FILSINGER ENERGY
PARTNERS

PG&E

INDEPENDENT SAFETY MONITOR STATUS UPDATE REPORT

October 6, 2023

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BACKGROUND

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

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

Based on PG&E's electric operations and infrastructure changes, the ISM's findings, and discussions with the CPUC, the ISM's electric operations and infrastructure focus has narrowed from its previous report. The current ISM reporting period is directed toward 1) System Inspections and Repair; 2) Vegetation Management; and 3) Enhanced Powerline Safety Settings (EPSS). These focus areas are likely to continue evolving.

Based on PG&E's gas operations and infrastructure changes, the ISM's findings, and discussions with the CPUC, the ISM's gas operations and infrastructure focus has changed and is currently directed toward 1) Gas Quality Monitoring (e.g., status of PG&E addressing Benzene, Xylene and other components); 2) Leak Surveys/Abatement (including Picarro Leak survey); 3) Operator Qualification; 4) Construction Standards Quality Assurance/Quality Control (QA/QC); and 5) Tee Cap replacement program. These focus areas are likely to continue evolving.

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

This PG&E Independent Safety Monitor Status Update Report, hereafter referred to as "Q3 2023 ISM Report", covers the period April 1, 2023, through September 30, 2023. It was

[1] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M338/K816/338816365.PDF.

[2] https://s1.q4cdn.com/880135780/files/doc_downloads/wildfire_updates/2021/11/1524-1.Exhibit-Monitor-Report.pdf.

[3] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M397/K322/397322603.PDF.

developed based on the stipulations of the ISM Contract and the reporting directive included within CPUC Resolution M-4855. This Q3 2023 ISM Report is designed to summarize the oversight activities performed by the ISM during the period described and the related observations.

This Q3 2023 ISM Report also includes a summary of potential emerging risks identified during the oversight activities performed during the current ISM reporting period. With respect to potential emerging risks, consistent with the ISM Contract scope, the ISM has documented the initial observations and performed certain initial monitoring activities. Depending upon the observations, in consultation with the CPUC, it may be determined that the ISM will perform additional monitoring activities.

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

The information included in this Q3 2023 ISM Report should be considered a "snapshot" of observations during the current ISM reporting period. The ISM may continue to perform monitoring activities related to certain observations noted herein. Not all topics and/or observations identified in the ISM Previous Reports will be discussed in the current report. If no new material changes or information were identified during the current ISM reporting period, the topic/observation may be omitted from the current report and reintroduced in the future when material additional changes or information is obtained. Observations may change for various reasons (e.g., additional information becomes available, operational changes are implemented by PG&E, etc.). General facts and information contained within this report have been derived from internal PG&E meetings, presentations, data, and external reports which may not always be footnoted.

GENERAL OBSERVATIONS

CORE LEADERSHIP CHANGES

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

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

- In August 2023, Alex Vallejo, Senior Vice President of Ethics & Compliance was named Chief Risk Officer. This position had been filled on an interim basis since February 2023 by Stephen Cairns, Vice President, Chief Audit Officer.
- Also in August 2023, an external hire was named to fill the Vice President Vegetation Management position which had been filled on an interim basis since May 2023. As of the report date, the name of the successor has not been made public.
- Additionally in August 2023, Mike Delaney was hired as Vice President Utility Partnerships and Innovation. This is a new position created with a focus on developing third-party

collaborations and deploying new technology necessary to help accelerate PG&E's True North Strategy.

- Also in August 2023, Ron Richardson was named Vice President, Electric Distribution Operations. Mr. Richardson had previously served as Vice President, North Coast Region. He replaced Jeff Deal, who retired from the company in September.
- In September 2023, Julius Cox, Executive Vice President, People, Shared Services & Supply Chain left the company. This position will be filled on an interim basis.
- Also in September 2023, an internal candidate was promoted to backfill the position of Vice President, North Coast Region. As of the report date, the name of this individual has not been made public.

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

SUPPLY CHAIN

Critical Spares and Inventories

The ISM continues to monitor supply chain issues and inventory level metrics that are provided within various periodic operational reports that the ISM reviews each reporting period, or that may be discussed in meetings that the ISM attends. Reporting on supply chain issues will only continue should the ISM note any material negative shifts in the global or U.S. electric and gas utility sector supply chain trends, or if the ISM observes any material lengthening of PG&E specific supply chain delivery times, or a reported inability to receive inventory in quantities needed to achieve planned PG&E safety related work.

ASSET AGE AND USEFUL LIFE

No material changes in the ISM's observations were identified during the current ISM reporting period. The ISM will continue to monitor and analyze PG&E's asset management strategies affecting asset age, useful life, and replacement timing.

CONTRACTOR MANAGEMENT

In the ISM Previous Reports, the ISM observed that PG&E substantially relies on its contract workforce to perform wildfire mitigation efforts with approximately two-thirds of PG&E distribution inspectors being contractors in 2022. In 2023, PG&E revised its work plans regarding system inspection work which will, in effect, reduce the number of High Fire Threat District (HFTD) structures receiving ground inspection as well as expand the time period over which its HFTD inspections will be conducted. PG&E stated it believes the changes being made will result in a reduced dependence on a contractor workforce and an increase in risk mitigation as inspection schedules are shifted to address assets based on risk.

There have been no material changes in the ISM's observations during the current ISM reporting period. The ISM will continue to monitor and analyze PG&E's contractor management strategies.

ELECTRIC OPERATIONS OBSERVATIONS

HISTORICAL IGNITIONS AND TRENDS

As part of its safety monitoring, the ISM is provided with monthly updates to PG&E's ignition tracking database, which contains detailed information on ignitions (from 2014 to date) within PG&E's service territory associated with PG&E's equipment and facilities. The ISM monitors this database for ignition trends and outliers that may warrant root cause follow-up with PG&E. This section provides an overview of observed ignition characteristics, information on long-term trends, comparative year-to-date ignitions data, as well as a look at how PG&E's normalized ignition frequency compares against other large California utilities.

The 10-year PG&E database includes information on approximately 15,000 ignitions. Approximately 8,300 of these ignitions identified PG&E facilities as the suspected source of the ignition, with the remainder having damaged PG&E facilities by fire, where PG&E was not identified as the suspected source. These 8,300 PG&E facility ignitions are further segregated into those which are classified as CPUC Reportable and those that are not. For an ignition to be CPUC Reportable, it must meet the following fire-event criteria[4]: 1) a self-propagating fire of material other than electrical and/or communication facilities; 2) the resulting fire traveled greater than one linear meter from the ignition point; and 3) the utility has knowledge that the fire occurred. Fire caused damage to utility facilities whose ignition is not associated with PG&E's utility facilities are excluded from this reporting requirement.

Of the approximate 8,300 ignitions in the database, 95.5% occurred on PG&E electrical distribution equipment, 4.0% on transmission equipment, and approximately 0.4% on substation equipment. These proportions have been relatively stable throughout the nearly 10-year database period. Accordingly, PG&E focused the majority of its recent wildfire mitigation efforts on its distribution assets. Within the distribution category, ignitions have also been recorded as to whether they occurred on primary, secondary, or service lines. Over the 2014-to-date period, approximately 87% of CPUC Reportable ignitions in HFTD occurred on primary distribution lines, 9% on secondary lines and 4% on service lines. Although PG&E historically focused its wildfire mitigation work in HFTD on primary distribution lines, the ISM has been informed that in the future, secondary and service lines may have additional focus since large fires occurred from ignitions from secondary lines in the past. The ISM intends to monitor and report on any such strategy shifts.

Of these same approximately 8,300 PG&E facility ignitions, approximately 50% are identified as CPUC Reportable. The percentage of ignitions which become CPUC Reportable varies by fire threat district, with 71% of those in the Tier 2 and Tier 3 HFTD becoming Reportable, and 46% of ignitions in non-HFTD becoming Reportable. PG&E attributed this difference primarily to the differing environments in which these ignitions occur, with non-HFTD ignitions occurring generally in more urban environments, or environments where there is a greater likelihood of sparks falling onto non-vegetative ground cover.

[4] California Public Utilities Commission Decision 14-2-015.

One notable trend has been the reduction in the percentage of ignitions which have become CPUC Reportable over time. In 2017, prior to the start of PG&E's more intensive wildfire mitigation activities, approximately 61% of non-HFTD and 86% of HFTD ignitions were Reportable. By 2022, these percentages had dropped to 44% and 71% respectively. Due to the wetter conditions in the service territory in the first part of 2023, these percentages have been further reduced during 2023 year-to-date. In addition to a declining trend in the number of ignitions that become CPUC Reportable, as seen in Figure 1, the ISM observed that the number of ignitions within the HFTD (the area which has been experiencing more of the catastrophic fires) is also trending downward.

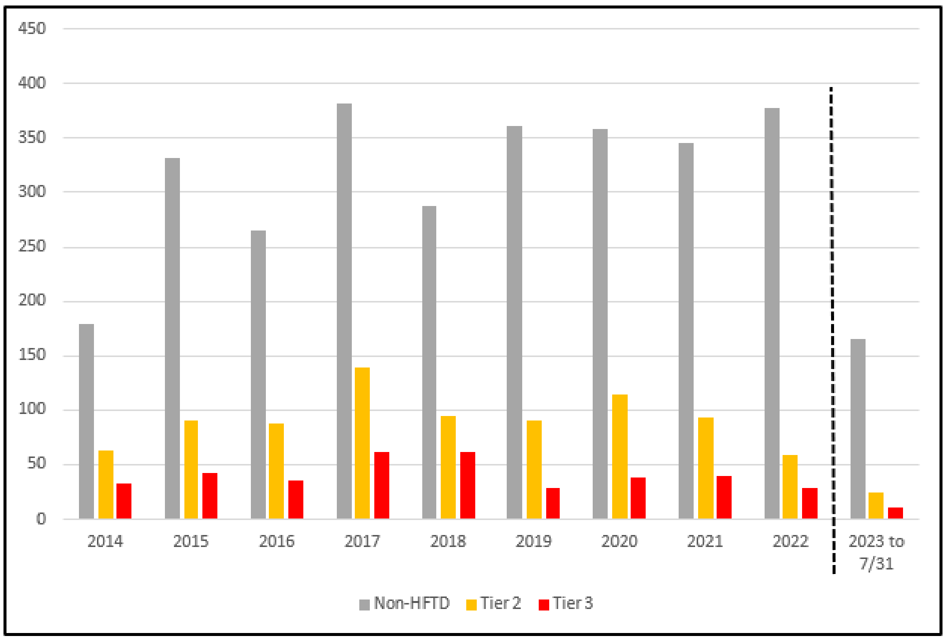

Figure 1: CPUC Reportable Ignitions by Tier

It should be noted that the larger number of ignitions in non-HFTD areas is due to this area having approximately 70% of the combined total distribution and transmission overhead lines within PG&E's service territory. As seen in Figure 2, when normalized by the number of ignitions per mile of overhead lines in each district, this large disparity is eliminated. Additional trends that can be observed from this figure include 1) since PG&E began its more intensive wildfire mitigation activities in 2018 (predominantly focused on the higher risk and higher consequence HFTD areas), and with the introduction of its EPSS and Public Safety Power Shutoff Program (PSPS) programs, there has been a 56% decrease in the number of ignitions per overhead mile over this 2017-2022 period; and 2) continuing declines occurred in 2021 when the EPSS pilot program was in place, and in 2022 when EPSS on overhead distribution lines was extended to cover all of HFTD (as further detailed later in this report).

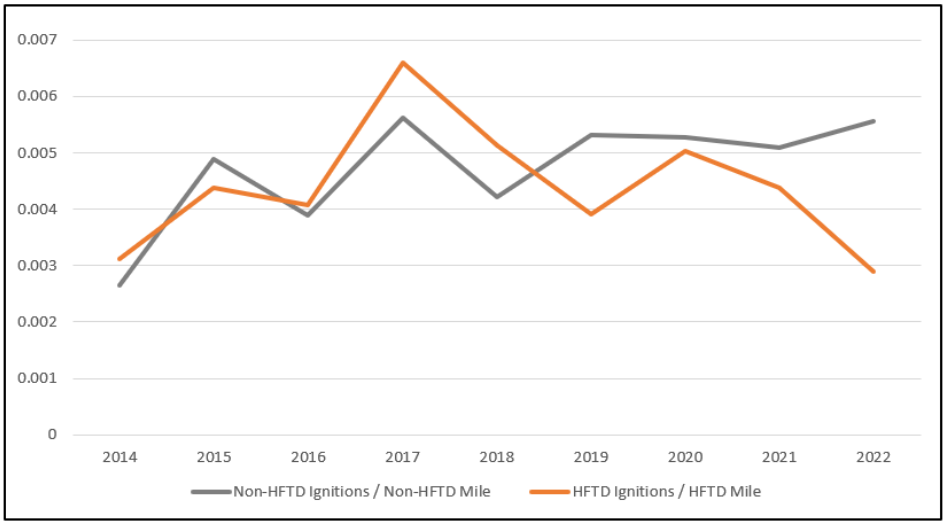

Figure 2: Normalized PG&E Facility Ignitions per Year per Mile of Distribution and Transmission Overhead Lines by Tier

Weather conditions vary from year to year, and these varying weather conditions can have a significant impact on the level of ignition activity in any particular year. PG&E uses its Fire Potential Index scores as a proxy for days with higher fire spread potential in order to normalize the year-to-year ignitions data for weather. On the R1 to R5 Fire Potential Index scale, PG&E selected R3+ days as the time period which is the highest correlation to more catastrophic fires. In modeling 2,437 historical fires (utility and non-utility caused) in its service territory greater than 100 acres in size, PG&E observed that fires starting in R3 conditions and above accounted for 95% of the acres burned in this historical dataset and 100% of the fatalities and structures destroyed.

