements apart from work identified by our EVM program. EVM work management is based upon a risk prioritization that has been updated annually through the performance period. These changes result in identified tree work from prior period risk prioritizations that are no longer included within the current period risk-based book of work. This has resulted in an inventory that we will target for completion.

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

FIGURE 3.11-1
GO 95 CORRECTIVE ACTIONS IN HFTDS – HISTORICAL PERFORMANCE

C. 1-Year Target and 5-Year Target

1. Target Methodology

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

- Historical Data and Trends: The targets are based on the projected volume of GO 95 Rule 18 Priority Level 2 notifications, which consider existing open corrective action notifications and forecasted new corrective action notifications that are due for each year;
- Benchmarking: Not available;
- Regulatory Requirements: GO 95 Rule 18 requirements;
- Attainable Within Known Resources/Work Plan: Yes, however attainability is subject to other emerging higher risk priorities that may influence our ability to meet projected targets. If emerging higher risk priorities emerge throughout the course of the year, we may need to prioritize our available resources to address these higher risk priorities and adjust our work plan accordingly;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: Yes, performance at projected levels is sustainable, subject to other emerging higher risk priorities may influence ability to meet projected targets. If emerging higher risk priorities emerge throughout the course of the year, we may need to prioritize our available resources to address these higher risk priorities and adjust our work plan accordingly; and
- Other Considerations: This target was established with the consideration of our risk informed strategy, as opposed to a corrective notification due date prioritization approach.

2. 2022 Target

Our target for Priority Level 2 corrective maintenance notifications on time completion rates is 70 percent for the year 2022. This metric performance is comprised of an aggregated performance, where the projected year 2022 volume of corrective notifications for electric distribution, electric transmission and vegetation are 72,718; 13,514; and 157,321, respectively.

For year 2022, electric distribution notifications completed on time percentage is projected at approximately 24 percent and electric transmission notifications completed on time percentage is projected at approximately 50 percent. The projected forecast for VM is approximately 92 percent. It is important to note that within this aggregated year 2022 performance, we are forecasting that our electric Level 2 Priority “B” notifications performance to achieve completed on time percentages of 95 percent for both electric distribution and electric transmission notifications. As described earlier, we consider electric Level 2 Priority “B” notifications to have a higher likelihood of creating an equipment failure than other electric Level 2 Priority notifications.

Our corrective notifications strategy will continue to focus on reducing wildfire risk associated with our open corrective notifications by working the highest risk Level 2 corrective notifications first versus managing corrective notification due dates. Using this approach in 2022, we are forecasting to reduce the relative wildfire risk associated with open electric distribution corrective maintenance notifications in HFTD Tiers 2 and 3 by as much as 38 percent.

The following tables summarize PG&E’s Year 2022 Target for Priority Level 2 notifications completed on time percentage, as well as a breakdown between the electric distribution, electric transmission and VM Priority Level 2 notifications performance.

TABLE 3.11-2
GO 95 RULE 18 PRIORITY LEVEL 2 PROJECTED 2022
CORRECTIVE ACTIONS PERFORMANCE AND TARGET
(ELECTRIC DISTRIBUTION, ELECTRIC TRANSMISSION AND VEGETATION MANAGEMENT)

Line No.	Year 2022	Level 2 Priority “E”	Level 2 Priority “B”	Level 2 Priority “B” From “E”	Level 2 Results
1	On Time	12,305	152,945	2,477	167,727
2	Past Due	58,723	13,869	134	72,726
3	% On Time	17%	92%	95%	70%

TABLE 3.11-3
GO 95 RULE 18 LEVEL 2 PROJECTED 2022
CORRECTIVE ACTIONS PERFORMANCE AND TARGET
(ELECTRIC DISTRIBUTION ONLY)

Line No.	Year 2022	Level 2 Priority "E"	Level 2 Priority "B"	Level 2 Priority "B" From "E"	Level 2 Results
1	On Time	7,771	6,772	2,435	16,978
2	Past Due	52,155	356	128	52,639
3	% On Time	13%	95%	95%	24%

TABLE 3.11-4
GO 95 RULE 18 LEVEL 2 PROJECTED 2022
CORRECTIVE ACTIONS PERFORMANCE AND TARGET
(ELECTRIC TRANSMISSION ONLY)

Line No.	Year 2022	Level 2 Priority "E"	Level 2 Priority "B"	Level 2 Priority "B" From "E"	Level 2 Results
1	On Time	4,534	2,245	42	6,821
2	Past Due	6,568	119	6	6,693
3	% On Time	41%	95%	88%	50%

TABLE 3.11-5
GO 95 RULE 18 LEVEL 2 PROJECTED 2022
CORRECTIVE ACTIONS PERFORMANCE AND TARGET
(VEGETATION MANAGEMENT)

Line No.	Year 2022	EVM Dead and Dying	Vegetation Dead and Dying	Vegetation Priority 2	Level 2 Results
1	On Time	42,222	78,002	23,704	143,928
2	Past Due	10,555	1,592	1,247	13,394
3	% On Time	80%	98%	95%	91%

3. 2026 Target

Our 5-year target for Priority Level 2 corrective maintenance notifications on time is 76 percent. This metric performance is comprised of an aggregated performance where the projected year 2026 volume of corrective notifications for electric distribution, electric transmission and vegetation are at 54,731; 11,339; and 159,820, respectively.

For year 2026, we are projecting an on-time percentage of approximately 32 percent, 56 percent, 92 percent for electric distribution, electric transmission, and vegetation notifications performance, respectively.

Our corrective notifications strategy will continue to focus on reducing wildfire risk associated with our open corrective notifications by working the highest risk Level 2 corrective notifications first versus managing corrective notification due dates. Furthermore, we are also revisiting opportunities to further align our electric corrective action Priority levels (e.g., A, B, E, F, and H) with that of GO 95 Rule 18 (e.g., Levels 1, 2, and 3), which we expect will improve our performance in the long-term.

The following tables summarize our Year 2026 Target for Priority Level 2 notifications completed on time percentages, as well as a breakdown between the electric distribution, electric transmission and vegetation Priority Level 2 notifications completed on time percentages.

TABLE 3.11-6
GO 95 RULE 18 PRIORITY LEVEL 2 PROJECTED 2026 CORRECTIVE ACTIONS PERFORMANCE AND TARGET (ELECTRIC DISTRIBUTION, ELECTRIC TRANSMISSION AND VEGETATION MANAGEMENT)

Line No.	Year 2022	Level 2 Priority “E”	Level 2 Priority “B”	Level 2 Priority “B” From “E”	Level 2 Results
1	On Time	14,061	152,480	2,456	168,997
2	Past Due	39,447	14,215	131	53,793
3	% On Time	26%	91%	95%	76%

TABLE 3.11-7
GO 95 RULE 18 LEVEL 2 PROJECTED 2026 CORRECTIVE ACTIONS PERFORMANCE AND TARGET (ELECTRIC DISTRIBUTION ONLY)

Line No.	Year 2022	Level 2 Priority “E”	Level 2 Priority “B”	Level 2 Priority “B” From “E”	Level 2 Results
1	On Time	9,446	4,771	2,435	16,652
2	Past Due	34,600	251	128	34,979
3	% On Time	21%	95%	95%	32%

TABLE 3.11-8
GO 95 RULE 18 LEVEL 2 PROJECTED 2026 CORRECTIVE ACTIONS PERFORMANCE AND TARGET (ELECTRIC TRANSMISSION ONLY)

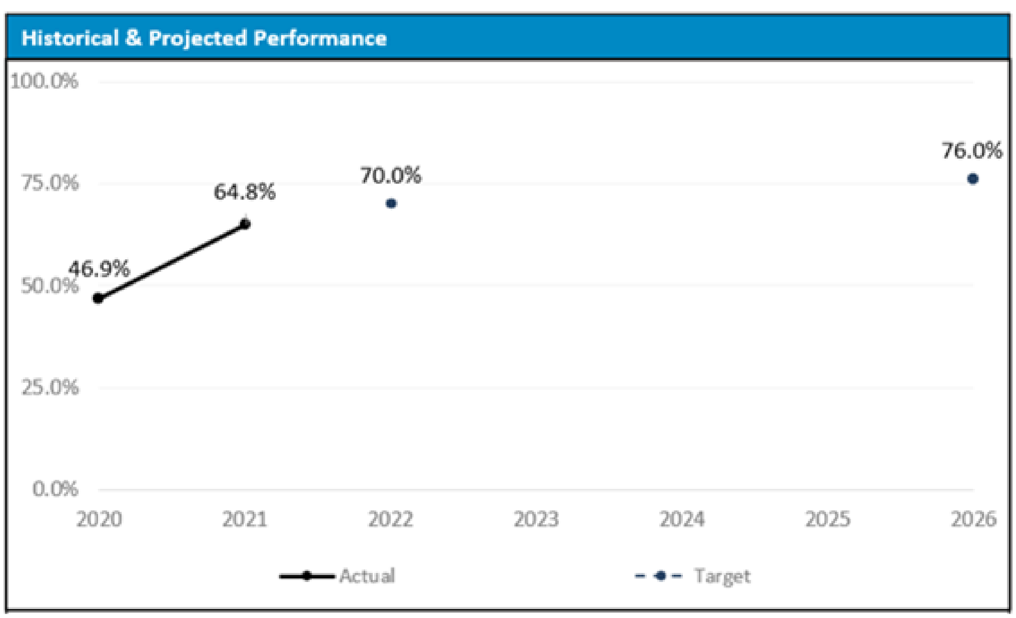
Line No.	Year 2022	Level 2 Priority “E”	Level 2 Priority “B”	Level 2 Priority “B” From “E”	Level 2 Results
1	On Time	4,615	1,760	21	6,396
2	Past Due	4,847	93	3	4,943
3	% On Time	49%	95%	88%	56%

TABLE 3.11-9
GO 95 RULE 18 LEVEL 2 PROJECTED 2026 CORRECTIVE ACTIONS PERFORMANCE AND TARGET (VEGETATION MANAGEMENT)

Line No.	Year 2026	EVM Dead and Dying	Vegetation Dead and Dying	Vegetation Priority 2	Level 2 Results
1	On Time	44,000	77,990	23,959	145,949
2	Past Due	11,000	1,610	1,261	13,871
3	% On Time	80%	98%	95%	91%

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

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



D. Current and Planned Work Activities

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

- System Hardening: System Hardening Program focuses on mitigating wildfire risk posed by distribution overhead assets in and near Tier 2 and 3 HFTDs in our service territory. This program targets high wildfire risk miles and applies various mitigation activities, including: (1) line removal, (2) conversion of distribution lines from overhead to underground, (3) application of Remote Grid alternatives, (4) mitigation of exposure through relocation of overhead facilities, and (5) in-place overhead system hardening.
- Overhead Preventative Maintenance and Equipment Repair: Focuses on repair of electric equipment identified with corrective notifications. Our corrective notifications strategy will continue to focus on reducing wildfire risk associated with our open corrective notifications by working the highest risk Level 2 corrective notifications first versus managing corrective notification due dates. We plan to accomplish this by continuing to complete Level 1 and Level 2 Priority “B” corrective notifications first and manage the inventory of Level 2 Priority “E” corrective notifications in a risk informed manner, where the highest risk Level 2 Priority “E” corrective notifications are targeted first, while deploying safety controls to manage the lower risk Level 2 Priority “E” corrective notifications. Using this approach in 2022, we are forecasting to reduce the relative wildfire risk associated with open electric distribution corrective maintenance notifications in HFTD Tiers 2 and 3 by as much as 38 percent.
- Our corrective notifications strategy will continue to focus on reducing wildfire risk associated with our open corrective notifications by working the highest risk Level 2 corrective notifications first versus managing corrective notification due dates. Furthermore, we are also revisiting opportunities to further align our electric corrective action Priority levels (e.g., A, B, E, F, and H) with that of GO 95 Rule 18 (e.g., Levels 1, 2, and 3).
- See Exhibit (PG&E-4), Chapters 4.3, 9, and 11 in PG&E’s 2023 General Rate Case for more information.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3.12

SAFETY AND OPERATIONAL METRICS REPORT:

ELECTRIC EMERGENCY RESPONSE TIME

PACIFIC GAS AND ELECTRIC COMPANY
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A. Overview

1. Metric Definition

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

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

2. Introduction of Metric

This metric 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. Measuring response to 911 calls within 60 minutes has been a long-standing top public safety measure for PG&E and within the industry, and this metric, although calculated differently, is similar in its intent for responding quickly to our customers and any potentially unsafe conditions reported.

B. Metric Performance

1. Historical Data (2015-2021)

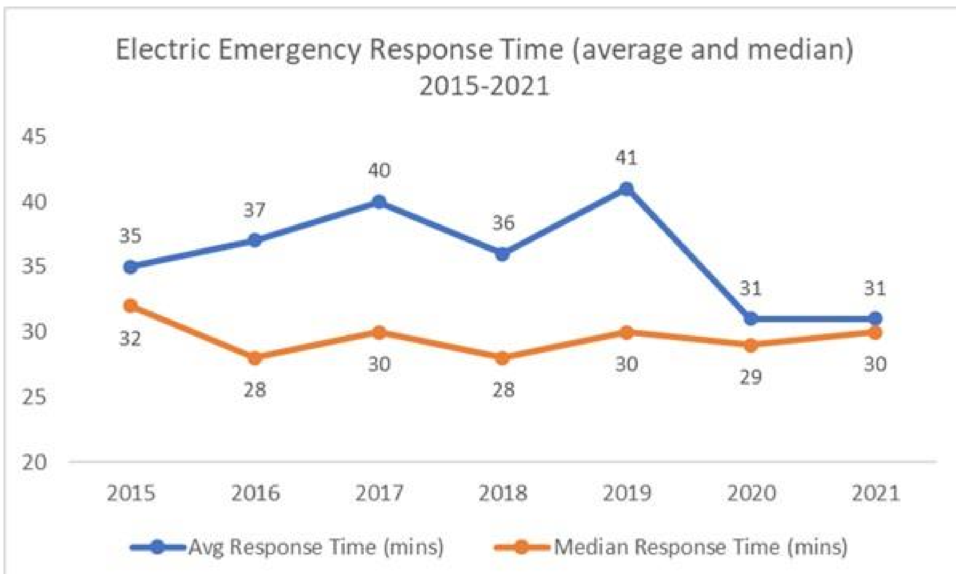
2015-2021 performance results are provided. Although emergency response data exists prior to 2015 (as mentioned below), current validation practices were not in place until 2015 and therefore only data from 2015 is reported here for consistency and comparability.

Over the timeframe of 2015-2021, total average response time across all years is 35 minutes, and the median for across all years is 30 minutes.

From a trending standpoint, PG&E's response to 911 electric-related emergencies has improved by roughly 50 percent since 2012 and has been consistent from 2015-2021.

Metric performance has been driven by accurately predicting when large volumes of calls will occur (based on weather forecasts), proactive scheduling of resources for 911 response, cross-functional coordination across PG&E to train non-traditional stand-by staff, availability of resources for weather days and improved understanding of shifts in storm fronts and impacts on the system.

FIGURE 3.12-1
ELECTRIC EMERGENCY RESPONSE TIME HISTORICAL DATA (2015-2021)



2. Data Collection Methodology

The metric performance data is captured and stored in the Outage Information System (OIS) database. 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 is 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 removes the delay between the time the call is received and entered into the system, and the raw data is then reviewed for duplicate entries, which are cancelled (if found). The timestamp of when

PG&E personnel responds on site is captured via the Outage Management Tool (OMT) and troubleman/technician is ensured to be onsite, which marks the completion of the response. The response time in minutes is calculated by the difference between the two timestamps. From each call's response time, the average and median time is calculated for all calls.

3. Metric Performance

In 2021, PGE's average and median response times increased by two and one minutes from 2020 performance, respectively, driven by weather events experienced in January and December. In context, these results are still considered strong performance as: (1) weather severity is a known uncontrollable variable, and (2) the corresponding measure—percent response time within 60 minutes—remains at the top of industry performance.

C. 1-Year and 5-Year Target

1. Target Methodology

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

- Historical Data and Trends: Comparable data is available starting in 2015. This historical data context confirms PG&E's current results are improved, sustained, and reasonably considered strong performance, which has informed the target setting direction to "maintain";
  - Benchmarking: Industry benchmarking is available under the emergency response time measure calculated as percent time responding on site within 60 minutes. Targets are set at a level consistent with strong performance. They are used with the intention of PG&E continuing performance better than these levels to maintain results consistent with strong performance. Target values should not be interpreted as a plan for or expectation of worsening performance;
- Regulatory Requirements: None;

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

- Attainable With Known Resources/Work Plan: Yes;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: Historical data and trends confirm that maintaining estimated performance informed by available benchmarking data is a sustainable target in both the 1-year and 5-year timeframes. Available benchmarking data further confirms targets are set at levels for which any results below (i.e., better than) will be consistent with strong performance. Therefore, any results above (i.e., worse than) targets would be an appropriate indicator light to examine potential performance issues; and
- Other Considerations: None.

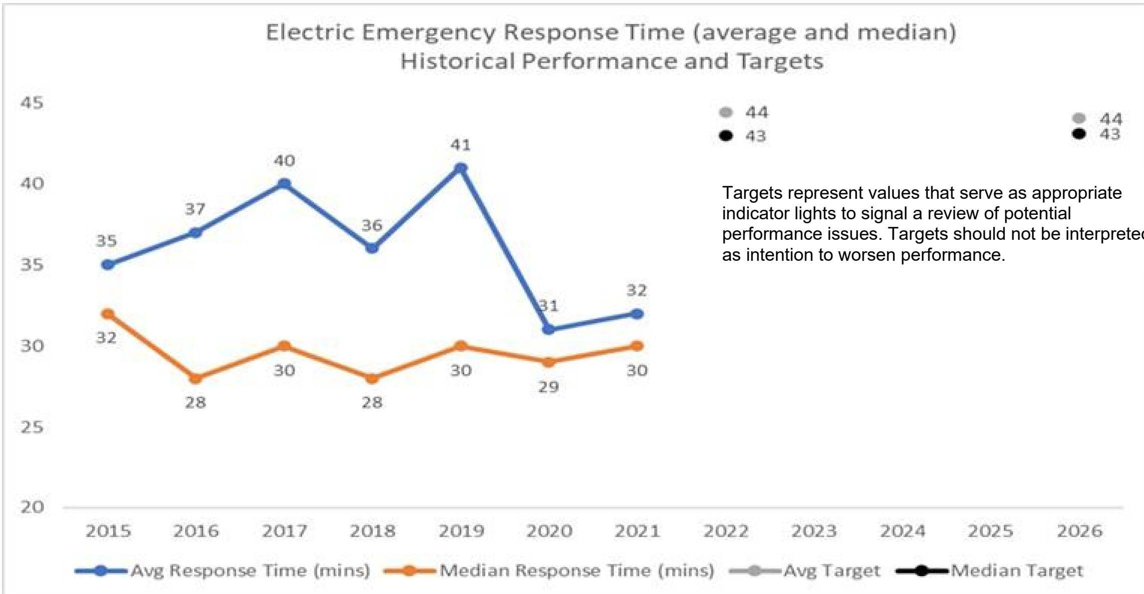
2. 2022 Target

The 2022 Target is to remain better than 44 minutes for average emergency response time and better than 43 minutes for median emergency response time.

3. 2026 Target

The 2026 Target is to remain better than 44 minutes for average emergency response time and better than 43 minutes for median emergency response time.

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



D. Current and Planned Work Activities

Additional actions that have been recently implemented to maintain top-level performance:

- Meteorology, Operations, and Dispatch Support:
  - PG&E Electric Distribution Operations and PG&E Meteorology will be partnering to validate and enhance 911 forecasting. This effort includes using historical data to train the forecasting model and system to provide better 911 resource requirement recommendations based on predicted weather. Improved molding will allow for effective staffing adjustments.
  - A ‘concierge’ Meteorology advisor will be assigned pre-event and identified for in event support.
  - Meteorology will provide proactive reach out to Electric Dispatch if a specific geographic area is looking to worsen over the forecast period. Meteorology will also be modifying PG&E’s general wind alert system to see if it can be tailored to provide in event systematic support to Dispatchers.
- Mobile Solution Deployment: Transition non-electric standby personnel into Field Automation System tool to allow for quicker dispatching to 911 standby requests.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3.13

SAFETY AND OPERATIONAL METRICS REPORT:

NUMBER OF CPUC-REPORTABLE IGNITIONS IN HFTD AREAS

(DISTRIBUTION)

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A. Overview

1. Metric Definition

Safety and Operational Metrics (SOM) 3.13 – the Number of California Public Utilities Commission (CPUC) Reportable Ignitions in High Fire Threat Districts (HFTD) Areas (Distribution) is defined as:

The number of CPUC-reportable ignitions involving overhead distribution circuits in HFTD Areas.

A CPUC-Reportable Ignition refers to a fire incident where the following three criteria are met: (1) ignition is associated with Pacific Gas and Electric Company (PG&E) electrical assets, (2) something other than PG&E facilities burned, and (3) the resulting fire travelled more than one linear meter from the ignition point.[1]

For this SOM, reporting is specific to Tier 2 and Tier 3 HFTDs.

PG&E provides the CPUC with annual ignition data in the Fire Incident Data Collection Plan, to the Office of Energy Infrastructure and Safety quarterly via quarterly geographic information system, data reporting, in quarterly Wildfire Mitigation Plan updates, and the Safety Performance Metrics Report.

2. Introduction of Metric

The number of CPUC-reportable ignitions in HFTDs provides one way to gauge the level of wildfire risk that customers and communities are exposed to from overhead distribution assets. PG&E's objective is to minimize the number of CPUC-reportable ignitions in the right locations during the right conditions that may trigger a catastrophic wildfire.

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[1] Please see CPUC Decision (D.) 14-02-015, issued February 5, 2014 for additional details.

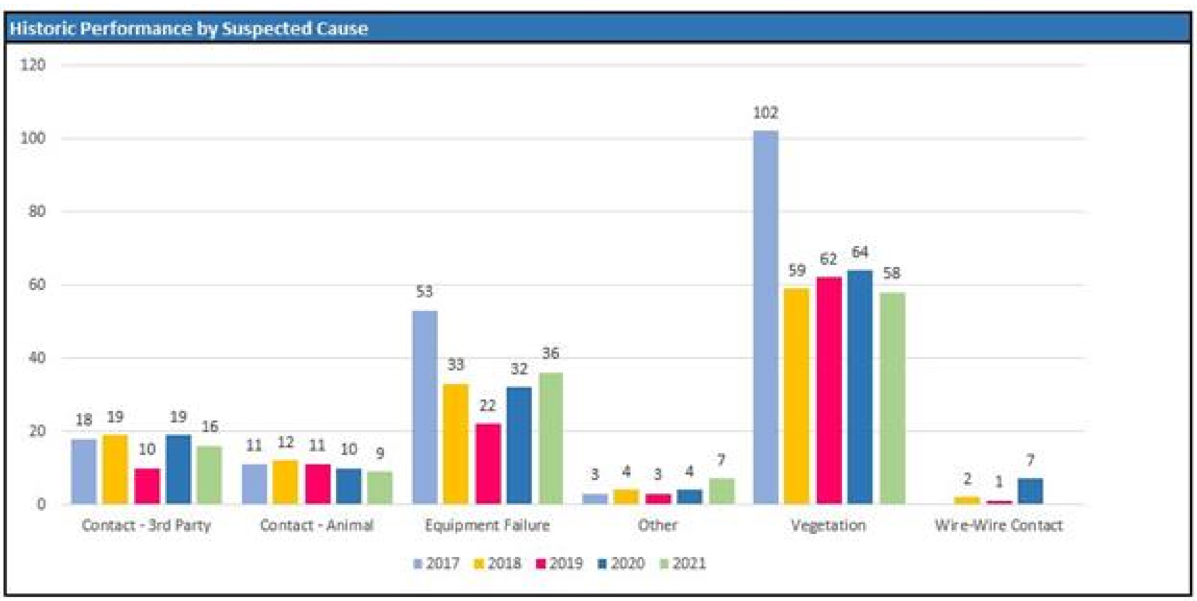
B. Metric Performance

1. Historical Data (2015-2021)

PG&E implemented the Fire Incident Data Collection Plan in response to D.14-02-015 in June 2014. PG&E's Ignitions Tracker includes all CPUC-reportable ignitions from June 2014 to present. The 2014 data does not represent a complete year and is excluded in this analysis.

PG&E's overhead distribution circuits traverse approximately 25,500 miles of terrain in the HFTD areas where the overhead conductor is primarily bare wire, supported by structures consisting of poles, cross arms, associated insulators, and operating equipment such as transformer, fuses and reclosers. The main causes of CPUC-reportable ignitions have been collected and classified. These fall into six broad categories: vegetation contact, equipment failure, third party contact, animal contact, wire to wire contact, and other causes. The counts for 2017 to 2021 are shown in the graph below, highlighting the degree of variability that occurs from year to year relative to each category.

