UNITED STATES DISTRICT COURT

NORTHERN DISTRICT OF CALIFORNIA

UNITED STATES OF AMERICA,

Plaintiff,

v.

PACIFIC GAS AND ELECTRIC COMPANY,

Defendant.

No. CR 14-00175 WHA

REQUEST FOR CRITIQUES

United States District Court
Northern District of California

The Court thanks the Monitor and PG&E for their recent reports and responses. These have important information for the public and the regulators. To assist in clarifying that information, by **DECEMBER 16 AT NOON**, the Monitor and PG&E are requested to critique each other's report/response as follows. The Monitor's report, submitted November 19, 2021, is appended hereto. Please read the other's report/response and identify those passages or portions thereof, if any, that you believe are misleading, inaccurate, incomplete, or in need of clarification and/or important to the public's understanding of the issues involved. Please reproduce those passages or portions to be critiqued along with your response.

PG&E should, for example, state whether it's true, as stated by the Monitor at page 45, that "multiple" times between 2019 and 2021, PG&E failed to alert all account holders in advance of impending PSPS events. For another example, PG&E should state whether it's true that "without counting projects built to the fire rebuild standard toward its annual system

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hardening goal . . . PG&E would not have satisfied its annual system hardening WMP target for 2019 or 2020" (pages 43–44). Additionally, PG&E should clarify what it meant by the phrase "stood up" at page 24. (Possibly, it was an editing error.)

Please limit these critiques to 20 pages plus 10 pages of exhibits. The United States is invited to file its own critique of both reports/responses (up to the same page limits as to each) by the same date. Also, it would be useful for PG&E and the Monitor to file a separate agreed-on glossary of terms explaining in a single sentence terms like "DIRT," etc. PG&E shall file its critique as a public document. The Monitor's shall be filed publicly as well.

IT IS SO ORDERED.

Dated: November 23, 2021.

WILLIAM ALSUP
UNITED STATES DISTRICT JUDGE

KIRKLAND & ELLIS LLP

PG&E Independent Monitor Report of November 19, 2021

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I. INTRODUCTION

A. Factual Background

On September 9, 2010 PG&E's 30-inch gas transmission line in San Bruno ruptured, exploded, and burned uncontrollably for hours while PG&E employees attempted to shut off the gas. The explosion destroyed the Crestmoor neighborhood in San Bruno and killed eight people: Lavonne Bullis, 82; Greg Bullis, 50; William Bullis, 17; James Franco, 58; Jacqueline Greig, 44; Janessa Greig, 13; Jessica Morales, 20; and Elizabeth Torres, 81.

Six years later, PG&E was found guilty by a federal jury after a multi-week trial of six felony violations. These included various felony violations related to Gas Operations recordkeeping and another felony violation for obstruction of justice concerning a National Transportation Safety Board investigation of gas pipeline testing. The guilty verdict resulted in the imposition of a federal monitor and the creation of this Monitorship in 2017. The initial foci of the Monitorship, as set forth in a January 26, 2017 judgment and Court order (Dkt. 916), were: (1) 15 technical requirements related to PG&E's Gas Operations; (2) PG&E's Compliance and Ethics program; and (3) PG&E's efforts to become a safer utility. Those areas are discussed below at Sections III-V.

The Monitorship proceeded along those lines from 2017 to 2018. In late 2018 and early 2019, the Court expanded the scope of the Monitorship to include an assessment of PG&E's wildfire mitigation efforts following the 22 deaths and destruction caused by PG&E in the 2017 Northern California wildfires (including the Wine Country Fires and the North Country Fires), as well as the Camp Fire of 2018, in which 84 people were killed and the city of Paradise in Butte County was destroyed. Including the Camp Fire fatalities, over 110 people have died as a result of wildfires where CAL FIRE has determined PG&E equipment was involved since the San Bruno incident.[1]

[1] During the course of the Monitorship, the Monitor team did not investigate or make any determinations about the cause and origin of fires. Those issues were the province of many other authorities, including regulators and law enforcement agencies which took possession of certain evidence and sometimes initiated prosecutions, and numerous

Appended as Exhibit 1 is a list of the victims of those wildfires.

The Court's oversight of PG&E's wildfire mitigation efforts substantially augmented the scope of the January 2017 order. Since that time, the Monitor team's evaluation of PG&E's wildfire mitigation efforts has focused on four core areas: (1) vegetation management ("VM"); (2) infrastructure inspections and repairs; (3) system hardening; and (4) emergency preparedness and response. Those areas are discussed in Sections VII-X below.

PG&E wildfire mitigation efforts the past few years have been insufficient to stop wildfires caused by PG&E equipment. Each year since 2017, PG&E equipment has been associated with at least one catastrophic wildfire. That is obviously unacceptable, and PG&E must improve and fix this situation.

B. Overarching Themes

As explained below, PG&E has demonstrated progress within the scope of the Monitorship, and sometimes substantial progress. Regarding Gas Operations, PG&E's reform and improvement work, some of which began after San Bruno and before the Monitorship started, has been sustained and substantial. There has also been sustained and substantial improvement in the Compliance and Ethics area, although the Company needs to continue to try to overcome worker skepticism, particularly among longer-tenured employees, that the Company does not want to hear bad news and will retaliate for it, and that PG&E admonitions to "Speak Up" are not sincere.

Progress regarding wildfire mitigation obviously has been inadequate, and we doubt anyone would seriously dispute that, given the ongoing and profound safety issues in that area of operations.

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civil litigants and their attorneys with their own due process rights to present their own claims. The numbers here of deaths caused by PG&E come from data such as PG&E's 84 guilty pleas in June 2020 to involuntary manslaughter in connection with the Camp Fire and deaths, as well as CAL FIRE determinations on cause and origin of fires.

Nothing in this report purports to assert a factual finding or evidence concerning any pending or future litigation. These observations are intended to be candid comments based on our work as a Monitor team, but we did not conduct that work in a manner structured by state or federal adjudicatory rules or process.

As we have documented in prior Court filings, PG&E's initial steps in the wake of recent catastrophic fires were not planned and executed well. However, some of the key leaders who drove improvements in Gas Operations are now working on wildfire efforts, and hopefully they can drive similar positive change going forward.

We relate progress and issues in the various operational areas below. We also will discuss the six most salient challenges PG&E faces going forward, which are:

1. Retaining a core leadership team, in the wake of near constant turnover in recent years. During the four-and-a-half year Monitorship period alone, the Company has had five CEOs, six heads of Gas Operations, four heads of Electric Operations, and five heads of the Safety organization. Multiple other senior officers have otherwise turned over. PG&E also has had no less than 45 different board members during that time.

2. Continuing to improve records integrity, which has been an issue for PG&E for many years and remains a central challenge.

3. Continuing to improve contractor management, because contractors are a critical workforce base, including on the wildfire mitigation front.

4. Adhering to commitments to invest in long-term safety projects, including undergrounding efforts for electrical distribution lines and the repair and replacement of at-risk electrical equipment, and sustaining completion dates and not letting them slide.

5. Improving planning and execution of wildfire mitigation efforts.

6. Ensuring the employment of resources to improve wildfire safety does not result in cannibalization of gas safety teams and results that have been achieved during recent years.

II. SAFETY OBSERVATIONS

Safety observations are presented in roughly chronological order by subject matter. That is, the topics that were the subject of the original Monitorship are presented first. Newer subjects that were added by the Court in the aftermath of the Camp Fire and thereafter are presented second. Then observations of ongoing challenges are discussed.

Before proceeding, we wish to acknowledge the assistance and cooperation of several relevant parties during the period of the Monitorship. These include present and former government officials in San Bruno; family members of those killed in the San Bruno tragedy; federal law enforcement officials, including agents, task force officers, and federal prosecutors; PG&E's United States Probation Officer; local officials in Paradise; and leaders and employees at PG&E, as well as its outside counsel on the Monitorship, Jenner & Block. The issues that arose under this Monitorship were and remain profound. There were many serious and extended discussions about progress or the lack thereof. During that entire period of time, we were met with professional and honest input from all of the persons listed above. We also wish to thank the external experts who assisted the Monitor team. They are some of the best safety experts in their respective fields, and we are grateful for their contributions.

III. GAS OPERATIONS

A. Introduction

This Monitorship was the result of PG&E's 2016 jury conviction in the U.S. District Court for the Northern District of California. That prosecution took place in the wake of the San Bruno gas explosion, which killed eight people, injured 58 more, and destroyed many peoples' homes. As a result, the original scope of the Monitorship naturally centered on PG&E's Gas Operations and ethics and integrity functions. Wildfire issues were not part of that scope.