As seen in Figure 3, when PG&E considered R3+ ignition rates by 100,000 circuit mile days in HFTD/High Fire Risk Area (HFRA), a similar downward trend exists. Note that each year represents the January to August time frame, so that it can be compared against the similar year-to-date period for 2023.

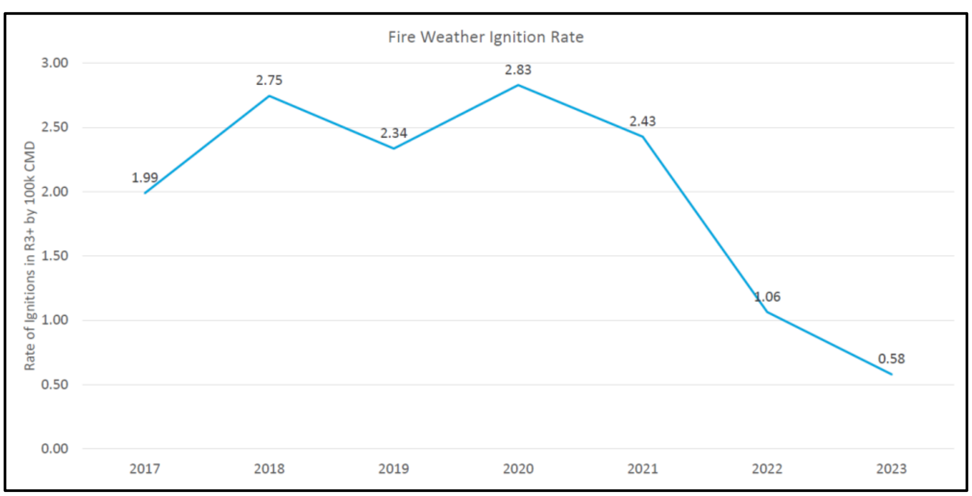

Figure 3: R3+ Ignition Rates by 100k circuit Mile Days in HFTD/HFRA from January to August YTD

In addition to looking at ignition trends in aggregate, the ISM also reviewed the ignition database for trends or outliers in other areas. One such area is that of suspected ignition events. Figure 4 provides an overview of the ignition counts by primary cause in HFTD. As reflected in the graph, vegetation contact and equipment failure/overloaded equipment constitutes the largest sources of ignitions in HFTD, and the majority of categories shows a decline in ignitions in 2022 corresponding to the first full year of distribution EPSS enablement across the full HFTD service territory and lower than average R3+ days in 2022.

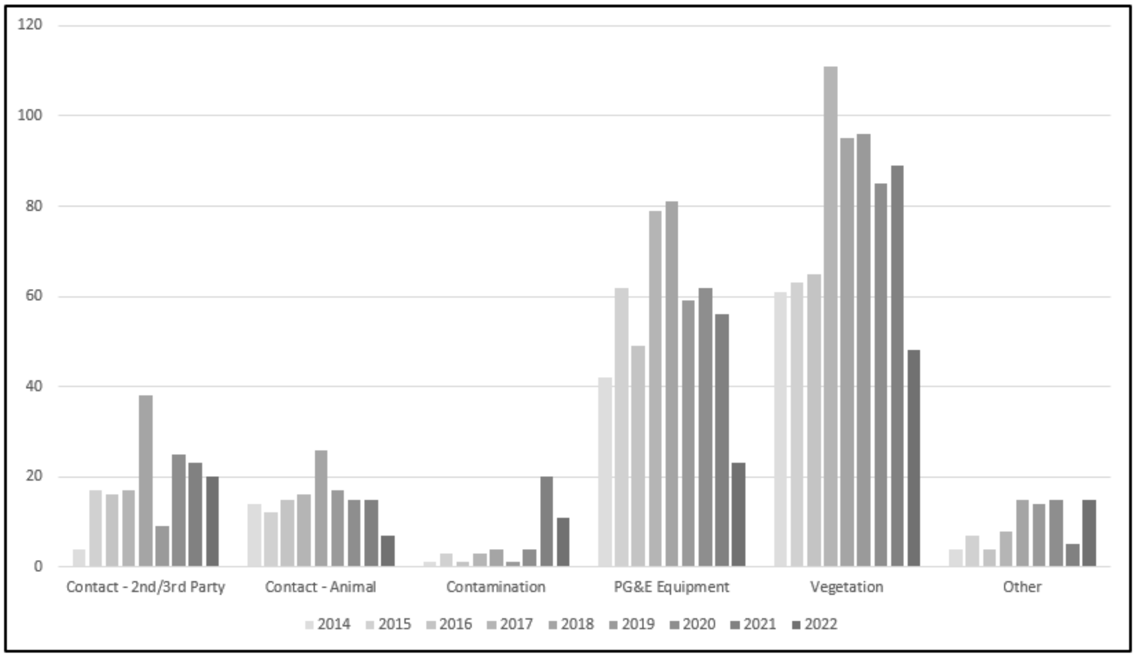

Figure 4: PG&E Facility Ignitions in HFTD by Suspected Initiating Event

The ISM also reviewed trends in individual ignition source failure sub-drivers. This is an additional breakdown of the primary drivers into 40-plus sub-categories, such as wire-to-wire contact, specific equipment type failures, utility work, vandalism, animal or third-party contact by type, contamination, etc. The ISM observed that in almost all categories in HFTD, the longer-term trend has been either flat (mostly in very low frequency categories) or downward.

Relative to PG&E's more recent ignition experience, Figure 5 represents the further reduction in CPUC Reportable ignitions in HFTD/HFRA in 2023 year-to-date versus 2022 (when EPSS was also enabled). This figure also compares the longer term 2020-2022, three-year average relative to Reportable Fire Ignition (RFI) Target 1.0[5].

[5] RFI 1.0: Target is set based on the forecast reduction in ignitions primarily driven by Enhanced Powerline Safety Settings (EPSS) and the deployment of Down Conductor Detection (DCD).

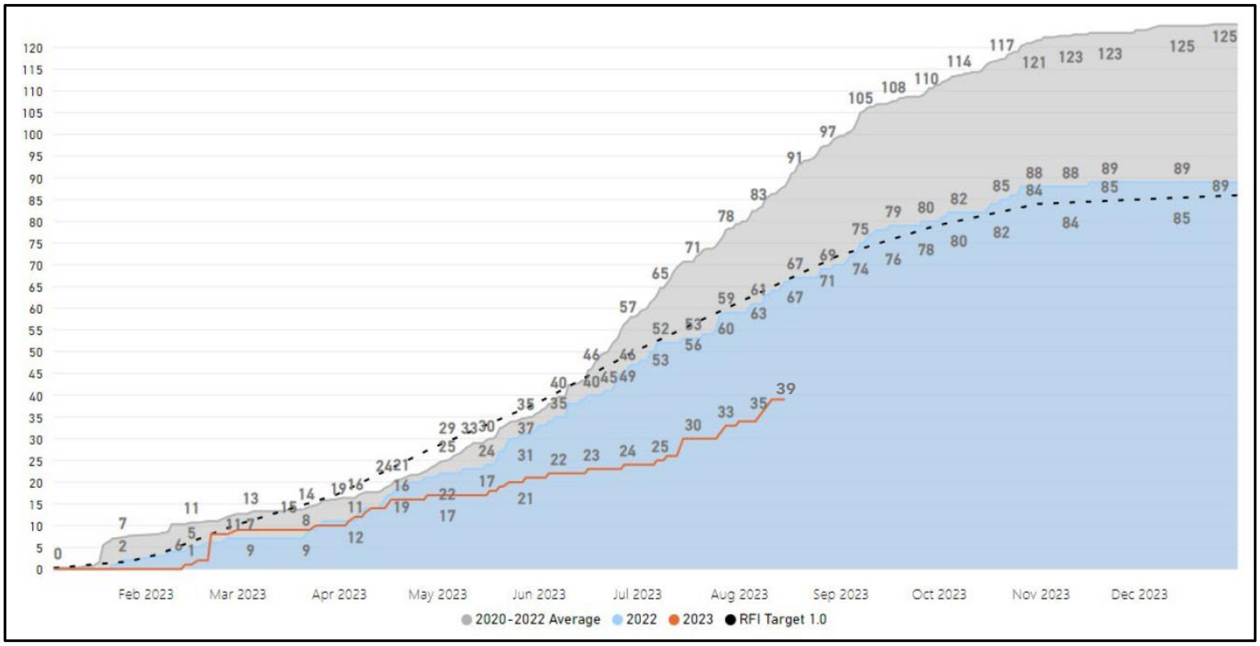

Figure 5: PG&E CPUC Reportable Ignitions in HFTD + HFRA

Of the 39 CPUC Reportable ignitions in 2023 through August 7, similar to the historical distribution/transmission ratios, 36 occurred on distribution overhead lines and three occurred on overhead transmission lines. Also similar to the long-term averages, 16 of these ignitions have been attributed to vegetation contact, 12 to equipment failure, four to third party contact and the remaining seven to utility error/contact and avian strike.

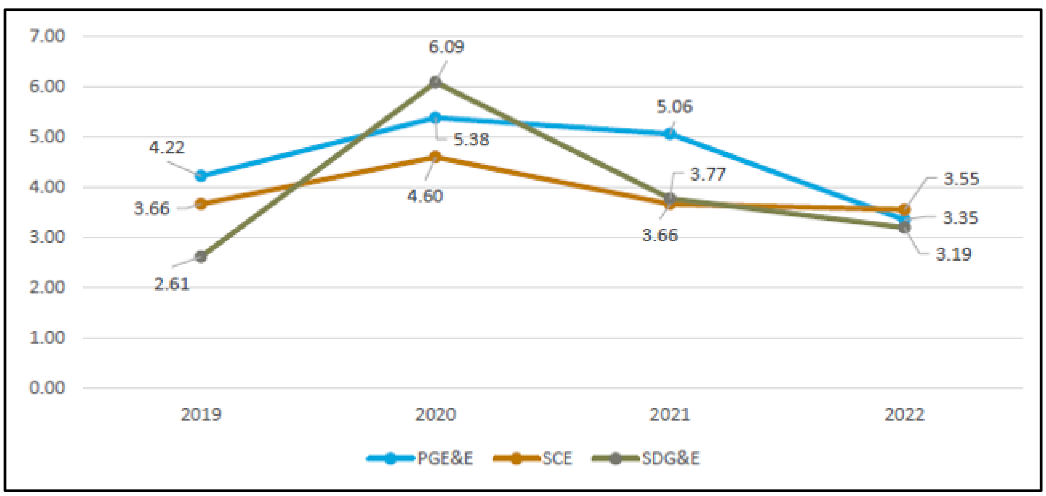

Figure 6: Distribution Ignitions of Large California Utilities Normalized by 1k Circuit Miles[6]

Finally, the ISM observed data prepared by PG&E from public domain sources which tracks its ignition frequency compared to Southern California Edison and San Diego Gas & Electric, using a normalized rate of distribution line ignitions per 1,000 distribution circuit miles. As seen in

[6] CPUC.CA.GOV – Fire Ignition Data. PG&E, SCE, SDG&E WMP Tables.

Figure 6, on a normalized basis, PG&E's 2022 distribution ignition rates were consistent with the other large California utilities.

FAST TRIP SETTING PROGRAMS

PG&E has implemented and continues to implement several programs where its distribution and transmission lines may be rapidly de-energized during conditions that may lead to ignitions. These programs include EPSS (distribution and transmission lines), the Downed Conductor Detection (DCD) program (distribution lines), the Partial Voltage Force Out (PVFO) program (distribution lines) and the Communication Assisted Protection Systems (ComAPS) program (transmission lines). The ISM monitors these programs through the review of various periodic operational reports, meetings, and analyses. This section of the report includes discussion related to the ISM's observations of these programs.

2023 Electric Distribution EPSS Program Update

EPSS is a program that increases the fault detection sensitivity and reduces fault recognition response time on enabled powerline circuits such that, when the current exceeds a PG&E-specified setting, the EPSS equipment will quickly deenergize the powerline without automatically re-energizing the line as is done when EPSS is disabled. In ISM Previous Reports, it was noted that following the implementation of a pilot EPSS program in 2021, PG&E expanded the program in 2022 to encompass all HFRA distribution circuits in its service territory. During the current ISM reporting period, PG&E reported EPSS enablement currently uses 4,830 distribution line protection devices, covering 796 distribution circuits, with EPSS capable miles totaling 44,072. This number is comprised of 25,236 HFRA miles, 9,596 buffer area miles, and 9,240 additional miles (e.g., miles outside of HFRA or buffer areas electrically connected to an EPSS-capable device). PG&E also started implementing EPSS on PG&E's transmission lines in HFRA, starting with a small pilot program in 2021, that is now in the midst of a multi-year expansion. Details on this implementation and its expansion are included later within this section.