FIGURE 3.13-1
HISTORIC PERFORMANCE BY SUSPECTED CAUSE



There is also a seasonal pattern to the ignition events as shown in the chart of ignitions by month below for each of the years from 2017 to 2021.

FIGURE 3.13-2
HISTORIC PERFORMANCE BY YEAR/MONTH

Historic Performance by Year/Month

Month	2017 Total	2018 Total	2019 Total	2020 Total	2021 Total
January	2	1	1		19
February		4		7	2
March	1	6	2	3	5
April	6	5	4	3	6
May	9	4	8	9	17
June	19	19	14	25	22
July	36	30	23	23	24
August	33	25	15	27	17
September	28	6	16	17	7
October	42	15	13	17	6
November	5	14	12	2	
December	6		1	3	1
Grand Total	187	129	109	136	126

2. Data Collection Methodology

Data will be collected per PG&E's Fire Incident Data Collection Plan (Utility Standard/Procedure RISK-6306S/P). Results will be inclusive of unique HFTD CPUC-reportable Ignitions attributable to the distribution asset class with overhead construction types.

The following ignition events captured by PG&E's Fire Incident Data Collection Plan will be excluded for this metric:

- Duplicate events;
- Ignitions that do not meet CPUC reporting criteria;
- Ignition events outside of Tier 2 and Tier 3 HFTD;
- Transmission ignitions; and
- Ignitions attributable to underground or pad-mounted assets as these are not associated overhead assets. (Ignitions caused by non-overhead assets in HFTD are rare and, as the fires are often contained to the asset, pose less of a wildfire risk.)

3. Metric Performance

In 2021, PG&E observed a 46 percent reduction in ignitions across HFTD compared to 3-year averages during the time that EPSS was enabled in limited locations from July 28-October 20. Enhanced Powerline Safety Settings (EPSS) is a protective device strategy, primarily aimed at increasing fault sensitivity. PG&E is expanding this protection strategy across all distribution overhead assets in HFTD and HFRA in 2022, where feasible. Please see *Current and Planned Work Activities* section below for an overview of the EPSS Program.

PG&E concluded 2021 with 126 overhead distribution CPUC-reportable ignitions, slightly higher than the previous 3-year average (124 ignitions). However, 19 of those ignitions were observed during the bounds of the January 19, 2021 wind event. (Previous Januarys averaged two ignitions for the month (2018-2020). PG&E should continue to observe a reduction in reportable ignitions with the expansion of the EPSS Program in 2022.

C. 1-Year Target and 5-Year Target

1. Target Methodology

The two major programs that most directly impact ignition reduction in the near-term are PSPS and EPSS. Other important resiliency programs like undergrounding, system hardening, and vegetation management will have an impact as multiple years of work are completed.

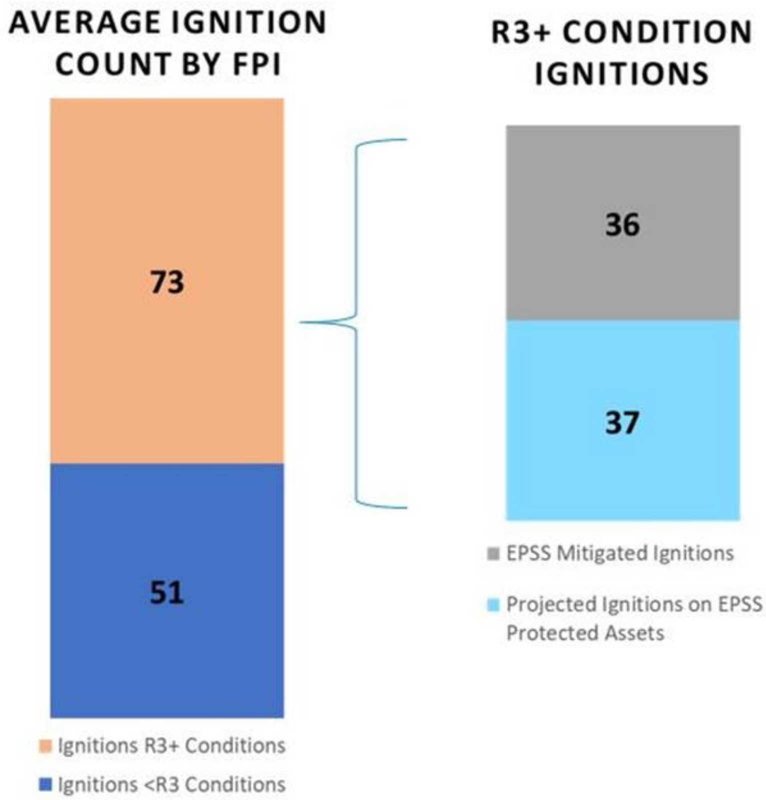
EPSS significantly decreased ignition events in 2021 and PG&E will be enabling this protection when overhead distribution circuits in a Fire Index Area have a forecasted Fire Potential Index (FPI) of R3 or higher across HFTD. Ignitions in R3+ conditions represent all historical reportable ignitions resulting in a fatality, all ignitions over 100 acres in size, and 99 percent of reportable ignitions where a structure was destroyed. See Figure 3.13-4 for fire statistics by FPI rating.

FIGURE 3.13-3
2018-2020 HFTD OVERHEAD REPORTABLE IGNITION STATISTICS
BY FPI, ALL ASSET CLASSES

	R2+	R3+
% of Total Reportable Ignitions in HFTD	84%	60%
% of Wildfires >10 Acres	81%	71%
% of Wildfires >100 Acres	100%	100%
% of Total Structures Destroyed	100%	99%
% of Total Fatalities	100%	100%

PG&E enabled EPSS in 2021 and has limited data to forecast the expected performance for this metric. Based on 3-previous year averages (124 ignitions) and the observed effectiveness of EPSS to mitigate facility ignitions in 2021 (49 percent), PG&E has projected 88 reportable distribution HFTD in 2022. See Figure 3.13-5 for details. However, ignition counts are dependent on weather conditions and are highly variable. As a result, PG&E forecasts a range of 82 to 94 reportable ignitions to account for variability (range is equal to projected target +/- 0.5 of standard deviation).

FIGURE 3.13-4
PROJECTED EPSS EFFECTIVENESS BASED ON 2018-2020 AVERAGES AND OBSERVED 2021 PERFORMANCE



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

- Historical Data and Trends: As 2021 was the first year of EPSS deployment and given the expansion of the program in 2022, there is no comparable historical data to help guide in target setting;
- Benchmarking: None;
- Regulatory Requirements: D.14-02-015;
- Attainable Within Known Resources/Work Plan: Yes;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: The targets for this metric are suitable for EOE as they consider the potential for an increase in severe weather events due to climate change; and
- Other Considerations: The target range takes consideration for some variability in weather.

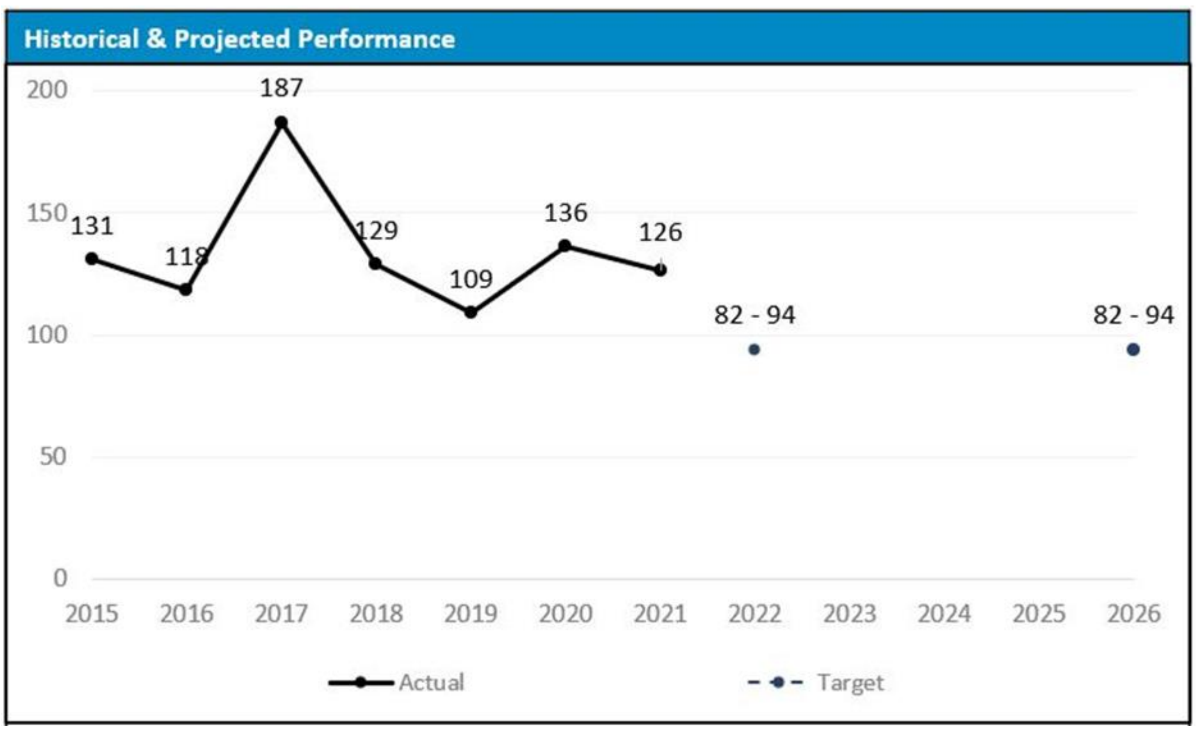
2. 2022 Target

The 2022 target is 82-94 ignitions. The upper end of this range represents a 25 percent reduction relative to the 3-year average (2018-2020). The lower end of this range represents a 34 percent reduction for the same period.

3. 2026 Target

The 2022 target is 82-94 ignitions. The upper end of this range represents a 25 percent reduction relative to the 3-year average (2018-2020). The lower end of this range represents a 34 percent reduction for the same period. Additional time and maturity of the EPSS Program will enable PG&E to reduce ignitions in R3+ conditions and forecast the effectiveness of the EPSS Program to help inform long-term target ranges.

FIGURE 3.13-5
HISTORICAL PERFORMANCE (2015-2021) AND TARGETS (2022 & 2026)



D. Current and Planned Work Activities

PG&E can expect to see improved performance on this metric through continual execution of the Wildfire Mitigation Plan (WMP) and maturation of key wildfire mitigation strategies, including:

- Enablement and Expansion of the EPSS Program: In July 2021, to address this dynamic climate challenge, we implemented the EPSS Program on approximately 11,500 miles of distribution circuits, or 45 percent of the circuits in HFTD areas. With EPSS, we engineered changes to our electrical equipment settings so that if an object such as vegetation contacts a distribution line, power is automatically shut off within 1/10th of a second, reducing the potential for an ignition. EPSS-enabled settings provide a layer of protection on days when the wind speeds are low. EPSS is especially important during hot-dry summer days, when there are low winds, but continued low relative humidity, low fuel moistures levels, and where the volume of dry vegetation, in close proximity to the distribution lines, increases the risk of an ignition becoming a large wildfire.

  In 2022, we will be expanding the EPSS scope to all HFTD and High Fire Risk Area (HFRA) areas in our service territory, as well as select non-HFTD areas. Our engineering team will continue to work through these circuits and program each protection device with the appropriate EPSS settings. Programming of EPSS settings into the protection devices along the circuits will be prioritized based on HFTD and HFRA exposure and forecasted Fire Potential Index (FPI) conditions. Once the devices are programmed, they will be capable of being enabled into EPSS mode. Enablement (activation) of EPSS settings will be determined based on FPI ratings throughout the service territory.

  Please see Section 7.3.6.8, Protective Equipment Device Settings in PG&E's 2022 WMP for additional details.

- Public Safety Power Shut Off (PSPS): PSPS is a wildfire mitigation strategy, first implemented in 2019, to reduce powerline ignitions during severe weather by proactively de-energizing powerlines (remove the risk of those powerlines causing an ignition) prior to forecasted wind events when humidity levels and fuel conditions are conducive to wildfires. PG&E's focus with the PSPS Program is to mitigate the risks associated with a catastrophic wildfire and to prioritize customer safety. In 2021, PG&E continued to make progress to its PSPS Program to mitigate wildfire risk, including updating meteorology models and scoping processes. In 2022, PG&E plans to install additional distribution sectionalizing devices, Fixed

Power Solutions, and other mitigations targeted at reducing the risk of wildfire.

Please see Section 8, PSPS, Including Directional Vision For PSPS in PG&E's 2022 WMP for additional details.

- Grid Design and System Hardening: PG&E's broader grid design program covers several significant programs to reduce ignition risk, called out in detail in PG&E's 2022 WMP. The largest of these programs is the System Hardening Program which focuses on the mitigation of potential catastrophic wildfire risk caused by distribution overhead assets. In 2022, we are rapidly expanding our system hardening efforts by:
  - Completing 470 circuit miles of system hardening work which includes overhead system hardening, undergrounding and removal of overhead lines in HFTD or buffer zone areas;
  - Completing at least 175 circuit miles of undergrounding work, including Butte County Rebuild efforts and other distribution system hardening work; and
  - Replacing equipment in HFTD areas that creates ignition risks, such as non-exempt fuses (3,000) and surge arresters (~4,500, all known, remaining in HFTD areas).

  As we look beyond 2022, PG&E is targeting 3,600 miles of undergrounding to be completed between 2023 and 2026 as part of the 10,000 Mile Undergrounding Program. This system hardening work done at scale is expected to have a material impact on ignition reduction

  Please see Section 7.3.3, Grid Design and System Hardening Mitigations in PG&E's 2022 WMP for additional details.

- Vegetation Management: PG&E's Vegetation Management Program, components of which exceed regulatory requirements, is critical to mitigating wildfire risk. Our vegetation management team inspects and identifies needed vegetation maintenance on all distribution and transmission circuit miles in PG&E's service area on a recurring cycle through Routine and Tree Mortality Patrols, as well as Pole Clearing. Our Enhanced Vegetation Management (EVM) Program goes above and beyond regulatory requirements for distribution lines by expanding minimum clearances and removing overhang in HFTD areas. In 2022 PG&E will complete 1,800 miles of EVM work.

Please see Section 7.3.5, Vegetation Management and Inspections in PG&E's 2022 WMP for additional details.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3.14

SAFETY AND OPERATIONAL METRICS REPORT: PERCENTAGE OF CPUC-REPORTABLE IGNITIONS IN HFTD AREAS (DISTRIBUTION)

PACIFIC GAS AND ELECTRIC COMPANY
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1. Metric Definition

Safety and Operational Metrics (SOM) 3.13 – The number of California Public Utilities Commission (CPUC) Reportable Ignitions in High Fire Threat Districts (HFTD) areas (Distribution) is defined as:

The number of CPUC-reportable ignitions involving overhead (OH) distribution circuits in HFTD areas divided by circuit miles of OH transmission lines in HFTD multiplied by 1000 miles (ignitions per 1000 HFTD circuit miles).

A CPUC-Reportable Ignition refers to a fire incident where the following three criteria are met: (1) Ignition is associated with PG&E electrical assets, (2) something other than PG&E facilities burned, and (3) the resulting fire travelled more than one linear meter from the ignition point.[1]

For this SOM, reporting is specific to Tier 2 and Tier 3 HFTDs.

PG&E provides the CPUC with annual ignition data in the Fire Incident Data Collection Plan, to the Office of Energy Infrastructure and Safety quarterly via quarterly geographic information system, data reporting, in quarterly Wildfire Mitigation Plan updates, and the Safety Performance Metrics Report.

2. Introduction of Metric

The number of CPUC-reportable Ignitions in HFTDs, normalized by circuit mileage, provides one way to gauge the level of wildfire risk that customers and communities are exposed to from OH distribution assets. PG&E's objective is to minimize the number of CPUC-reportable ignitions in the right locations during the right conditions that may trigger a catastrophic wildfire.

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1 Please CPUC Decision (D.) 14-02-015, issued February 5, 2014 for additional details.

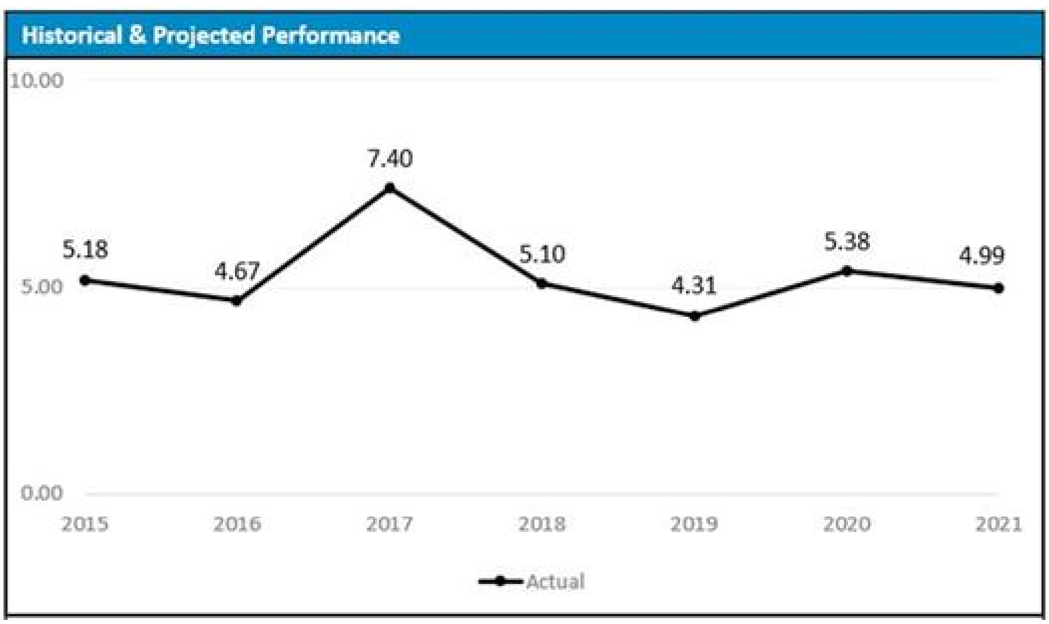
B. Metric Performance

1. Historical Data (2015-2021)

PG&E implemented the Fire Incident Data Collection Plan, in response to D.14-02-015, in June 2014 and our record, the Ignitions Tracker, includes all CPUC-reportable ignitions from June 2014 to present. The 2014 data does not represent a complete year and is excluded in this analysis.

PG&E's OH distribution circuits traverse approximately 25,500 miles of terrain in the HFTD areas where the OH conductor is primarily bare wire, supported by structures consisting of poles, cross arms, associated insulators, and operating equipment such as transformer, fuses and reclosers. Given the volume of equipment within the 25,500 miles of HFTD, the annual number of CPUC-reportable ignitions is too low to detect any statistical pattern.

FIGURE 3.14-1
HISTORICAL PERFORMANCE (2015-2021)



2. Data Collection Methodology

Data will be collected per PG&E's Fire Incident Data Collection Plan (Utility Standard/Procedure RISK-6306S/P). Results will be inclusive of unique HFTD CPUC-reportable ignitions attributable to the distribution asset class with OH construction types.

The following ignition events captured by PG&E's Fire Incident Data Collection Plan) will be excluded for this metric:

- Duplicate events;
- Ignitions that do not meet CPUC reporting criteria;
- Ignition events outside of Tier 2 and Tier 3 HFTD;
- Transmission Ignitions; and
- Ignitions attributable to underground or pad mounted assets as these are not associated OH assets. (Ignitions caused by non-OH assets in HFTD are rare and, as the fires are often contained to the asset, pose less of a wildfire risk.)

The circuit mileage utilized to calculate this metric originates from PG&E's Electrical Asset Data Reports refreshed December 8, 2021. Circuit mileage data from 2015 – 2018 is unavailable and PG&E used results from December 2021 to calculate this metric for all years for consistency.

3. Metric Performance

In 2021, PG&E observed a 46 percent reduction in ignitions across HFTD compared to 3-year averages during the time that EPSS was enabled in limited locations from July 28-October 20. Enhanced Powerline Safety Settings (EPSS) is a protective device strategy, primarily aimed at increasing fault sensitivity. PG&E is expanding this protection strategy across all distribution overhead assets in HFTD and HFRA in 2022, where feasible. Please see Current and Planned Work Activities section below for an overview of the EPSS Program.

PG&E concluded 2021 with 4.99 ignitions per 1,000 HFTD circuit mile, slightly higher than previous 3-year average (4.93 ignitions per 1,000 HFTD circuit mile). PG&E should continue to observe a reduction in reportable ignitions with the maturation of the EPSS Program in 2022.

C. 1-Year Target and 5-Year Target

1. Target Methodology

The two major programs that most directly impact ignition reduction in the near term are PSPS and EPSS, other important resiliency programs like undergrounding, system hardening, and vegetation management will have an impact as multiple years of work are completed.

EPSS significantly decreased ignition events in 2021 and PG&E will be enabling this protection when overhead distribution circuits in a Fire Index Area have a forecasted Fire Potential Index (FPI) of R3 or higher across HFTD. Ignitions in R3+ conditions represent all historical reportable ignitions resulting in a fatality, all ignitions over 100 acres in size, and 99 percent of reportable ignitions where a structure was destroyed; see Figure 3.14-2 for fire statistics by FPI rating.

FIGURE 3.14 2
2018-2020 HFTD OVERHEAD REPORTABLE IGNITION STATISTICS BY FPI, ALL ASSET CLASSES

	R2+	R3+
% of Total Reportable Ignitions in HFTD	84%	60%
% of Wildfires >10 Acres	81%	71%
% of Wildfires >100 Acres	100%	100%
% of Total Structures Destroyed	100%	99%
% of Total Fatalities	100%	100%

PG&E enabled EPSS in 2021 and has limited data to forecast the expected performance for this metric and has projected a range for 2022 and 2026. Please see the target setting methodology for *3.13 Number of CPUC-reportable Ignitions in HFTD Areas (Distribution)* for target setting details.

2. 2022 Target

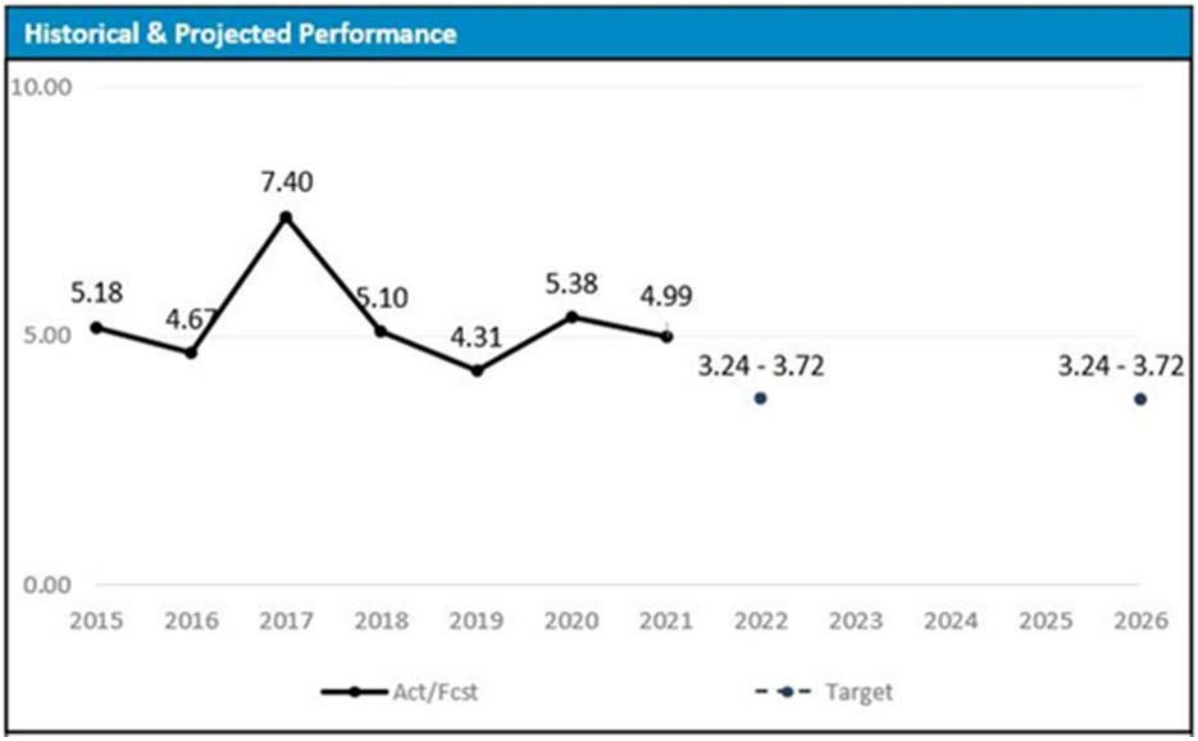
The 2022 target is 3.24-3.72 ignitions per 1000 HFTD circuit miles. The upper end of this range represents a 25 percent reduction relative to the 3-year average (2018 2020); the lower end of this range represents a 34 percent reduction for the same period.