After the Monitorship was established, we met with family members of some of the victims of the San Bruno explosion. The overwhelming message from them was they hoped the San Bruno tragedy would spur meaningful reform and change in PG&E's Gas Operations, so that no one would again suffer the losses that their loved ones and they had experienced.

The tragic deaths of the San Bruno victims and the federal prosecution have led to substantial progress in PG&E's Gas Operations since 2010. Since that time, there have been no customer fatalities or injuries caused by gas pipeline explosions, and as explained below, the Compliance and Ethics functions at the Company have improved. Measured within the confines of the original

Monitorship, the reforms and improvements in Gas Operations and ethics have been real and significant.

B. The 15 Technical Requirements

A substantial focus of the Monitorship as framed in the wake of the 2016 federal trial concerned 15 technical requirements designed to promote safer Gas Operations. PG&E has successfully completed several of these requirements, including some long ago. The other requirements are not of the nature that they are ever "completed," but rather focus on certain important safety practices that always admit of continuous improvement. As to these requirements, PG&E also has made substantial progress and is positioned to make more with sustained focus and effort. The challenge will be to maintain that focus, commitment of resources and talent, and continuous improvement once federal probation ends.

C. Progress Across the 15 Technical Requirements

Each of the 15 technical requirements is discussed here. The full list of technical requirements as set forth in the judgment is provided in Exhibit 2.

Requirement One focuses on PG&E's self-reporting system in Gas Operations. California Public Utilities Commission ("CPUC") regulations require PG&E to evaluate and self-report potential violations that it identifies. The Monitor team believes that PG&E's self-reporting system satisfies Requirement One. The self-report program includes appropriate information for evaluations, including submissions to the Corrective Action Program, employee notifications, internal and external audits, and submissions to PG&E's ethics hotline. The self-report team evaluates between six and twelve potential self-reports each week, and the evaluations are typically thorough and complete. Participants in self-report meetings include engineers, regulatory personnel, internal legal counsel, and other relevant stakeholders. Subject matter experts are engaged and consulted as necessary for technical issues. The self-report team's recommendations regarding self-report letters, other notification to the Safety Enforcement Division, or "no notification" determinations are accepted by Gas Operations and not overturned or second-guessed. Regulatory Compliance personnel handle disposition of regulatory safety citations effectively and with appropriate priority and urgency.

Requirement Two is focused on PG&E's traceable, verifiable, and complete ("TVC") records supporting the Maximum Allowable Operating Pressure ("MAOP") of its transmission pipeline. PG&E initiated work in this area in advance of the start of the Monitorship, implementing multiple quality control and assurance steps. The Monitor team believes PG&E's efforts have been reasonable and consistent with the goal of identifying TVC records for MAOP validation. The NTSB also found PG&E's efforts to identify TVC records satisfactory and, on March 14, 2013, it issued a "Closed—Acceptable Action" letter for Urgent Action P-10-03.

Requirement Three sets forth a goal of strength testing at least 500 miles of gas transmission pipeline in 2017 and 2018. Requirement Three was closed out in early 2019 after the Monitor team confirmed that PG&E properly strength tested 540 miles of its transmission pipeline: 253 miles in 2017 and 287 miles in 2018. The Monitor team attended several of the strength tests and reviewed the results to confirm the accuracy of PG&E's mileage calculations. The Monitor team and our experts are also satisfied that PG&E properly utilizes strength testing as an ongoing integrity management tool for its transmission pipeline.

Requirement Four required upgrading and/or retrofitting 300 miles of gas transmission pipeline to accommodate in-line inspection tools in 2017 and 2018. As with Requirement Three, this requirement was closed out in early 2019 after the Monitor team confirmed that PG&E upgraded 397 miles of transmission pipeline: 154 miles in 2017 and 243 miles in 2018. The Monitor team and our experts inspected several upgrade projects in 2017 and 2018, evaluated project as-builts, and met with PG&E specialists to confirm scope of work completed.

Requirement Five focuses on data gaps in PG&E's transmission pipeline records and requires PG&E to make conservative, supportable assumptions when TVC data are not available. Prior to the Monitorship, PG&E had developed and implemented initial policies to address this requirement, including issuing the Procedure for Resolution of Unknown Pipeline Features ("PRUPF"). PRUPF is PG&E's guidance document concerning the use of conservative, supportable assumptions and includes mandatory assumptions for unknown specifications based on subject matter expert judgments and industry data. PG&E reviews PRUPF on an annual basis to determine if revisions are needed. The Monitor team believes PRUPF sets forth a conservative approach for missing data and that PG&E has satisfied Requirement Five.

Requirement Six requires PG&E to collect and incorporate leak data in one database for use in gas pipeline integrity management. PG&E has made progress to satisfy this requirement and adequately incorporates transmission pipe leak data into its database of record. PG&E currently holds monthly leak review meetings where members of the Transmission Integrity Management Program ("TIMP") group meet to evaluate transmission line leaks. While progress has been made, at its core, this is a records issue that needs continual effort and work. PG&E should enhance this process to reduce the need for a manual evaluation by improving its digital records and automating the incorporation of transmission leaks directly into its database of record.

Requirement Seven focuses on PG&E's efforts to ensure that it is collecting adequate and quality data as inputs for its Gas Transmission Integrity Management Program. Over the course of the Monitorship, the Monitor team evaluated PG&E's data gathering, collection, and review processes across relevant gas data sources for its Integrity Management Program. At this time, the Monitor team believes that those efforts substantially meet the requirements of 49 C.F.R. Part 192.917(b) and ASME B31.8S. The Monitor team concluded that PG&E properly identifies the individual data elements required for its threat and risk modeling work, and PG&E has conducted gap analyses to inform its remediation of observed deficits in its data gathering requirements. PG&E's Gas Operations models appropriately identify the necessary data and the organization is focused on improving the data inputs for those elements. This is a "continuous improvement" area, and it merits sustained focus because of its impact on gas pipeline safety.

Requirement Eight required PG&E to develop and update an Integrity Management Program that is "effectively assessing and evaluating the integrity of each covered segment" of gas transmission pipeline. The Monitor team believes that PG&E has an appropriate Integrity Management transmission risk model for Gas Operations which satisfies the requirements of ASME B31.8S and meets NTSB recommendation P-11-29. The risk model is comprehensive and properly incorporates data consistent with ASME B31.8S.

Additionally, the Monitor team has seen improvement in the annual update cycle for the risk model each year. In the 2018 annual model update cycle, the Monitor team observed process deficiencies and a lack of rigor in PG&E discussions and analyses and we raised our concerns with the TIMP organization. In 2019, TIMP made substantial improvements to the process and those have been maintained and developed in each of the past two update cycles, through 2021. The TIMP program is on the right course, particularly with the implementation of its recently issued five-year roadmap for the risk model's development. This is a "continuous improvement" area, and it merits sustained focus because of its impact on gas pipeline safety.

Requirement Nine focuses on PG&E's efforts to reclaim and maintain its right of way over its gas transmission pipeline. As with some other requirements, PG&E implemented procedural reforms related to encroachments even prior to the Monitorship. Currently, PG&E has not yet completed its remediation of encroachments identified as part of the 2010 centerline survey, although the gap is modest and the function of forces beyond PG&E's control. More specifically, as of June 2021, 99% of legacy structural and vegetative encroachments have been removed and there are 9.28 miles of vegetative encroachments (out of 1,544 miles initially identified) and eight structural encroachments (out of 2,613 initially identified structures) remaining. In the remaining instances, corrective measures have been delayed by litigation or municipalities blocking the work. Nonetheless, the Company plans to address the remaining structural encroachments by the end of 2021 and to remove the remaining vegetation by the end of 2022.

In addition to remediating legacy encroachments, PG&E's ongoing program to ensure that no new encroachments occur is appropriate. Employees conduct annual patrols, and PG&E leverages its aviation technology to assess the centerline and any potential encroachments.

Requirement Ten focuses on PG&E's assessment and evaluation of stress corrosion cracking in its gas transmission pipeline. The Monitor team and our experts have reviewed PG&E's Stress Corrosion Cracking ("SCC") threat assessment model and analysis and concluded that PG&E properly identifies, evaluates, and addresses the SCC threat. Additionally, the Monitor team assessed four gas transmission pipeline segments that had SCC-related leaks and found that PG&E's procedures properly account for risks on those segments.

Requirement Eleven requires PG&E to implement procedures to ensure that relevant data are incorporated into gas threat identification and assessment procedures. PG&E's threat logic and assessment procedures appropriately consider relevant data for purposes of identifying threats recognized pursuant to applicable regulations and standards. In the past year, under new leadership within TIMP, PG&E has undertaken an effort to improve the accuracy and stability of its threat identification logic to better reflect real-world mileage subject to various threats, which was a necessary improvement. The new initiative aims to align threat identification and field assessments to calibrate PG&E's Integrity Management Program with real-world risk. The new initiative reflects a focus on continual improvement of data, records, and risk modeling in Gas Operations, which must continue in the future.