EPSS is a supplemental wildfire mitigation program that PG&E operates in conjunction with its PSPS that began in 2018. A PSPS event consists of activities directly associated with PG&E's proactive de-energization of its electric transmission and/or distribution lines following a determination of high-risk weather-related imminent threats to power line assets and increased risk of catastrophic wildfire. While PG&E's EPSS and PSPS programs are designed to reduce the risk of ignitions and wildfires, they both do so at the cost of increasing average customer duration of unscheduled and planned outages (in the event of EPSS and PSPS events, respectively) for its customers, that can also result in other types of public safety concerns. For this reason, in long-term planning sessions that the ISM observed, PG&E indicated that it does not view these two programs as system-wide long-term wildfire mitigation solutions, but instead as interim risk reduction programs that can help reduce ignition and wildfire risk while other mitigation programs (such as PG&E's 10,000-mile undergrounding program) have an opportunity to be more fully realized.

While approximately 1.1 million customers were protected by EPSS enabled lines and did not experience any EPSS related outages in 2022, approximately 770,000 other customers experienced one or more EPSS outages that year, with more than 122,000 customers experiencing five or more outages while EPSS was enabled. PG&E stated that reducing the number and length of outages for those customers experiencing multiple outages will be a focus of its reliability mitigation work in 2023.

During this current ISM reporting period, the ISM focused its efforts on observing the impacts of EPSS program changes, as well as quantifying the impact of PG&E's ongoing efforts to minimize customer impacts. This includes areas such as outage response time, outage causes, identification of customers or circuits experiencing higher number of outage occurrences, and introduction of additional equipment and technologies (such as fault indicators which are designed to help locate outage causes and restore customer power more rapidly).

EPSS Enablement and Outage Related Trends

One discretionary timing decision that PG&E makes each year is when to switch EPSS enablement from off-peak (enabled only in specific circumstances) to the peak fire season enablement (when it is always on unless certain conditions are met). Based on analysis of historical PG&E ignitions, acres burned of any cause, and fuel moisture trends relative to this year, the EPSS team made the decision to shift to peak fire season enablement on June 14, 2023. This is slightly later than in the prior year, when the three indicators were all met earlier, and the decision to shift to peak fire season enablement was made on June 6, 2022. In both instances, the actual enablement was made within one week following the respective decision date.

As seen in Figure 7, the number of miles of distribution lines with EPSS enablement from May through mid-July 2023 was considerably lower than in the prior year. This later start of the fire season enablement was attributed to more precipitation in the early part of the year and a slower increase in the cumulative rate of circuit-mile days in R3+ Fire Potential Index conditions.

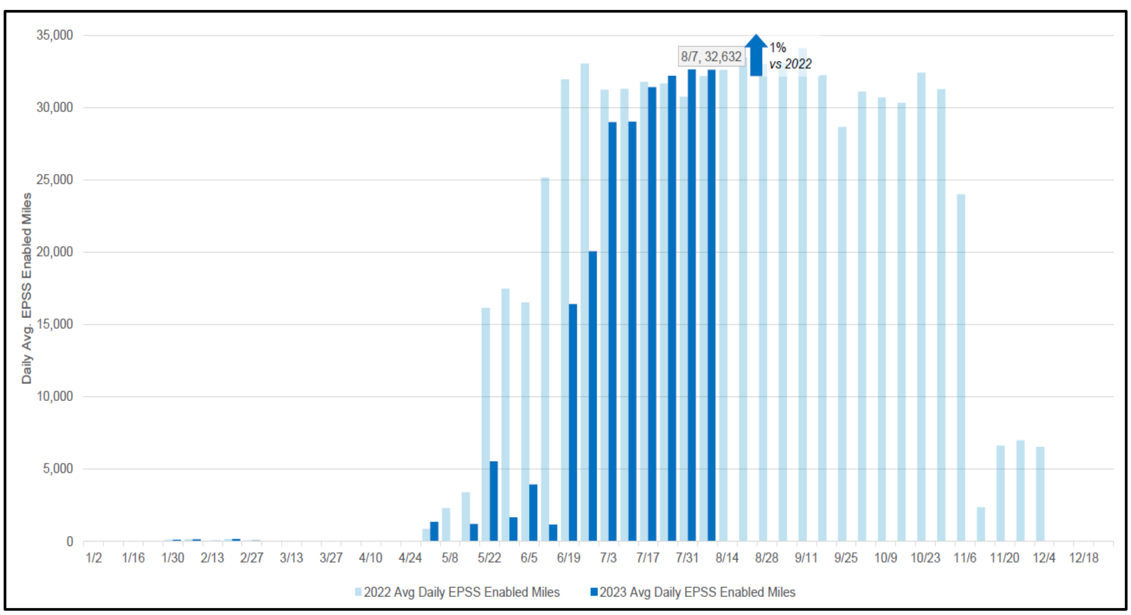

Figure 7: Daily Average Miles EPSS Enabled by Week (Data through 8/7/2023)

During 2022, there were 2,375 EPSS outages. In its 2023 Wildfire Mitigation Plan (WMP), PG&E projected the following EPSS outages over the 2023, 2024, and 2025 period: 2,350, 2,300, and 2,250, respectively. The lower enablement in the first half of 2023 led to 731 EPSS outages through July 31, versus 964 for the comparable seven-month period in 2022.

Table 1 provides a comparison of the EPSS related data for both 2022 and 2023 through July 31. For the first seven months of 2023, PG&E enabled 769 circuits versus 850 circuits during the same period in 2022 as a result of the later enablement and wetter weather conditions in 2023.

Table 1: EPSS Data January 1 through July 31 — 2022 vs. 2023

	Jan - July 2022	Jan - July 2023
EPSS Outages	964	731
Ignitions on EPSS Enabled Lines	17	7
EPSS CAIDI (min)	189	204
Response Time Within 60 minutes	84%	90%
Average Response Time (min)	47	41
Average Full Restoration Time (min)	385	377
% Restorations <= 60 minutes	6.6%	8.9%
% Restorations > 12 hours	15.2%	16.3%
Total Customers Experiencing EPSS Outages	852,179	689,082
Medical Baseline Customers	55,045	46,682
Life Support Customers	38,356	33,154
Critical Customers	14,010	11,221
Schools	1,646	1,524
Hospitals	91	84
Well Water Dependent customers	1,689	1,357
Outage Cause (% of total)		
3rd Party	9.3%	9.6%
Animal	16.5%	14.1%
Company Initiated	3.9%	8.5%
Environmental/External	0.5%	1.5%
Equipment	12.8%	14.8%
Unknown	44.5%	39.8%
Vegetation	12.4%	11.8%

Notable observations include a 24% reduction in EPSS outages, and a 59% reduction in ignitions on EPSS enabled lines between these two seven-month periods.

Although the average duration of customer EPSS outages increased 8% over this comparative period, this increase was largely attributed to a small number of long duration restorations in the early part of 2023 which were not similarly experienced in early 2022, and a number of remote device patrols which extended some of these restoration times. During the first seven months of 2023, PG&E improved its average time to have personnel on-site by 13% and was able to achieve 90% of its response times to within 60 minutes (up from 84% through end July in 2022), both of which were stated focus areas for improvement by PG&E in 2023. The percentage of time that PG&E was able to restore power to the last customers impacted by an EPSS outage within 60 minutes also improved by 34% (from 6.6% to 8.9% of total EPSS outages) over this comparative period. As reported in ISM Report 2, one item that contributed to this improved metric was the introduction of an EPSS outage patrol policy amendment in November 2022 that allowed PG&E to avoid having to patrol a line that experienced an EPSS outage if PG&E was aware that the outage was company-initiated and was related to increasing or reducing load during planned switching operations.

During the current ISM reporting period, the ISM observed PG&E's efforts on tracking response time and Customer Average Interruption Duration Index (CAIDI)[7] target metric misses by division. PG&E's reporting reflects that it is working with field supervisors to conduct reviews of extended outage response times for main drivers to CAIDI, seeking to improve its response time documentation and variance explanations in its EPSS and dispatch software applications, and developing processes to collect containment and countermeasure actions from regional daily operating reviews to share with other regional teams. The ISM also observed PG&E's reporting of lessons learned from detailed reviews on select high outage circuits which focus on underlying causes, ways to improve personnel coordination (including stationing personnel closer to circuits experiencing higher frequency outages and shifting resources toward divisions with slower response times), and possibly adjusting select equipment settings. This focus on select outages is part of an EPSS related program that is set to examine 19 circuits and the associated 57 protection zones where customers experienced more than 10 outages in 2022 while EPSS was enabled.

In addition, the ISM observed that PG&E continued with its Multiple Outage Review (MORE) program on high outage circuits. In 2022, over 200 circuits underwent these in-depth reviews, generating approximately 1,400 action items. This program continued into 2023 with 35 circuits having had a detailed MORE (with several of these circuits being on their second or third review) through early August, generating an additional 135 MORE action items. These include recommendations for things such as animal guards, accelerated project timelines, additional outage information gathering, requests for additional detailed patrols, and sectionalization and fault indicator assessments. One refinement of the MORE program in 2023 is that PG&E is now focusing its reviews on shorter circuit protection zone segments, rather than full circuits, which allows for a more targeted approach to seeking reliability improvements on circuit segments experiencing multiple EPSS outages.

PG&E has also been focusing on reducing the high number of EPSS outages coded as being of unknown cause, which in the seven months of 2022 represented 44.5% of all EPSS outages. As noted in ISM Report 2, PG&E personnel indicated that the likely causes for most of the unknown EPSS outages are bird, animal, or tree branch contacts, where the patrols are unable to find any evidence of such contact. During the first seven months of 2023, the percentage of these

[7] CAIDI is an electric system reliability metric defined in IEEE 1366.

unknown outages decreased by 10.5% to 39.8%, which is consistent with the 40% key performance indicator target for unknown outages set for 2023 for the operations section of the EPSS project management team. In order to further improve its cause identification, PG&E implemented a more rigorous outage review program; during the seven months of 2023, 62 of the 353 outages originally classified as unknown were later reclassified (e.g., 25 to Company Initiated, 18 to Equipment Failure, etc.). More accurate reclassification allows PG&E to better understand causes that may be behind repeat multiple outages and may also allow for better deployment of supplemental wildfire mitigation methods (such as installing more animal guards or identifying where to deploy more targeted vegetation management).

Approximately 1.8 million customers were serviced on lines that were EPSS enabled through August 7 of both 2022 and 2023, of which 70.8% in 2022 and 76.1% in 2023 experienced no EPSS outages. The remaining customers experienced approximately the same number of multiple outages between the two years, with approximately 12,000 customers in both years experiencing five-plus outages.

Continuing EPSS Program Improvements

Per PG&E, one of the contributors in achieving a steady improvement in full average restoration times throughout 2022 was the installation of 1,581 new fault indicators. These fault indicators allow patrolling personnel to identify the section of the line more quickly where the EPSS outage may have occurred and allows earlier sectionalizing to restore power to select customers faster. The ISM observed that PG&E continued to expand the number of fault indicators in service, with an additional 1,353 having been installed by the end of July 2023 (ahead of its original intended installation completion date).

Additional distribution line sectionalization also helps isolate an EPSS outage to shorter circuit segments, which in turn allows more customers to have the power restored more quickly. Through August 7, 2023, the ISM observed that PG&E installed 124 additional protective devices on the most reliability-challenged circuit protection zones to help reduce customer count exposure should a fault occur. PG&E projects that this additional sectionalization in 2023 may result in approximately 8,000 fewer customers experiencing five or more EPSS outages, and projects a reduction in its count of customers experiencing an EPSS outage by approximately 92,000.

As was reported in the ISM Report 2, the EPSS program was allocated an additional $50 million to fund future mitigations on circuits experiencing the highest frequency of EPSS outages (generally eight-plus in 2022). Per PG&E leadership, this includes funding that will be directed toward items previously identified during PG&E's MORE analysis, such as animal guard retrofit (e.g., birds and squirrels), additional targeted vegetation management (discussed later in this report under the Vegetation Management for Operational Mitigations (VMOM) Program) and customer resiliency programs. These funded programs are in the initial phases of deployment; PG&E is beginning to track progress in their weekly internal reports. The ISM will continue to track these new programs and will report on their progress in future report(s) as material changes are identified.

Another new program that PG&E started in 2023 is the installation of EPSS devices on single phase distribution lines. These new installations are projected to further reduce customer reliability impacts by allowing smaller sections of single-phase circuits to be tripped during an outage event, rather than having an upstream three-phase device trip, which could cause an outage to more customers. In 2022, 34,000 customers served by single-phase lines experienced at least one EPSS outage and 2,200 experienced five or more EPSS outages on single phase distribution lines.

PG&E projects that the installation of 67 new EPSS devices on eligible single-phase lines will allow approximately 67,500 customers to be descoped and removed from EPSS coverage (since they reside outside HFTD and can be isolated from the portions of the lines within HFTD) or added to the EPSS buffer areas. PG&E plans to prioritize the installation of devices on these single-phase lines where customers experienced three or more EPSS outages in 2022. The ISM observed that while PG&E targeted all 67 devices to be installed and in-service by July 2023, technical problems with device integration, and a need to develop new engineering logic to address gaps in vendor features, has delayed completion of this program into late-2023.