3. 2026 Target

The 2022 target is 3.24-3.72 ignitions per 1000 HFTD circuit miles. The upper end of this range represents a 25 percent reduction relative to the 3-year average (2018 2020); the lower end of this range represents a

34 percent reduction for the same period. Additional time and maturity of the EPSS Program will enable PG&E to reduce ignitions in R3+ conditions and forecast the effectiveness of the EPSS Program to help inform long-term target ranges.

FIGURE 3.14-3
HISTORICAL PERFORMANCE (2015-2021) AND
TARGETS (2022 AND 2026)



D. Current and Planned Work Activities

PG&E can expect to see improved performance on this metric through continual execution of the WMP and maturation of key wildfire mitigation strategies, including:

- <u>Enablement and Expansion of the EPSS Program</u>: In July 2021, to address this dynamic climate challenge, we implemented the EPSS Program on approximately 11,500 miles of distribution circuits, or 45 percent of the circuits in HFTD areas. With EPSS, we engineered changes to our electrical equipment settings so that if an object such as vegetation contacts a distribution line, power is automatically shut off within 1/10th of a second, reducing the potential for an ignition. EPSS enabled settings provide a layer of protection on days when the wind speeds are low. EPSS is especially important during hot dry summer days, when there are low winds but continued low relative humidity, low fuel moistures levels, and where the volume of dry vegetation, in close proximity to the distribution lines, increases the risk of an ignition becoming a large wildfire.

In 2022, we will be expanding the EPSS scope to all HFTD and High Fire Risk Area (HFRA) areas in our service territory, as well as select non HFTD areas. Our engineering team will continue to work through these circuits and program each protection device with the appropriate EPSS settings. Programming of EPSS settings into the protection devices along the circuits will be prioritized based on HFTD and HFRA exposure and forecasted Fire Potential Index (FPI) conditions. Once the devices are programmed, they will be capable of being enabled into EPSS mode. Enablement (activation) of EPSS settings will be determined based on FPI ratings throughout the service territory.

Please see Section 7.3.6.8, Protective Equipment Device Settings in PG&E's 2022 WMP for additional details.

- Public Safety Power Shut Off: PSPS is a wildfire mitigation strategy, first implemented in 2019, to reduce powerline ignitions during severe weather by proactively de-energizing powerlines (remove the risk of those powerlines causing an ignition) prior to forecasted wind events when humidity levels and fuel conditions are conducive to wildfires. PG&E's focus with the PSPS Program is to mitigate the risks associated with a catastrophic wildfire and to prioritize customer safety in 2021, PG&E continued to make progress to its PSPS Program to mitigate wildfire risk, including updating meteorology models and scoping processes. In 2022, PG&E plans to install additional distribution sectionalizing devices, Fixed Power Solutions, and other mitigations targeted at reducing the risk of wildfire.

  Please see Section 8, PSPS, Including Directional Vision For PSPS in PG&E's 2022 WMP for additional details.

- Grid Design and System Hardening: PG&E's broader grid design program covers several significant programs to reduce ignition risk, called out in detail in PG&E's 2022 WMP. The largest of these programs is the System Hardening Program which focuses on the mitigation of potential catastrophic wildfire risk caused by distribution OH assets. In 2022, we are rapidly expanding our system hardening efforts by: completing 470 circuit miles of system hardening work which includes OH system hardening, undergrounding and removal of OH lines in HFTD or buffer zone areas; completing at least 175 circuit miles of undergrounding work, including Butte County Rebuild efforts and other distribution system hardening work; replacing equipment in HFTD areas that creates ignition risks, such as non-exempt fuses (3,000) and surge arresters (~4,500, all known, remaining in HFTD areas). As we look beyond 2022, PG&E is targeting 3,600 miles of Undergrounding to be completed between 2023 and 2026 as part of the 10,000-Mile Undergrounding Program. This system hardening work done at scale is expected to have a material impact on ignition reduction

Please see Section 7.3.3, Grid Design and System Hardening Mitigations in PG&E's 2022 WMP for additional details.

- Vegetation Management: PG&E's VM Program, components of which exceed regulatory requirements, is critical to mitigating wildfire risk. Our VM team inspects and identifies needed vegetation maintenance on all distribution and transmission circuit miles in PG&E's service area on a recurring cycle through Routine and Tree Mortality Patrols, as well as Pole Clearing. Our Enhanced Vegetation Management (EVM) Program goes above and beyond regulatory requirements for distribution lines by expanding minimum clearances and removing overhang in HFTD areas. In 2022 PG&E will complete 1,800 miles of EVM work.

  Please see Section 7.3.5, Vegetation Management and Inspections in PG&E's 2022 WMP for additional details.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3.15

SAFETY AND OPERATIONAL METRICS REPORT:

NUMBER OF CPUC-REPORTABLE IGNITIONS IN HFTD AREAS

(TRANSMISSION)

PACIFIC GAS AND ELECTRIC COMPANY
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1. Metric Definition

Safety and Operational Metrics (SOM) 3.15 – Number of California Public Utilities Commission (CPUC)-Reportable Ignitions in High Fire Threat District (HFTD) areas (Transmission) is defined as:

Number of CPUC-reportable ignitions involving overhead transmission circuits in HFTD Areas.

A CPUC-Reportable Ignition refers to a fire incident where the following three criteria are met: (1) Ignition is associated with Pacific Gas and Electric Company (PG&E) electrical assets, (2) something other than PG&E facilities burned, and (3) the resulting fire travelled more than one linear meter from the ignition point.[1]

For this SOM, reporting is specific to Tier 2 and Tier 3 HFTDs.

PG&E provides the CPUC with annual ignition data in the Fire Incident Data Collection Plan, to the Office of Energy Infrastructure and Safety quarterly via quarterly geographic information system, data reporting, in quarterly Wildfire Mitigation Plan updates, and the Safety Performance Metrics Report.

2. Introduction of Metric

The number of CPUC-Reportable Ignitions in HFTDs provides one way to gauge the level of wildfire risk that customers and communities are exposed to from overhead transmission assets. PG&E's objective is to minimize the number of CPUC-Reportable ignitions in the right locations during the right conditions that may trigger a catastrophic wildfire.

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[1] Please CPUC Decision (D.) 14-02-015, issued February 5, 2014 for additional details.

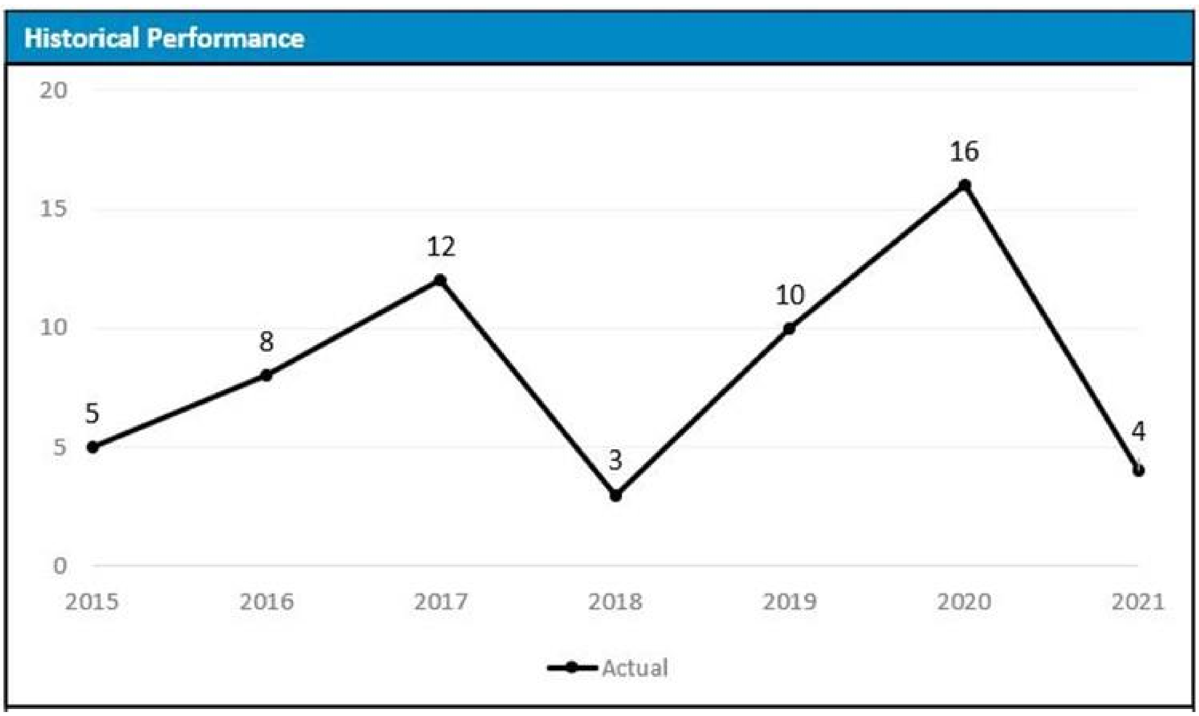
B. Metric Performance

1. Historical Data (2015-Present)

PG&E implemented the Fire Incident Data Collection Plan, in response to D.14-02-015, in June 2014 and our record, the Ignitions Tracker, includes all CPUC-Reportable ignitions from June 2014 to present. The 2014 data does not represent a complete year and is excluded in this analysis.

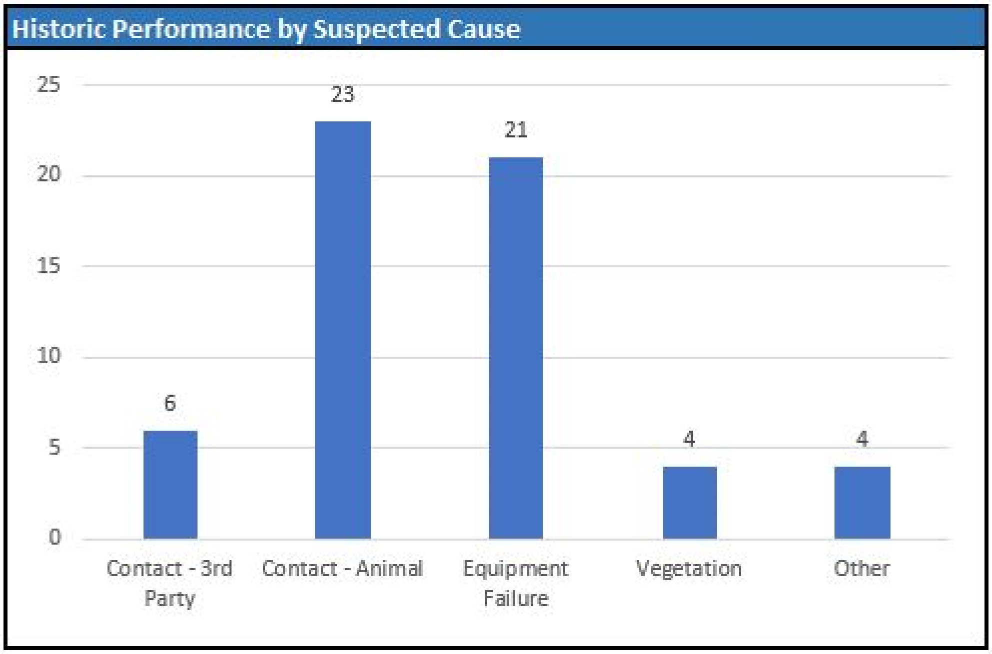
PG&E's overhead transmission circuits traverse approximately 5,000 miles of terrain in the HFTD areas where the overhead conductor is primarily bare wire, supported by structures consisting of poles and towers. The annual number of CPUC-Reportable ignitions is too low to detect any statistical pattern.

FIGURE 3.15-1
HISTORICAL PERFORMANCE (2015-2021)



The main causes of CPUC-Reportable ignitions have been collected and classified. These fall into five broad categories: third-party contact, animal contact, equipment failure, vegetation contact, and other causes. The counts for 2015-2021 are shown in the graph below.

FIGURE 3.15-2
HISTORIC (2015-2021) PERFORMANCE BY SUSPECTED CAUSE



2. Data Collection Methodology

Data will be collected per PG&E's Fire Incident Data Collection Plan (Utility Standard/Procedure RISK-6306S/P). Results will be inclusive of unique HFTD CPUC-Reportable ignitions attributable to the transmission asset class with overhead construction types.

The following ignition events captured by PG&E's Fire Incident Data Collection Plan (Utility Standard/Procedure RISK-6306S/P) will be excluded for this metric:

- Duplicate events;
- Ignitions that do not meet CPUC reporting criteria;
- Ignition events outside of Tier 2 and Tier 3 HFTD;
- Distribution Ignitions; and
- Ignitions attributable to underground or pad mounted assets as these are not overhead assets. Ignitions caused by non-overhead assets in HFTD are rare and, as the fires are often contained to the asset, pose less of a wildfire risk.

3. Metric Performance

Historically, reportable transmission ignitions in HFTD are low in volume with variability year-to-year, which complicates the detection of significant trends. PG&E observed four reportable overhead ignitions in 2021 in comparison to a 3-previous year average of 10 ignitions; one ignition was cause by vegetation contact, two by equipment failure, and one by bird contact.

C. 1-Year Target and 5-Year Target

1. Target Methodology

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

- Historical Data and Trends: Target ranges are based on both PG&E's stand that catastrophic wildfires shall stop and historical performance. The bottom end of the range is 0 in both 2022 and 2026, which reflects our stand that catastrophic wildfires shall stop. The upper end of the range is 10 in both 2022 and 2026, which is based on our average performance over the last three years. The upper end of the range stays at 10 for 2026 because the volume of transmission ignitions is low, while variability year-to-year remains high;
- Benchmarking: None;
- Regulatory Requirements: CPUC D.14-02-015;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: The targets for this metric are suitable for EOE as they consider the potential for an increase in severe weather events due to climate change; and
- Other Considerations: The target range takes consideration for some variability in weather.

2. 2022 Target

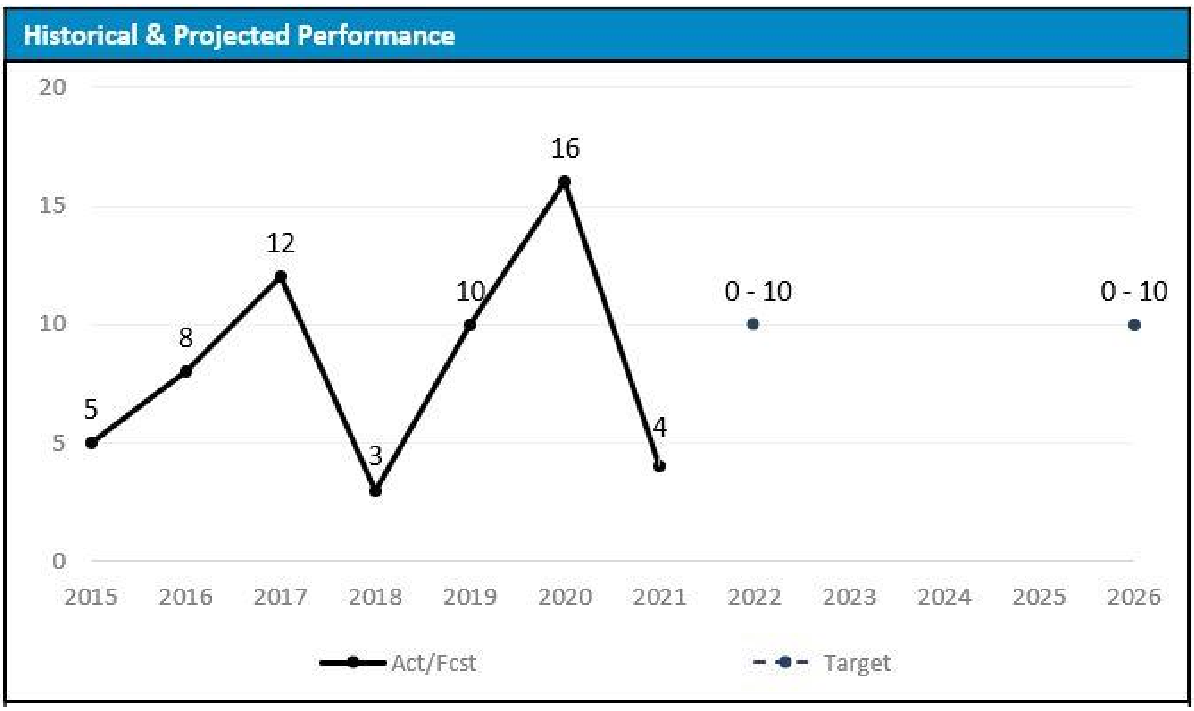
PG&E's target for 2022 is 0-10. The bottom end of the range is 0 in 2022, which reflects our stand that catastrophic wildfires shall stop. The upper end of the range is 10 in 2022, which is based on our average performance over the last three years. The upper end of the range stays at

10 in 2022 and 2026 because the volume of transmission ignitions is low, while variability year-to-year remains high.

3. 2026 Target

PG&E's target for 2026 is 0-10. The bottom end of the range is 0 in 2026, which reflects our stand that catastrophic wildfires shall stop. The upper end of the range is 10 in 2026, which is based on our average performance over the last three years. The volume of reportable ignitions caused by transmission assets is so low and highly variable.

FIGURE 3.15-3
HISTORICAL PERFORMANCE (2015-2021) AND TARGETS (2022 AND 2026)



D. Current and Planned Work Activities

Through continual execution of its WMP, PG&E has taken action to reduce ignition risk associated with its transmission system, including:

- Enhanced Inspection Protocols: In 2022, PG&E is continuing to evolve our inspection programs and LiDAR data collection to proactively identify and treat pending failures and reduce wildfire risk associated with Transmission Facilities. In 2022, PG&E will complete 39,000 detailed ground and aerial inspections on transmission assets, climbing inspections on

1,800 transmission structures, and ground and aerial inspection of 43 transmission substations.

Please see Section 7.3.4.2, Detailed Inspections of Transmission Electric Lines and Equipment in PG&E's 2022 WMP for additional details.

- Public Safety Power Shut Off (PSPS): PSPS is a wildfire mitigation strategy, first implemented in 2019, to reduce powerline ignitions during severe weather by proactively de-energizing powerlines. PG&E's main focus on PSPS is to mitigate the risks associated with a catastrophic wildfire and to prioritize customer safety. To that end, PG&E continued to make progress to its PSPS program to mitigate wildfire risk, including updating meteorology models and scoping processes.

  In 2022, PG&E plans to install additional distribution sectionalizing devices, Fixed Power Solutions, and other mitigations targeted at reducing the risk of wildfire.

  Please see Section 8, Public Safety Power Shutoff, Including Directional Vision For PSPS in PG&E's 2022 WMP for additional details.

- Conductor Replacement and Removal: In 2021, PG&E completed 93.8 miles of conductor replacements and 10 miles of conductor removals. All this work took place on lines traversing HFTD areas. In 2022, PG&E will continue this effort by removing or replacing 32 circuit miles of conductor in HFTD or High Fire Risk Area.

  Please see section 7.3.3.17.2, System Hardening – Transmission in PG&E's 2022 WMP for additional details.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3.16

PERCENTAGE OF CPUC-REPORTABLE IGNITIONS IN HFTD AREAS

(TRANSMISSION)

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Safety and Operational Metrics (SOM) 3.15 – percentage of California Public Utilities Commission (CPUC)-Reportable Ignitions in High Fire Threat District (HFTD) Areas (Transmission) is defined as:

The number of CPUC-reportable ignitions involving overhead transmission circuits in HFTD divided by circuit miles of overhead transmission lines in HFTD multiplied by 1,000 miles (ignitions per 1,000 HFTD circuit mile).

A CPUC-reportable ignition refers to a fire incident where the following three criteria are met: (1) Ignition is associated with Pacific Gas and Electric Company (PG&E) electrical assets, (2) something other than PG&E facilities burned, and (3) the resulting fire travelled more than one linear meter from the ignition point.[1]

For this SOM, reporting is specific to Tier 2 and Tier 3 HFTDs.

PG&E provides the CPUC with annual ignition data in the Fire Incident Data Collection Plan, to the Office of Energy Infrastructure and Safety quarterly via quarterly GIS data reporting, in quarterly Wildfire Mitigation Plan (WMP) updates, and the Safety Performance Metrics Report.

2. Introduction of Metric

The number of CPUC-reportable ignitions in HFTDs, normalized by circuit mileage, provides one way to gauge the level of wildfire risk that customers and communities are exposed to from overhead transmission assets. PG&E's objective is to minimize the number of CPUC-reportable ignitions in the right locations during the right conditions that may trigger a catastrophic wildfire.

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[1] Please see CPUC Decision (D.) 14-02-015, issued February 5, 2014 for additional details.

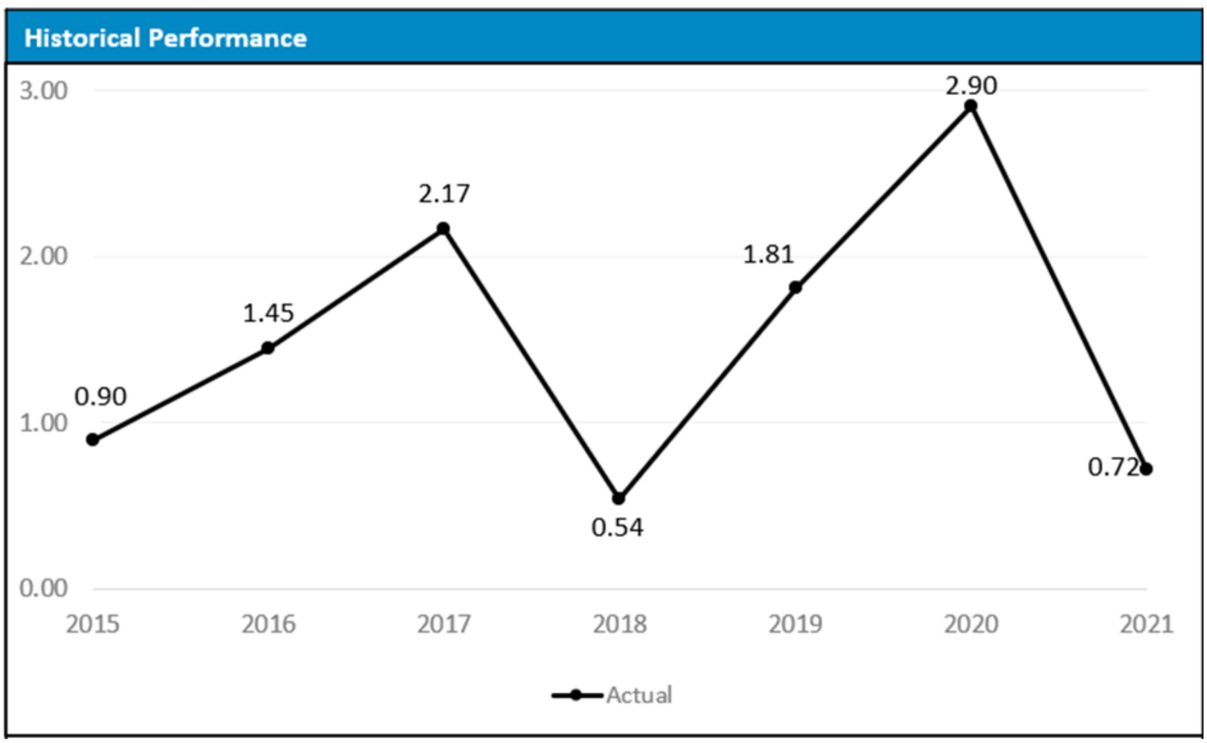
B. Metric Performance

1. Historical Data (2015-Present)

PG&E implemented the Fire Incident Data Collection Plan, in response to CPUC D.14-02-015, in June 2014 and our record, the Ignitions Tracker, includes all CPUC-reportable ignitions from June 2014 to present. The 2014 data does not represent a complete year and is excluded in this analysis.

PG&E's overhead transmission circuits traverse approximately 5,000 miles of terrain in the HFTD areas where the overhead conductor is primarily bare wire, supported by structures consisting of poles and towers. The annual number of CPUC-reportable ignitions is too low and too variable to detect any statistical pattern.

FIGURE 3.16-1
HISTORICAL PERFORMANCE (2015-2021)



2. Data Collection Methodology

Data will be collected per PG&E's Fire Incident Data Collection Plan (Utility Standard/Procedure RISK-6306S/P). Results will be inclusive of unique HFTD CPUC-reportable ignitions attributable to the transmission asset class with overhead construction types.

The following ignition events captured by PG&E's Fire Incident Data Collection Plan (Utility Standard/Procedure RISK-6306S/P) will be excluded for this metric:

- Duplicate events;
- Ignitions that do not meet CPUC reporting criteria;
- Ignition events outside of Tier 2 and Tier 3 HFTD;
- Distribution Ignitions; and
- Ignitions attributable to underground or pad mounted assets, as these are not overhead assets. Ignitions caused by non-overhead assets in HFTD are rare and, as the fires are often contained to the asset, pose less of a wildfire risk.