Requirement Twelve focuses on PG&E's efforts to identify High Consequence Areas ("HCAs") across its gas system. Since San Bruno, PG&E has developed a thorough process for identifying class locations, HCAs, and, under the new federal PHMSA Mega-Rule, Medium Consequence Areas ("MCAs"). PG&E reported in its 2020 HCA study that there were a total of 1,593 miles of HCAs and 821.3 miles of MCAs, which will help in risk assessment and oversight prioritization. In 2020, an additional 1,985 pipeline sections (totaling 19.02 miles) were added to HCAs, and 24 pipeline sections (totaling 0.32 miles) were de-designated as HCAs. The Monitor team and our experts assessed two pipeline segments for which the HCA designation was removed, and we are comfortable with PG&E's decisions.

PG&E has taken several steps to improve its HCA and MCA determination processes such as using enhanced structures databases. This is the sort of continual improvement that PG&E must sustain and that the people of California should expect.

Requirement Thirteen focuses on PG&E's ability to incorporate changed circumstances into its risk planning, consistent with ASME B31.8S. The Monitor team believes that PG&E has satisfied this requirement, although there is opportunity for continued progress. Over the course of the Monitorship, the Monitor team has seen improvements in PG&E's efforts and ability to incorporate changed circumstances. Within TIMP there is now a dedicated Continual Evaluation ("CE") Group specifically tasked with this function. The CE Group evaluates Company and industry trends and is conducting longer-term pilot projects to calibrate threat models with field data (for example, third-party damage) through machine learning applications. These are examples of positive, continual improvement under this requirement.

Requirement Fourteen focused on ensuring that PG&E ceased its ill-advised legacy practice of raising pressure in its pipeline to the perceived maximum allowable pressure to re-establish "system MAOP." This requirement was successfully completed. The Monitor team and our experts verified PG&E's representations that it had ceased this practice shortly after the San Bruno tragedy through an independent audit of pressure data in various PG&E pipelines. There was no indication in any of the reviewed data that any planned pressure increases were taking place. Additionally, the Monitor team verified that any pipeline traditionally put through the "planned pressure increase" program to establish system MAOP had been assessed through: (a) strength testing, (b) replacement, or (c) down-rating of applicable operating pressure.

Requirement Fifteen focuses on proper calculation of cyclic fatigue and fatigue life of the gas pipeline system. The Monitor team and our experts believe PG&E's methodology for calculating fatigue life, which was designed and implemented by external consultants, is consistent with and more conservative than industry standards, which enhances the safety of PG&E's gas transmission system. The Monitor team collected data for 11 pipeline segments and performed an independent fatigue life calculation in accordance with industry standards. This data and analysis supports the Monitor team's conclusion that the cyclic fatigue calculation methodologies employed are consistent with and more conservative than industry standards.

D. Gas Operations Challenges

While Gas Operations has done a good job in focusing on the technical requirements and making progress against those targets, it has faced challenges as well. These episodes reflect the need for continued vigilance. Our hope is that the efforts to work together through the issues discussed below and others have enhanced the capacity of PG&E Gas Operations to successfully confront similar issues alone in the future.

For instance, there was a rise in overpressure events in 2019 and through mid-year 2020. Overpressure events, even small ones, are significant issues, and because the numbers were above PG&E's targets and the trend was moving in the wrong direction, the Monitor team flagged the issue in the fall of 2020. At that time, there was an Overpressure Elimination Program ("OEP") with a goal of changing training and workflow by the spring of 2021. Because 2020 had already seen nine large overpressure events (defined by PG&E as an exceedance more than 10% beyond MAOP), that timeline required more urgency and we notified and engaged with senior management in Gas leadership to secure that commitment. Once senior Gas leadership became directly involved, that timeline quickly accelerated and the OEP rolled out additional training earlier, worked on identifying root causes and root cause trends across the overpressure events, and continued work on pipeline design changes. So far, 2021 has seen a reduced number of large overpressure events and, when they do occur, cause evaluations are conducted promptly and lessons learned are distributed quickly. Overall, this is a positive story.

As another example, over the summer and fall of 2018, PG&E personnel reviewed all leak cancellation notifications entered from January 1, 2014 through August 1, 2018 because of a concern that leak notifications that had been improperly canceled (for example, cancelled without documentation supporting a conclusion that a leak was no longer emitting pipeline gas). Given the uncertainty regarding the leak records, the Company expeditiously re-inspected approximately 47,600 canceled leak notifications. Coming out of this process, in Q4 2018, PG&E created a working group to assess its leak survey and closure process, and thereby to identify opportunities for improvement across all leak survey work and leak survey tools.

One of the instructions coming out of this working group was that a "Leak Cancellation Desk" should be established. Although efforts were made within PG&E's Leak Survey group to establish the Leak Cancellation Desk, these efforts foundered such that, by the summer of 2019, the Leak Cancellation Desk still had not been created. Because it failed to timely establish the Leak Cancellation Desk, PG&E again had to conduct a re-review and re-survey process for approximately 8,000 canceled leak notifications, this time for the period between September 1, 2018 and June 30,

2019. After the second re-review project, the Leak Cancellation Desk was actually established, it has been refined over time, and its work continues today.

Overall, the recent history of reform and improvement in Gas Operations is positive. There are two main risk factors to this improvement. The first is the risk of complacency—of assuming that things will remain good when, in fact, every day requires constant vigilance. The second risk is that the people who drove much of the reform and improvement in Gas Operations (including the current Chief Risk Officer, Sumeet Singh) have often been moved to wildfire issues related to Electric Operations. This is to some degree inevitable and prudent given recent lethal problems and issues with wildfires. However, thoughtful analyses and assessments must be made as to when additional resources are needed overall, including in Gas Operations, to prevent cannibalization of the efforts to drive progress in Gas Operations since San Bruno.

IV. COMPLIANCE AND ETHICS

In addition to the 15 individual requirements, the Monitor team was tasked by the January 26, 2017 Court order "to assure PG&E's compliance with the goals outlined in the United States Sentencing Guidelines Section 8B2.1: Effective Compliance and Ethics Program." (Dkt. 916). The Federal Sentencing Guidelines require measures to prevent, detect, and address criminal misconduct and to promote an organizational culture that encourages ethical conduct and a commitment to compliance with the law. U.S. Sentencing Guidelines Manual § 8B2.1 (2021). Such a compliance and ethics program "shall be reasonably designed, implemented, and enforced so that the program is generally effective in preventing and detecting criminal conduct." *Id.* § 8B2.1(a). The Monitor team believes that PG&E's Compliance and Ethics ("C&E") program is consistent now with these requirements.

PG&E's central C&E department promotes legal compliance and ethical behavior, guides Lines of Business ("LOBs") in implementing PG&E's C&E agendas, and reports on C&E

performance. During the course of the Monitorship, and under the leadership of people like Julie Kane, John Simon, and Alex Vallejo, PG&E has established an appropriate governance structure to foster communications with the LOBs. PG&E's C&E-related governing bodies and senior leaders, including its Board of Directors and Compliance and Public Policy Committee at the Board-level, and its Compliance, Ethics, and Audit Committee at the operational level, are engaged in understanding and providing oversight and guidance for PG&E's C&E program. Monthly joint Compliance and Ethics Leadership Team ("CELT") and Compliance Liaisons meetings, focused on day-to-day implementation of C&E strategies, provide an efficient means for discussing and shaping the C&E agenda and coordinating among C&E stakeholders. PG&E should continue to make conversations between LOB leaders and their designated C&E professionals a regular feature of the LOBs' C&E activities to ensure adequate messaging and alignment and to help PG&E's C&E program gain traction in the field. Such direct coordination with and support from senior leadership are essential to empowering CELT members and Liaisons to effectively execute on and drive PG&E's C&E agenda, including into the broader workforce.

PG&E's C&E programs and practices are guided by and assessed under a compliance "Maturity Model." The Maturity Model establishes a C&E framework with eight elements based on the Federal Sentencing Guidelines. The C&E team has also developed an oversight model for PG&E's top 35 compliance risks, assigning each to one of four levels of central C&E oversight. PG&E's recent shift to risk-informed compliance work is consistent with heightened focus on such an approach by PG&E's regulators. While adapting to regulatory trends and changing circumstances is appropriate and consistent with the DOJ's emphasis on having an evolving and tailored C&E program, PG&E should ensure that its new approach includes sufficiently objective, systematic oversight of PG&E's C&E performance.