New Technology Operational Mitigations

As an additional enhancement to its EPSS program, PG&E also began implementing two new technology operational mitigations in 2022: Downed Conductor Detection (DCD) and Partial Voltage Detection (PVD) / Partial Voltage Force Out (PVFO).

Downed Conductor Detection

DCD uses electrical sensor information and software to identify the presence of specific electrical characteristics (i.e., signatures or patterns) produced by arcing conductors with the earth's surface, thus initiating trips on circuit interrupting devices. DCD is complementary to EPSS since DCD is designed to identify high-impedance (low current) faults, which may be difficult to detect through EPSS.

PG&E installed 409 DCD protective device controllers in 2022. PG&E established targets in the 2023 WMP to install an additional 500 devices in 2023, 400 devices in 2024, and 250 devices in 2025. The devices installed by the end of 2022 covered 5,372 miles of electrical distribution lines (of which approximately 3,700 miles are in the HFRA). Per PG&E leadership, the expansions over the next three years are expected to extend DCD coverage within the HFRA to approximately 20,500 miles. The ISM confirmed that prioritization of DCD implementation is based on the Wildfire Distribution Risk Model (WDRM) Version 3 circuit protection zone risk ranking.

As of August 7, 2023, the ISM observed that 358 new DCD devices had been installed year-to-date 2023, and that the installations were progressing in line with the WMP plan for the year. Minor installation delays were observed earlier in the year due to Advanced Distribution Management System (ADMS) screen build delays, telecom issues, and construction schedule constraints due to storm activity earlier in the year. PG&E reported that it is back on target. The new devices installed in 2023 so far increased the total count to 767 devices, covering an incremental 9,602 HFRA miles, bringing the total coverage to 13,112 HFRA miles.

PG&E indicated a total of 16 DCD outages occurred in 2022. Each outage impacted an average of 761 customers with an average customer outage duration of 132 minutes. As seen in Figure 8, there have been 98 DCD outages in 2023 through August 7. The increase over 2022 is primarily due to an increase in the average number of devices active during the respective time frame.

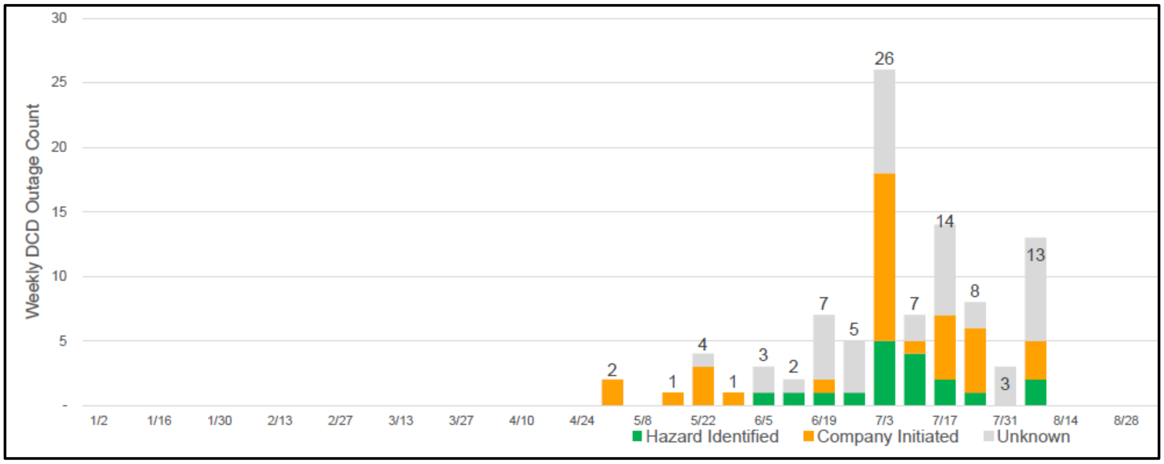

Figure 8: 2023 Downed Conductor Detection Outages (Data through 8/7/2023)

Each of these outages impacted an average of 1,103 customers with an average customer outage duration of 284 minutes. Of the 98 outages, 44 were of unknown cause, 37 were identified as being due to either coordination failure or personnel/company, and 17 were due to identified hazards (eight equipment failure, four animal contact, three vegetation contact, and two third-party contact).

PG&E noted that through August 7, 2023, five ignitions were likely avoided in 2023 due to DCD outages (three associated with overhead equipment, and two with vegetation contacts).

Partial Voltage Detection / Partial Voltage Force Out

The other program which PG&E began implementing in 2022 was the Partial Voltage Detection (PVD)/Partial Voltage Force Out (PVFO) program. PG&E enabled single-phase and polyphase SmartMeters™ to send real-time alarms to the Distribution Management System when partial voltage (25 to 75 percent of nominal voltage) or full/partial loss of phase (in polyphase) conditions are detected. Detection of partial voltage conditions allows Control Center operators to dispatch field personnel to locations where equipment may be in a condition that increases wildfire risk. This technology helps detect and locate a wire down, broken electrical connection, blown single-phase fuse and other low voltage conditions within minutes, instead of relying on customer phone calls or employee assessment to provide notification of equipment causing a low voltage condition. This also has the potential to reduce the amount of time a line is energized while problems exist on the system (where it could potentially cause an ignition) and allow first responders to extinguish wire-down or other equipment related ignitions more quickly.

The PVFO process leverages PG&E's extended SmartMeter™ network to further help identify and respond to high impedance faults. When a partial voltage alarm indicates low SmartMeter™ voltage on two or more SmartMeter™ devices at the fuse level[8], the Distribution

[8] The fuse level refers to a segment that does not have an automated protection device.

Control Center operator will force out, or remotely trip, the next upstream protection device and dispatch response teams to the area of the alarm to assess potential hazards.

PG&E's SmartMeter™ network currently covers approximately 90% of HFRA miles. The use of partial voltage protection was initiated in June 2022. A total of 13 PVFO outages occurred in 2022, with nine field hazards identified and an average response time of 13 minutes. Through August 7, 2023, eight PVFO outages occurred, with seven field hazards identified (three equipment failures, two vegetation contact, one animal contact, and one third-party contact), and an average response time of 11 minutes.

Transmission EPSS and ComAPS

Given their experience to date in reducing ignitions on distribution lines that have been enabled with EPSS, PG&E is also seeking to mitigate wildfire risk on its 60kV/70kV/115kV/230kV transmission system, through the implementation of EPSS and Communication Assisted Protection Systems (ComAPS). For lines without these two systems, the transmission line protection scheme design criteria are to clear bolted (i.e., zero impedance) faults in less than one and a half seconds, with high impedance faults possibly resulting in much longer clearing times. Faults close to source substations on radial transmission lines, without ComAPS, may clear in much less time as well. Implementing these systems on transmission lines has the potential to reduce fault clearing times and the associated arc energy on both looped and radial lines with the objective of reducing ignitions.

The Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC) implemented Reliability Standards designed to increase reliability and prevent cascading outages or disrupted scheduled path flows on Bulk Electric System (BES) transmission lines[9]. The NERC Reliability Standards do not currently address the use of EPSS on BES transmission lines. PG&E elected not to implement EPSS on BES lines but may consider it in the future or review installing ComAPS on these lines. Non-BES lines (e.g., radial lines) are being considered for EPSS.

Of the 525 transmission lines traversing HFRA, 75 are currently eligible for EPSS implementation. Following an initial pilot program where PG&E installed EPSS capability on seven test transmission lines in 2021, PG&E expanded the program in 2022 to cover 47 60kV/70kV/115kV lines. PG&E indicated that currently 48 lines are capable, 13 lines are being prepared for activation, and 14 lines are planned for EPSS capability in the future.

For the BES transmission lines, PG&E is intending to use ComAPS, which uses a high-speed communication channel between two or more ends of a transmission line to provide "no-intentional time delay" clearing over 100% of the line. There are several types of ComAPS schemes available, with PG&E noting that its preferred scheme for wildfire ignition reduction is Line Current Differential (LCD), which has much lower current thresholds compared to other ComAPS methods, lower pick-up thresholds, and zero-time delays that limit equipment damage and hot particle expulsion.

The difference between EPSS and ComAPS enabled transmission line protection is that EPSS

[9] BES transmission lines are generally defined as transmission lines operated 100kV or above.

does not require high-speed communication channels between end of line terminals, and that it can apply to Non-BES Radial lines. ComAPS, however, can be used on both BES and Non-BES Network transmission lines since it preserves system reliability.

There are currently 158 PG&E transmission lines that have existing ComAPS protection with continuous fast tripping capability. PG&E has these in service for all 500kV lines, a majority of 230kV lines, and a portion of 115kV lines.

A subset of the remaining 292 lines is either planned for ComAPS implementation or requires additional high-speed communication upgrades to provide protection. The majority of the 60kV/70kV lines are multi-terminal which require significant investment in substation primary equipment and/or system reconfiguration (e.g., construction of new switching stations) to enable ComAPS. PG&E is currently planning on implementing ComAPS on 80 more lines over the 2024-2034 period, with the remaining lines dependent on risk buydown and feasibility.

The ISM observed that while the majority of modeled wildfire risk is concentrated in a smaller number of the 525 transmission lines in HFRA, EPSS/ComAPS enabled transmission lines so far covers 38% of projected transmission total wildfire risk and 41% of the wildfire consequences risk. With the implementation of EPSS on the next 27 lines, PG&E projects that this will increase the levels to 46% and 55%, respectively. The remaining circuits are being risk-prioritized to study for future fast tripping implementation.

The ISM observed that fast trip outages on EPSS enabled transmission lines occurred with much lower frequency than those experienced on PG&E's enabled distribution lines. In 2022, a total of 11 transmission EPSS outages occurred between May and August, impacting 20,507 customers, with full restoration times ranging from 113 to 1,560 minutes and with an average customer outage duration of 328 minutes. Of these 11 outages, six were identified as caused by animal contact, one by equipment failure, one by third-party contact, and three of unknown causes.

For the first seven months of 2023, a total of 16 transmission EPSS outages occurred during the May to July period, impacting 39,807 customers, with full restoration times ranging from 14 to 569 minutes, and with an average customer outage duration of 139 minutes. Of these 16 outages, six were identified as involving equipment failure, five due to environmental/external factors, two to third-party contact, one to animal contact, and two of unknown causes.

Once EPSS capable transmission lines are enabled for the season, they will not be disabled unless operating conditions require otherwise. The ISM reviewed PG&E's policies for patrolling transmission lines that experienced a fast trip outage. Under a Fire Potential Index score of R3, patrols of the entire line are required unless fault targeting devices can be used to evaluate, isolate, and restore power. For R4, R5 and R5+ Fire Potential Index conditions, the policy is to not test the facilities until the entire line, or line section, has been patrolled and all found trouble/fault condition(s) have been isolated.

DISTRIBUTION INFRASTRUCTURE OBSERVATIONS

In the current ISM reporting period, the ISM began observing how changes in PG&E's infrastructure inspection process over time impacted the rate at which maintenance repair tags (the process through which certain asset defects and deficiencies are identified) has developed. Changes in both the rates at which PG&E's inspectors have been creating new maintenance repair tags (or upgrading the priority of existing tags upon reinspection), as well as changes in the rate at which related repair work has been completed in the past, have both resulted in a backlog of repair tags. The ISM is currently analyzing data and related trends.

PG&E's current plan to clear the maintenance tag backlog is detailed in the 2023 WMP, and there are several short and long term WMP commitments addressing this planned tag backlog clearance that are being separately monitored by the Office of Energy Infrastructure Safety. While observations relating to this backlog clearance are beyond the ISM's scope, the ISM is aware that in PG&E's latest WMP revision notice, PG&E is planning to revise the manner in which it prioritizes and bundles tag backlog. PG&E stated this could reduce the period of time in which the backlog may be cleared in a more cost-effective and risk-informed manner.

In its ongoing analyses of historical maintenance tag find rates, the ISM has also been comparing select individual inspector defect find rates against company-wide averages. The ISM has held ongoing discussions with PG&E to learn how inspectors flagged as not meeting established standards are tracked, identified, and addressed. PG&E provided the ISM with details of its inspector monitoring and quality assurance programs.

The ISM plans to complete the data analyses regarding the above and provide its related observations in a future report.

ISM 2023 Targeted Distribution Asset Inspections

Priority Tags

During the current ISM reporting period, the ISM performed data analysis of a 10-year historical ignition database to identify areas with proportionally high ignition counts. The ISM then performed distribution inspections in the targeted areas utilizing PG&E's Distribution 2023 Checklist (the same used by PG&E inspectors).

The ISM inspected a total of 83 poles in one of the targeted areas. Twenty-two of the poles (i.e., 27%) were identified as having pole damage (e.g., cracked, burned, corroded, deformed, rotten, or decayed). Further analysis by the ISM determined that nine of the poles were in HFTD Tier 2 and 13 of the poles were in HFTD Tier 3. Consistent with the ISM's findings, PG&E's inspectors also recognized that there were maintenance conditions on each of the poles. However, even though PG&E identified pole damage on all poles, the documentation provided to the ISM noted tags assigned to four of the poles did not address the specific pole damage identified by the ISM until the 2023 inspections. Accordingly, 18 of the poles had been originally assigned a Priority E tag by PG&E. Of these 18 poles, three have since been upgraded to a Priority B tag[10].