The circuit mileage utilized to calculate this metric originates from PG&E's Electrical Asset Data Reports refreshed December 8, 2021. Circuit mileage data from 2015-2018 is unavailable and PG&E used results from December 2021 to calculate this metric for all years for consistency.

3. Metric Performance

Historically, reportable transmission ignitions in HFTD are low in volume with variability year-to-year, which complicates the detection of significant trends. PG&E observed 0.72 ignitions per HFTD circuit mile in 2021 in comparison to a 3-previous year average of 1.75 ignitions per 1,000 HFTD circuit miles.

C. 1-Year Target and 5-Year Target

1. Target Methodology

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

- <u>Historical Data and Trends</u>: Target ranges are based on both PG&E's stand that catastrophic wildfires shall stop and historical performance. The bottom end of the range is 0 ignitions per 1,000 HFTD circuit miles in both 2022 and 2026, which reflects our stand that catastrophic wildfires shall stop. The upper end of the range is 1.75 ignitions per 1,000 HFTD circuit miles in both 2022 and 2026, which is based on our average performance over the last three years. The upper end of the range stays at 1.75 for 2026 because the volume of transmission ignitions is low, as variability year-to-year remains high;

- Benchmarking: None;
- Regulatory Requirements: CPUC D.14-02-015;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: The targets for this metric are suitable for EOE as they consider the potential for an increase in severe weather events due to climate change; and
- Other Considerations: The target range takes consideration for some variability in weather.

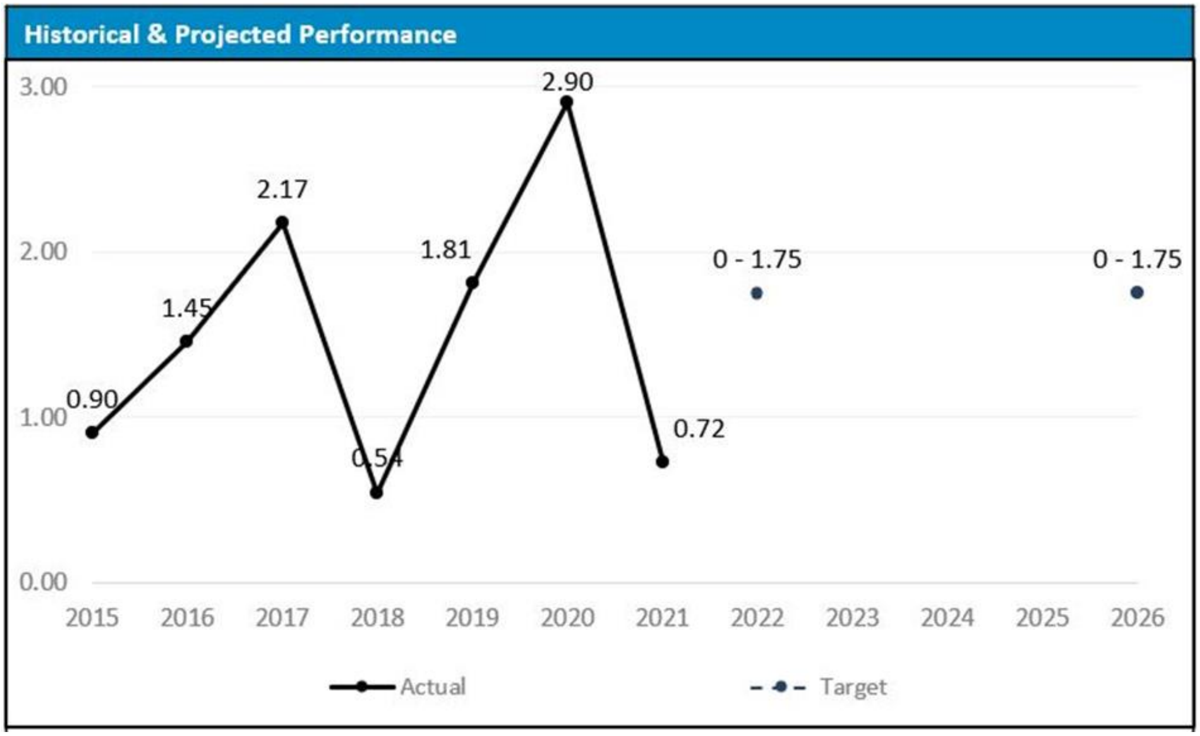
2. 2022 Target

PG&E's target for 2022 is 0-1.75 ignitions per 1,000 HFTD circuit miles. The bottom end of the range is 0 in 2022, which reflects our stand that catastrophic wildfires shall stop. The upper end of the range is 1.75 ignitions per 1,000 HFTD circuit miles in 2022, which is based on our average performance over the last three years.

3. 2026 Target

PG&E's target for 2026 is 0-1.75 ignitions per 1,000 HFTD circuit miles. The bottom end of the range is 0 in 2026, which reflects our stand that catastrophic wildfires shall stop. The upper end of the range is 1.75 ignitions per 1,000 HFTD circuit miles in 2026, which is based on our average performance over the last three years. The volume of reportable ignitions caused by transmission assets is so low and highly variable.

FIGURE 3.8-2
HISTORICAL PERFORMANCE (2015-2021) AND
TARGETS (2022 AND 2026)



D. Current and Planned Work Activities

Through continual execution of its WMP, PG&E has taken action to reduce ignition risk associated with its transmission system, including:

- Enhanced Inspection Protocols: In 2022, PG&E is continuing to evolve our inspection programs and LiDAR data collection to proactively identify and treat pending failures and reduce wildfire risk associated with Transmission Facilities. In 2022, PG&E will complete 39,000 detailed ground and aerial inspections on transmission assets, climbing inspections on 1,800 transmission structures, and ground and aerial inspection of 43 transmission substations.

  Please see Section 7.3.4.2, Detailed Inspections of Transmission Electric Lines and Equipment in PG&E's 2022 WMP for additional details.

- Public Safety Power Shut Off (PSPS): PSPS is a wildfire mitigation strategy, first implemented in 2019, to reduce powerline ignitions during severe weather by proactively de-energizing powerlines. PG&E's main focus on PSPS is to mitigate the risks associated with a catastrophic wildfire and to prioritize customer safety. To that end, PG&E continued to make progress to its PSPS Program to mitigate wildfire risk, including updating meteorology models and scoping processes.

In 2022, PG&E plans to install additional distribution sectionalizing devices, Fixed Power Solutions, and other mitigations targeted at reducing the risk of wildfire.

Please see Section 8, PSPS, Including Directional Vision for PSPS in PG&E's 2022 WMP for additional details.

- Conductor Replacement and Removal: In 2021, PG&E completed 93.8 miles of conductor replacements and 10 miles of conductor removals. All this work took place on lines traversing HFTD areas. In 2022, PG&E will continue this effort by removing or replacing 32 circuit miles of conductor in HFTD or High Fire Risk Area.

  Please see Section 7.3.3.17.2, System Hardening – Transmission in PG&E's 2022 WMP for additional details.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4.1

SAFETY AND OPERATIONAL METRICS REPORT: NUMBER OF GAS DIG-INS PER 1,000 UNDERGROUND SERVICE ALERT (USA) TICKETS ON TRANSMISSION AND DISTRIBUTION PIPELINES

PACIFIC GAS AND ELECTRIC COMPANY
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1. Metric Definition

Safety and Operational Metric 4.1 – Number of Gas Dig-Ins per 1,000 tickets on Transmission and Distribution Pipelines is defined as:

The number of gas dig-ins per 1,000 Underground Service Alert (USA) tickets received for gas. A gas dig-in refers to damage (impact or exposure) which occurs during excavation activities and results in a repair or replacement of an underground gas facility. Excludes fiber and electric tickets. Also excludes tickets originated by the utility itself or by utility contractors.

2. Introduction of Metric

Reducing gas dig-ins increases public safety and improves reliability. It is therefore important to take reasonable steps reduce this risk because gas dig-ins represent a potential risk to people, property, and the environment.

If ignited, gas from a dig-in could produce a fire or explosion, either of which, could result property damage, injury or even death. Release of gas from a dig-in also produces a possible health hazard from inhalation of natural gas. Finally, dig-ins typically produce a disruption or loss of service to one or more customers.

For all these reasons, fewer dig-ins reduces risk to public safety and minimizes interruption to the gas business and customers.

B. Metric Performance

1. Historical Data (2018-2021)

For this metric, PG&E has four years of historic data available, which includes 2018-2021. The past four years were used for analysis in target setting. Over the historical reporting period, performance improved as demonstrated by both an increase in USA tickets and a decrease in gas dig-ins.

FIGURE 4.1-1
THIRD-PARTY TICKETS AND TOTAL DIG-IN COUNTS

	USA Ticket Count			
Month	2018	2019	2020	2021
January	66,605	66,900	74,736	69,544
February	62,387	58,586	70,016	74,323
March	66,538	74,563	69,991	95,177
April	71,514	85,215	67,071	93,335
May	75,794	86,339	71,786	87,432
June	69,824	81,989	80,614	93,008
July	68,927	92,787	80,926	84,316
August	74,158	89,869	76,521	87,507
September	64,678	84,840	79,684	84,126
October	77,779	91,022	81,680	82,106
November	64,861	72,476	72,089	82,859
December	56,219	64,452	73,995	71,744
Grand Total	819,284	949,038	899,109	1,005,477

	Dig-In Count			
	2018	2019	2020	2021
January	100	89	93	118
February	131	78	119	116
March	103	103	98	126
April	147	140	117	147
May	209	140	128	139
June	176	176	170	183
July	190	196	201	170
August	186	200	182	175
September	173	167	178	163
October	179	191	155	135
November	139	147	131	101
December	110	86	126	64
Total	1,843	1,713	1,698	1,637

2. Data Collection Methodology

The data used for this metric reporting is maintained in two files. Together, these databases identify the number of dig-ins and the 811 tickets, respectively. To ensure accuracy of the Master Dig-In File data, three data sources are reviewed:

1) The repair data file recorded in SAP-(Obtained using Business Objects GCM058 Quarterly GQI Extract Report);
2) The Event Management Tool obtained from Gas Dispatch, (EM Tool) data file; and
3) The Dig-In Reduction Teams (DiRT) Pronto download file, obtained from the DiRT team data download report.

Events that meet the definition of dig-in are recorded as a ratio of total dig-ins (count) divided by the third-party USA tickets (count) multiplied by 1,000. This metric does not include tickets originated by the utility itself or by utility contractors.

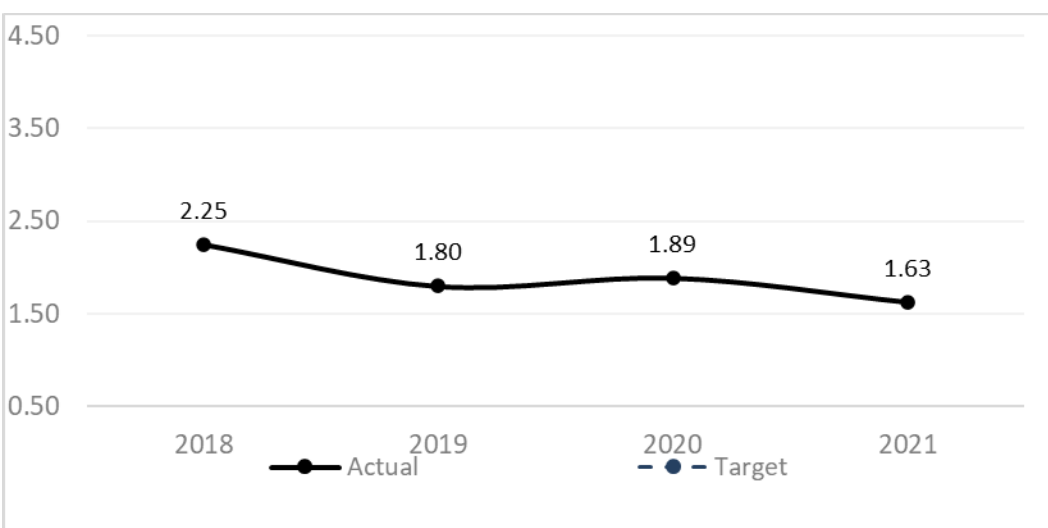
This metric also does not include PG&E dig-ins to third parties (e.g., sewer, water, telecommunications). Dig-ins are reported in real-time, so they should be captured for the reporting period. However, in the event dig-ins are reported after the reporting cycle is closed, the dig-in would be captured in the next reporting cycle (i.e., the next quarter of the current year or the first quarter of the next year). Electric and Fiber dig-ins are also excluded from the dig-in count. Also excluded from the dig-in count are the following (since damages are not from excavation activity):

- Damages to above-ground infrastructure, such as meters and risers, or overbuilds;
- Pre-existing damages (e.g., due to corrosion or old wrap);
- Any intentional damage to a pipeline (e.g., drilling or cutting);
- Damage caused by driving over a covered facility (heavy vehicles damage gas pipe, non-excavation);
- Damage to abandoned facilities;
- Damage due to materials failure (e.g., Aldyl-A pipe); and
- Damage caused to gas or electric lines by trench collapse or soldering work.

3. Metric Performance for 2021

There has been an overall downward trend in the number of dig-ins per 1,000 third-party USA tickets. PG&E attributes the reduction to current and planned Damage Prevention activities. Overall, PG&E has worked to increase knowledge of the requirement to call 811 before digging through Public Awareness Campaigns and by providing training and education to contractors. PG&E continues to show an improvement in its dig-in ratio.

FIGURE 4.1-2
TOTAL DIG-INS PER 1,000 THIRD-PARTY TICKETS 2018-2021



C. 1-Year Target and 5-Year Target

1. Target Methodology

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

- Historical Data and Trends: Comparable data is available starting in 2018. Performance has been consistent with a downward trend from 2018-2021;
- Benchmarking: Although this metric is not benchmarkable as defined (benchmarkable metrics include total tickets rather than only a subset of tickets), benchmark data was used and derived as proxy guideposts to understand PG&E performance for third-party tickets to inform target setting. The target is set at a level consistent with strong performance.
- Regulatory Requirements: None;
- Attainable Within Known Resources/Work Plan: Yes;
- Appropriate/Sustainable Indicators for Enhanced Oversight Enforcement: Yes, performance at or below the set target is a sustainable assumption for maintaining metric performance, plus room for non-significant variability; and
- Other Considerations: None.

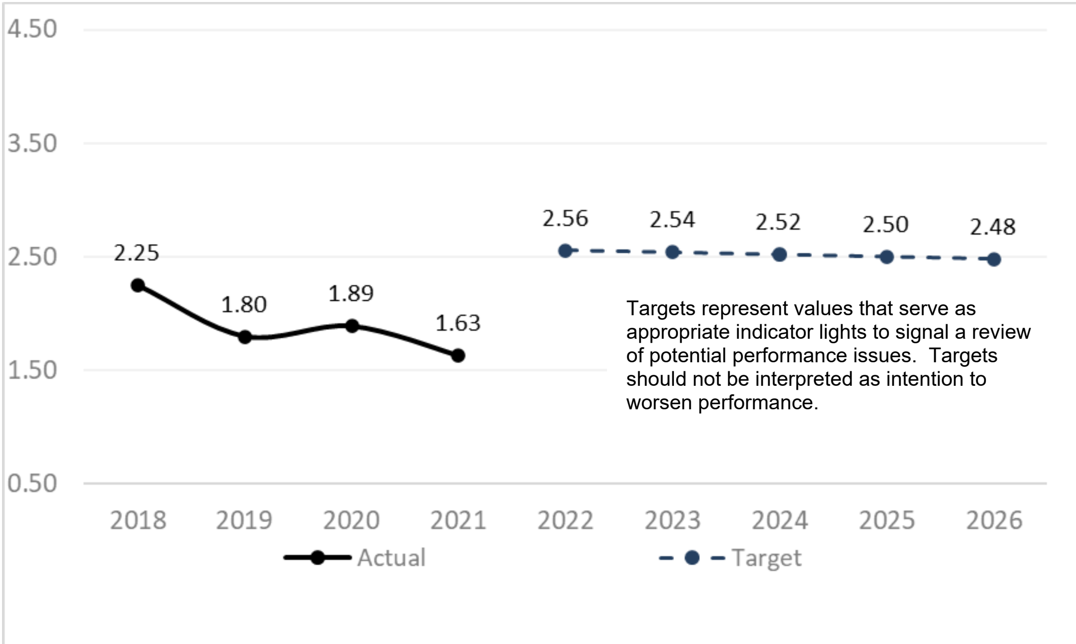
2. 2022 Target

The 2022 target is to maintain performance at or better than a rate of 2.56 based on the factors described above. This target represents an appropriate indicator light to signal a review of potential performance issues. Target should not be interpreted as intention to worsen performance.

3. 2026 Target

The 2026 target is to maintain performance better than a rate of 2.48 based on the factors described above. Annual targets should continue to be informed by available benchmarking data.

FIGURE 4.1-3
TOTAL DIG-INS PER 1,000 THIRD-PARTY TICKETS 2018-2021 AND TARGETS THROUGH 2026



D. Current and Planned Work Activities

PG&E's Damage Prevention team is responsible for the overall management of PG&E's Damage Prevention Program, by managing the risks associated with excavations around PG&E's facilities and conducting investigations. As an additional control to manage the Damage Prevention Program, PG&E has its DiRT). DiRT consists of 25 people (18 PG&E Employees and 7 Contractors) deployed systemwide to investigate dig-ins. Team members work closely with various local PG&E operations personnel and respond to referrals from those employees when they observe excavations potentially not in compliance with the requirements of California Government Code Section 4216. DiRT personnel also assist the Ground Patrol team when they respond to immediate threats identified in the air by the Aerial Patrol team and other PG&E groups, in order to intervene in unsafe digging activities by third parties and follow-up to educate excavators as necessary.

PG&E's Damage Prevention activities include educational outreach activities for professional excavators, local public officials, emergency responders, and the general public who lives and works within PG&E's service territory. The program communicates safe excavation practices, required actions prior to excavating near underground pipelines, availability of pipeline location information, and other gas safety information through a variety of methods throughout the year. These efforts are aimed at increasing public awareness about the importance of utilizing the 811 Program before an excavation project is started, understanding the markings that have been placed, and following safe excavation practices after subsurface installations have been marked. Specific activities aimed at preventing dig-ins include:

- Updating the Locate and Mark Field Guide to provide clear instruction around critical processes for locating underground assets, including troubleshooting of difficult to locate facilities;
- Continued participation in the Gold Shovel Standard (GSS). PG&E began this program that is now run by a third party and available to utilities and excavators across the nation. The program sets safety criteria that PG&E contractors are required to meet to be eligible to do work on behalf of the Utility. The GSS became an internationally-recognized program, with companies in Canada adopting and implementing its certification requirements. The GSS Program is a way that PG&E is making its own communities safer, and also bringing best safety practices to the industry; and
- An 811 Ambassador program, which utilizes all PG&E employees to properly identify unsafe excavation activities where employees learn how to identify excavation-related delineations and utility operator markings.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4.2

SAFETY AND OPERATIONAL METRICS REPORT:

NUMBER OF OVERPRESSURE EVENTS

PACIFIC GAS AND ELECTRIC COMPANY
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1. Metric Definition

Safety and Operational Metric 4.2 – Number of Overpressure (OP) events is defined as:

OP events as reportable under General Order (GO) 112-F 122.2(d)(5).

2. Introduction of Metric

An OP event occurs when the gas pressure exceeds the Maximum Allowable Operating Pressure (MAOP) of the pipeline, plus the build ups, set forth in the Code of Federal Regulations (CFR) – 49 CFR 192.201.

This metric tracks the occurrence of OP events, which includes:

1) High pressure Gas Distribution (GD):
   a) (MAOP 1 pound per square inch gauge (psig) to 12 psig) greater than 50 percent above MAOP;
   b) (MAOP 12 psig to 60 psig) greater than 6 psig above MAOP; and
2) Gas Transmission (GT) pipelines greater than 10 percent above MAOP (or the pressure produces a hoop stress of ≥75 percent Specified Minimum Yield Strength, whichever is lower).

OP events on low pressure systems are excluded from this metric because they are not defined in federal code 49 CFR 192.201.

OP events have the potential to overstress pipelines which pose significant safety and operational risks to Pacific Gas and Electric Company's (PG&E) gas system. PG&E has implemented multiple controls and mitigations to reduce OP events.

Following the San Bruno event in 2010, an Overpressure Elimination (OPE) task force was established to identify the root causes of OP events and develop corrective actions.

In 2011, several decisions were made in response to San Bruno incident. One of the most important corrective actions was to lower the normal operating pressure below the MAOP across the system, which resulted in a significant drop-off of OP events from 2011-2012.

Beginning in 2013, causal evaluations were conducted on all OP events. Corrective actions from these evaluations included: equipment and design review, training, fatigue management, improved Gas Event Reporting, and improved work procedures.

In 2015, several benchmarking studies and industry evaluations were conducted to learn OP elimination best practice. The benchmarking studies and analyses helped influence the development and strategies of the OPE Program.

In 2017, after the Folsom OP event,[1] the OPE Program was stood up under one sponsor with dedicated resources. The OPE Program formalized a two-pronged strategy to mitigate the risk of large OP events, while reducing operational risk: (1) Human (HU) Performance Strategy, and (2) Equipment (EQ)-Related Strategy.

In 2020, PG&E retooled an effort to reduce the number of HU Performance-related events. PG&E contracted with Exponent to perform an analysis on the OP and near hit events using the Human Factors Analysis and Classification System to drive focused actions to improve. This effort helped the team to develop the HU Performance tools to: identify and control risk, improve efficiency, avoid delays, reduce errors, prevent events, and promote excellent performance at every facility.

B. Metric Performance

1. Historical Data (2011-2021)

Historical data of OP events is available since year 2011. Various data points of each OP event including location, Corrective Action Program (CAP) number, date, cause, corrective action, etc. which are documented in

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[1] On January 24, 2017, the Hydraulically Independent System that delivers gas to the Folsom area experienced a large OP event in excess of the system's 60 psig MAOP. The OP event caused damage to the regulator station equipment and resulted in a significant number of leaks on plastic distribution piping. Inspection of the station revealed that the station filter had been clogged with debris and the regulator boot had been eroded by contaminants. Further investigation revealed that an upstream pigging project scraped corrosion scales from internal pipe walls. The scale—along with other debris—traveled downstream, until eventually collecting at Folsom, causing the OP event.

the OP master list files located in PG&E's "Safety and Operational Metrics Report: Supporting Documentation."

Data source of the metric is commonly from the Supervisory Control and Data Acquisition (SCADA) system, and from direct accounts, including: gauge pressure readings, chart recorders, electronic recorders, and metering data.

The availability of data has expanded throughout the years due to the increase in pressure monitoring devices allowing more OP events to be identified and recorded. In 2012, PG&E had 1,409 SCADA pressure points on its pipeline system, and by end of year 2021, that number has grown to 6,496.

2. Data Collection Methodology

PG&E has both an automated process and field process for logging Gas OP events. For the automated process, the SCADA system monitors EQ pressure and notifies potential issues to Gas Control through alarms. For the field process, field personnel are required to gauge pressure during maintenance and clearances and report to Gas Control if an abnormal operating condition arises.