Promoting a compliant and ethical culture, particularly through PG&E's "Speak Up, Listen Up, Follow Up" initiative, has been an appropriate and central focus for the C&E team throughout the Monitorship. One highlight of efforts is PG&E's roughly 80-member Ethics Council, comprised of employees from all levels of PG&E— including critically, field personnel—which meets monthly with the goal of promoting a culture that embraces and advances ethical behavior in PG&E's operations and employee relationships. These meetings provide an important opportunity for employees across the organization to have frank discussions about C&E issues with senior leaders, and PG&E should continue to promote such openness. Although the Company continues to face impediments to a culture of speaking up, including employee fear of retaliation, the Monitor team believes PG&E is committed to and making meaningful strides toward effecting culture change.

The Monitor team encourages PG&E's C&E leaders to continue to amplify and drive forward PG&E's core C&E agenda and messages to make clear that they are enduring and that the Company is committed to their effective implementation. It is imperative that PG&E work assiduously to earn the trust of its workforce, who (especially among longer-serving PG&E personnel) often doubt whether their managers and supervisors actually want to hear bad news. This commitment also includes ensuring that PG&E's C&E program is resourced and empowered to function effectively and that PG&E has objective, systematic means for ensuring accountability and assessing and monitoring its C&E program and performance. New and unexpected challenges will continue to arise. PG&E's C&E program must be adequately resourced and cultivated to withstand those challenges.

V. SAFETY AT PG&E

At the outset of the Monitorship, it is likely that nobody anticipated the scope of the Company's profound public safety issues, with more than 110 PG&E customers killed in recent years due to wildfires associated with PG&E equipment. PG&E needs to take complete ownership of those deaths—by focusing on public safety, and by doing all that it can to protect its employees and contractors from the risks they face in their jobs and the public from the risks it faces when PG&E employees and contractors do not do their jobs effectively.

PG&E's Safety program now sits at the enterprise level and is managed and overseen by the Chief Safety Officer and Senior Vice President of Enterprise Health and Safety ("EH&S"). In June 2021, PG&E began implementing a regionalized model for the EH&S organization, which includes Regional Safety Directors with LOB, functional, and regional responsibilities. The Regional Safety Director for the Central Coast Region is responsible for supporting safety in Gas Operations, and the Regional Safety Director for the North Coast Region is responsible for supporting safety in Electric Operations.

In addition to organizational changes, PG&E is implementing a comprehensive, long-term plan, the "2025 Safety Plan," which, at a high level, aims to improve safety by addressing both PG&E's existing systems and its safety culture. In terms of systems, the plan primarily focuses on incorporating critical risk management into the Company's work, refining and improving safety standards, ensuring the universal use of effective safety tailboards, and managing public safety. This also includes a focus on contractor management, which is essential to improving safety in the future. In parallel, PG&E has continued its efforts to implement an Enterprise Safety Management System, which, after significant delays, the Company developed and began to implement throughout 2020 and 2021. To improve safety culture, the 2025 Safety Plan aims to increase and improve safety observations in the field; incorporate safety into hiring decisions, performance appraisals, and trainings; and assess and improve PG&E's safety culture using the National Safety Council's Safety Barometer Survey and associated action development and management template. It is important that PG&E stay committed to a strategic long-term safety plan and allocate sufficient resources to that plan. Additionally, given PG&E's ongoing leadership turnover, it is important that incoming leaders in all roles fully commit to PG&E's plans. No organization can sustain long-term progress if there is substantial turnover of senior leaders, with each wave of leaders having their own particular priorities, even if each wave and individual operated during their respective brief tenures in good faith.

Further, management engagement with field-level employees is essential to improving safety, including by reducing injuries and fatalities. PG&E's emphasis on grassroots safety teams and engagement with its workforce as changes to policies and work procedures are made are important steps in becoming a safer organization. While PG&E has made progress, the Monitor team encourages the Company to continue its efforts to empower employees and contractors to raise safety issues, such that employees and contractors feel confident in their obligation and ability to stop work if they are concerned about safety. Importantly, the Company should also continue to provide employees contractors with the tools and support needed to mitigate safety issues.

VI. WILDFIRE MITIGATION EFFORTS

The Monitor team's work concerning PG&E's Electric Operations and wildfire mitigation efforts substantially began in early 2019, following multiple years of horrific wildfires. At that time, the Court imposed a number of probation conditions designed to promote safer and more thorough wildfire abatement efforts by PG&E. These included requiring PG&E to comply with all vegetation management laws; to meet the targets in its state-approved wildfire mitigation plan; to maintain traceable, verifiable, accurate and complete records; and to ensure that sufficient resources, both financial and personnel, were devoted to achieving the conditions of probation. The Court also ordered the Monitor team to conduct field inspections of PG&E's vegetation management and electric equipment work. (Apr. 3, 2019 Order, Dkt. 1040). The Court has since modified and augmented PG&E's conditions of probation on several occasions. *See* Exhibit 3.

PG&E's performance in Electric Operations has not matched its performance in Gas Operations and Compliance and Ethics. As detailed in prior reports to the Court, PG&E made many errors in design and execution of wildfire abatement efforts from the beginning of probationary review. *See, e.g.,* July 26, 2019 Letter to the Court, Dkt. 1089 (highlighting substantial numbers of missed trees and recordkeeping issues within PG&E's EVM program); Oct. 16, 2020 Letter to the Court, Dkt. 1247-1 (highlighting the lack of risk prioritization of PG&E's EVM work and deficiencies in PG&E's System Inspections program). Much more progress is required, both quickly and over a sustained period of years, as detailed below.

We doubt anyone would seriously contend that PG&E's performance has been even adequate, or that substantial improvement is not still imperative, given the staggering losses of life and property caused by recent wildfires for which the Company has either pleaded guilty criminally or otherwise been determined responsible. While progress is occurring, and should be recognized, there is a long way to go. Sustained, focused, and unwavering commitment in the future will be required to achieve stated goals.

By way of background, PG&E conducts its wildfire mitigation work pursuant to a Wildfire Mitigation Plan ("WMP") submitted to and approved by the CPUC, and this year, the California Office of Energy Infrastructure Safety. That WMP contains targets and metrics that form the basis of PG&E's annual wildfire mitigation work. The Monitor team does not only focus on whether PG&E meets the CPUC approved targets (the Company largely has, despite the tremendous wildfire damage caused). Rather, we focus also on *how* PG&E meets those targets and metrics, in terms of the quality of the work, and whether work is performed so as to reasonably maximize risk-mitigation. We evaluate those efforts through regular discussions with PG&E leadership, employees, and contractors performing the work (both in the office and in the field), as well as our own field inspections of PG&E work. Information collected from that work forms the basis of our observations discussed herein.

As stated, PG&E substantially complies with the numerical targets set forth in the WMP, and where there are misses from CPUC requirements, they are oftentimes not far off. This is important because despite substantial compliance with the mitigation plans, PG&E's equipment continues to cause wildfires. We understand that the WMP process was meant to be a multi-year process, with the goal of substantially reducing wildfire risk over time. While that may be the case, the Monitor team emphasizes that achieving the targets and metrics in the WMP, as they have been set since 2019, has been insufficient to stop lethal wildfires. And since 2019, some core WMP targets, as submitted and approved, have been *decreasing* year over year, not increasing, including in PG&E's Enhanced Vegetation Management ("EVM") program. So while the path to success under the WMP process is an extended one, the Company would be well served to take a more aggressive approach to wildfire mitigation than it has in the past to stop wildfires today, understanding there are longer term initiatives that are also key, such as infrastructure replacement, which PG&E has identified is one of its most important safety steps going forward.

Notwithstanding the shortcomings and needed improvements in PG&E's wildfire mitigation efforts described below, there have been some positive steps. Perhaps one of the largest and most important improvements we saw during the Monitorship was the amount of resources and leadership brought to bear on the Company's risk-based planning and prioritization of wildfire mitigation work. There was a turning point in the fall of 2020, when PG&E's then new Chief Risk Officer Sumeet Singh established the Wildfire Risk Governance Steering Committee, comprised of various Company leaders whose divisions perform wildfire mitigation work. As a result of the efforts of this Committee and the Chief Risk Officer, all wildfire mitigation work performed by PG&E pursuant to the WMP underwent project-level selection, planning, scrutiny, and deliberation before a committee whose focus, in sum, was to ensure the highest risk work was being addressed sooner rather than later according to PG&E's models.

This was important because addressing the highest risk work sooner rather than later was PG&E's stated goal when it first published its 2019 WMP, but that is not what was happening until PG&E's Chief Risk Officer changed the trajectory and focus of the Company's wildfire mitigation efforts in the fall of 2020. Prior to that time we raised to both PG&E and the Court that the Company had been completing the majority of its EVM work on lower priority circuits according to its own risk models. *See* Oct. 16, 2020 Letter to the Court, Dkt. 1247-1. That is no longer the case, and PG&E is on a better path now from a risk based planning and work execution perspective. That makes the people and State of California safer, but continued vigilance over the risk-based planning and execution of work will be necessary. Otherwise, work can get "done" and state requirements and targets can be "met," but with suboptimal corresponding risk-reduction.