According to PG&E data, many of the Priority E tags for these identified damaged poles were first included in PG&E's maintenance system database in 2019 and 2020. Since that time, each

[10] Priority E tags are to be completed within 12 months in Tier 2 and completed within six months in Tier 3; Priority B tags are to be completed within three months in Tier 2 and Tier 3.

year a PG&E Safety Reassessment[11] has been performed. The PG&E inspector returning to these identified poles updated the condition of the pole as, "remains damaged and the condition needs to be addressed within the next 12 months". Each reassessment resulted in the assignment of a new completion due date within the ensuing 12-month period. The ISM observed that in these instances, the reassessment associated with the Priority E tags of the poles inspected by the ISM were being extended for additional periods rather than corrective actions being completed within the expected timeframe.

According to PG&E data, the Priority B tags for the three identified damaged poles were first identified in PG&E's maintenance system database in 2019 as Priority E tags. Consistent with the Priority E tags noted above, each year since 2019, a PG&E Safety Reassessment of these poles was performed to reassess the condition of the damaged poles noting that the poles remain damaged and extending the period for which the issues needed to be addressed within the ensuing 12-month period.

In 2023, the PG&E Safety Reassessment of these poles was performed stating that the previously classified Priority E tags needed to be expedited to Priority B tags with new assigned completion due dates at the end of August and beginning of September 2023. Upon review of PG&E's maintenance database the corrective work for the reassigned Priority B tags was completed by the due dates for two of the Priority B tags; however, one of the Priority B tags was completed five days late due to the project being reassigned based on work prioritization schedules.

During the current ISM reporting period, the FEP distribution subject matter experts performed field inspections as part of this contract, in addition to contracts with other parties, on over 1,000 PG&E distribution poles in HFTD. These inspections support the observations made during the targeted distribution field inspection referenced above as well as the specific areas of equipment replacement, open secondary wire, and quality control and assurance which follow.

Equipment Replacement

During the current ISM reporting period while conducting distribution inspections, the ISM observed cases where old poles had new equipment installed (including non-exempt equipment[12]) as well as new poles that have all new equipment (including non-exempt equipment). As an example, as seen in Figure 9, the ISM observed a new pole with new equipment installed but still had non-exempt lightning arresters on the pole.

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[11] PG&E will monitor field conditions and perform safety re-assessments on an annual basis before the initiation of Fire Season (as determined by CAL FIRE) for the tags meeting the following conditions ("tags subject to safety re-assessment"): a) Exceed their compliance date; b) Remain open; c) Contain time-dependent asset deterioration based on "Facility, Damage, Action" (FDA) SAP work management code of the corrective tag; d) On line temporarily de-energized (for Transmission only); Source: PG&E's 2019 Corrective Tag Execution Approach, Utility Bulletin: TD-8999B-001, Publication Date 11/23/2019 Rev: 0

[12] Non-exempt equipment may generate exposed electrical arcs, sparks or hot material during operation that may lead to the ignition of flammable materials. Non-exempt equipment is subject to California Public Resources Code 4292 clearance requirements.

Figure 9: New Pole/New Equipment/Non-Exempt Lightning Arresters

Another example, as shown in Figure 10, includes an old pole with new crossarms installed along with non-exempt fuses.

Figure 10: Old Pole/New Crossarms/Non-Exempt Fuses

The ISM has an open data request regarding PG&E's policies related to equipment replacement when 1) new equipment and/or poles are installed; and 2) determining factors for installation of animal protection when upgrading poles/installing new equipment.

Non-Insulated Open Wire Secondary

Non-insulated open wire secondary are conductors from the secondary side of the transformer that are not bundled together and are not insulated. Prior to 2023, vegetation in non-insulated open wire secondary was flagged only if there was strain or abrasion to the open wire. The ISM observed during the current ISM reporting period and in prior reporting periods trees in contact with non-insulated open wire secondary as well as a distribution pole having a tree in full contact with energized non-insulated open wire secondary. In 2023, PG&E revised its distribution system inspection checklist to include separate questions regarding non-insulated open wire secondary or non-insulated open wire service overgrown with vegetation absent of strain or abrasion[13]. Additional discussion of this topic is included in the Vegetation Management Observations section of this report.

Quality Control

For the 2023 distribution system inspections, PG&E indicated that it is aiming to complete a quality check on 100% of inspections performed in HFTD and HFRA this year. PG&E stated that its goal is to complete approximately 40,000 field inspections (with higher priority designated to higher risk areas) and an additional 200,000 desktop reviews. The quality control team typically conducts reviews within two weeks of the inspection in order that any systemic issues or inspector miscommunications can be addressed. Regardless of whether a field or desktop review is being conducted (wherein the desktop review inspector performs the task using photos taken by the field-inspector), the quality control team conducts the review using a blind audit methodology without previously referencing the inspector's results, then compares the results to that of the initial field inspection. Any reported findings are provided to the system inspection team on a weekly basis.

During the current ISM reporting period, as of August 31, 2023, PG&E's Quality Control (QC) reported a 94% and 87% pass rate for correctly identifying critical attributes[14] during distribution inspections for desktop and field QC, respectively.

VEGETATION MANAGEMENT OBSERVATIONS

EVM Versus EPSS Effectiveness

In ISM Report 2, it was reported that PG&E ended its Enhanced Vegetation Management (EVM) program at the end of 2022. Per PG&E, this program expended $2.5 billion from 2019-2022, providing extra vegetation clearances, including increased rates of tree removal, on over 1.1 million trees, and along 8,283 miles of HFTD distribution lines (approximately 32% of all lines in HFTD). PG&E's rationale for stopping the EVM program was that with the full rollout of the EPSS program across all HFTD in 2022, and with the additional protection of the PSPS program, these mitigation programs were providing a more cost-effective means for PG&E to reduce wildfire risk.

At the same time that the EVM program was ending, PG&E began working on three replacement vegetation management programs (further described below). The replacement programs were designed to take a more targeted approach to risk reduction, as well as attempt

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[13] There are separate questions regarding vegetation causing strain or abrasion to secondary.

[14] Critical Attributes include a) Quality Verification – Evaluation of whether an asset complies with the regulation, requirement, or specification within the scope of a specific audit; b) Critical Attribute Condition – a condition which could lead to either an ignition point or a wire down situation that could result in a potential fire ignition; and c) Critical Attribute Checklist – a subset of all the inspection questions; governed by a change control process.

to reduce customer impacts on EPSS circuits where customers experienced multiple outages due to vegetation contacts with EPSS enabled lines.

In ISM Report 2, it was noted that just prior to the end of its reporting period, PG&E provided an internal analysis comparing the historical effectiveness of its EVM and EPSS programs, and that the ISM had questions regarding the comparative analysis. The ISM also reported that it needed to collect additional information, as well as review a third-party report which had been commissioned by PG&E, to review the effectiveness assessment. The ISM completed this review during the current ISM reporting period.

The ISM's initial observations of PG&E's analysis were that PG&E used a much more rigorous statistical analysis on the EVM data than had been used with the EPSS data, which made it more difficult to equally compare the two results. Because PG&E's analysis was using a much smaller before/after EVM ignition database (which only included 4,750 HFTD EVM miles in scope) than existed on the EPSS side (which covered approximately 25,500 miles of HFTD distribution miles in scope), PG&E also elected to look at a much larger set of outages (including those that occurred one year before and one year after EVM work was completed) as a proxy for EVM in-scope ignitions.

The ISM also noted an incorrect usage of a historical outage-to-ignition conversion factor which, in effect, reduced the ignition reduction effectiveness for EVM to a figure significantly smaller than it should have been. PG&E acknowledged that this usage was in error but asserts that correcting this error would not have impacted its decision to end the EVM program as detailed below.

During the current ISM reporting period, the ISM obtained and reviewed the third-party report and found that the third party did not review the side-by-side comparison, but only assessed the methodology regarding EVM effectiveness as they were not tasked with providing comments on the different analytical methods between the two wildfire mitigations. The ISM observed that the report (which also did not look at the outage-to-ignition conversion factor usage) found PG&E's effectiveness analysis on the EVM outage side to be sound, with the following commentary:

- One year before and one year after accounts for seasonality, but the analysis does not take into consideration seasonal variations between the years.
- The event rates should have been normalized by circuit segment distances.
- Specific to the ignitions and outages occurring between 2018 and 2022, approximately 30% were not inspected, and therefore could be assigned to incorrect circuit segments, thus reducing the level of confidence in the results.

PG&E's Wildfire Risk Governance Steering Committee (WRGSC) had tasked PG&E's Risk and Data Analytics (RADA) group to review the EPSS team's 2022 EPSS Effectiveness Calculations and determine how EPSS ignition reduction should be modeled in the Wildfire Distribution Risk Model (WDRM) Version 4. The ISM reviewed the RADA group's May 2023 report, which noted several differences in ignition data usage, test years, ignition type (i.e., CPUC reportable versus all ignitions) and circuit segment vintages that were used between the EPSS group and the RADA team working on the wildfire risk models. The RADA team also noted that "based on the small sample of data to date, the statistically estimated effectiveness likely has a wide confidence interval. This points out that the effectiveness of the EPSS program should continue to be the focus of further data gathering and analysis."

In order to continue to examine EPSS effectiveness, PG&E is working with the B. John Garrick Institute for the Risk Sciences at UCLA and expects to receive its first report on EPSS effectiveness toward the end of this ISM reporting period. The ISM observed PG&E using this UCLA resource in the past on other complex risk modeling workstreams.

In commenting on the reason for ending the EVM program in its 2023 WMP, PG&E stated, "While EVM was successful in mitigating vegetation risk in the HFTD, we determined that EPSS, along with routine VM, was more effective at reducing risk and was less resource intensive. We determined that EPSS is more effective at mitigating wildfire risk at a lower cost as shown by comparing the RSEs (Risk Spend Efficiency) for the two programs: at the time we filed the 2023 GRC[15], the RSE for EVM was 14.5 compared to the EPSS RSE of 105.7. While we are not adding new circuit segments to the EVM program we will maintain previously completed segments through the Routine VM program unless lines are undergrounded." Note that this 14.5 RSE was for a proposed lower cost modified EVM program, and that the original RSE score for the full EVM program was originally calculated at 3.9 ($7.0 billion of 2023-2026 risk reduction net present value (NPV) benefit / $1.8 billion of 2023-2026 NPV cost).

As part of its analyses, the ISM reviewed the build-up of the original RSE scores, and also observed that since the filing of the GRC, the EPSS RSE score was later revised upward to 171 in late 2022. This increase was due to lower than originally expected reliability impacts (primarily due to the current enablement being more seasonally differentiated than was originally contemplated), and to actual EPSS costs coming in lower than originally expected.

These RSE figures are derived as the ratio of the NPV of the 2023-2026 risk reduction for each program divided by the 2023-2026 NPV of the costs for that program. While the EVM program cost was approximately $817 million in 2022, this mitigation only covered approximately 1,900 miles of distribution HFTD miles that year (approximately 7.5% of the 25,500 HFTD distribution miles) with an original, pre-analysis PG&E forecast 21% ignition reduction rate over those 1,900 miles. According to PG&E, the reason this projected ignition reduction rate is not higher is that even though EVM used vegetation clearances up to 12 feet (versus four feet for normal VM), high winds can still cause branches and trunks to come in contact with the lines from distances beyond the cleared area, noting not all types of vegetation contacts can be mitigated.

EPSS on the other hand covers the entire 25,500 miles of HFTD and was projected to reduce 68% of risk (versus the 2022 calculated reduction of 63%) from all types of ignition potential. This results in a forecast risk reduction benefit approximately seven times larger than for EVM, at approximately one-eighth the cost per year.

The ISM observed that in calculating the cost/benefit of the EPSS program (as with the PSPS program), PG&E incorporates the estimated negative impact upon its customers for

[15] General Rate Case (GRC).

experiencing these unscheduled and planned outages as a subtraction against the wildfire risk reduction benefit. These negative customer impacts are calculated using the Lawrence Berkely National Laboratory Interruption Cost Estimate Calculator (expressed in dollars per customer minute interrupted by customer type), multiplied by the number of PG&E customers by types (e.g., industrial, commercial, residential), and multiplied by the number of expected EPSS outage minutes per year over the 2023-2026 period.

The ISM observes that the large gap between the EVM and the EPSS cost/benefit ratios are such that even if:

- the EVM effectiveness is calculated higher (to incorporate the fact that each annual 1,800 to 2500-mile EVM section should continue to provide ongoing vegetation contact risk reduction benefits over many years if the extended clearances are maintained);
- the EVM effectiveness is calculated higher after correcting the outage to ignition conversion factor (which would bring the effectiveness over the 4,750 in-scope miles more in line with original effectiveness expectations); and
- the EPSS ignition reduction effectiveness dropped in future years (since 2022 had a lower-than-average percentage of R3+ days than the prior six-year average reflecting more calm average weather conditions),

EPSS would still be expected to remain more efficient at reducing equivalent wildfire risk.