Several controls are in place for this metric:

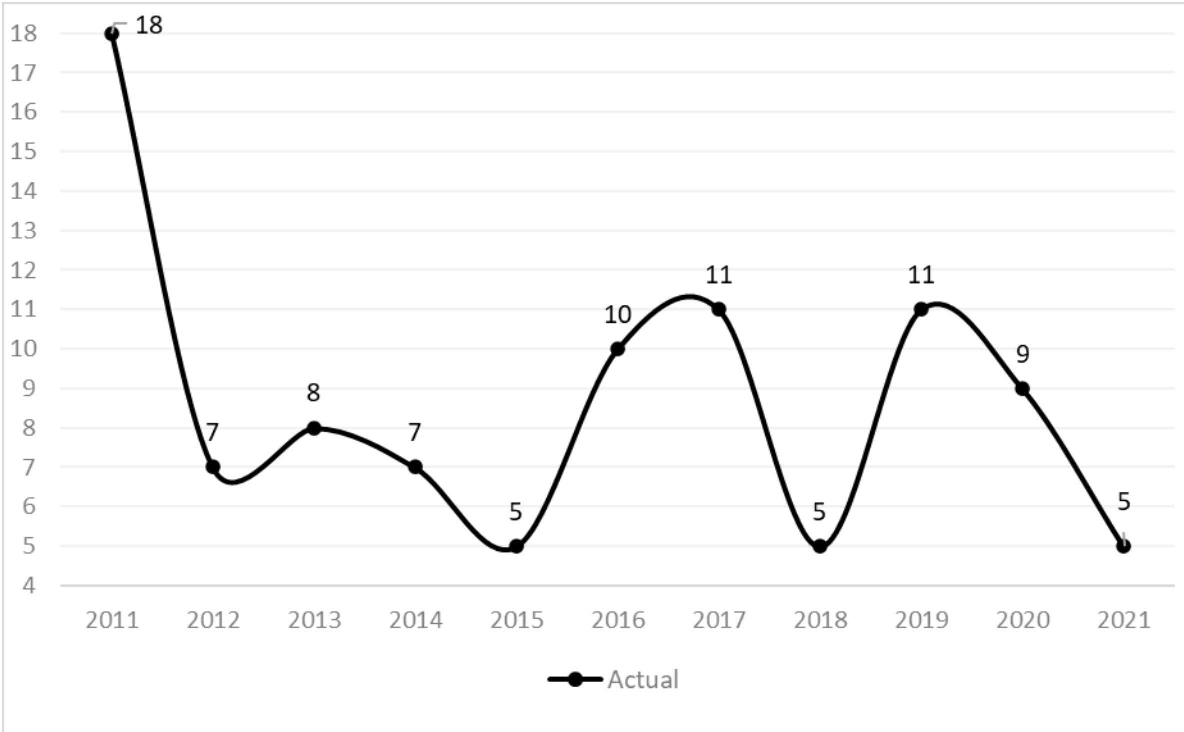
1) Each OP event is entered into our system of record SAP system CAP to ensure retention of record history;
2) Each OP event's datasets (location, CAP number, date, cause, corrective action etc.) are reviewed by Facility Integrity Management Program team to ensure accuracy and are logged in the OP master list which is viewable by all PG&E employees; and
3) Each OP event is distributed to stakeholders by an electronic page (epage) and an e-mail (Quick Hit), reviewed on the next Daily Operations Briefing with leadership.

3. Metric Performance for 2011-2021

In 2021 there were five OP events, an improvement from 2019 and 2020 of 11 and 9, respectively. The following factors contributed to this performance:

- Leading indicators (pressure anomalies, daily alarms review, billing correction data) are being used to drive proactive field response;
- Enhanced clearance review and approval process is being used to identify complex clearances and provide additional review prior to approval;
- Slam Shut installation Program to mitigate EQ-related events is gaining momentum. In 2021, 281 and 17 slam shuts were installed respectively in GD and GT system;
- 16 Slam Shut activations that prevented larger events have occurred since late December 2020;
- Completed Dynamic Learning Activity HU Tool Training capability building activities for all Supervisors and Grassroots Leads;
- Developed curriculum to educate non-traditional Supervisors, Quality Assessors, and others about gas system, regulation, qualification, and clearance requirements; and
- Completed detailed review of HU data to determine common causes of HU-related OP.

FIGURE 4.2-1
OVERPRESSURE EVENTS 2011-2021



C. 1-Year Target and 5-Year Target

1. Target Methodology

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

- Historical Data and Trends: OP events have ranged from 5 to 11 events per year since 2012. The target is based on the maximum number of events in the past seven years;
- Benchmarking: This metric is not traditionally benchmarkable, however PG&E has contracted with third parties to conduct international and North American industry evaluations. The benchmarking studies indicated that PG&E has demonstrated strong performance in this area.
- Regulatory Requirements: OP events as reportable under California Public Utilities Commission GO No.112-F, 122.2(d)(5);
- Attainable Within Known Resources/Workplan: Yes;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: Yes, performance at or below the maximum of the past

seven years is a sustainable assumption for maintaining metric performance, plus room for non-significant variability; and

- Other Considerations: The approach of using the maximum of the past seven years includes the consideration of the expected impact of ongoing SCADA device installations—improved system visibility and monitoring points may result in a higher number of observed OP events. Additionally, as the OP Program has expanded, there has been an increase in pressure monitoring devices throughout the system, which allows more OP events to be identified and recorded.

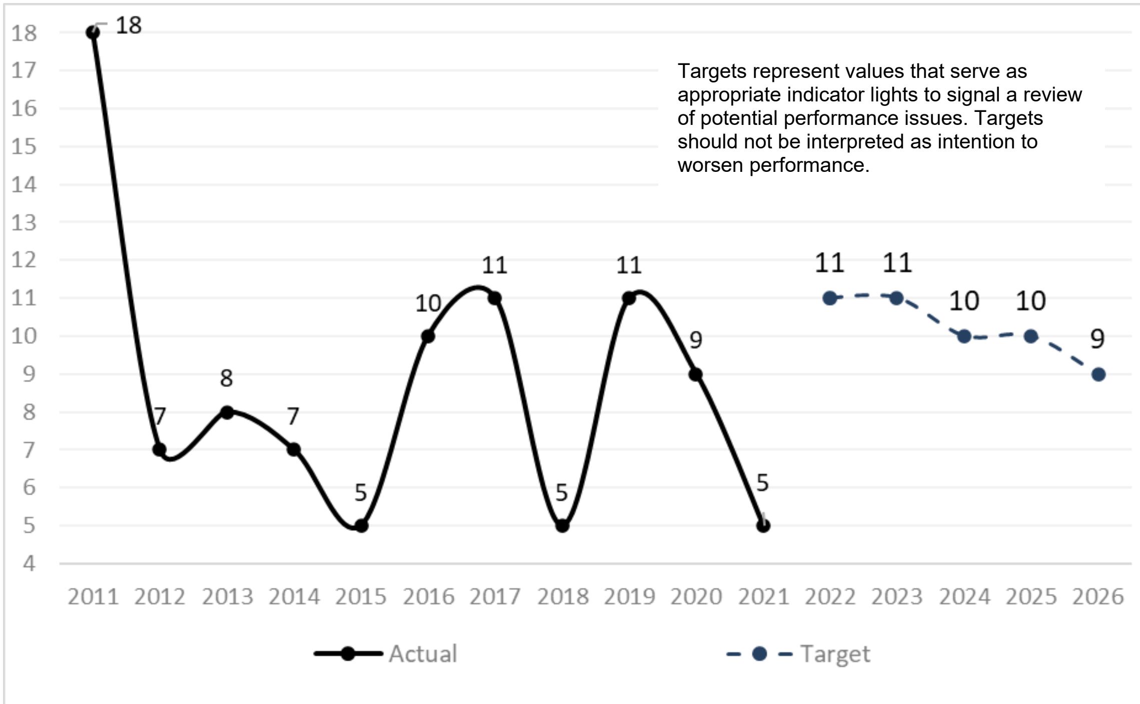
2. 2022 Target

The 2022 target is to maintain performance at or better than 11 events, based on the factors described above. This target represents an appropriate indicator light to signal a review of potential performance issues. Target should not be interpreted as intention to worsen performance.

3. 2026 Target

The 2026 target is to maintain performance better than nine events, based on the factors described above, along with stepped-improvement of one event every two years. This target demonstrates continued focus on improvement year-over-year. PG&E continues to review operations and look for opportunities to perform work to further reduce OP events and contribute to system safety.

FIGURE 4.2-2
OVERPRESSURE EVENTS 2011-2021 AND TARGETS THROUGH 2026



D. Current and Planned Work Activities

PG&E's strategic objective includes plans to execute the secondary Overpressure Protection Program (OPP) to mitigate common failure mode failure OP events for both GT and GD over a 10-year period (2018-2027).

- Gas Distribution: For 2019-2022 , PG&E plans to retrofit 50 percent of GD pilot-operated stations by the end of 2022.[2] Moving forward, PG&E plans to complete retrofits on the remaining GD high pressure stations by 2025. This plan will have installed secondary OPP at all GD pilot-operated stations (which carry the common failure mode risk) by 2025.
- Gas Transmission: In 2019, we began rebuilding and retrofitting Large Volume Customer Regulators sets specifically to address OP risks. All Large Volume Customer Regulators (LVCR) are forecasted to be rebuilt or retrofitted by the end of 2023.[3] PG&E plans to retrofit GT Large Volume Customer Meter sets and GT simple stations with common failure mode risks during 2023-2026, and expects to conclude the program in 2027.

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2 From 2019-2021, PG&E has retrofitted approximately 457 GD pilot-operated stations.

3 From 2019-2021, PG&E has rebuilt and retrofitted approximately 43 LVCRs.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4.3

SAFETY AND OPERATIONAL METRICS REPORT:

TIME TO RESPOND ON-SITE TO EMERGENCY NOTIFICATION

PACIFIC GAS AND ELECTRIC COMPANY
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1. Metric Definition

Safety and Operational Metric (SOM) 4.3 – Time to Respond On-Site to Emergency Notification is defined as:

Average time and median time to respond on-site to a gas-related emergency notification from the time of notification to the time a Gas Service Representative (GSR) (or qualified first responder) arrived onsite. Emergency notification includes all notifications originating from 911 calls and calls made directly to the utilities' safety hotlines.

The data used to determine the average time and median time shall be provided in increments as defined in General Order 112-F 123.2 (c) as supplemental information, not as a metric.

2. Introduction of Metric

Gas emergency response measures Pacific Gas and Electric Company's (PG&E) ability to respond with urgency to hazardous or unsafe situations that may be a threat to customer and public safety. In some situations, GSRs respond to emergency situations as first responders. Responding to emergency situations is PG&E's highest priority so that PG&E can prevent or ameliorate hazardous situations. PG&E's goal is to have a GSR on-site as quickly as possible for customer generated gas odor calls. Faster response time to Emergency Notifications reduces the length of emergent situations.

PG&E's GSRs respond to approximately 500,000 gas service customer requests annually. These requests include: investigating reports of possible gas leaks; carbon monoxide monitoring; re-lights; appliance safety checks; and maintenance work, including Atmospheric Corrosion remediation and regulator replacements.

Consistent with current practice, PG&E will continue to treat all customer-reported gas odor calls as Immediate Response (IR) and will attempt to respond to such calls within 60 minutes. To meet this goal, PG&E utilizes industry best practices, such as: mobile data terminals, real-time Global Positioning Systems, backup on-call technicians, and shift coverage of 24 hours a day, seven days a week.

B. Metric Performance

1. Historical Data (2011-2021)

Historical data is presented as a value in minutes for response time, indicated as both an average and a median value for all Emergency Notifications for each calendar year.

Data sets prior to 2014 come from historically submitted documentation; data sets from 2014 forward come from the Customer Data Warehouse system (a database for Field Automated Systems (FAS) data) and go through a rigorous, multi-step audit process prior to submission to ensure accuracy and precision.

2. Data Collection Methodology

The response time by PG&E is measured from the time PG&E is notified—defined as the order creation time in Customer Care and Billing by the contact center—to the time a GSR or a PG&E-qualified first responder arrives on-site to the emergency location (including Business Hours and After Hours). PG&E notification time is defined as when a gas emergency order is created and timestamped.

Using PG&E's Field Automation System (FAS), the average response time is measured for all IR gas emergency orders generated where a GSR or qualified first responder is required to respond.

The following IR gas emergency jobs are excluded in the total gas emergency orders volume count:

- Level 2 and above emergencies;[1]
- If the source is a non-planned release of PG&E gas, the original call is included—the gas emergency itself—and all subsequent related orders are excluded;

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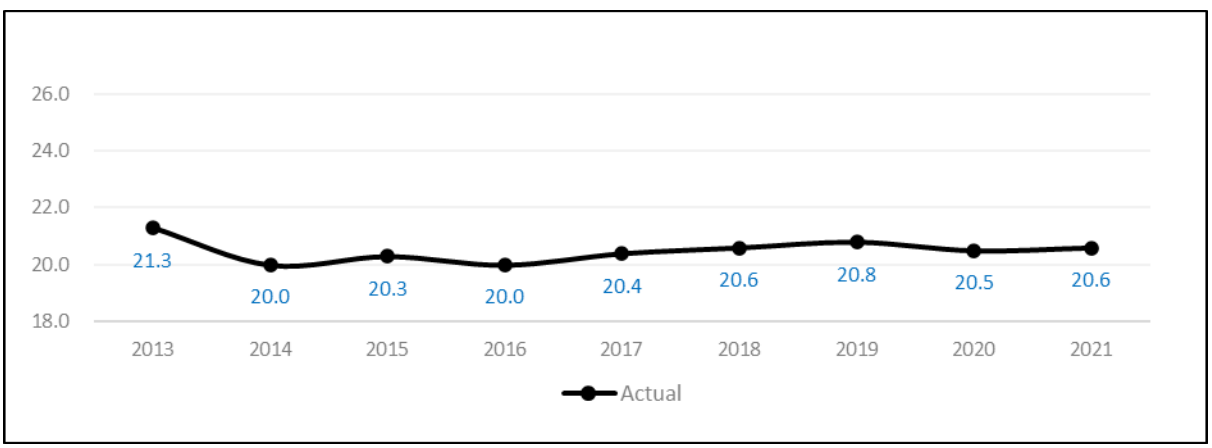
[1] Defined in the Gas Emergency Response Plan as a region-wide emergency event that may require 1-2 days for service restoration.

- If the source is either a planned release of PG&E gas or another non-leak-related event, all related orders from the metric are excluded, including the original call;
- Duplicate orders for assistance;
- Cancelled orders;
- For multiple leak calls from the same Multi-Meter Manifold;[2]
- Unknown premise tag with no nearby gas facility; and
- If the FAS system is unavailable—such as during a tech down event—the jobs cannot be created in our system, and are therefore, an exception (not available to be included in the volume).

3. Metric Performance for 2021

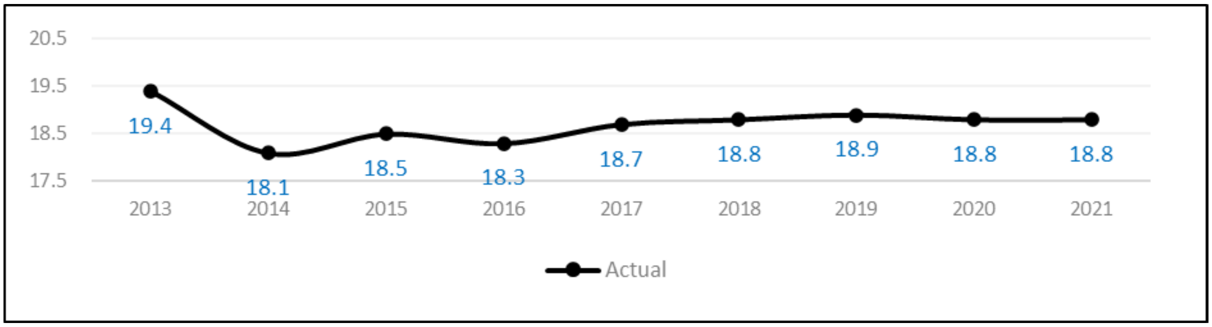
Since 2011, PG&E has improved and maintained strong performance in this metric. Over the past 12 months, we have continued this excellence by achieving an average of 20.6 minutes and a recorded median of 18.8 minutes.

FIGURE 4.3-1
AVERAGE RESPONSE TIME 2013-2021



2 The first order is included, and all subsequent orders are excluded.

FIGURE 4.3-2
MEDIAN RESPONSE TIME 2013-2021



C. 1-Year Target and 5-Year Target

1. Target Methodology

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

- Historical Data and Trends: Comparable data is available starting in 2015. Performance has been consistent from 2015-2021;
- Benchmarking: The targets for average response time and median response time are informed by available benchmarking data and targets are set at a level consistent with strong performance;
- Regulatory Requirements: None;
- Attainable Within Known Resources/Work Plan: Yes;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: Yes, performance at or below the set targets is a sustainable assumption for maintaining average and median response time performance, plus room for non-significant variability; and
- Other Considerations: None.

2. 2022 Target

The 2022 target is to maintain performance better than or equal to 21.6 minutes for average response time and 19.8 minutes for median response time, based on the factors described above. These targets represent values that serve as appropriate indicator lights to signal a review of potential performance issues. Targets should not be interpreted as intention to worsen performance.

3. 2026 Target

The 2026 target is to maintain performance better than or equal to 21.2 minutes for average response time and 19.4 minutes for median response time, based on the factors described above. Annual targets should continue to be informed by available benchmarking data.

FIGURE 4.3-4
AVERAGE RESPONSE TIME 2013-2021 AND TARGETS THROUGH 2026

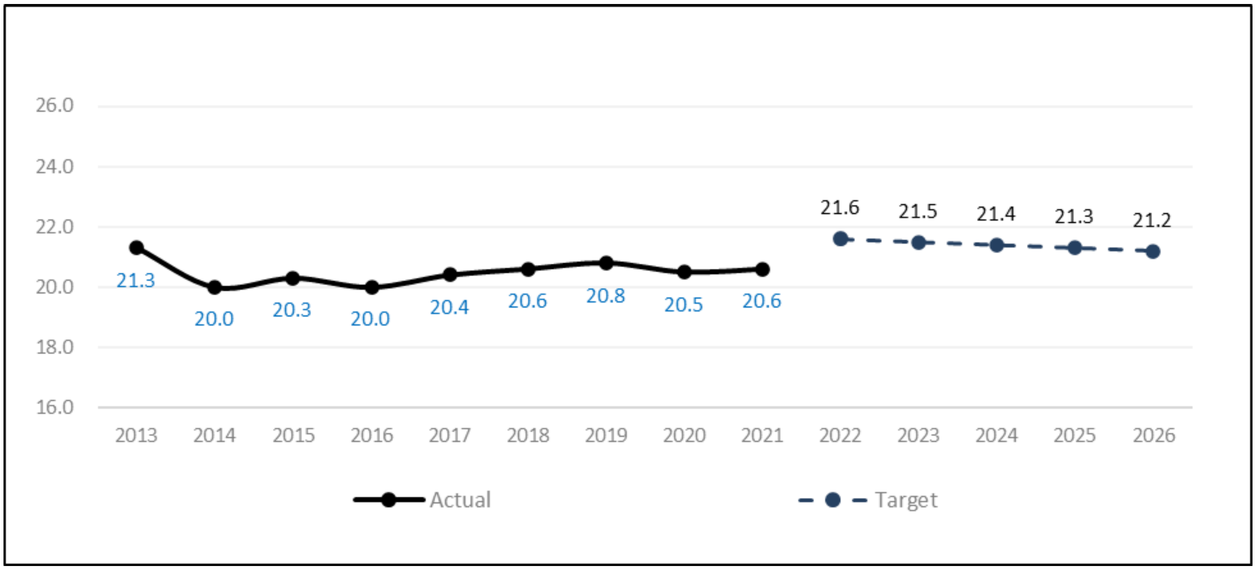
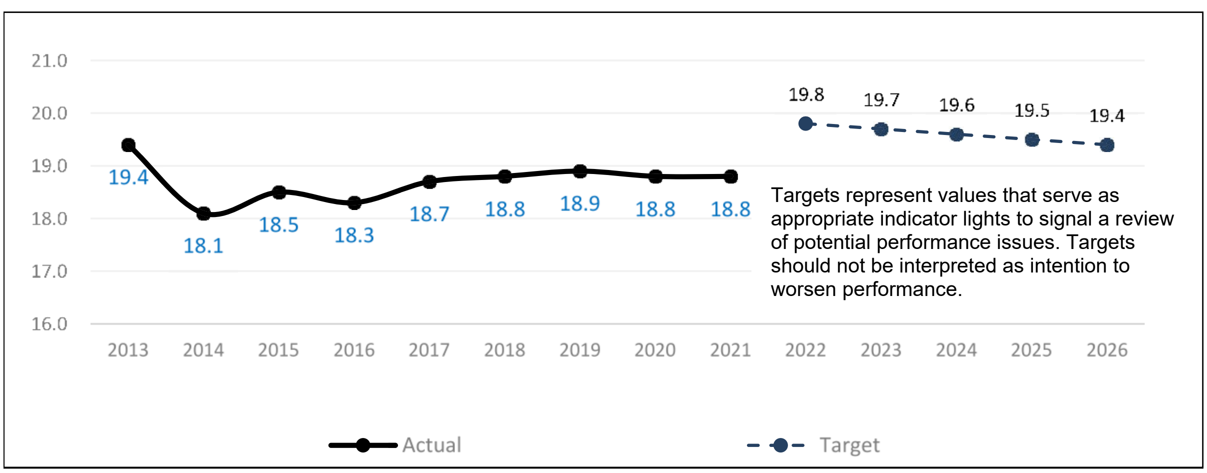


FIGURE 4.3-5
MEDIAN RESPONSE TIME 2013-2021 AND TARGETS THROUGH 2026



D. Current and Planned Work Activities

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

- Field Service and Gas Dispatch: PG&E's Field Service and Gas Dispatch partner together to respond to customer Gas Emergency (odor calls). There is a shared responsibility in the overall performance of this work. GSRs are deployed systemwide, 24 hours a day—utilizing an on-call as needed.
- Monitoring Controls: Activities which help us to maintain our Gas Emergency Response include: continued focus and visibility in our Daily Operating Reviews, Weekly Operating Reviews, and Cross Functional Reviews. These help to illustrate several key drivers, including: Dispatch Handle Time, Drive Time, and Wrap Time.
- Audits: PG&E performs audits on Emergency calls to identify opportunities.
- Data Analysis: Staffing and historical Gas Emergency Response volume are reviewed to help drive decisions. We utilize Best Practice of Dispatching to the closest resource. In addition, Dispatcher Ride Alongs with GSRs and an extensive shift optimization review are underway in 2022.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4.4

SAFETY AND OPERATIONAL METRICS REPORT:

GAS SHUT-IN TIME, MAINS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 4.4
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CHAPTER 4.4
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A. Introduction

1. Metric Definition

Safety and Operational Metric (SOM) 4.4 – Gas Shut-In Time, Mains is defined as:

Median time to shut-in gas when an uncontrolled or unplanned gas release occurs on a main. The data used to determine the median time shall be provided in increments as defined in General Order 112-F 123.2 (c) as supplemental information, not as a metric.

2. Introduction of Metric

The measurement of Gas Shut in Time captures the median duration of time required to respond to and mitigate potentially hazardous gas leak conditions. These leak conditions are associated with the public safety risk of loss of containment on Gas Distribution Main or Service. The term “shut in” refers to the act of stopping the gas flow. It is important for the flow of gas to be stopped to avoid consequences such as overpressure events or explosions and so that work can be safely performed to make repairs in a timely manner. Performance aims for faster response times as a measure of prevention resulting in lower risk of an incident impacting public safety and minimized interruption to the gas business and customers. It is imperative that we promptly and effectively resolve any hazardous conditions on our distribution network while balancing timeliness, customer outages, and employee safety.

The timing for the response starts when the Pacific Gas and Electric Company (PG&E or the Utility) first receives the report of a potential gas leak and ends when the Utility’s qualified representative determines, per the Utility’s emergency standards, that the reported leak is not hazardous, a leak does not exist, or the Utility’s representative completes actions to mitigate a hazardous leak and render it as being non-hazardous (i.e., by shutting-off gas supply, eliminating subsurface leak migration, repair, etc.) per the Utility’s standards.

This metric measures the median number of minutes required for a qualified PG&E responder to arrive onsite and stop the flow of gas as result of damages impacting gas mains from PG&E distribution network. It does not include instances where a qualified representative determines that the reported leak is not hazardous or a leak does not exist.

B. Metric Performance

1. Historical Data (2014-2021)

Historical data for shut-in the gas (SITG) Main metric is available for the period 2014-2021. The data captures the median time that a qualified first responder requires to respond and stop gas flow during incidents involving an unplanned and uncontrolled release of gas on distribution mains. This data includes incidents related to distribution main pipelines and regulator stations because of third-party dig-ins, vehicle impacts, explosion, pipe rupture, and material failure.

Before 2014, PG&E used a decentralized emergency process to manage emergencies (i.e., each division used its own resources like mappers, planners, among others to track and manage emergencies). Similarly, support organizations like Dispatch, Mapping and Planning used their own management tools to help schedule and manage emergency information. Dispatch used a management tool called Outage Management that recorded times at various stages of the process (i.e., when the emergency call came in, when the Gas Service Representative (GSR) arrived at the site, when the leak was isolated, etc.). The Distribution Control Room used a tool called Gas Logging System to record incoming information.

In 2014, a centralized process was implemented to allow Distribution, Transmission, Dispatch, Planning and Mapping personnel to be co-located and work together as a team to manage emergencies. This centralized process also allowed the development of the Event Management Tool (EMT) system.