VII. VEGETATION MANAGEMENT

VM is a critically important aspect of wildfire mitigation. From 2017-2021, as of October 13, 2021 data, PG&E has reported approximately 259 ignitions caused by vegetation striking PG&E's distribution assets in high fire-threat district ("HFTD") areas. Given the very real and catastrophic potential consequences of an ignition in PG&E's HFTD service territory, there is little room for error in vegetation management work, and the Company should promote a culture that does not tolerate any error in VM. To be sure, VM work is complex given the volume and dynamic nature of trees that threaten PG&E's electric lines. Tree growth and tree failure cannot be precisely predicted. But the reality of that challenge underscores the importance of devoting sufficient resources to ensure that vegetation risks are mitigated effectively, including by adopting more conservative trimming measures that remove guesswork and subjectivity as much as possible, while also maintaining vegetation in accordance with applicable regulations and PG&E policy. PG&E

would also benefit from adopting a uniform, territory-wide, and year-round approach to vegetation management scope and trimming in high fire-threat areas—one that exceeds regulatory minimum requirements.

Our work in vegetation management has focused on five main areas: (1) quality of work execution; (2) prioritization of work in terms of risk abatement; (3) scope of work; (4) recordkeeping; and (5) contractor management. The field inspection component of the Monitor team's review of PG&E's VM efforts began in the summer of 2019.

PG&E's VM organization has improved work quality since 2019. The Monitor team's field inspections have revealed that the percentage of trees missed by PG&E's EVM workers has decreased. PG&E has also taken significant recent steps to align the work being performed in the field with the risk-based priorities established by the Company's leadership—an alignment that was unacceptably missing in 2019 and 2020. However, in other areas, such as enhanced hazard tree assessments in HFTD areas and needed records improvements, PG&E concedes the need for improvements but has not yet effectively established or demonstrated sufficient reforms.

A. Background

PG&E's transmission and distribution lines receive annual vegetation inspections as a part of the Company's Routine VM program. During Routine VM work, PG&E is supposed to trim trees with potential to grow within the minimum clearance distance delimited by California regulations and remove hazard trees that pose a risk of striking the lines. In 2019, PG&E included EVM as a more robust component of its WMP commitments, pursuant to which PG&E agreed to perform enhanced tree work on select distribution circuits within HFTDs, with the ultimate goal of performing enhanced work on all 25,500 HFTD miles at some point during the multi-year EVM program. Enhanced work includes tree removals based upon region-specific tree-species analysis and clearance of limbs overhanging primary distribution conductors. EVM records are largely administered through software referred to as Arc Collector.

B. Quality of Work Execution

The Monitor team assessed the quality of PG&E's VM work execution via various means, including unannounced field inspections performed in HFTDs as specified in the Court's probation order (Apr. 3, 2019 Order, Dkt. 1040). Field inspections are performed on distribution conductor segments subject to EVM and segments subject to Routine VM, that is, areas where EVM has yet to be performed, which includes the vast majority of PG&E's high threat areas.

As a general matter, the Monitor team sought to inspect at least 10% of PG&E's annual EVM mileage goal each year, but the mileage inspected was higher in 2019 due to PG&E's EVM scope changes and lower in 2020 due to COVID travel restrictions and statewide stay-at-home orders. When the Monitor team began inspecting PG&E's fieldwork in summer 2019, we inspected 130.49 miles and identified a substantial number of trees that were out of compliance with PG&E's EVM scope of work as reported in detail in a letter to the Court dated July 26, 2019, Dkt. 1089. Over half of the segments we inspected did not conform to the EVM scope. After several discussions between PG&E and the Monitor team in July and August 2019 regarding these deficiencies, PG&E implemented a new scope of work, new training materials, and a new training program. Since then, the Monitor team has noticed improvement. In fall 2019, the Monitor team inspected 323.93 miles of EVM work. Out of 25,165 trees inspected in fall 2019, the Monitor team identified 203 hazard trees, 33 radial clearance issues, and 119 overhang issues. In other words, 98.6% of strike trees—trees tall enough to strike electric assets—inspected by the Monitor team were in compliance with the EVM scope. In 2020, the Monitor team inspected 42.03 miles of EVM work. Out of 11,280 trees inspected in 2020, the Monitor team identified 83 hazard trees, 34 radial clearance issues, and 32 overhang issues. 98.7% of strike trees were thus in compliance with the

EVM scope. So far in 2021, the Monitor team inspected 199.75 miles of EVM work. Out of 32,269 trees inspected in 2021, the Monitor team identified 77 hazard trees, 24 radial clearance issues, and 53 overhang issues. That is, 99.5% of strike trees have been compliant with EVM scope in 2021. For additional year-over-year statistics from Monitor team EVM inspections, *see* Exhibit 4.

For areas not subject to EVM work, but still within the HFTD service territory (Routine VM), the Monitor team inspected 13.95 miles in summer 2019; 22.32 miles in fall 2019; 20.13 miles in 2020; and 138.71 miles in 2021. The Monitor team increased its mileage in 2021 because prior years' inspection results indicated that additional attention to Routine VM in HFTDs was warranted because of underperformance in that program as compared to EVM. Out of 4,661 trees inspected by the Monitor team in fall 2019, the Monitor team identified 59 hazard trees and 41 radial clearance issues. That is, 97.85% of strike trees were in compliance with the Routine VM scope in fall 2019. Out of 2,645 trees inspected in 2020, the Monitor team identified 19 hazard trees and 20 radial clearance issues. In 2020, 98.53% of strike trees were in compliance with the Routine VM scope. Thus far in 2021, out of 23,025 trees inspected, the Monitor team identified 268 hazard trees and 55 radial clearance issues. That is, 98.6% of trees have been in compliance with the Routine VM scope in 2021. For additional year-over-year statistics from Monitor team Routine VM inspections, *see* Exhibit 5. The Quality Management inspections performed by PG&E's internal group have identified a similar percentage of missed trees. PG&E's internal VM Quality team efforts are an improvement by PG&E during the last couple years. That is, PG&E recently has self-identified shortcomings and instituted corrections better than it historically has.

While PG&E's improvement from 2019 to 2021 on EVM is encouraging, these results are currently inadequate because they still allow very substantial wildfire risks even in EVM-worked areas. The Monitor team continues to find hazardous trees in the field missed by PG&E's workers. *See* Exhibit 6. While the analogy is admittedly imperfect, we doubt that a vehicle brake manufacturer, or even officials in PG&E's nuclear or gas operations, would be satisfied with a 1.5% miss rate on important safety work. Moreover, extrapolating the Monitor team's inspection statistics across PG&E's full HFTD service territory suggests that approximately 60,000 trees were missed by PG&E in 2021, even after Enhanced and Routine vegetation management work. That is an unacceptably high number, given the threat each missed tree poses and the collective threat posed by such a volume of misses. As discussed further in Section VII.D below, enhancements to PG&E's scope of work, and better contractor management, may allow for greater risk mitigation.[2]

C. Prioritization of Work

The Monitor team's findings from our field observations and data analyses suggested that PG&E completed the majority of its 2019 EVM work in relatively low-risk portions of its HFTDs according to the Company's risk model. That unsatisfactory dynamic continued in 2020, with work spread roughly evenly across the highest and lowest ranked circuits under applicable risk models. *See* Oct. 16, 2020 Letter to the Court, Dkt. 1247-1. Put differently, while PG&E was "meeting state requirements" by doing sufficient EVM work in HFTDs, the parts of the HFTDs where actual work was being completed were not the highest risk portions of the HFTD. As a result, the "meeting requirements" approach achieved formalistic compliance with CPUC requirements without reducing risk in a commensurate way.

As noted, in the wake of concerns raised by the Monitor team about this approach (*see, e.g.,* Oct. 16, 2020 Letter to the Court, Dkt. 1247-1), PG&E has made significant improvement in the risk-based prioritization and execution of work in 2021. The Company developed a tree-weighted risk model for 2021 and committed to performing nearly all 2021 EVM work within the top 100

[2] To be clear, not every fire can be prevented through vegetation management; for example, a terrible wildfire could be caused by lightning alone and neither PG&E (nor any utility) would be responsible. There are other examples (irresponsible campers, animals, and large birds, etc.). However, when PG&E and its contractors perform vegetation work in high-threat areas, it is important that results are as close to 100% correct as is humanly possible, given the role EVM and VM play in risk mitigation and wildfire deaths.

circuit protection zones. This year, for example, PG&E has performed over 80% of EVM work in the top 10% of riskiest areas—to put that number in perspective, that percentage was only 18.6% in 2019, and even lower, 6.3% in 2020. *See* Exhibit 7 (showing percentage of EVM miles completed in 2019-2021 within the top 10% of risk-ranked circuit miles under PG&E's models each year). The Monitor team commends PG&E, and in particular its Chief Risk Officer, for the quick pivot to ensuring consistent use of a risk-based approach for EVM work in 2021 and, we expect, beyond.