Vegetation Management Programs

As documented in PG&E's 2023 WMP, PG&E's Vegetation Management (VM) distribution program is designed to ensure inspection of approximately 80,000 miles of overhead distribution electric facilities on a recurring cycle and includes different types of patrols designed to comply with various state and federal laws and regulations. As discussed in ISM Report 2, at the end of 2022 PG&E transitioned from the EVM Program to three new programs to manage vegetation risk. The programs consist of Vegetation Management for Operational Mitigations (VMOM), Tree Removal Inventory (TRI), and Focused Tree Inspections (FTI).

During the current ISM reporting period, the ISM interviewed PG&E VM leadership to gain additional insight regarding these areas as detailed below.

Vegetation Management for Operational Mitigation (VMOM)

No new material information regarding the three tranches described below was observed.

- Tranche 1 – Work in Progress on approximately 4,500 trees from the VMOM pilot program.
- Tranche 2 – A proactive patrol on nine circuits that have experienced higher customer outages (2022 EPSS outages that resulted in eight or more Customers Experiencing Multiple Interruptions).
- Tranche 3 – Reactive work after a vegetation caused EPSS outage, working five spans in either direction of the outage.

Tree Removal Inventory (TRI)

As reported in ISM Report 2, the TRI focuses on 1) an inventory of approximately 385,000 trees which were identified in 2022 and previously assessed using PG&E's Tree Assessment Tool (TAT) or during an EVM inspection prior to the use of the TAT; and 2) a targeted removal of the trees, including 15,000 trees in 2023 increasing incrementally in subsequent years.

PG&E indicated that through August 2023 a total of 33,000 trees have been mitigated, including 4,500 trees removed by VM crews and the additional 28,500 trees being mitigated through either 1) removal under other VM programs; 2) determination of no longer having strike potential; 3) relocation of the assets; or 4) the trees no longer existed.

Additionally, PG&E indicated 90,000 trees out of the 385,000 total that were generated under the EVM Program were identified as the highest priority trees using PG&E's Vegetation Asset Strategy and Analytics (VASA) Risk Model Version 3. PG&E also noted that approximately 57,000 of the 90,000 trees of highest priority were generated by TAT. Approximately 33,000 trees had an "abate" result within TAT. The balance of approximately 24,000 trees consists of those that need to be assessed by a Vegetation Management Inspector (VMI) due to a "do not abate" TAT result.

The balance of the trees that TAT determined "do not abate" will be assessed utilizing a Level 2 (360 degree) inspection. Inspection by ISA Certified Arborists/Tree Risk Assessment Qualification (TRAQ) credentialed personnel will be required if a tree is to be officially delisted from the backlog of trees within the program.

Focused Tree Inspections (FTI)

As reported in ISM Report 2, the FTI program prioritizes VM efforts to address miles based on areas of concern – specifically miles associated with increased vegetation related outages and/or including particular tree species. PG&E indicated that an Area of Concern (AOC) was designated for 270 miles of conductor. ISA Certified Arborists/TRAQ credentialed personnel performed Level 1 & 2 inspections in HFTD targeting specific species of trees. The results identified approximately 24 trees/mile that require mitigation.

Vegetation Point Status Clarification

During the current ISM reporting period, the ISM's field inspections identified multiple "hold/constrained" hazard trees that exceed time periods specified in PG&E's VM Distribution Inspection Procedure (VMDIP), including trees that have been classified as Priority 1[16] (P-1) or Priority 2[17] (P-2). Hazard trees identified as "hold/constrained" negate the required mitigation period documented in the VMDIP. Accordingly, there are instances where these hazard trees remained in the "hold/constrained" status for in excess of a year.

Per discussions with PG&E, this "hold/constrained" category of hazard trees relates to

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[16] Priority 1 tags must be mitigated within 24 hours of identification when reported.

[17] Priority 2 tags must be mitigated within 20 business days, unless constrained.

environmental "holds" and permitting "constraints" on state and federal lands. PG&E stated that state and federal agencies may require extended time periods for permitting processes and reviews addressing environmental and cultural issues as examples of holds. These agency lands typically do not have easement language specific to VM activities and, as such, require permits detailing the work that has been identified for mitigation. These permits may take between 3-6 months, and in some cases longer than a year, for approval to be granted.

During the reporting period, the ISM observed PG&E reports noting approximately 26,000 "Constrained[18]" OPEN VM tags and approximately 184,000 "Prescribed" OPEN VM tags. In related discussions, PG&E stated that per General Order (GO) 95 Rule 35, immediate hazards (P-1) are mitigated by pruning or removal under execution of the "emergency clause". A "Central Constraint Team" was created to expedite resolution of constrained customers/landowners VM conditions. Initiating the involvement of this team is currently voluntary.

Additionally, PG&E noted, "beginning in the 2024 inspection cycle, unless a constraint or external factor is documented, tree work shall be completed within one year of identification. Priority work is addressed according to the Vegetation Priority Tag Procedure…"

Implementation of One VM

One VM is a GIS application used to create and manage vegetation management projects, assign projects, monitor work progress & completion, and manage constraints by combining multiple vegetation management work platforms into one (thus the term, "One VM"). Eventually, PG&E leadership, VM Tech Power Users, PG&E Billing Clerks, and VM vendors will utilize One VM to manage all VM work activities.

PG&E indicated that the initial implementation of One VM occurred[19] on March 15, 2023, with the understanding that bringing all VM programs into this consolidated platform will require a multi-year transition period. PG&E indicated that, during the transition, the multiple platforms currently in use cause confusion for contractors (e.g., Vegetation Management Inspectors (VMIs) and Tree Crews (TCs)). PG&E indicated that, additionally, trees listed under the previously utilized EVM have been worked under different work streams which creates inconsistencies and difficulties in migrating the data to One VM and the corresponding tracking vegetation points.

Currently, the ISM has limited visibility into all of the various platforms, which limits the ability to view the information associated with specific vegetation points. The ISM will continue to monitor the various platforms including the implementation of One VM.

VM Process of Work Assignment to Vendors

With respect to PG&E's annual patrols, PG&E indicated that it does not prioritize work

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[18] Constrained: A situation that occurs when a customer, property owner, or agency obstructs or delays PG&E pre-inspection work or the completion of the intended tree work.

[19] While One VM has been implemented and is currently being used in the field, not all VM programs have been transferred into One VM. The One VM rollout is expected to take several years.

assignments in HFTD. PG&E patrols its entire system each year and VM maintenance activities are to be performed on a 12-month cycle regardless of HFTD or non-HFTD based on limited operating periods (e.g., related to customer farming or ranching activities), animal nesting seasons, and other known operational conditions (e.g., customer access requirements). PG&E stated that once the circuit has been issued to the VMI or the TC it is at the VMI's or TC's discretion as to how the circuit will be worked.

Secondary Conductor Clearances

During the current ISM reporting period, the ISM observed that PG&E's 2023 WMP states that "the VM routine program performs scheduled inspections on all overhead primary and secondary distribution facilities to maintain radial clearance between vegetation and conductors by identifying trees that will encroach within the MDR [Minimum Distance Requirement] in accordance with regulatory requirements and/or PG&E procedures. In addition, dead, dying, and declining trees that may fail and strike conductors are identified and mitigated." The ISM observed that secondary conductors are not addressed in detail in PG&E's Vegetation Management Distribution Inspection Procedure (VMDIP)[20] or Distribution Vegetation Management Program (DVMP)[21]. Additionally, the ISM observed that in PG&E's VMDIP or DVMP, triplex and open wire secondary[22] do not have a stated MDR and only references to "strain or abrasion".

PG&E's VM team indicated that VMIs are to treat and work conditions for contact/grow-throughs, hazard trees, and vines on secondary conductors the same as on primary conductor. However, PG&E's VM team indicated there are no MDRs for open wire secondary conductors; therefore, tree work is not considered necessary when contact/grow-through conditions are occurring unless "strain or abrasion" is present. The ISM identified trees contact/grow-throughs, above, and between open wire secondary during VM field inspections within "tree work completed line segments" for the primary conductor. The ISM also identified hazard trees with potential to strike, vines, contact/grow-throughs on non-insulated open wire secondary and strain/abrasion on triplex which have not been mitigated.

PG&E's VM team responded to the ISM's specific observation of "strain and abrasion" on a secondary conductor that involves three Incense cedars that were identified for removal in front of a residence. The trees ranged in size from 14", 18", & 22" Diameter at Breast Height (DBH) and all were over 80 feet in height. The ISM inquired as to whether alternatives to removal were considered by PG&E due to the size and condition of the trees, cost effectiveness of tree removal versus engineering options, and environmental stewardship. PG&E stated that no alternative options were considered as it involves "system hardening."

[20] PG&E Internal Document

[21] PG&E Internal Document.

[22] Triplex and open wire secondary are types of secondary conductors.

FEP VM Field Inspection Findings

ISM 2023 Targeted VM Field Inspections

During the current ISM reporting period, the ISM performed targeted VM field inspections based on the same data-driven approach described previously in the "ISM 2023 Targeted Distribution Asset Inspections" section of this report. Additionally, the scope for the inspections was refined to include the most recent thirty days of completed work by PG&E VMIs.

During the first phase of the inspection, the ISM sample-inspected circuit locations completed by PG&E's VMIs to verify compliance with all state statutes and PG&E internal procedures. Table 2 includes a summary of the ISM's observations identified on the primary, open wire secondary, and triplex conductors that were missed by PG&E's VMI.

Table 2: Phase 1 ISM Targeted VM Inspection Summary of Data Collection

Attribute	Inspection Area A	Inspection Area B	Total
Number of Observations (Radial Clearance, Hazard Tree)	15	1	16[23]
Number of Level-1 Tree Inspections[24]	202	189	391
Number of Spans Inspected	53	22	75

During the second phase of the inspection, the ISM inspected specific locations of tree work that were completed by PG&E's tree crew vendors on the execution of previously inspected work by the VMIs for compliance with state statutes and PG&E internal procedures. Table 3 includes a summary of the ISM's observations identified on primary, open wire secondary, and triplex conductors.

Table 3: Phase 2 ISM Targeted VM Inspection Summary of Data Collection

Attribute	Inspection Area C	Inspection Area D	Inspection Area E	Total
Number of Observations (Radial Clearance, Hazard Tree)	0	7	0	7[25]
Number of Level-1 Tree Inspections	430	437	108	975
Number of Verified/Assessed Completed Vegetation Points	38	44	9	91
Number of Spans Inspected	16	58	85	159

[23] Of the 16 Phase 1 Observations, 4 were missed hazard trees and 12 were radial clearance violations.

[24] Level-1 Tree Inspection is a one-sided inspection (i.e., walking past, flying over, etc.).

[25] Of the seven Phase 2 Observations, 4 were missed hazard trees and 3 were radial clearance violations.

Missed Trees

During the current ISM reporting period, the ISM's VM field inspections identified "missed trees" that were not in compliance with state statutes such as GO 95 Rule 35, PRC (Public Resource Code) 4293, and/or PG&E's revised internal procedures such as VMDIP and DVMP, as well as archived Distribution Vegetation Management Standard (DVMS)[26] and Distribution Routine Patrol Procedure (DRPP)[27] for vegetation management work practices.

The observations included hazard trees which had the potential to strike the primary conductor, radial clearances, major woody stems, strain, and abrasion on triplex, and contact/grow-throughs on bare open wire secondary conductor.

Several examples have been documented where the VMI/TC worked on trees adjacent to, intertwined with, or between trees that had been identified by the ISM. Specific ISM VM field inspections were performed after the VMI completed work (Phase 1) as well as after the TC completed work (Phase 2).

Additionally, FEP has ongoing VM field inspections as part of this contract, in addition to contracts with other parties, regardless of the work completion status performed by PG&E VMI and/or TC. During the current ISM reporting period, FEP VM consultants performed field inspections on almost 400 miles of PG&E's distribution infrastructure in HFTD, which has helped support the observations made during the targeted two-phased VM field inspections. Although specific numbers of assessments performed outside of the ISM scope are not available, the work performed has supported these observations which are consistent throughout the service territory.

Conflicting and Incorrect Data

During the current ISM reporting period, the ISM's VM field inspectors identified incorrect data associated with vegetation points in Work Verification for Defined Scope Map (WVDSM). These included tree attributes such as species, height, and diameter. Notes within the vegetation point have indicated discrepancies where the tree resides versus where the tree icon in WVDSM was plotted.

Additionally, conflicting data with specific comments identifying GPS locations for assigned work recorded with the vegetation point may not be closely aligned with the findings in the field and associated comments. Further, duplicate vegetation points have been identified in the Work for Verification Defined Scope Map (WVDMS)/Field Maps database for the same tree.

The ISM also observed trees that were pruned in the field were not consistent with reported vegetation points and specific attributes in WVDSM. During the ISM VM field inspections vegetation points were routinely observed as plotted incorrectly with respect to the true location of the trees as they exist in the field.

PG&E indicated that they are aware of these noted issues and are working to correct them through the implementation of One VM. While the current use of One VM will help moving

[26] PG&E Internal Document.

[27] PG&E Internal Document.

forward, PG&E indicated that the use of their various legacy databases will make it difficult to transpose the geographical data correctly.

Customer Relations

During the current ISM reporting period, the ISM's VM field inspectors were approached on multiple occasions by PG&E customers while performing field inspections. The ISM observed the following common themes from these interactions: 1) frustration regarding repeated and multiple PG&E VM representatives appearing on the property; 2) lack of notification prior to work being performed; and 3) references to property damage.