2. Data Collection Methodology

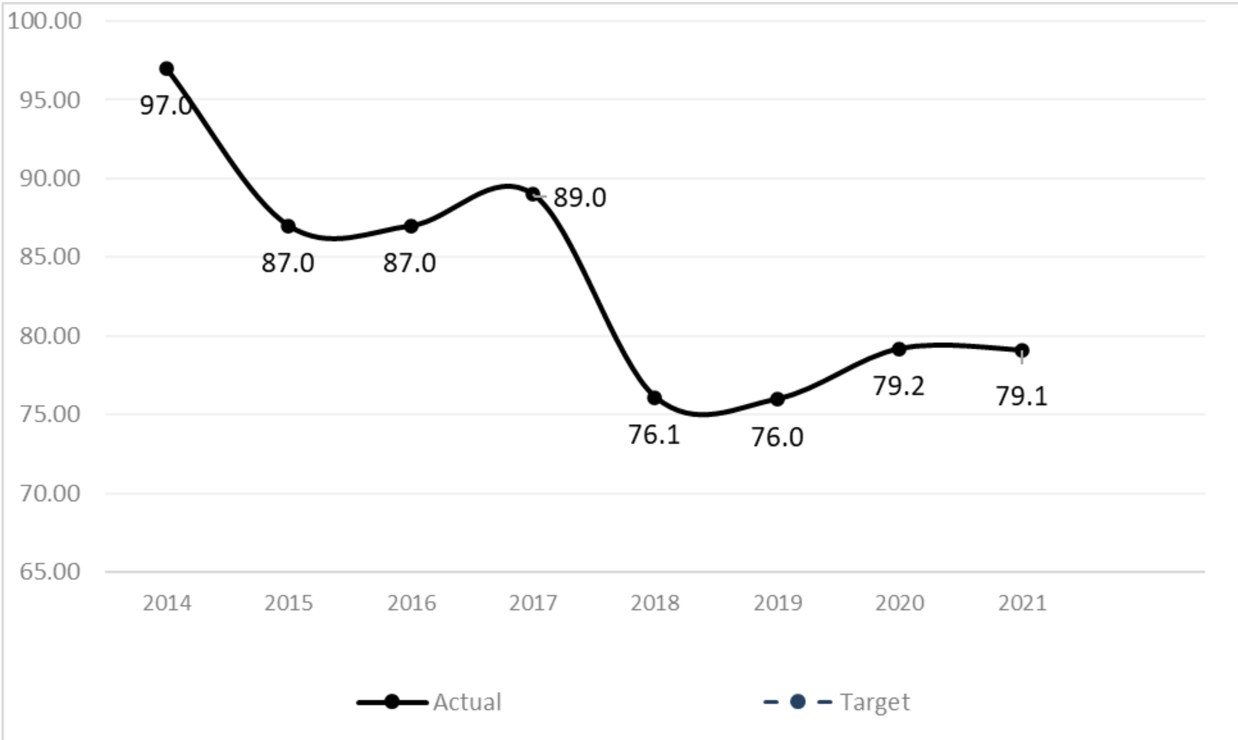
The EMT is currently used as the official system to track gas emergencies from start to finish. It is used by Dispatch and Gas Distribution

Control Center (GDCC) teams to create emergency events and collect incident information and allows PG&E to run reports and retrieve historical information. The data captures the time that a qualified first responder requires to respond and stop gas flow during incidents involving an unplanned and uncontrolled release of gas on distribution mains. There are distinct types of incidents recorded in the EMT: explosions, corrosion, cross bore, pipe damage, dig-ins, evacuations, exposed pipe—no gas leak, fires, gas leaks (including Grade 1), high concentration areas, Hi/Lo pressures, material failure, pipe ruptures, vehicle impacts, among others. The EMT provides access to the latest information on an incident. All emergency data is consolidated and stored in one place.

3. Metric Performance (2014-2021)

The range of data available to calculate the historical shut-in the gas median time for Mains is from 2014 to 2021. Over this reporting period, performance improved, decreasing from 97 minutes in 2014 to 79.1 minutes median time in 2021. Comparing 2021 performance to 2020, the median time decreased from 79.2 to 79.1 minutes.

FIGURE 4.4-1
GAS SHUT IN TIME, MAINS MEDIAN RESPONSE TIME 2014-2021



C. 1-Year Target and 5-Year Target

1. Target Methodology

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

- Historical Data and Trends: The target is based on the average of the past four years of median historical data, plus 10 percent. The past four years were used because 2018 was when the FAS system was first utilized, and this data period is consistent with current operational practices. The use of 10 percent allows for non-significant variability, and accounts for the consideration of risk during shut in events;
- Benchmarking: Not available;
- Regulatory Requirements: None;
- Attainable Within Known Resources/Work Plan: Yes;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: Yes, performance at or below the average of the past four years annual median response time plus 10 percent is a

sustainable assumption for maintaining the improvement from 2018-2021 time frame plus room for non-significant variability; and

- Other Considerations: Reducing shut in time to the lowest possible result is not necessarily the best approach from a public safety standpoint, and there is consideration of risk in various situations. In some instances, the safest decision for our employees and the public is to allow the gas to escape before crews shut it off.

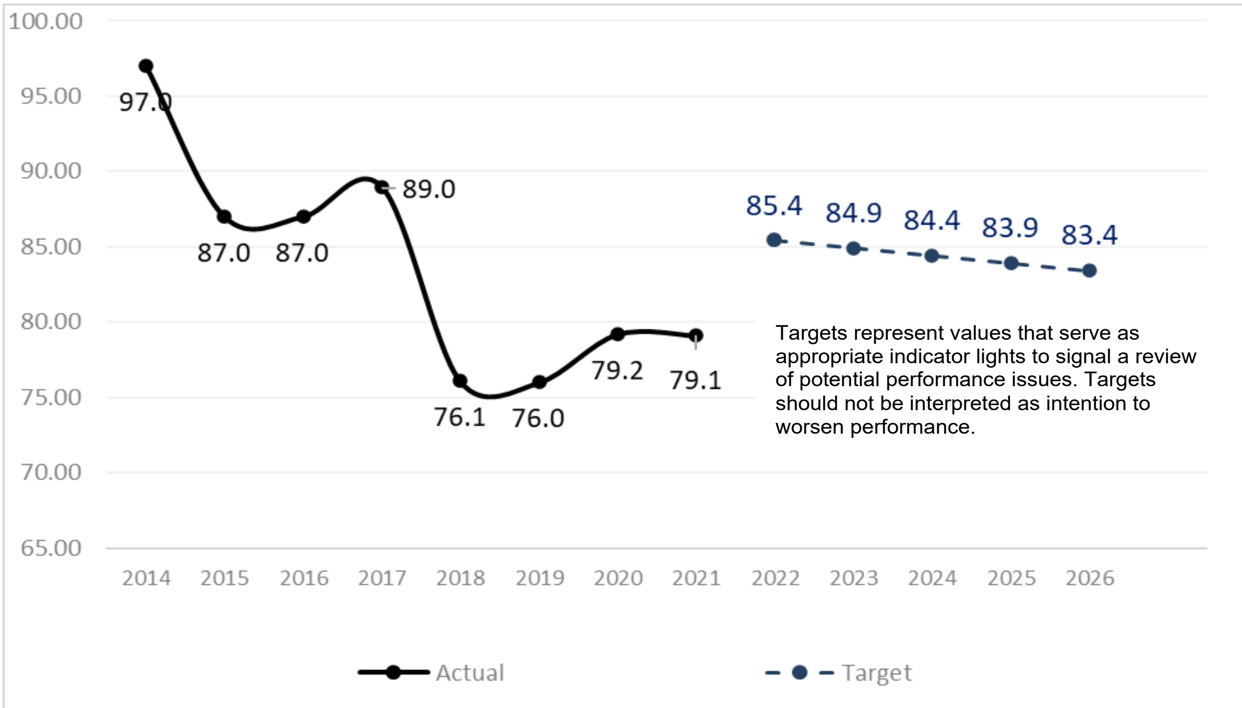
2. 2022 Target

The 2022 target is to maintain performance at or lower than 85.4 minutes based on the factors described above. This target was established to account for the consideration of risk in various situations and aligns with our commitment to the safe operations of our assets. This target represents an appropriate indicator light to signal a review of potential performance issues. Target should not be interpreted as intention to worsen performance.

3. 2026 Target

The 2026 target is to maintain performance at or lower than 83.4 minutes, based on the factors described above, along with stepped improvement of 0.5 minutes forecast year-over-year.

FIGURE 4.4-2
GAS SHUT IN TIME, MAINS MEDIAN RESPONSE TIME 2014-2021 AND TARGETS THROUGH 2026



D. Current and Planned Work Activities

PG&E will continue to drive metric progress through performance management and supervisor-out-in-the-field initiatives. This metric will continue to mitigate the risk of loss of containment on Gas Distribution Main or Service by reducing distribution pipeline rupture with ignition.

The metric is supported by the following programs which focus on improving public safety: Field Services and Gas Maintenance and Construction (M&C).

- Gas Field Service: Field Service responds to gas service requests, which include investigation reports of possible gas leaks, carbon monoxide monitoring, customer requests for starts and stops of gas service, appliance pilot re-lights, appliance safety checks, as well as emergency situations as first responders.
- Gas Maintenance and Construction: Gas M&C performs routine maintenance of PG&E's gas distribution facilities, which includes emergency response due to dig-ins, as well as leak repairs.

The following process improvement initiatives have been implemented to help achieve metric results:

- Enhanced plastic squeeze capability from approximately 50 percent to all GSRs for < 1.5” plastic pipe;
- Purchased and implemented emergency trailers in every division, allowing for emergency equipment to be accessed quickly and easily;
- Purchased additional steel squeezers for 2-8” steel pipe (housed on emergency trailers);
- Implemented Emergency Management tool (EM tool) to alert maintenance and construction (M&C) of SITG events when notified by third-party emergency organizations;
- Established concurrent response protocol (dispatch M&C and Field Service resources) when notified by emergency agencies. Utility Procedure TD-6100P-03 Major Gas Event Response: Fire, Explosion, and Gas Pipeline Rupture was updated in 2021 to align with PG&E’s response and communication protocols;
- Implemented 30-60-90-120+ minute communication protocols between Gas Distribution Control Center and Incident Commander to ensure consistent communication and issue escalation during events; and

The following process improvement initiatives are on-going to help achieve metric results:

- Tier 3 incident review meetings monthly to share best practices and review long duration events;
- Provide yearly plastic squeeze training for all Field Service employees as part of Operator Qualification refresher.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4.5

SAFETY AND OPERATIONAL METRICS REPORT:

GAS SHUT-IN TIME, SERVICES

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 4.5
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A. Overview

1. Metric Definition

Safety and Operational Metric 4.5 – Gas Shut-In Time, Services is defined as:

Median time to shut-in gas when an uncontrolled or unplanned gas release occurs on a service. The data used to determine the median time shall be provided in increments as defined in General Order 112-F 123.2 (c) as supplemental information, not as a metric.

2. Introduction of Metric

The measurement of Gas Shut-In Time captures the median duration of time required to respond to and mitigate potentially hazardous gas leak conditions. These leak conditions are associated with the public safety risk of loss of containment on Gas Distribution Main or Service. The term "shut-in" refers to the act of stopping the gas flow. It is important for the flow of gas to be stopped to avoid consequences such as overpressure events or explosions and so that work can be safely performed to make repairs in a timely manner. Performance aims for faster response times as a measure of prevention resulting in lower risk of an incident impacting public safety and minimized interruption to the gas business and customers. It is imperative that we promptly and effectively resolve any hazardous conditions on our distribution network while balancing timeliness, customer outages, and employee safety.

The timing for the response starts when Pacific Gas and Electric Company (PG&E or the Utility) first receives the report of a potential gas leak and ends when the Utility's qualified representative determines, per the Utility's emergency standards, that the reported leak is not hazardous, a leak does not exist, or the Utility's representative completes actions to mitigate a hazardous leak and render it as being non-hazardous (e.g., by shutting-off gas supply, eliminating subsurface leak migration, repair, etc.) per the Utility's standards.

This metric measures the median number of minutes required for a qualified PG&E responder to arrive onsite and stop the flow of gas as result of damages impacting gas mains from PG&E distribution network. It does not include instances where a qualified representative determines that the reported leak is not hazardous or a leak does not exist.

B. Metric Performance

1. Historical Data (2014-2021)

Historical data for Shut-In the gas (SITG) Services metric is available for the period 2014-2021. The data captures the median time that a qualified first responder is required to respond and stop gas flow during incidents involving an unplanned and uncontrolled release of gas on services. This data includes incidents related to distribution services and related components such as service lines, valves, risers, and meters due to third party dig-ins, vehicle impacts, explosion, pipe rupture, and material failure.

Before 2014, PG&E used a decentralized emergency process to manage emergencies, i.e., each division used its own resources like mappers, planners, among others to track and manage emergencies. Similarly, support organizations like Dispatch, Mapping and Planning used their own management tools to help schedule and manage emergency information. Dispatch used a management tool called Outage Management that recorded times at various stages of the process (i.e., when the emergency call came in, when the Gas Service Representative (GSR) arrived at the site, when the leak was isolated, etc.). The Distribution Control Room used a tool called Gas Logging System to record incoming information.

In 2014, a centralized process was implemented to allow Distribution, Transmission, Dispatch, Planning and Mapping personnel to be co located and work together as a team to manage emergencies. This centralized process also allowed the development of the Event Management Tool (EMT) system.

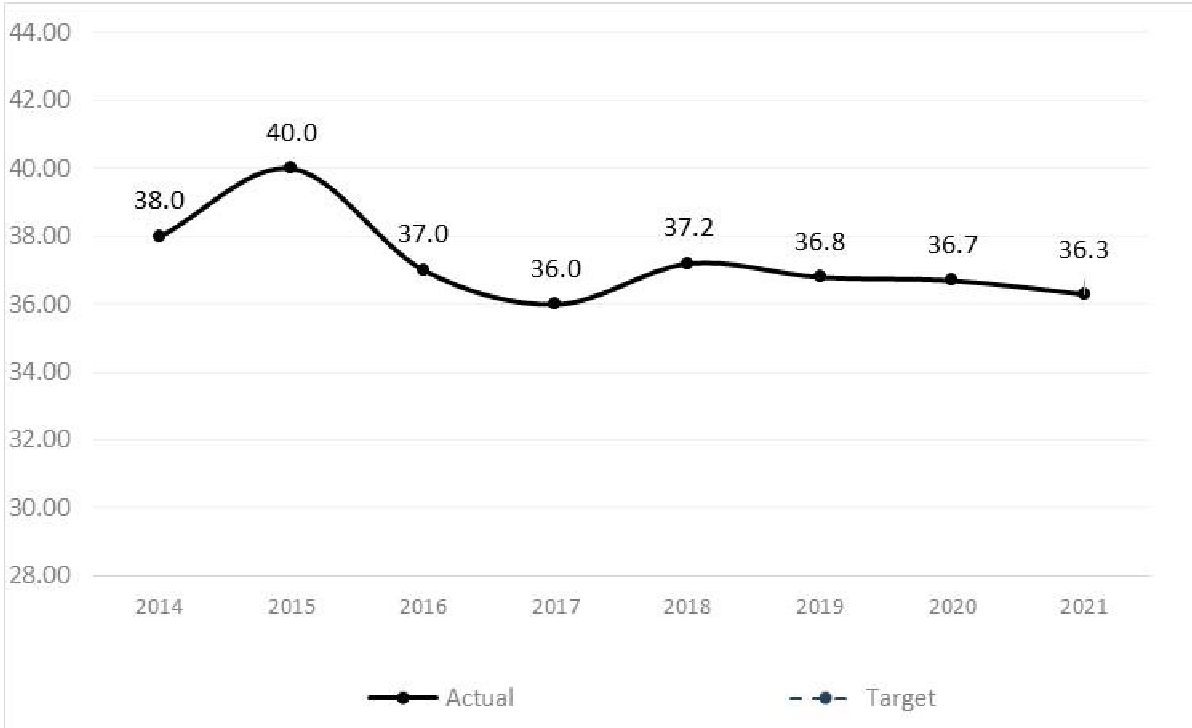
2. Data Collection Methodology

The EMT is currently used as the official system to track gas emergencies from start to finish. The EMT is used by Dispatch and Gas Distribution Control Center (GDCC) teams to create emergency events and collect incident information and allows PG&E to run reports and retrieve historical information. There are distinct types of incidents recorded in the EMT: explosions, corrosion, cross bore, pipe damage, dig-ins, evacuations, exposed pipe—no gas leak, fires, gas leaks (including Grade 1), high concentration areas, Hi/Lo pressures, material failure, pipe ruptures, vehicle impacts, among others. The EMT provides access to the latest information on an incident. All emergency data is consolidated and stored in one place.

3. Metric Performance (2014-2021)

The range of data available to calculate the historical SITG median time for Services is from 2014 to 2021. Over this reporting period, performance improved, decreasing from 38.0 minutes in 2014 to 36.3 minutes in 2021 (~4.4 percent improvement). Specifically, performance has consistently improved, decreasing from 38.0 minutes in 2014 to 36.3 minutes in 2021. Comparing 2021 performance to 2020, the median time decreased from 36.7 to 36.3 minutes (~1 percent improvement).

FIGURE 4.5-1
GAS SHUT IN TIME, SERVICES MEDIAN RESPONSE TIME 2014-2021



C. 1-Year Target and 5-Year Target

1. Target Methodology

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

- Historical Data and Trends: The target is based on the average of the past four years of median historical data, plus 10 percent. The past four years were used because 2018 was when the FAS system was first utilized, and this data period is consistent with current operational practices. The use of 10 percent allows for non-significant variability, and accounts for the consideration of risk during shut in events;
- Benchmarking: Not available;
- Regulatory Requirements: None;
- Attainable Within Known Resources/Work Plan: Yes;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: Yes, performance at or below the average of the past four years annual median response time plus 10 percent is a

sustainable assumption for maintaining the improvement from 2018-2021 time frame plus room for non-significant variability; and

- Other Considerations: Reducing shut in time to the lowest possible result is not necessarily the best approach from a public safety standpoint, and there is consideration of risk in various situations. In some instances, the safest decision for our employees and the public is to allow the gas to escape before crews shut it off.

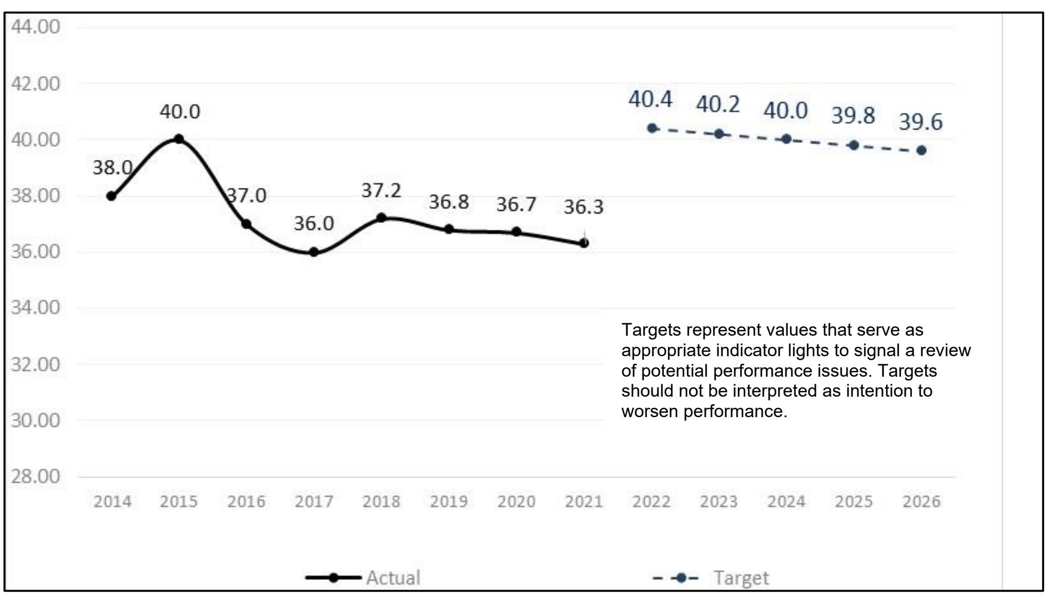
2. 2022 Target

The 2022 target is to maintain performance at or lower than 40.4 minutes based on the factors described above. This target was established to account for the consideration of risk in various situations and aligns with our commitment to the safe operations of our assets. This target represents an appropriate indicator light to signal a review of potential performance issues. Target should not be interpreted as intention to worsen performance.

3. 2026 Target

The 2026 target is to maintain performance at or lower than 39.6 minutes based on the factors described above along with stepped improvement of 0.2 minutes year-over-year.

FIGURE 4.5-2
GAS SHUT IN TIME, SERVICES MEDIAN RESPONSE TIME 2014-2021 AND TARGETS THROUGH 2026



4. Current and Planned Work Activities

PG&E will continue to drive metric progress through performance management and supervisor-out-in-the-field initiatives. This metric will continue to mitigate the risk of loss of containment on Gas Distribution Main or Service by reducing distribution pipeline rupture with ignition.

The metric is supported by the following programs which focus on improving public safety: Field Services and Gas Maintenance and Construction (M&C).

- <u>Gas Field Service</u>: Field Service responds to gas service requests, which include investigation reports of possible gas leaks, carbon monoxide monitoring, customer requests for starts and stops of gas service, appliance pilot re-lights, appliance safety checks, as well as emergency situations as first responders.
- <u>Gas M&C</u>: Gas M&C performs routine maintenance of PG&E's gas distribution facilities, which includes emergency response due to dig-ins, as well as leak repairs.

The following process improvement initiatives have been implemented to help achieve metric results:

- Enhanced plastic squeeze capability from approximately 50 percent to all GSRs for < 1.5" plastic pipe;
- Purchased and implemented emergency trailers in every division, allowing for emergency equipment to be accessed quickly and easily;
- Purchased additional steel squeezers for 2-8" steel pipe (housed on emergency trailers);
- Implemented Emergency Management tool (EM tool) to alert M&C of SITG events when notified by third-party emergency organizations;
- Established concurrent response protocol (dispatch M&C and Field Service resources) when notified by emergency agencies. Utility Procedure TD-6100P-03 Major Gas Event Response: Fire, Explosion, and Gas Pipeline Rupture was updated in 2021 to align with PG&E's response and communication protocols; and
- Implemented 30-60-90-120+ minute communication protocols between GDCC and Incident Commander to ensure consistent communication and issue escalation during events.

The following process improvement initiatives are on-going to help achieve metric results:

- Tier 3 incident review meetings monthly to share best practices and review long duration events; and
- Provide yearly plastic squeeze training for all Field Service employees as part of Operator Qualification refresher.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4.6

SAFETY AND OPERATIONAL METRICS REPORT:

UNCONTROLLED RELEASE OF GAS ON

TRANSMISSION PIPELINES

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 4.6
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A. Overview

1. Metric Definition

Safety and Operational Metrics (SOM) 4.6 – Uncontrolled Release of Gas on Transmission Pipelines is defined as:

The number of leaks, ruptures, or other loss of containment on transmission lines for the reporting period, including gas releases reported under Title 49 Code of Federal Regulations (CFR) Part 191.3.

2. Introduction of Metric

This metric tracks the total number of Grade 1, 2, and 3 leaks, as well as ruptures and other losses of containment on gas transmission (GT) pipelines. Leaks are an important indicator because each leak's uncontrolled flow of gas into the surrounding area can increase the consequence of incidents and cause disruption to our customers' gas service. Leaks are also an important indicator in evaluating the likelihood for where other incidents could occur due to similar criteria or conditions.

B. Metric Performance

1. Historical Data (2016-2021)

Pacific Gas and Electric Company (PG&E) used six years of historical data, comprising the years 2016 to 2021. In evaluating the data, PG&E noted changes in detection capabilities and frequency of surveys for the years after 2018. For this reason, the data used to develop these metrics is focused on 2019-2021.

2. Data Collection Methodology

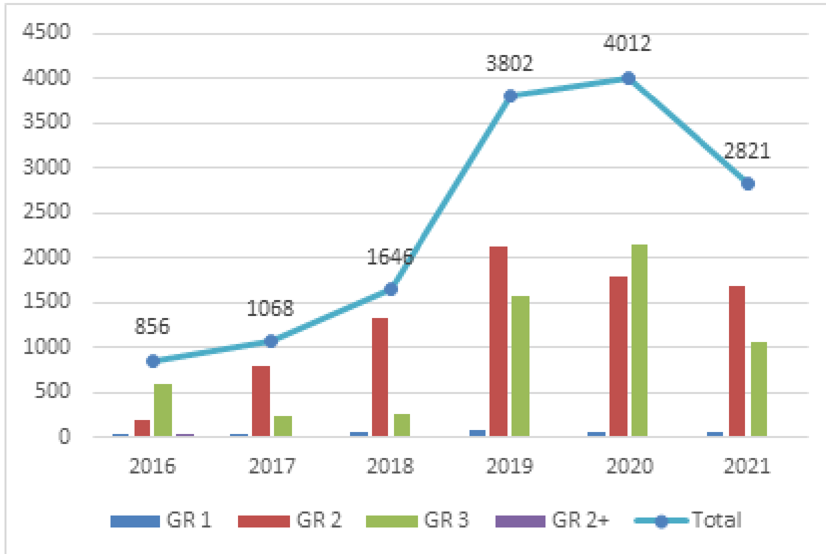
Leak data is managed and pulled by the PG&E Leak Survey Process team. This data is extracted from PG&E's GCM013 report using SAP data. This report aggregates all leaks found during the reporting period including the location, line type, and grade of leak. Original grade is used for the metric criteria because it is not subject to change even if the leak condition or status changes due to regrade, cancelation, or repair.