D. Scope of Work

PG&E's scopes of work in both Routine VM and EVM could be improved to ensure that vegetation risks are better mitigated. First, PG&E limits radial clearance trimming to trees capable of growing within the minimum clearance distance within one year and limits Routine VM hazard tree removals to trees that could fail within one year. A more conservative approach would help ensure that risks are mitigated before they materialize, while further reducing potential error in what is oftentimes a difficult, subjective determination.[3]

Second, PG&E's EVM work—which goes above and beyond the minimum compliance requirements of Routine VM—is being performed slowly, that is, on *less than 10%* of the HFTD annually. Put another way, despite all of the emphasis the Company places on EVM, 90% (or more) of PG&E's HFTD territory annually is left untouched by the EVM program. The Company stated in 2019 that it expected to perform at least 2,450 miles of EVM work per year, with the goal of finishing EVM on all HFTD circuits by the end of 2026. But PG&E's annual targets decreased in 2020 and 2021 to 1,800 miles (and were approved at those levels by the CPUC). If this pace continues, the Company will need more than 10 years to complete EVM work on the HFTDs. Given

[3] We appreciate that state regulators may have views about the appropriate amount of clearance distances PG&E can create. We do not purport to speak for the CPUC and other regulators of course. However, given the severity and ferocity of recent wildfires, we would hope everyone would keep an open mind about more aggressive fire prevention efforts and whether regulations may need to be modified in light of tragic recent history.

the threat of wildfires in California, and the existence of a more effective EVM program, the Monitor team respectfully believes that PG&E should not limit its EVM targets to 1,800 miles per year out of the 25,500 HFTD miles.

One consequence of PG&E's limited annual target for EVM is that most trees across its HFTD service territory are not receiving detailed hazard tree assessments, which presently do not occur under the Routine VM program. PG&E developed a Tree Assessment Tool ("TAT") for EVM, which requires thorough inspection of trees—including, for example, 360-degree assessments. Because EVM is only performed annually on approximately 10% (now less) of PG&E's HFTD service territory, the great majority of trees to date have not received detailed 360-degree or TAT inspections on an annual basis. The Monitor team was also concerned that, after segments completed EVM, PG&E was not maintaining those segments to the EVM scope in future years. For example, vegetation "overhanging" the primary conductors was being cleared to the sky under EVM, but that conductor-to-sky clearance was not being maintained in future years. After discussing these issues with the Monitor team, PG&E recently informed the Monitor team that it soon will require 360-degree tree assessments in all HFTD areas by augmenting its Routine pre-inspection program and will maintain EVM-completed segments to the EVM scope going forward. Both are prudent initiatives, and demonstrate significant commitments, improvements, and investments.

Another consideration for PG&E is to implement a single, enhanced scope of vegetation work applicable to all HFTDs that applies year-round and exceeds regulatory requirements. This would bring uniformity to the vegetation management approach in HFTD areas, eliminate contractor confusion regarding scope, improve recordkeeping and, most importantly, result in greater annual risk reduction in HFTD areas.

E. Recordkeeping

Traceable, verifiable, accurate, and complete records are essential for ensuring public safety. From the beginning of the Monitor team's review of VM work, we have identified significant recordkeeping issues—which, to be fair, are often the result of decades of issues and conflicting systems, not merely recent developments or lack thereof. Nonetheless, that is an explanation and not an excuse, and this is an area where improvement will promote safer operations.

In 2019, we observed that PG&E's electronic Arc Collector maps sometimes reflected that electric conductor segments and trees were in the wrong location, inconsistent data was often recorded (such as trees assessed for removal as hazards but then given a prescription of "no work required"), and EVM work verification data was sometimes being deleted from the Arc Collector system. *See* July 26, 2019 Letter to the Court, Dkt. 1089, at 21-27.

In response to the Monitor team's recordkeeping feedback, PG&E made significant changes to its system in September 2019. Those changes included modifying how work was recorded, so that EVM work verification data would not be deleted, and instituting data checks to ensure that certain conflicting or missing data are fixed. PG&E also collected aerial Light Detection and Ranging ("LiDAR") data in early 2020 to improve the location of its electric conductor segments.

PG&E's technology team often fixes data issues, once identified, quickly. For example, in October 2020, as described in a letter to the Court dated Oct. 16, 2020, Dkt. 1247-1, the Monitor team observed a tree singed from contact with a primary conductor. A pre-inspector had twice flagged the tree as a "Priority 2 tag" to be worked within 30 days, but that pre-inspector did not have access to the database used to generate Priority 2 tags, and the work request was never generated. After the Monitor team raised this issue, the Company immediately identified the gap in its process and, in relatively short order, built a new mobile application through which any VM worker can generate Priority tags. That is certainly helpful, but the goal must be to have a system where self-correction (without an external force) is routine.

Despite these improvements, PG&E's records are still not sufficiently reliable. First, PG&E plans to unify its fragmented VM records databases into a single tool, but the tool has not yet been developed and will not be applied to all VM programs until 2023 or 2024. Second, approximately one-third of the circuit maps were never updated from the inaccurate versions used in 2019. PG&E is undertaking a circuit-by-circuit process of updating the maps yet again, but the Monitor team continues to observe inaccuracies in even the newest maps. *See* Exhibit 8. Third, the Monitor team continues to observe inconsistent data within PG&E's records systems. *See* Exhibit 9. In sum, PG&E's progress in addressing the accuracy and integrity of its VM records has been slow. Given the history of recordkeeping issues with the Company, improvement here needs to remain a focus and priority.

F. Contractor Management

PG&E relies on contractors to perform its VM work. Accordingly, effective contractor management is critical to the success of PG&E's VM program (and other programs). The Court imposed a new probation condition on August 7, 2020 pursuant to which PG&E was required to staff an in-house VM inspector workforce of at least 30 inspectors by January 2021. (Aug. 7, 2020 Order, Dkt. 1243). These inspectors are important to PG&E contractor oversight. PG&E not only met that condition but has also significantly expanded its commitment to field monitoring work through in-house Vegetation Management Inspectors ("VMIs") and work verifiers. Both programs have generated actionable feedback in 2021 that PG&E used to clarify and materially improve its procedures. PG&E has also acknowledged that its VMI and work verification programs are not yet fully developed, so continued improvement and attention are and will be required.

To drive additional improvement in VM work quality, PG&E should (1) make procedures, scopes of work, and recordkeeping tools simpler for contractors to understand and (2) require ongoing, annual trainings and rigorous assessments for all pre-inspectors and work verifiers to ensure that hazard tree assessments are performed consistently across HFTDs.

VIII. ELECTRIC INFRASTRUCTURE INSPECTIONS AND REMEDIATION WORK

As explained below, while PG&E has made improvements to its electric infrastructure inspection and remediation programs, it has struggled to execute plans in a timely manner. PG&E needs to dedicate more resources to remediating identified risks, because its lack of emphasis on timely remediating lower priority repairs, and even some priority repairs, has produced a significant repair backlog. Recordkeeping issues persist, posing challenges to electric infrastructure inspection and remediation efforts. And the Monitor team's field review of PG&E inspections revealed ongoing quality issues, suggesting the need for more oversight and training. Our field reviews, however, typically do not identify imminent hazards, suggesting that PG&E inspectors are at least identifying and addressing the highest priority issues.

In 2019, PG&E established an enhanced inspection protocol to identify conditions that could present fire ignition risk. When launching its enhanced inspection program, PG&E undertook an unprecedented amount of work, inspecting all of its approximately 685,000 distribution poles, 50,000 transmission structures, and 200 substations in HFTDs in a calendar year. That 2019 effort led to an unprecedented number of orders (673,968) for remediation work ("tags"). There are over 500,000 tags from 2019 to present that remain unresolved to date. For 2020 and 2021, PG&E continued to inspect all infrastructure in Tier 3 HFTDs annually (although we understand PG&E may be considering to reduce the frequency of Tier 3 inspections—the riskiest areas—which we would not support in the near-term). PG&E moved to a three-year rotating inspection cycle for infrastructure in Tier 2 HFTDs (one-third each year) and a five-year rotating inspection cycle for infrastructure outside of Tier 3 and 2 HFTDs (one-fifth each year).