The ISM discussed these themes with PG&E management. Per PG&E, it has several projects underway (i.e., VM program changes, One VM, Integrated Grid Plan, etc.) that it expects will enhance coordination of certain VM activities, limit the number of VM visits to a customer's property, and increase communication to customers.

Clearance to Conductor

In discussions with PG&E's VM team, it was indicated that the targeted clearance to conductor is 12 feet. Per PG&E, this is based on the VMIs prescribed clearance for the tree. If the prescribed clearance is not achieved, the Work Verification Team will advise the contractor to return to the location to obtain the specified clearance.

During the ISM's targeted VM inspections referenced above, it was noted that minimal clearance had been achieved, with the majority of completed tree work averaging five to six feet of clearance to the primary conductor.

Wood Management

PG&E Best Management Practices (BMP) states, "Woody debris created by chipping, lop and scatter, or brush mowing operations must be left at an average depth of less than 18 inches from the ground surface unless otherwise specified in an easement or landowner agreement."

During the current ISM reporting period, compared to the previous year, the ISM's VM field inspectors observed an increase in out of compliance conditions regarding the extent of wood management – specifically an increase of large wood and slash remaining at sites in the field generated from recent tree work not consistent with the BMP. Figure 11 is representative of these observations.

Figure 11: Example of Improper Wood Management

In related discussions, PG&E indicated that they are actively continuing to honor previous agreements with landowners under the EVM program or those in "fire cleanup" areas. The ISM plans to monitor in the future if there is a change to wood management for routine work.

Integrated Vegetation Management/Best Management Practices

The ISM observed that PG&E's VM procedures include industry Integrated Vegetation Management (IVM) principles (including ISA Best Management Practices and ANSI A-300 Pruning Standards); however, the ISM observed these industry standards, such as proper pruning practices, are not consistently adhered to in the field. Accordingly, Figure 12 is an example of an improper pruning practice.

Figure 12: Example of Improper Pruning Practice[28]

[28] The tree pictured is a Conifer. The primary top of the tree, commonly referred to as the leader, has been topped/cutoff forcing a secondary branch (which would typically grow horizontally) to turn upward and become the new leader. The new leader is structurally weaker and therefore poses a higher risk of failure/breakage.

PG&E indicated that they are working to establish assessment yards which will require tree crew personnel tasked with performing tree work to be qualified to perform certain tasks (e.g., limbing and bucking, tree felling, chainsaw operations, etc.).

RISK MODEL UPDATING

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

No material changes in the ISM's observations in this area were identified during the current ISM reporting period. Members of the PG&E's risk modeling group informed the ISM that updated versions of the Wildfire Distribution Risk Model (WDRM) Version 4 and the Wildfire Transmission Risk Model (WTRM) Version 2 will be presented to the Wildfire Risk Governance Steering Committee toward the end of this ISM reporting period. The ISM expects to report on model updates and their impact on circuit risk rank changes in the next report.

GAS OPERATIONS OBSERVATIONS

During the current ISM reporting period, the ISM continued: 1) conducting interviews with PG&E leadership and personnel within gas storage operations; 2) attending periodic meetings held by P&E's gas operations group regarding various topic such as risk, risk modelling (steering committee meetings), self-report, TIMP leak tracking, and weekly operating reviews; 3) performing interviews on specific topics with selected PG&E personnel, including the Locate and Mark Program, leak management and grading, the Facility Integrity Management Program (FIMP), Benzene and BTEX (Benzene, Toluene, Ethylbenzene and Xylene) monitoring, and Picarro utilization; 4) performing reviews of PG&E gas operation's program, policy, and risk assessment documents; and 5) a detailed review of the CPUC and NTSB findings and recommendations regarding the San Bruno Incident.

During the reporting period the ISM visited PG&E's Gas Safety Academy and its Gas Command Center. A description of both facilities based on these visits is included below.

PG&E's Gas Safety Academy was constructed in 2016 and includes a gas training qualification and certification center for all PG&E gas transmission and distribution job skills, including construction, operation, and maintenance. The facility has several dedicated buildings to house specific training curriculum including valves, controls, and metering setup that operate with pressurized air to simulate natural gas pressures and near-actual flow characteristics. The campus also provides an area including multiple realistic residential structures for training distribution service operations, maintenance, and leak surveys. Several other 'hands on' labs are available to work directly on automated valves, motor control center (MCC) controls, Supervisory Control and Data Acquisition (SCADA), and multiple excavation equipment simulators. The ISM toured the facility and observed training in the classroom setting as well as hands-on training and practices.

The Gas Command Center is PG&E's main monitoring and control center for its transmission and distribution pipeline networks. The center is staffed 24 hours a day, seven days a week; PG&E employees monitor the pipeline network's operating conditions as well as control many of its transmission assets. The command center includes a standalone simulation tool that can simulate PG&E's pipeline network. The simulator can be used as a training tool where "what-if" scenarios can be administered to simulate issues or problems on PG&E's system, and operators can react in real-time to address the issue. The ISM toured the gas command center and viewed a demonstration of the simulation tool.

GAS STORAGE OPERATIONS

No new material changes were identified during the current ISM reporting period associated with PG&E's gas storage operations. Reporting on gas storage operations, including wellbore conversions, direct inspections of wellbore casing, and the status of California Geologic Energy Management Division official inspection results and PG&E's associated actions, will only continue should the ISM observe any material change in status.

PIPELINE INTEGRITY MANAGEMENT

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

PG&E TIMP Risk Model Update Initiative

During the current ISM reporting period, the ISM interviewed the PG&E TIMP Risk and Threat Team to understand both the initiative and process to update the PG&E TIMP risk model. The general goal of the initiative is to provide a more streamlined TIMP risk assessment process while providing flexibility to perform multiple 'what-if' risk scenarios to supplement the current annual TIMP risk assessment report and provide visualizations describing TIMP category risks. The new risk model is expected to adopt the Arc GIS Pro data model to support propagating data to PG&E dashboards and other technical visualizations.

PG&E indicated that it has been working with an energy industry recognized, U.S.-based risk modeling software vendor who develops and provides pipeline integrity management software and services to energy transportation companies. PG&E worked with the vendor to ensure specific risk modeling algorithm scripting functionality is available within the proposed latest risk model version to be adopted by PG&E's TIMP risk modeling team. PG&E stated that its risk model algorithms will not change with adoption of the new risk model, but the new risk model is expected to provide additional user input control and functionality for PG&E to perform incremental 'what-if' scenario risk analyses.

The current PG&E risk model input data preparation process utilizes an "annual data snapshot" approach which includes the process of TIMP Asset Knowledge Management (AKM) Team performing a quality control (QC) assessment of annual TIMP data across all PG&E TIMP asset classes during the calendar first quarter (Q1). The top three PG&E gas operations assigned performance-based risk categories are 1) loss of containment on gas transmission pipelines; 2) loss of containment on gas distribution main or service; and 3) large over pressure event downstream of gas measurement and control facility. PG&E identified specific gas operation risk drivers within each of these three risk categories to apply preventative practices to avoid approximately 94% of identified overall gas operation risks. PG&E assigned and actively manages gas risk critical datasets for each gas operation risk driver category. The ISM will continue to monitor PG&E performance-based risk categories and their risk critical datasets.

PG&E's first calendar quarter (Q1) TIMP asset class data also aggregates supplemental TIMP risk data generated by PG&E's threat steering committees, including feedback from PG&E TIMP subject matter experts. This TIMP annual data QC assessment also supports preparation of PG&E's annual report submittal to the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA).

During the second calendar quarter (Q2) the AKM Team makes QC adjustments to the aggregated Q1 TIMP data. Near the end of Q2 the TIMP Risk Team takes a data snapshot of the post-QC adjusted data to provide input supporting the existing TIMP risk model.

This same Q1 and Q2 data aggregation and QC process also supports testing and validation of the new PG&E risk model. PG&E expects risk model support by annual data snapshots to continue for several years until gas data asset upgrades described below are implemented to provide continual QC assessment and 'live' gas asset risk data access to the new risk model.

PG&E plans to run 'parallel' risk model analyses with the current and new TIMP risk models to certify the new model is properly calculating existing PG&E risk algorithms through the 2023 and 2024 risk model analysis cycles. In 2023, PG&E's TIMP Risk personnel will fully implement the new risk software tool, which will integrate PG&E's current risk model algorithms. PG&E expects to rely on the new TIMP risk model for 2024 risk analysis results.

The ISM intends to continue monitoring PG&E's progress toward transition to the new TIMP risk model. Reporting on progress will only continue should the ISM observe any material changes in status.

PG&E GAS ASSET DATA MANAGEMENT PLAN INITIATIVE

Per review of PG&E guideline documents, PG&E created the Gas Data Asset Family in 2017 to recognize gas data assets on an equivalent level of importance to physical gas assets, providing focus on the structure and implementation of gas data management, governance, data evaluation processes, and relative assignment of risk. PG&E created a gas data asset management plan to formalize management of critical data as an asset with tangible value.

PG&E defines business-critical data as that which is vital to successful gas organization operation and is aligned with PG&E's critical or mission-critical processes. The gas data asset management guidelines describe "the greatest threat to gas operations is the lack of access to usable trusted data". PG&E describes data access as:

- "… the user's ability to find the existing gas data when needed. With the loss of any degree of certainty in the quality of the data being used, informed decision making is jeopardized and related business processes and safe operations are put at risk."

PG&E documents gas organization threats within PG&E's established data sources including:

- "… the Corrective Action Program (CAP), Process Hazard Analyses (PHAs), Pre-Startup Safety Reviews (PSSRs), various on-going maintenance, assessment programs, and industry events. Each gas asset family owner works with his/her team and other subject matter experts to determine the relative risk, including impact and frequency levels, associated with each threat."

PG&E performed its first critical data asset audit beginning in 2019 and completed it in 2020 in order to understand organizational and physical location of critical data and to evaluate the perceived quality of these gas data assets.

PG&E indicated that its risk models identify gas data assets relative to high-likelihood and high-consequence risk. The hypothetical data-based risk event included in Figure 13 demonstrates how hypothetical risk drivers on the left may influence an associated hypothetical gas operations data risk event on the right.

Inadequate / ineffective data input Inadequate / ineffective data maintenance Lack of data ownership / stewardship Lack of clearly defined source of record Lack of consensus regarding data quality	➡	Inadequate data management resulting in an operational incident and/or adverse business result, including any potential negative impacts occurring after the event itself

Figure 13: Hypothetical Data-based Risk Event

PG&E's hypothetical data-based risk event (i.e., Figure 13) demonstrates how inadequate data collection, storage, or accessibility (e.g., risk drivers) increases the likelihood of risk by reducing the available trusted data within the decision-making process (e.g., risk event). Accordingly, PG&E data quality improvement initiatives, some of which are described below, represent a risk mitigation strategy.

PG&E's current data quality metrics evaluations rely on several detailed internal manual data evaluation processes. PG&E has an initiative to automate these data evaluations to make them available on-demand and scalable. Per PG&E, a key component of work is the implementation of the ontology-powered multi-modal data modeling and retrieval system, Palantir Foundry (Foundry). Initial efforts began in 2022 to load data from Gas GIS and SAP system repositories into Foundry and to align and synchronize gas data across physical gas assets and these internal PG&E data repositories. PG&E believes this scalable automated methodology will provide continual refinement through input from its subject matter experts, asset family owners, data experts, and their leadership.

In late 2021, PG&E hired its first designated enterprise level Chief Data and Analytics officer "…to ensure the health and usefulness of PG&E's data assets, through trustworthy and accessible data, [and] enable effective and informed decisions that advance the mission of PG&E".

PG&E acknowledges several data improvement initiatives either currently in progress or recently completed to reduce data quality risk. With respect to the gas operations, these initiatives include but are not limited to collection and digitization of records into centralized repositories, collection of data from records and the field into centralized systems of record, updating of systems of record (GT-GIS, GD-GIS, SAP, Documentum, ARMS), and targeted projects to address data unknowns including inspection data, metallurgical data, and establishing an opportunistic data collection process.

The ISM intends to continue monitoring this data management initiative. Reporting of activities will only continue should the ISM observe any material changes in status.

TEE CAP REPLACEMENT PROGRAM

On October 8th, 2022, there was an explosion at 2793 River Plaza Dr., a residential area in Sacramento, California, with no injuries or fatalities reported. PG&E hired Exponent to study the incident. During the current ISM reporting period, Exponent issued its Root Cause Evaluation (RCE) and final report. The final report describes Exponent's evaluation of the incident including an examination of the site, evaluation of gas migration, records review, and emergency response to the incident. The RCE provides findings on the cause of the incident and corrective actions to be taken by PG&E.

The RCE identified a direct cause, a root cause, and a contributing cause, each addressed in corrective actions identified in the evaluation. The direct cause was found to be: "Defective or failed material", "cracked tee cap that led to gas leak." The tee cap was manufactured by Plexco using Celcon polyacetal material. This type and vintage of tee cap had been addressed in a PHMSA Advisory Bulletin in 2007 as known to be susceptible to cracking. These tee caps are known to become brittle and crack over time, with overtightening during installation being an exacerbating factor. Because this was a known issue, PG&E has a proactive tee cap replacement program in place to address this issue. PG&E has replaced an average of 1,000 such tee caps each year since the program began in 2013.