In addition, transmission incidents reported to Pipeline and Hazardous Materials Safety Administration (PHMSA) that meet the incident reporting definition in CFR 191.3 are considered for metric inclusion. These events may be leaks, ruptures, or other incidents. For each reporting period, PG&E will review any transmission incidents reported to PHMSA and compare against the GCM013 leaks using available information like incident location (Route/MP, latitude/longitude, or street address) and date/time of incident to remove any duplicates between the two datasets.

3. Metric Performance (2016-2021)

The annual count of all leaks, ruptures, and loss of containment has been increasing steadily since 2016, with the largest increase seen from 2018 to 2019. This increase is primarily due to a California Air Resources Board (CARB) rule change which requires more frequent leak surveys. The increase has improved visibility and results in a larger leak dataset relative to prior years. In March 2017, CARB finalized and approved the Oil and Gas Greenhouse Gas (GHG) Rule codified under California Code of Regulations, Title 17, Division 3, Chapter 1, Subchapter 10, "Climate Change," Article 4. Effective January 1, 2018, the GHG Rule covers emission standards, including, but not limited to, stringent leak detection and repair requirements for facilities in certain Oil and Gas sectors. This rule applies to PG&E's underground natural gas storage facilities and GT compressor stations. As a result, PG&E performs a quarterly leak survey at the impacted facilities and performs leak repairs based on CARB's repair timelines.

FIGURE 4.6-1
LEAKS BY GRADE TYPE 2016-2021



C. 1-Year Target and 5-Year Target

1. Target Methodology

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

- Historical Data and Trends: The targets are based on the average of the past three years of historical data. The most recent three years was used as it is the timeframe most representative of current leak survey practices;
- Benchmarking: Not available;
- Regulatory Requirements: None;
- Attainable Within Known Resources/Work Plan: Yes;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: Yes, performance at or below the average of the past three years is a sustainable assumption for maintaining the 2019-2021 performance and allows for non-significant variability; and
- Other Considerations: The target also takes into consideration that the results for this metric may fluctuate based on miles of leak surveys performed. The number of leaks found has a correlative relationship to the miles of leak surveys performed. While this is a positive impact for

risk visibility and mitigation, it can be a driver of varying trends appearing in the results.

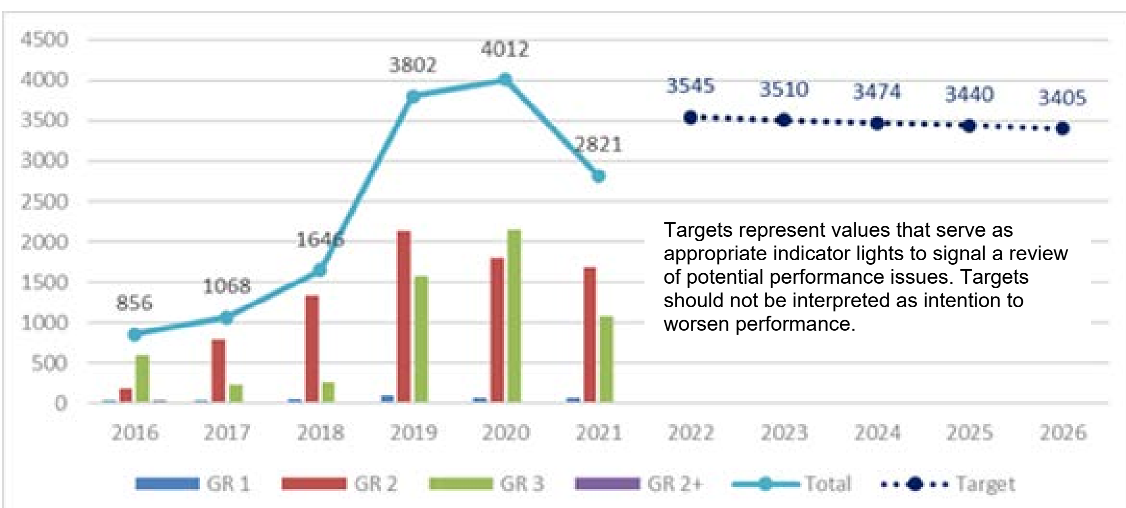
2. 2022 Target

The 2022 target is to maintain performance at or lower than 3,545 leaks, ruptures, or other loss of containment on GT pipelines. This target, which is the average of performance over the last three years, is based on the factors described above. This target aligns with our commitment to the safe operations of our assets. This target represents an appropriate indicator light to signal a review of potential performance issues. Target should not be interpreted as intention to worsen performance.

3. 2026 Target

The 2026 target is to maintain performance at or lower than 3,405 events, and is based on the factors described above, along with a 1 percent annual reduction.

FIGURE 4.6-2
LEAKS BY GRADE TYPE 2016-2021 AND TARGETS THROUGH 2026



D. Current and Planned Work Activities

The primary programs that support the risk reduction goals of this metric are Transmission Integrity Management and Leak Management.

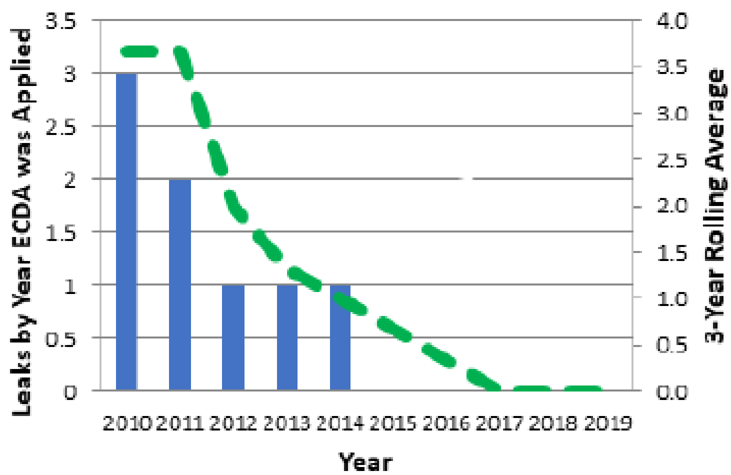
- Transmission Integrity Management: The Integrity Management Program provides the tools and processes for risk ranking and prioritization which enable PG&E to focus on identifying and remediating threats to its system.

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

- <u>Leak Management</u>: The Leak Management Program addresses the risk of Loss of Containment (LOC) by finding and fixing leaks. PG&E performs leak survey of the GT and storage system twice per year, by either ground or aerial methods in accordance with General Order 112-F. Leak surveys of pipeline and equipment are commonly accomplished on foot or vehicle, by operator-qualified personnel, using a portable methane gas leak detector. Aerial leak surveys, in remote locations and areas difficult to access on the ground, are performed by helicopter using Light Detection and Ranging Infrared technology. Additional activities that complement the TIMP include: risk-based leak surveys, continued use of Picarro, mobile leak quantification, and replacing/removing high bleed pneumatic devices at its compressor stations and storage facilities
- <u>In-line Inspection (ILI)</u>: PG&E plans on performing ILI upgrades at a pace of 12 upgrades per year. By the end of 2022, PG&E is estimated to have 56 percent of the system capable of ILI. Work during the rate case will contribute to PG&E's overall goal of upgrading the system so that 4,553 transmission miles, 69 percent of PG&E's GT pipeline miles, are capable of ILI by end of 2036.
- <u>External Corrosion Direct Assessment (ECDA)</u>: PG&E has assessed the effectiveness of its ECDA Program by evaluating the leak rates on pipe where ECDA has previously been applied, and by tracking the number of immediate indications found during the ECDA surveys. Both indicators are trending down over time. Figure 5-4 shows the leaks found over time in locations where ECDA was previously applied. The significant decline over

time, indicates that the ECDA Program are reducing leaks. PG&E expects to conduct ECDA indirect inspections on approximately 268 miles of transmission pipeline in HCAs during the rate case period.

FIGURE 4.6-3
LEAK REDUCTION OVER TIME BY ECDA



- Close Interval Survey: PG&E also has a Close Interval Survey (CIS) Program targeted at monitoring the effectiveness of the transmission pipelines' cathodic protection (CP) systems by reading the CP levels between the annual monitoring locations. Assessing the levels of CP between test points provides increased confidence that the readings obtained at test stations reflect conditions along the entire system and enable PG&E to make CP adjustments where CIS indicates additional CP is warranted. CIS is recognized as a best practice to assess CP along the entire pipeline, verify electrical isolation, and identify potential interference gradients that may compromise the integrity of the system.
- Strength Testing: Strength tests are conducted as a qualifying test for MAOP and to assess integrity for reasons that may include the following which can contribute to reducing leaks:
  - A section of pipe lacks a Traceable, Verifiable, and Complete (TVC) record of a test that supports the MAOP; or
  - Verify that pipeline threats have not compromised pipeline integrity, such Subpart O integrity assessments.

PG&E's plan is to continue to perform strength tests on all HCA pipe that lack a TVC test record, and where the pipeline requires MAOP reconfirmation under the new federal regulations. Locations operating over 30 percent specified minimum yield strength will be the highest priority. To meet these objectives, PG&E estimates that 161 miles of strength testing or pipe replacement will be performed during the rate case period.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4.7

SAFETY AND OPERATIONAL METRICS REPORT:

TIME TO RESOLVE HAZARDOUS CONDITIONS

PACIFIC GAS AND ELECTRIC COMPANY
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A. Overview

1. Metric Definition

Safety and Operational Metric (SOM) 4.7 – Time to Resolve Hazardous Conditions (TRHC) is described as:

Median response time to resolve Grade 1 leaks. Time starts when the utility first receives the report and ends when a utility's qualified representative determines, per the utility's emergency standards, that the reported leak is not hazardous or the utility's representative completes actions to mitigate a hazardous leak and render it as being non-hazardous (i.e., by shutting-off gas supply, eliminating subsurface leak migration, repair, etc.) per the utility's standards.

The data used to determine the Median Time shall be provided in increments as defined in General Order 112-F 123.2 (c) as supplemental information, not as a metric.

2. Introduction of Metric

The measurement of TRHC captures the duration of time required to mitigate hazardous gas leak conditions. These leak conditions are associated with the public safety risk of loss of containment on Gas Distribution Main or Service. Performance aims for faster resolution times as a measure of prevention resulting in lower risk of an incident impacting public safety and minimized interruption to the gas business and customers. It is imperative that we promptly and effectively resolve any hazardous conditions on our distribution network while balancing timeliness, customer outages, and employee safety. Long duration blowing gas events have the potential to negatively impact public safety if an ignition source is present, as well as it poses a risk if migration into sub-surface structures occurs.

B. Metric Performance

1. Historical Data (2018-2021)

Historical data for TRHC Grade 1 Leaks metric is available for 2018-2021. The data captures the time that a qualified first responder requires to respond and stop gas flow due to Grade 1 leaks. This data includes leaks identified in our distribution system and includes all facility types, i.e., customer facilities, service and main pipelines, meters, regulator stations, service risers, valves. It includes leaks identified by PG&E personnel only and with a final resolution of leak repaired.

Before 2014, PG&E used a decentralized emergency process to manage emergencies (i.e., each division used its own resources like mappers, planners, among others to track and manage emergencies). Similarly, support organizations like Dispatch, Mapping and Planning used their own management tools to help schedule and manage emergency information. Dispatch used a management tool called Outage Management that recorded times at various stages of the process (i.e., when the emergency call came in, when the Gas Service Representative arrived at the site, when the leak was isolated, etc.). The Distribution Control Room used a tool called Gas Logging System to record incoming information.

In 2014, a centralized process was implemented to allow Distribution, Transmission, Dispatch, Planning and Mapping personnel to be co located and work together as a team to manage emergencies. This centralized process also allowed the development of the Event Management Tool (EMT) system which was implemented in 2018.

PG&E started tracking gas flow stop times for Grade 1 leaks in 2018 although this has not been a mandatory requirement, except when the incident is California Public Utilities Commission or Department of Transportation reportable.

2. Data Collection Methodology

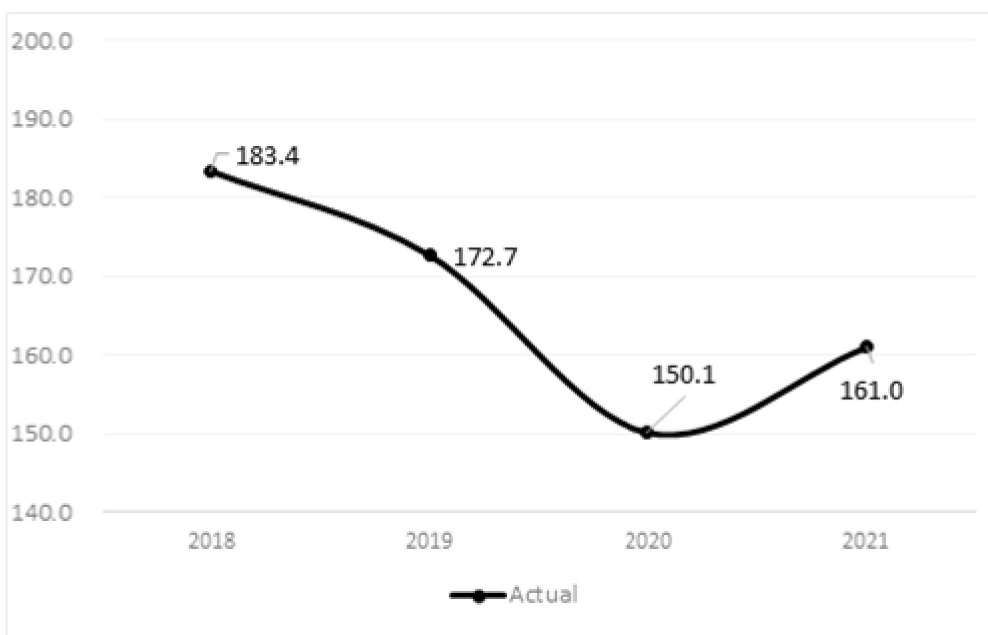
The EMT is currently used as the official system to track gas emergencies from start to finish. The EMT provides access to latest information on an incident. All emergency data is consolidated and stored in one place.

The EMT is used by Dispatch and Gas Distribution Control Center teams to create emergency events and collect incident information. It also allows us to run reports and retrieve historical information. There are distinct types of incidents recorded in the EMT: explosions, corrosion, cross bore, pipe damage, dig-ins, evacuations, exposed pipe—no gas leak, fires, gas leaks (including Grade 1), high concentration areas, Hi/Lo pressures, material failure, pipe ruptures, vehicle impacts, among others. No transmission events are included in the metric.

3. Metric Performance (2018-2021)

The range of data available to calculate the historical TRHC for Grade 1 leaks is from 2018 to 2021. In this timeframe, performance improved significantly, decreasing from 183.4 minutes in 2018 to 161 minutes in 2021. Comparing 2021 performance to 2020, the median time increased from 150.1 to 161.0 minutes. The fluctuations during the 2018-2021 period are due to random variability without any operational significance.

FIGURE 4.7-1
TIME TO RESOLVE HAZARDOUS CONDITIONS MEDIAN RESPONSE TIME 2018-2021



C. 1-Year Target and 5-Year Target

1. Target Methodology

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

- Historical Data and Trends: The target is based on the average of the past four years of historical data, plus 10 percent. The past four years were used because 2018 is the first year of available historical data. The use of 10 percent allows for non-significant variability, as well as unknown variability given that this is a new metric that has not been well measured and tracked in the past;
- Benchmarking: Not available;
- Regulatory Requirements: None;
- Attainable Within Known Resources/Work Plan: Yes;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: Yes, performance at or below the average of the past four years, plus 10 percent, is a sustainable assumption for maintaining the improvement from 2018-2021 time frame, plus room for non-significant variability and other unknown variables; and
- Other Considerations: This is a new metric to PG&E that has not yet been closely tracked or well understood.

2. 2022 Target

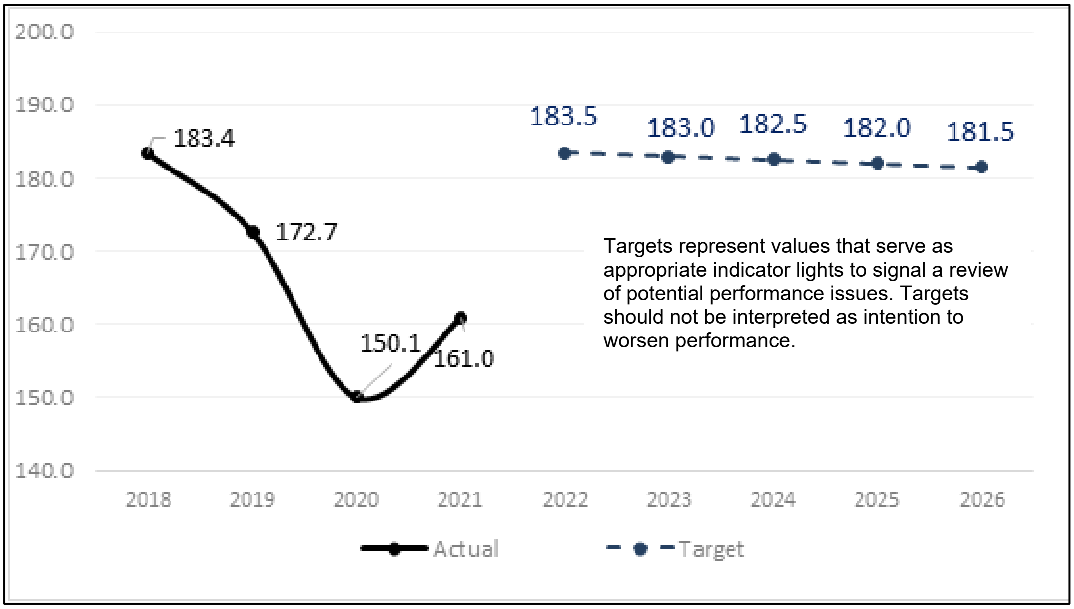
The 2022 target is to maintain performance at or lower than 183.5 minutes based on the factors described above.

This target aligns with our commitment to the safe operations of our assets. This target represents an appropriate indicator light to signal a review of potential performance issues. Target should not be interpreted as intention to worsen performance.

3. 2026 Target

The 2026 Target is to maintain performance at or lower than 181.5 minutes based on the factors described above along with stepped improvement of 0.5 minutes year-over-year.

FIGURE 4.7-2
TIME TO RESOLVE HAZARDOUS CONDITIONS MEDIAN RESPONSE TIME 2018-2021 AND TARGETS THROUGH 2026



D. Current and Planned Work Activities

Starting in 2022, PG&E is applying the definition as stated in Decision 21-11-009 to existing data for further visibility. There are on-going efforts in place to ensure traceable and verifiable data. PG&E plans to implement SAP controls to ensure that Field Service and Maintenance and Construction (M&C) personnel are capturing this data at each occurrence. This will drive visibility into the metric to allow for performance management. This metric will continue to mitigate the risk of loss of containment on Gas Distribution Main or Service by reducing distribution pipeline rupture with ignition.

The metric is supported by the following programs which focus on improving public safety: Field Services and Gas M&C.

- Gas Field Service: Field Service responds to gas service requests, which include investigation reports of possible gas leaks, carbon monoxide monitoring, customer requests for starts and stops of gas service, appliance pilot re-lights, appliance safety checks, as well as emergency situations as first responders.
- Gas M&C: Gas M&C performs routine maintenance of PG&E's gas distribution facilities, which includes emergency response due to dig-ins, as well as leak repairs.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 5.1

SAFETY AND OPERATIONAL METRICS REPORT:

CLEAN ENERGY GOALS COMPLIANCE METRIC

PACIFIC GAS AND ELECTRIC COMPANY
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1. Metric Definition

Safety and Operational Metric 5.1 – Clean Energy Goals Compliance Metric is defined as:

Progress towards Pacific Gas and Electric Company's (PG&E) procurement obligations as adopted in Decision (D.) 21-06-035, D.19-11-016 and any subsequent decision(s) in Rulemaking (R.) 20-05-003, or a successor proceeding, updating these requirements.

2. Introduction to the Clean Energy Goals Metric

The Clean Energy Goals Compliance Metric (CEG Metric) directs PG&E to report on its progress towards the procurement obligations in the following California Public Utilities Commission (Commission) decisions: (1) D.19-11-016 and (2) D.21-06-035 (together, the Integrated Resource Planning (IRP) Decisions).[1]

In November 2019, the Commission issued D.19-11-016 in part to address near-term system reliability concerns beginning in 2021. D.19-11-016 requires incremental procurement of system-level resource adequacy (RA) capacity of 3,300 megawatts (MW) by all Commission-jurisdictional load serving entities (LSE).[2] In line with state policy goals, the Commission also expressed a preference that LSEs pursue "preferred resources" such as new clean electricity capacity.[3] Of the 3,300 MW procurement order, PG&E is directed to procure 716.9 MW of RA

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[1] See D.22-02-004 directing PG&E to make progress towards procuring a 95 MW four-hour energy storage project at the Kern-Lamont substation and a 50 MW 4-hour energy storage project at the Mesa substation, pp. 160-162; Ordering Paragraph (OP) 13 of D.22-02-004 exempts these energy storage projects from the Clean Energy Goals Compliance Metric.

[2] D.19-11-016, p. 34.

[3] D.19-11-016, Conclusion of Law 22.

capacity on behalf of its bundled service customer portfolio with online dates between the years 2021-2023.[4]

D.19-11-016 also allowed each non-investor-owned utility (IOU) LSE an opportunity to “opt-out” of its procurement obligation and required notification to the Commission in February 2020 exercising this option. On April 15, 2020, the Commission issued a ruling increasing PG&E’s procurement obligation by 48.2 MW, totaling 765.1 MW, to account for LSEs that chose to opt-out of self-providing their required obligation.[5] Of the 765.1 MW, 50 percent (382.6 MW) are to have online dates by August 1, 2021, 25 percent (191.3 MW) with online dates by August 1, 2022 and 25 percent (191.3 MW) with online dates by August 1, 2023.[6]

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 further achieve the state’s greenhouse gas (GHG) emissions reduction targets. Accordingly, all of the 11,500 MW of incremental procurement ordered in D.21-06-035 are to be zero-emitting, unless the resource would otherwise qualify under the Renewables Portfolio Standard eligibility requirements.[7] 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 energy, and serve as replacement capacity for the retiring Diablo Canyon Power Plant.[8]

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4 D.19-11-016, OP 3.

5 See Administrative Law Judge’s Ruling Finalizing Load Forecasts and GHG Benchmarks for Individual 2020 IRP Filings and Assigning Procurement Obligations Pursuant to D.19-11-016, issued on April 15, 2020, p. 11.

6 Due to rounding, numbers presented throughout this chapter may not add up precisely to the totals provided.

7 D.21-06-035, OP 1.

8 *Id*., p. 35; See also D.21-06-035, p. 56 requiring PG&E to procure 500 MW of zero-emitting resources by 2025 and 400 MW of long lead-time resources by 2026.

In aggregate, the total amount of procurement ordered upon PG&E in the IRP Decisions is 3,067.1 MW with online dates between 2021-2026. Table 1 outlines PG&E's procurement obligation for each year.

TABLE 5.1-1
PG&E'S TOTAL PROCUREMENT OBLIGATION PURSUANT TO THE IRP DECISIONS
(PRESENTED AS MW OF NET QUALIFYING CAPACITY (NQC))

Line No.	Online Date	D.19-11-016	D.21-06-035	Total
1	8/1/2021	382.6		382.6
2	8/1/2022	191.3		191.3
3	8/1/2023	191.3	400	591.3
4	6/1/2024		1,201	1,201
5	6/1/2025		300	300
6	6/1/2026		400	400
7	Total	765.1	2,302	3,067.1

3. Background on Net Qualifying Capacity

For the purpose of assessing whether an LSE's procurement obligation has been met in accordance with the IRP Decisions, the Commission uses capacity counting rules based on the Commission's RA program and the results of effective load carrying capability (ELCC) modeling by consultants E3 and Astrapé.[9] The counting rules are generally expressed as a percentage that is applied to the nameplate capacity of the procured resource. For example, a 4-hour energy storage resource with a nameplate capacity of 100 MW can count 90.7 MW towards an LSE's 2024 requirement (100 MW * 90.7 percent ELCC = 90.7 MW of NQC). PG&E's procurement progress herein is presented as MW of NQC based on the applicable counting rules and guidance provided by the Commission.[10]

9 D.21-06-035, p. 71.

10 See the Incremental ELCC Study for Mid-Term Reliability Procurement, pp. 8-9 at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/20211022_irp_e3_astrape_incremental_elcc_study_updated.pdf; See also the Staff Memo on Incremental ELCC to be Used for Mid-Term Reliability Procurement at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/20211022_irp_mtr_elccs_staff_transmittal_memo.pdf.