A. PG&E's Wildfire Mitigation Plan Commitments to the CPUC

For each year since 2019, PG&E has set forth specific, annual inspection commitments in its WMP, in addition to internal goals. In 2019 and 2020, PG&E did not meet its inspection targets, which are largely aimed at ensuring that identified priority repairs are made in advance of fire season. In 2021, PG&E failed to inspect 5,107 distribution structures by the deadline. This was due to 41,000 structures that were added to the work plan in July, largely because of incomplete records identified through PG&E internal validation efforts. Since July, PG&E has continued to identify additional structures that should have been inspected by the July 31, 2021 deadline but were not mostly because of faulty records which do not accurately reflect assets in the field, including at least 995 distribution and two transmission structures.

In sum, in no year has PG&E met all of the inspection commitments in its WMP. PG&E would benefit from additional planning, resource, recordkeeping improvements, and procedural enhancements to ensure it meets all external and internal inspection commitments going forward. These inspections are important because they are a part of an integrated wildfire risk-abatement program that cannot function most effectively if one component is lagging.

B. Quality of Work

The success of PG&E's enhanced electric equipment inspections depends not only on timeliness, but also on quality. Since 2019, the Monitor team has conducted field inspections of a sample of PG&E's inspected electric structures across the high threat service territory. After the inspections, the Monitor team identified and reported to PG&E "potential exceptions," that is, field conditions that should have been identified by an inspector in accordance with PG&E guidance but were not, or a recordkeeping question that was answered inaccurately by a PG&E inspector. The frequency and nature of the Monitor team's findings suggest ongoing quality concerns, and a continued need to improve PG&E's oversight of its contract workforce.

1. Distribution Inspection Results

In 2019, the Monitor team conducted an in-field review of 1,652 electric distribution structures in HFTDs that had been inspected by PG&E. Approximately 12% of the structures inspected by the Monitor team had potential exceptions related to field conditions, for a total of 222 missed field issues by PG&E inspectors across 201 structures. Approximately 34% of the structures had potential exceptions related to recordkeeping, for a total of 522 missed recordkeeping issues across 377 structures.

In 2020, due to COVID restrictions, the Monitor team conducted an in-field review of a much smaller sample of 94 distribution structures in HFTDs that were inspected by PG&E. Recognizing "small sample size" dynamics can skew outcomes, nonetheless approximately 48% of the sampled structures had potential exceptions related to field conditions, totaling 75 missed field issues by PG&E inspectors across 45 structures. Approximately 53% of structures had potential exceptions related to recordkeeping, for a total of 60 missed recordkeeping issues by PG&E inspectors across 50 structures.

In 2021, the Monitor team conducted an in-field review of 1,628 distribution structures in HFTDs that had been inspected by PG&E. Approximately 27% of the structures had potential exceptions related to field conditions, for a total of 583 missed field issues by PG&E inspectors across 435 structures. Approximately 31% of the structures had potential exceptions related to recordkeeping, for a total of 642 potential exceptions by PG&E inspectors across 507 structures. While these figures represent an improvement over the limited sample from 2020, there is a significant increase in the frequency of field condition-related potential exceptions (27%) as compared to 2019 (12%). For example, the number of field conditions related to pole damage identified by the Monitor team in 2021 (164 potential exceptions) was substantially higher than 2019 (50 potential exceptions), suggesting that there may still be issues with the clarity of PG&E's pole damage criteria or with PG&E's training on that subject. The same holds true for field conditions where the PG&E inspector failed to identify structures with equipment deemed non-exempt by CAL FIRE and with dried vegetation present within a ten-foot radius of the pole (55 potential exceptions in 2021 compared to five in 2019). While the Monitor team has observed relatively few emergency conditions (that is, those that would require immediate attention from PG&E), it continues to find many conditions that could present fire ignition risk based on PG&E's own inspection criteria and guidance, including pole damage, guy wire clearance, and the proximity of splices to the structure. *See* Exhibit 10 for additional detail on observations.

2. Transmission Inspection Results

In 2020, the Monitor team established an inspections program whereby it conducted photographic inspections of PG&E's transmission assets using PG&E's aerial photography database. This method was used by the Monitor team because it was not realistic or safe for us to conduct in-field inspections of high towers, for example, either directly via ascents or by the Monitor team operating drones. The Monitor team reviewed 297 transmission structures that had been subject to aerial inspections by PG&E, meaning that the Monitor team reviewed the same helicopter and drone photographs that PG&E's AIR+ inspectors used in their aerial inspections. Approximately 83% of the steel structures inspected had potential exceptions that were not identified by PG&E, for a total of 291 missed issues across 123 structures. Approximately 78% of the wood structures also had potential exceptions, for a total of 243 missed issues across 116 structures. We acknowledge that PG&E uses additional inspection methodologies for transmission assets that may catch some of the issues missed by PG&E's AIR+ team, including ground and climbing inspections, but those additional methods do not eliminate concerns raised by the potential exception numbers noted immediately above.

In 2021, the Monitor team inspected 304 electric transmission structures via PG&E aerial photography records. Approximately 47% of the steel structures inspected had potential exceptions, for a total of 160 missed issues across 88 structures. Approximately 53% of the wood structures also had potential exceptions, for a total of 136 missed issues across 76 structures. This decrease in the rate of potential exceptions coincided with improvements in the AIR+ training program and efforts to clarify the guidance materials utilized by inspectors, as well as a continuing accumulation of experience by AIR+ inspectors, but the numbers were still quite high. To be clear, in both 2020 and 2021, potential exceptions overwhelmingly were comprised of non-emergent conditions (e.g., non-acute contamination on an insulator), recordkeeping errors (e.g., failure to identify a structure as located near a dwelling), and situations where the Monitor team was unable to properly assess the condition of a component due to the insufficient quality of PG&E's aerial photographs. *See* Exhibit 11 for additional detail on the Monitor team's observations. Nonetheless, greater precision and performance can fairly be expected, given the safety impact the inspections have.

3. PG&E Quality Control Efforts

In 2021, PG&E made significant progress in developing and implementing additional quality control measures, including field verification for electric transmission and distribution asset inspections. PG&E also engaged external resources to complete a review of all of its tags involving C-hooks. PG&E has also been leveraging automated technologies and machine learning to further bolster its inspections programs, including through photographic analysis to "train" computers to spot equipment issues that warrant additional review. The efforts are a positive development in verifying and supplementing the quality of inspections.

C. Inspection Guidance Materials, Resources and Training

The quality of PG&E's enhanced inspections depends in large part on the clarity and objectivity of the questions asked of inspectors via checklists and the detail provided in job aids. In 2019, the Monitor team identified certain questions in PG&E's distribution checklist that were unclear and noted that PG&E's job aid was not tailored to conducting enhanced electric inspections. In 2020, PG&E made some improvements to its program, including revising its electric distribution inspection checklist to reduce ambiguities. PG&E also created a job aid specifically for enhanced distribution inspections that contained additional detail and illustrative photographs to improve consistency in identifying field conditions. In 2021, PG&E has further improved its job aids for both electric distribution and transmission inspections with additional details, diagrams, and photographs. There is still room for improvement. In particular, the guidance in the job aids is not well-tailored to the questions as worded on the inspection checklists. Additionally, System Inspections is responsible only for execution of inspection commitments, and it is not clear that inspectors have regular and meaningful access to other teams that could provide additional clarity on standards. Lastly, one of the most common issues identified by the Monitor team had to do with failure of PG&E inspectors to identify an asset as being located within 600 feet of a structure or dwelling. The high failure rate on an objective question like this indicates that inspectors may not be paying the requisite attention to detail throughout the inspection process, and that further training and oversight is required.

The quality of enhanced electric inspections also depends on the effectiveness of PG&E's inspector training program. As part of its onboarding process, PG&E provides inspectors with a multi-day training for enhanced inspections, including classroom and field sessions. From 2019 to 2021, the Monitor team has attended several of PG&E's in-person and virtual training sessions for enhanced electric distribution and transmission inspections. The Monitor team found these training sessions generally informative, well-run, and critical to the success of PG&E's enhanced inspections. For further improvement, PG&E should incorporate more experiential field training into the curriculum and further utilize testing both during and at the end of trainings to ensure comprehension and retention of information.

D. Maintenance and Construction

While PG&E has improved in addressing high priority tags, there continues to be a high volume of outstanding remediation work, for which PG&E lacks a clear plan on which it has been able to effectively execute.