The RCE identified the root cause to be: "Corrective action for previously identified problem or event was not adequate to prevent reoccurrence", "threshold for proactive mitigation was not low enough to include this job in the existing proactive program based on the historic performance of the system". This indicates that even though PG&E has a proactive tee cap replacement program in place, the particular tee cap that failed had not yet been flagged for replacement. The failure of the tee cap replacement program to identify this particular tee cap is addressed in the RCE corrective actions discussed below.

Contributing causes were found to be: "Previous success in use of rule reinforced continued use of rule", and "Loss of coupon increased the amount of gas flow through cracked cap." Plastic Tapping Tees with tee caps are added to gas distribution pipelines for many reasons such as to provide service to a new customer that is not yet connected to the existing main distribution pipeline. A Tapping Tee with cap is added to the distribution system by cutting a hole in the existing plastic pipe. The tapping tee cap is a single self-contained part, so the cutting mechanism is inside the tee cap. The tee cap is designed so that when the hole is made in the existing plastic pipe the coupon, or the piece of pipe that was cut out, stays inside the cutting mechanism. The coupon limits the amount of gas that can pass through the cutting mechanism and into the tee cap.

The RCE found that the cutting mechanism did not retain the coupon as designed, therefore when the leak occurred, the leak allowed significantly more gas to flow through the tee cap. The RCE further indicated that a cutting mechanism with an intact coupon can be expected to flow less than 10 cubic feet per hour of gas, however if the coupon is missing the flow could be hundreds of cubic feet per hour of gas.

The RCE provided corrective actions, for which PG&E indicated that a Corrective Action Plan (CAP) has been created. The first corrective action was that the twenty-four tee caps associated with the original installation would be replaced and provided to Exponent for analysis, which PG&E indicates was performed directly after the incident.

The next RCE corrective action was to "Evaluate pacing and scope of current tee cap replacement program & determine if changes are required. Update DIMP Risk model and tee cap prioritization", which PG&E assigned a due date of December 15, 2023. Per review of PG&E's documentation and discussion with PG&E management, PG&E's tee cap replacement program determines which tee caps to replace each year based on a risked-based assessment in which those tee caps with the highest risk of failure are prioritized for replacement. The analysis includes factors such as failure history, gas service volume, and location-based consequences of failure.

The leaking tee cap that led to the incident was located underneath a paved parking lot. The RCE identified opportunities to improve the risk model calculations, including the addition of a "wall to wall pavement" risk factor that could increase the risk priority for replacement of jobs with similar pavement risks. The RCE determined that the "wall-to-wall" pavement over the tee cap may have been a factor both in the migration of the gas, and the fact that the leak was not detected via smell. Under this CAP, PG&E will evaluate making these additions to their risk-based analysis and updating their DIMP Risk model appropriately.

The next RCE corrective action was to "Incorporate a factor into the risk model indicating likelihood of a dropped coupon", which PG&E also assigned a due date of December 15, 2023. There are factors, mostly related to installation, which can increase the likelihood of a coupon not being properly retained in the cutting mechanism, or a "dropped coupon". When the tee is installed, it is fused to the plastic pipe, and there is a cooling period required before the pipe is tapped, which creates the coupon. If the pipe is tapped while still hot, the coupon could contract in size when it cools, which would increase the likelihood of it "dropping". The RCE identified other environmental conditions, that if they were present during construction, could lengthen the time required for the parts to cool down. These include warm ambient temperatures and/or lack of air flow in the vicinity of the fused components. Under this CAP, it is these and other factors that PG&E will evaluate for potential incorporation into their risk model calculations.

The final corrective action was related to an additional finding of the RCE, "a review to increase the likelihood of detecting gas inside residences is required". PG&E indicated that this CAP would include an evaluation of the potential to install methane detectors in residences. A due date for this CAP is not identified in the RCE.

The ISM will continue to monitor PG&E's progress under these CAPs.

LEAK MANAGEMENT – GRADE 1 LEAKS

Due to their large customer base, PG&E responds to a high volume of leak investigations each year. Leaks are generally given a grade of 1, 2, or 3 with Grade 1 being the highest priority. For Grade 1 leaks, before PG&E responders leave the scene, PG&E requires immediate repair, or continuous action until the conditions are no longer hazardous.

During the current ISM reporting period, the ISM reviewed the length of time Grade 1 leaks remain open. The ISM observed instances where PG&E had Grade 1 leaks open past the due date by an average of 13 days[29]. The ISM presented these observations to PG&E, and upon investigation, PG&E noted that the actual leak can be mitigated or repaired long before the leak shows complete in the process. PG&E's leak process duration is considered to start at the dispatching of the leak and end with the posting of the final as-built information into the geographic information system (GIS). The multi-step process involves capturing data by several sources, handoffs to multiple departments, and "kickbacks" (when necessary) that return the open leak to the previous step for missing data.

As a result of the multiple steps and process completion time for Grade 1 leaks, PG&E may have leaks open longer in the system than the actual leak repair completion time and date. PG&E indicated that in order to ensure all open Grade 1 leaks are mitigated or repaired as required regardless of an open/closed system status, the PG&E dispatching department monitors an Event Management Tool or "EM Tool" number for each Grade 1 leak. The dispatching department along with operations personnel monitor the leaks for a "Yes" or "No" EM Tool status. A "Yes" EM Tool status indicates the responders completed repairs or otherwise mitigated the leak. A "No" EM Tool status indicates the leak has not been mitigated or repaired by first responders. If "No" EM Tool status remains two hours after dispatch, the leak is checked at follow-up intervals until the leak has a "Yes" EM Tool status.

A list of "No" EM Tool number leaks is sent each evening along with the time and date originated. Though not often, Grade 1 leaks can take multiple days to mitigate or repair. Dispatching and operations personnel monitor the EM Tool status.

The ISM intends to continue monitoring the status of Grade 1 open leaks. Reporting of changes will only continue should the ISM observe any material changes and/or trends.

BTEX MEASURING AND MONITORING PLAN

On January 23, 2023, the CPUC's Safety and Enforcement Division (SED), Gas Safety and Reliability Branch (GSRB) issued a Directive (Directive) as a result of an October 24, 2022, press release issued by California State Senator Henry Stern. The Directive referenced a study published in the journal Environmental Science & Technology regarding benzene levels in natural gas, which indicated that the gas piped into California homes for heating and cooking contained elevated levels of benzene and other hazardous pollutants. The study suggested that leaks from kitchen stoves create elevated levels of benzene in the home. The Directive required PG&E to provide a plan to develop and implement a procedure to measure and monitor Benzene, Toluene, Ethylbenzene and Xylene (BTEX) in its natural gas pipeline system.

PG&E responded to the Directive on February 2, 2023, providing its plan to implement measuring and monitoring procedures for BTEX (BTEX Plan). The BTEX Plan included a program development timeline outlining the timing of critical tasks in developing and implementing its procedure. These tasks include 1) developing baseline BTEX concentrations

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[29] Average days open is from Grade 1 Open Leaks detail report - 8/23/2023.

in PG&E's system; 2) evaluating sampling methods and frequency; 3) determining sampling locations; 4) developing a database to retain sampling records; 5) evaluating resources required to execute sampling plan; 6) developing recordkeeping process and practices; 7) establishing BTEX thresholds; 8) submitting a sampling plan for SED's review; 9) training personnel on sampling operations; and 10) implementing a sampling program.

The ISM interviewed PG&E leadership and discussed its progress on the BTEX plan. PG&E indicated that sampling would take place where gas enters the pipeline system, which includes border receipts, storage facilities, local producers, and transmission pipeline interconnections. PG&E identified approximately 65 test locations on their system and plans to begin sampling at or around these points to establish a baseline for BTEX concentrations, with samples taken at a minimum during high flow conditions and low flow conditions.

PG&E's response indicated that its BTEX Plan will be reviewed by the California Office of Environmental Health Hazard Assessment (OEHHA) and California Air Resources Board (CARB) to obtain guidance on the appropriate thresholds for BTEX in natural gas pipelines, as there are currently no such regulations. PG&E's Gas Rule 29 covers renewable natural gas receipt points, and it does contain allowable thresholds established for Ethylbenzene but is silent on Benzene, Toluene, and Xylene. PG&E indicated that it plans to evaluate whether leveraging these existing Toluene and Ethylbenzene limits is appropriate for its BTEX Plan. PG&E is awaiting guidance from OEHHA and CARB but does not have a timeframe regarding when a response might be received and whether said response will provide specific guidelines/thresholds.

PG&E's BTEX Plan includes evaluating various sampling methods for BTEX and developing processes for the collection, transportation and chain of custody and testing operations for laboratories to process and analyze the samples. This includes executing contracts with couriers and multiple laboratories to minimize bottlenecks in analysis of the samples. PG&E indicated that the capacity of these laboratories is limited and may be further constrained as it and other California operators are required to contract with them for BTEX analysis, which could create a potential bottleneck and potentially impact the attainable sampling frequency.

The ISM intends to continue monitoring both the development and implementation of PG&E's BTEX measurement and monitoring plan. Reporting of activities will only continue should the ISM observe any material changes in status.

LEAK SURVEY – PICARRO UTILIZATION AND EFFECTIVENESS

For the leak survey task, PG&E uses Picarro Advanced Mobile Leak Detection (AMLD) leak survey units in addition to traditional leak survey methods. PG&E has 10 vehicles equipped with Picarro units. PG&E is considering the use of Picarro AMLD units only for emission surveys while continuing to use traditional leak survey methods for the entire distribution system.

PG&E indicated that there is a range of the total PG&E system that can be leak-surveyed using the AMLD process. The range changes from year to year based on variable factors such as wind speed and direction at the time of the survey. PG&E estimates that the system range that can be surveyed by the AMLD process is generally considered to be 75% to 85% for any given year.

PG&E is targeting utilization of AMLD for system leak surveys within this range each year.

Beginning in 2018, PG&E implemented a Super Emitter Program that accelerates the detection and repair of leaks measured at 10 standard cubic feet per hour (SCFH) or greater. At the start of 2023, PG&E lowered the super emitter threshold to seven SCFH and are using the AMLD units for this process at a higher rate. It is unknown at this time how much this process change will lower the total system leak survey by AMLD percentage for 2023.

AMLD is used in all PG&E service divisions and the threshold for a Leak Identification Search Area (LISA) is 35 parts per billion (ppb) when utilizing the "entire system" survey mode. Another use of AMLD is assisting when called for difficult to pinpoint leak complaints. AMLD is also used after significant geohazard events such as earthquakes and landslides.

The ISM intends to continue monitoring PG&E's AMLD transition and the associated trends. Reporting of activities will only continue should the ISM observe any material changes in status and/or trends.

OPERATOR QUALIFICATION – PIGGING

In April 2022, PG&E experienced a serious injury fatality (SIF) known as the Calistoga incident. Two PG&E employees were injured, one ultimately a fatality. The incident occurred during a dewatering task after a hydrotest had been performed on a 6" transmission line. The incident involved multiple foam and poly pig runs, one of which became stuck. The incident occurred during a reverse flow attempt to get the pig unstuck.

As a result of the Calistoga incident, PG&E made several changes to address safety during In-Line-Inspection (ILI) and pigging activities. An immediate change was stopping all out-of-service pipeline pigging and ILI tasks by PG&E employees, and instead using select contract companies to accomplish these tasks. The ISM is monitoring the Operator Qualification (OQ) changes to company and contract workers that have been developed since the incident.

Since the incident, PG&E established three OQ tasks involving launching and receiving tasks for ILI and pigging. The contractors are required to qualify under one of the three OQ tasks and are limited to using a 1:1 span of control ratio[30] when performing the task.

As for PG&E employees, training and testing for OQ certification is under development with roll-out planned for Q3 2024. This OQ certification will cover out-of-service pipelines.

PG&E, as defined by 49 CFR 192 subpart N, is required to have an Operator Qualification program. PG&E has approximately 144 OQ tasks; including three Launching and Receiving ILI tracks (code numbers 1631, 1641, and 5921). As discussed previously, these three tracks are for contractors only and PG&E is currently developing the OQ training and code numbers for PG&E employees.

OQ certification for these three tracks include training material, a written test, and a performance test. Each applicant has three "tries" to attain certification. A passing score for the

[30] A 1:1 ratio means there must be at least one qualified individual for every one unqualified individual on the job site.

written test is 80% and is allowed to be taken “open book”. The applicant can fail the written test once and immediately retake and pass, then move on to the performance test. The performance test requires a score of 100%. Failure to achieve this score requires the applicant to return to a new certification “try” that allows the three attempts. Before the applicant returns to a new test attempt, they are asked to remediate (retrain) prior to the next “try”. A passing grade in written and performance attains certification for the applicant covering a three-year term before recertification is required.

EMERGING OBSERVATIONS

In addition to the areas covered in this current ISM report, the ISM will continue to perform activities consistent with the ISM Contract (e.g., tracking, inspections, validations, analyzing, etc.) to monitor developments in other areas including but not limited to Integrated Grid Plan, Wildfire Distribution Risk Model (WDRM) Version 4, Wildfire Transmission Risk Model (WTRM) Version 2, Gas Distribution Integrity Management, Gas Leak Management, Gas Construction Quality Assurance/Quality Control, Gas Operator Qualification, and Gas Corrosion Quality Control.