B. Metric Performance

1. Historical Data

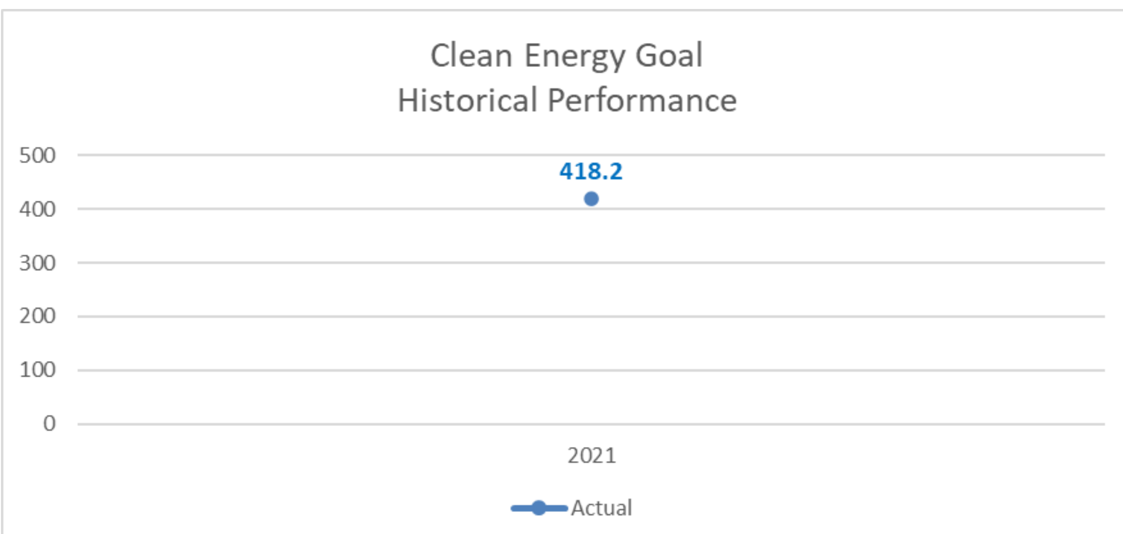
Pursuant to the IRP Decisions, procurement obligations began in 2021. Thus, historical data is limited to 2021 at this time.

TABLE 5.1-2
PG&E'S HISTORICAL METRIC PERFORMANCE (MW OF NQC)

Line No.	Online Date	Total Procurement Obligation	Actual Procured Capacity
1	8/1/2021	382.6	418.2

Note: On July 23, 2021, PG&E submitted a letter to the Commission ("Notification Regarding Delay of Projects Approved Under D.19-11-016") informing the Commission of Force Majeure notices received from certain developers indicating project development delays due to impacts of the Coronavirus (COVID-19) pandemic and supply chain disruptions that were preventing all of the projects from coming online by August 1, 2021. These projects have all since achieved completion and begun commercial operation.

FIGURE 5.1-1
PG&E'S CLEAN ENERGY GOAL HISTORICAL PERFORMANCE (MW OF NQC)



PG&E relies upon three main sources of available data to monitor its procurement progress of the IRP Decisions: (1) the baseline list of resources used to establish the procurement targets, (2) Commission rules and guidance on determining the MW of NQC, and (3) PG&E's internal database containing all of its energy procurement contracts approved by the Commission.

1) Baseline List of Resources: In establishing the procurement targets in the IRP Decisions, the Commission established baseline assumptions of resources available to meet system reliability needs. LSEs must demonstrate that the MW of NQC of the procured resource, new and/or existing, are incremental to the Commission's baseline assumptions.[11] PG&E uses this information to ensure resources are eligible to count towards its procurement obligations.

2) Commission Rules and Guidance on MW of NQC: As described above, the amount of MW of NQC that can be used to count towards an LSE's procurement obligation is based on Commission rules and guidance. PG&E uses this information to determine the amount of MW of NQC that is eligible to count towards its procurement obligations.

3) PG&E's Internal Database: This database contains PG&E's energy procurement contracts approved by the Commission, including procurement contracts to meet PG&E's procurement obligations from the IRP Decisions. The data contained in this database is consistent with the procurement contracts and respective advice letters (AL) filed for Commission approval.

2. Data Collection Methodology

As described above, PG&E uses the baseline list of resources and Commission rules and guidance on MW of NQC to monitor its procurement progress.[12]

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11 See the Commission's baseline assumptions at: https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=323767159 (D.19-11-016) and https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/d2106035_baseline_gen_list.xlsx (D.21-06-035).

12 See the information maintained by the Commission at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/more-information-on-authorizing-procurement/irp-procurement-track.

3. Metric Performance

As outlined in Table 5.1-3 below, PG&E has procured sufficient incremental MW of NQC to exceed its procurement obligations pursuant to D.19-11-016.[13] PG&E notes that the Commission stated that procurement:

> …amounts [that] are in excess of [an] LSE's obligation under D.19-11-016…may be counted toward the capacity requirements [in D.21-06-035] if they otherwise qualify.[14]

Moreover, D.21-06-035 stated that the Commission:

> …will allow LSEs to show procurement that they have conducted to support the Commission's orders or requirements in the context of the RPS program, as well as for emergency reliability purposes in R.20-11-003, as compliance toward the requirements herein.[15]

Accordingly, PG&E estimates that approximately 270 MW of NQC of its procurement from both D.19-11-016 and R.20-11-003 that have been approved by the Commission may be applied towards its procurement obligations from D.21-06-035.[16]

On January 21, 2022, PG&E filed AL 6477-E requesting Commission approval of nine agreements resulting from PG&E's Mid-Term Reliability Phase 1 solicitation to meet its procurement obligations from D.21-06-035. These agreements total 1,434 MW of NQC and are pending approval by the Commission as of the date of this filing.[17]

Collectively, and as outlined in Table 5.1-3 below, PG&E has made steady progress towards achieving its procurement obligations from D.21-06-035. As stated above, D.21-06-035 required that 900 MW of NQC (of PG&E's 2,302 MW of NQC) have specific operational characteristics. Specifically, PG&E has been directed to procure 500 MW of NQC of

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[13] PG&E's AL 5826-E and 6033-E.

[14] D.21-06-035, p. 80.

[15] *Id*.

[16] PG&E's AL 6289-E.

[17] On March 18, 2022, the Commission issued Draft Resolution E-5202 approving the nine agreements without modification as filed in PG&E's AL 6477-E. The Commission is expected to vote on the resolution in April 2022. When the Commission votes on a resolution, it may adopt all or part of it as written, amend, modify or set it aside and prepare a different resolution. Only when the Commission acts does the resolution become binding.

zero-emitting resources by 2025 and 400 MW of NQC of long lead-time (LLT) resources by 2026.[18] PG&E expects to launch another competitive solicitation in the first half of 2022 to satisfy its remaining procurement obligations to procure 500 MW of NQC of zero-emitting resources by 2025 and 400 MW of NQC of LLT resources by 2026.

C. 1-Year Target and 5-Year Target

1. Target Methodology

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

- Historical Data and Trends: One year of historical data;
- Benchmarking: Not applicable;
- Regulatory Requirements: The targets are set to match the cumulative procurement obligations set forth in Commission decisions;
- Attainable Within Known Resources/Work Plan: Yes;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: Yes; and
- Other Considerations:
  - The target approach was established to meet the current Commission procurement obligations. PG&E's obligation may increase if other LSEs fail to meet their obligations and PG&E is required to procure on their behalf;[19]
  - The ability for procured capacity to actually come online by established contractual online dates can be impacted by external factors, as has occurred recently due to impacts of the COVID-19 pandemic and supply chain disruptions; and
  - LSEs may request an extension of procurement obligations for LLT resources to 2028.

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18 The LLT resources are comprised of: (1) firm zero-emitting generation with a capacity factor of at least 80 percent and (2) long-duration storage resources defined as having at least eight hours of duration.

19 D.19-11-016, p. 67.

2. 2022 Target

The 1-year target for the CEG Metric is to procure 574 MW of incremental NQC with online dates by August 1, 2022, which is equal to the cumulative procurement obligations for 2021 and 2022 as outlined in Table 5.1-1.

3. Progress Towards 2022 Target

In its portfolio, PG&E has contracts with 9 energy storage resources, totaling 585.2 MW of NQC that are eligible to count towards its 1-year target.[20] This procurement is sufficient to exceed the 1-year target for 2022 of 574 MW of NQC.

4. 2026 Target

The 5-year target for the CEG Metric is to procure 3,067.1 MW of incremental NQC with online dates by June 1, 2026, which is equal to the cumulative procurement obligations for 2021-2026 as outlined in Table 5.1-1. The IRP Decisions allow for the possibility of PG&E to be ordered by the Commission to perform backstop procurement on behalf of non-IOU LSEs, which could increase the 5-year target in the future. Further, D.21-06-035 allows an extension for LLT resources to come online up to June 1, 2028, if that LSE demonstrates good faith efforts.[21] For purposes of the 5-year target, PG&E is not making any assumptions on these specific items and is basing its 5-year target solely on its procurement obligations in the IRP Decisions.

5. Progress Towards 2026 Target

In its portfolio, PG&E has contracts with 16 energy storage resources, totaling 1,036 MW of NQC that are eligible to count towards its 5-year

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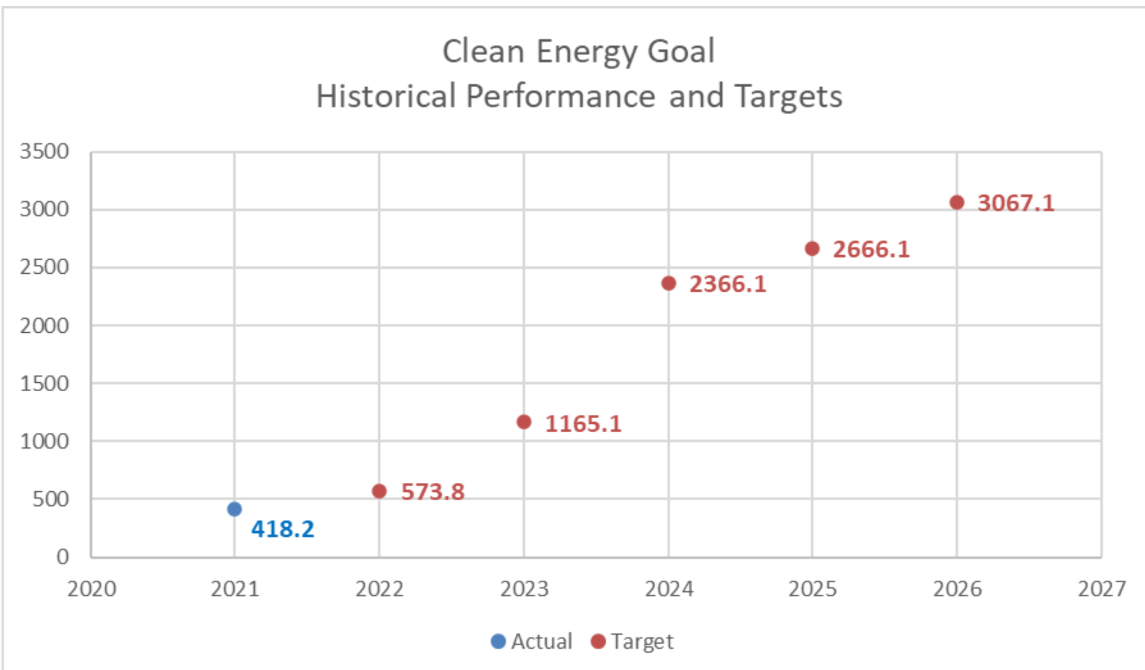
[20] On May 18, 2020, PG&E filed AL 5826-E requesting Commission approval of seven agreements to meet its 2021 procurement targets from D.19-11-016. On December 22, 2020, PG&E filed AL 6033-E requesting Commission approval of six agreements to meet its 2022 and 2023 procurement targets from D.19-11-016. The Commission approved these ALs in Resolution (Res.) E-5100 (August 27, 2020) and Res.E-5140 (April 15, 2021), respectively.

[21] D.21-06-035, OP 5.

target.[22] Further, as outlined above in Section II, PG&E requested Commission approval of an additional nine agreements totaling approximately 1,434 MW[23] of NQC. Upon Commission approval of those contracts, PG&E will have contracts in place for incremental NQC from 25 energy storage resources, totaling approximately 2,470 MW of NQC. However, only 2,167.1 MW of NQC from these contracts will be counted towards its 5-year target of 3,067.1 MW. This is because PG&E has yet to procure contracts for 900 MW of NQC with specific operational characteristics as outlined above.

FIGURE 5.1-2
PG&E'S CLEAN ENERGY GOAL HISTORICAL PERFORMANCE AND TARGETS (MW OF NQC)



D. Current and Planned Work Activities

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

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22 On August 6, 2021, PG&E filed AL 6289-E requesting Commission approval of four agreements to meet procurement targets from R.20-11-003. The Commission approved these agreements in a non-standard disposition letter on August 26, 2021.

23 Some of this capacity procured is in excess of that needed strictly for compliance with the IRP Decisions and will be used toward summer reliability in 2023 and beyond.

- <u>Solicitation</u>: PG&E expects to launch another competitive solicitation in the first half of 2022 to satisfy its remaining procurement obligations under the IRP Decisions, specifically to procure 500 MW of NQC of zero-emitting resources by 2025 and 400 MW of NQC of LLT resources by 2026.

TABLE 5.1-3
PROGRESS TOWARDS PG&E'S CUMULATIVE PROCUREMENT OBLIGATION, PURSUANT TO THE IRP DECISIONS (PRESENTED AS MW OF NQC)

Line No.	Description	8/1/2021	8/1/2022	8/1/2023	6/1/2024	6/1/2025	6/1/2026
1	<u>D.19-11-016 – Total Procurement Obligation</u>						
2	Total Procurement Obligation	382.6	573.8	765.1			
3	Incremental NQC Procured by PG&E	418.2	585.2	777.4			
4	Excess/(Remaining)	35.7	11.4	12.3			
5	<u>D.21-06-035 – Total Procurement Obligation</u>						
6	Total Procurement Obligation			400	1,601		
7	Incremental NQC Procured by PG&E			840.7	1,601		
8	Excess/(Remaining)			440.7[(a)]	–		
9	<u>D.21-06-035 – Zero-Emitting Resources</u>						
10	Zero-Emitting Resources					500	
11	Incremental NQC Procured by PG&E					–	
12	Excess/(Remaining)					(500)	
13	<u>D.21-06-035 – LLT Resources</u>						
14	LLT Resources						400
15	Incremental NQC Procured by PG&E						–
16	Excess/(Remaining)						(400)

(a) The excess capacity from 2023 will be counted towards the 2024 target.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6.1

SAFETY AND OPERATIONAL METRICS REPORT:

QUALITY OF SERVICE

PACIFIC GAS AND ELECTRIC COMPANY
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Safety and Operational Metric (SOM) 6.1 – The Quality of Service Metric which is defined as:

The Average Speed of Answer (ASA) for Emergencies metric is a safety measure related to multiple risks, as well as quality of service and management measure, and is defined as follows: ASA in seconds for Emergency calls handled in Contact Center Operations (CCO).[1] *The metric is calculated daily for weekly, monthly, and yearly reporting.*

1. Introduction of Metric

A call is classified as an emergency when a caller selects the option of an emergency or hazard situation through the Interactive Voice Response (IVR) system. Once this option is selected the call is routed to an agent to receive the highest priority attention possible.

Not only is Emergency ASA a quality measurement of how efficiently we are able to answer customers calling us to report an emergency, it is also a safety measurement. Answering the call is the first step ensuring the customer is safe.

The metric is calculated by determining the average amount of time it took to connect customers to a service representative for calls where the customer identifies via IVR that they are calling to report a hazardous or emergency situation, such as a suspected natural gas leak or downed power line.

2. Background

On an annual basis, Pacific Gas and Electric Company (PG&E) handles between 5 to 6 million customer calls. Between 2017 and 2021, emergency-related calls averaged nine percent of total call volume; however, in the last two years, emergency calls have increased due to weather related storms events, Rotating outages, Public Safety Shutoffs

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[1] D.21-11-019, Appendix A, p. 12.

(PSPS), and Enhanced Power Safety Settings (EPSS). In 2020 and 2021 emergency calls handled were 10 percent and 11 percent of total call volume, respectively.

Historically, PG&E has been able to successfully manage staffing needs to ensure emergency calls are answered quickly. The metric and associated targets are designed to maintain our performance.

B. Metric Performance

1. Historical Data (2015-2021)

PG&E has seven years of historical data representing 2015-2021 to include the total emergency calls handled and ASA by month.

See PG&E's "Safety and Operational Metrics Report: Supporting Documentation" for total emergency calls handled and the ASA performance by month and year.

2. Data Collection Methodology

The performance data is gathered from PG&E's telephony system, Cisco Unified Contact Center Enterprise (UCCE). The data includes the number of emergency calls handled, and the total wait times (in seconds). Data is compiled each day for daily, weekly, monthly, and yearly reporting.

Historical data is collected using Microsoft's Management Studio application via a Sequel Query Language server owned by the Workforce Management Reporting team.

The data is gathered by extracting summarized data for emergency specific call types. The call types are created by the Workforce Management Routing Team, to categorize the types of calls that are entering the phone system, Cisco UCCE.

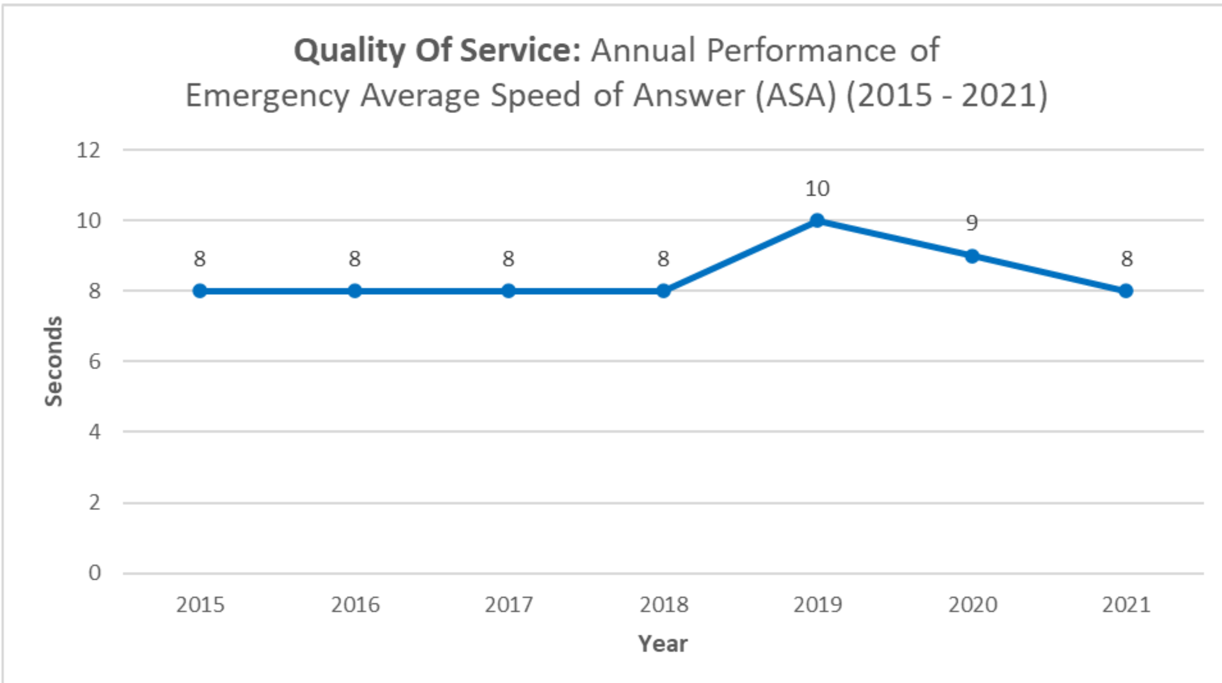
PG&E began archiving historical call data in 2015 once it was identified that Cisco UCCE system was truncating historical data as it was running out of storage.

3. Metric Performance (2015-2021)

Between 2015 and 2021, the performance of Emergency ASA ranged between eight and 10 seconds, with a median performance of eight seconds (see Figure 6.1-1). In 2019, PG&E's call handle time was highest

(10 seconds) primarily due to the increased scope of PSPS events, and the website failure, in the fall of 2019.

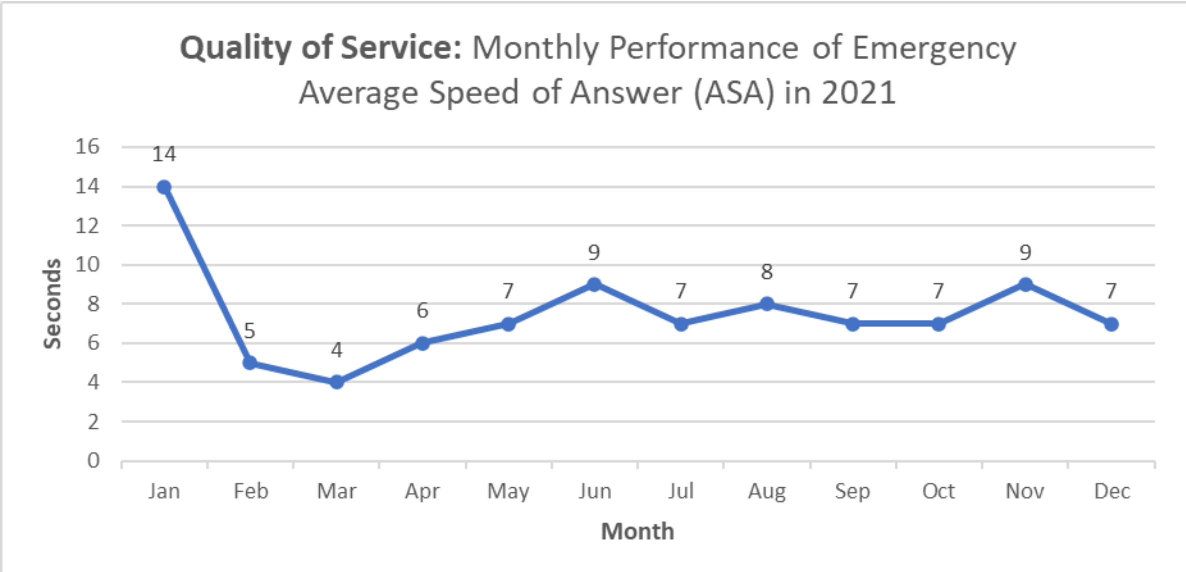
FIGURE 6.1-1
ANNUAL PERFORMANCE OF EMERGENCY ASA BETWEEN 2015 AND 2021



Most recently, in 2021, the Emergency ASA performance was eight seconds. Throughout the year, monthly performance ranged between four seconds and 14 seconds (see Figure 6.1-2). The primary drivers to the performance were based on unanticipated incidents (e.g., weather incidents impacting power outages, rotating outages, unplanned power outages) and call center representative staffing availability.

In January 2021, there was a significant, larger than anticipated weather event that resulted in increased overnight calls where staffing was not at standard levels for emergency events. The variation in monthly performance is primarily driven by unanticipated events that do not allow proper planning for staffing needs. Mitigation for unplanned event impacts going forward includes utilization of the Emergency Overtime protocol to increase staffing levels accordingly.

FIGURE 6.1-2
MONTHLY PERFORMANCE OF EMERGENCY ASA BETWEEN 2015 AND 2021



C. 1-Yr and 5-Yr Target

1. Target Methodology

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

- Historical Data and Trends: The target is based on the average of the past four years of historical data. The past four years were used because they are most consistent with current operation practices, including the expansion of PSPS, EPSS and Rotating outage programs. The average of this period is used as a reasonable indicator for sustaining and maintaining the performance going forward;
- Benchmarking: Not available;
- Regulatory Requirements: None;
- Attainable Within Known Resources/Work Plan: Yes, performance at or below the set target is sustainable; and
- Other Considerations: None.

2. 2022 Target

The 2022 target is at 15 seconds for the year to maintain performance based on the factors described above.

3. 2026 Target

The 2026 target is 15 seconds for the year to maintain performance based on the factors described above.

D. Current and Planned Work Activities

The performance of this metric is significantly driven by Contact Center Representative resourcing. The CCO are staffed to handle forecasted volume based on historical trends. As staffing needs change due to upcoming events (e.g., PSPS, weather impacts, storm or heat related outages) overtime is offered and planned in advance to increase staffing needs. Mandatory overtime (employees are required to stay on shift) and Emergency overtime (PG&E's Workforce Management team will send out notifications to offer Emergency overtime to employees currently not on shift.) are available options during same-day operations to support additional staffing needs. PG&E is forecasting to maintain the current level of staffing for 2022-2026.

Additionally, upfront messages provided to customers via IVR can be used to advise customers calling in of extended wait times to set expectations for customers to call back unless there is an emergency.