1. Volume and Timeliness of Remediation Work

PG&E's backlog of infrastructure-related remediation work has increased significantly since the start of enhanced inspections in 2019, although PG&E generally remains current on high priority tags (those requiring action immediately or within 90 days). For example, the overall number of pending, unresolved electric transmission and distribution tags increased by over 90,000 in 2019 and 60,000 in both 2020 and 2021. *See* Exhibit 12 for a visual representation of the backlog. As of June 30, 2021, there were 66,107 pending, unresolved transmission tags (25,013 in HFTDs) and 450,404 pending, unresolved distribution tags (222,058 in HFTDs). *See* Exhibit 13 for additional detail on the number of pending, unresolved electric infrastructure-related tags. Despite ongoing prioritization and remediation efforts, PG&E lacks a clear execution plan to address the increasing backlog in a timely way and has been constrained by available budget and resources in its ability to do so. Furthermore, conditions that are meant to be addressed within six months per PG&E guidance could sit unmitigated for several years. While PG&E has taken steps to address this, including implementing a "strike team" in 2021 focused on executing repairs and reassessing strategies related to tag prioritization and bundling, resource constraints continue to limit progress. As of July 2021, the estimated cost to address all existing tags was over $3 billion.

2. Effects of Pending, Unresolved Tags

PG&E, for the most part, resolves its Priority A tags (highest priority) in a timely way. PG&E's timeliness in addressing Priority B tags has needed improvement, and there is a tendency at PG&E to postpone mitigating its lower Priority E and F tags, contributing to backlog. Unresolved tags can collectively contribute to safety risks, including ignitions. The work of PG&E's Asset Failure Analysis Team may help to inform the prioritization of remedial work, by identifying conditions more likely to result in an ignition event. In any event, until PG&E resolves its significant backlog of remediation work, risky conditions will remain in the field.

For example, PG&E's recently established Asset Failure Analysis Team causally connected a June 2021 ignition to a broken cross arm. The cross arm was first identified in connection with an August 19, 2019 patrol. The tag had a due date of February 19, 2020 (a 6-month Priority E tag). The repair was permitted and ready for construction in April 2020 (which was already late), but was never completed. On September 10, 2020, the notification was reassessed and the crew lead requested that the work be expedited before the 2021 fire season (that is, August 30, 2021). On June 16, 2021, there was an ignition, which PG&E's Preliminary Ignition Investigation Report ("PIIR") attributed to "a rotten and decayed secondary, wooden cross arm failing and igniting the light, flashy fuels below the pole." As of the date of the PIIR, there were 1290 open notifications on the same circuit associated with common ignition drivers, of which 886 were past due and 256 were due within six months. Of these, 66 open notifications were associated with cross arms, of which 55 were past due and 11 were due within six months. The Monitor team recognizes PG&E's Asset Failure Analysis Team and the candid analysis contained in PIIRs, but until more is done by PG&E with the information in such reports, that is, actually addressing these risks in the field, PG&E's equipment will continue to cause unnecessary ignitions.

3. Field Safety Reassessments ("FSRs")

The FSR process, by which structures with pending, unresolved tags are periodically reviewed, is a stopgap measure put in place by PG&E to ensure that conditions do not further deteriorate while electric remediation work is pending, given the significant backlog of such work. While the Monitor team understands the need to reassess conditions when they are not timely remediated, FSRs divert resources away from enhanced inspections and execution of electric remediation work, and would, for the most part, be altogether unnecessary if PG&E were to address its asset repair tags in a timely way. In essence, while the FSR process is necessary, it has served to somewhat normalize the practice of not timely addressing "lower priority" repair tags, which can and do result in ignitions, as exemplified by the June 16, 2021 ignition identified above. While that ignition was small, had weather, moisture, or location circumstances been different, so too could have the outcome—PG&E cannot leave these matters to luck.

E. Recordkeeping

Recordkeeping issues that affect other operations also exist for electric infrastructure assets. PG&E has various recordkeeping issues that limit its electric infrastructure inspections and remediation programs, as PG&E does not maintain traceable, verifiable, accurate, and complete records of its electric infrastructure.

1. Paper Records

PG&E has migrated to mobile devices and applications for many aspects of its inspections program. This is an improvement. However, PG&E still uses paper records to document remediation work performed, for idle facilities, and to redline as-built drawings. This use of paper records can result in inaccuracies when information is migrated to electronic records due to transposition errors. Use of paper records also delays information transmission to the electronic system of record, which can result in data discrepancies between the paper and electronic databases until the transposition occurs. Data analysis is also more difficult with paper records.

2. Asset Location Issues

PG&E records do not always accurately reflect the existence and/or location of its assets. In some instances, records misidentify the location, type, or even the existence of an asset, resulting in inefficient and missed inspections. In both 2019 and 2020, there were issues with the accuracy of asset geo-location data provided to inspectors. These issues have existed for years, and until recently, PG&E has been slow to remediate the problem. In 2021, PG&E worked on pilots to identify these inaccuracies and verify location data prior to inspections to minimize disruptions to inspection execution. Efforts to validate the asset registry in 2021 resulted in the addition of thousands of assets to PG&E's inspections work plan, that is, assets that were supposed to be in the 2021 plan but were not initially due to faulty records. Given the large number of structures and the need for field personnel to verify electric asset location data and reconcile internally conflicting records databases, PG&E estimates it could take years to verify the accuracy of all structure location data and for its records to accurately reflect the existence of all electric assets in its service territory. The Monitor team suggests that greater resources be dedicated to these efforts moving forward as PG&E over the past several years has not devoted an appropriate level of attention and resources to these issues.

3. Asset Component Age

Probation Condition No. 9, imposed by Judge Alsup in 2020, requires PG&E to record the age of critical electric transmission tower components in HFTDs; to make conservative assumptions where age is unknown; to implement a program to determine the expected useful life of critical components; and incorporate that information into its risk-based asset management programs. (Apr. 29, 2020 Order Modifying Conditions of Probation, Dkt. 1186). The purpose of this probation condition is, in essence, to prevent wildfires by alerting PG&E that a transmission structure component, the failure of which could cause an ignition, is approaching the end of its useful life and should be replaced—like, according to state authorities, the C-hook that should have been replaced but instead failed and caused the Camp Fire and related 84 deaths and property damage. While PG&E experienced some delays in compliance with this probation condition, PG&E is now on track to comply. This is a substantial positive development.

PG&E's effort to collect component-level age data and to apply conservative assumptions where such data are not available is ongoing, and PG&E plans to complete its work for all 550 HFTD transmission circuits by the end of 2022. Currently, PG&E projects that by March 31, 2022 it will have developed risk models for each critical component grouping, incorporating component age, certain hazards, and wind threats to calculate expected useful life, while incorporating that data into its electric asset management plan. It is important that PG&E maintain focus and sustain progress to ensure this project is timely completed after probation ends.

4. Other Recordkeeping Issues

Recordkeeping issues have caused other problems in the electric space. A 2020 audit indicated there were 41,000 structures with missing or incomplete inspection records. In March 2021, PG&E self-reported to the CPUC that enhanced inspections were not performed on 24 hydroelectric substations. Recordkeeping gaps caused this oversight.

It bears mention that PG&E, for the most part, is now self-identifying many of these issues. Continuing to provide resources to internal teams to identify and remediate recordkeeping issues will be critical, as well as empowering those employees to raise matters and address them as they are identified, after probation ends.

IX. SYSTEM HARDENING PROGRAM

PG&E's system hardening program is a multi-year project aimed at reducing wildfire risk by enhancing PG&E's electric distribution system infrastructure through asset replacements, upgrades, undergrounding, and other means. According to the Company, system hardening is one of the most, if not the most, impactful wildfire mitigation initiatives the Company can undertake.

Over the past three years, PG&E's system hardening program has increasingly revolved around mitigating wildfire risk. Importantly, PG&E takes into account wildfire risk at several points in the process from identifying, scoping, and approving system hardening projects. While system hardening mileage targets have decreased over the past couple years, PG&E is on track to meet its target for 2021 and plans to ramp up mileage in 2022 and 2023.

PG&E faces certain challenges with respect to system hardening. In particular, PG&E personnel report that cities and counties can take a very long time to review and grant permits. Additionally, PG&E's ability to scale up annual system hardening mileage is subject to the impact of potential wildfires (that is, PG&E's annual hardening plans are oftentimes impacted by the need to rebuild areas destroyed by wildfires), and PG&E's ability to secure necessary resources, both personnel and financial.

A. System Hardening Approval Process

PG&E's system hardening planning function identifies potential electric system hardening projects using risk-based criteria, for example: (1) risk models that identify high-risk areas; (2) downed wires; (3) clusters of repair tags in the same geographic area; (4) whether system hardening in certain areas can help prevent Public Safety Power Shutoff ("PSPS") events; and (5) whether an area needs to be rebuilt due to wildfire damage. In addition, PG&E is increasingly seeking to underground its assets, thereby significantly mitigating future risk. PG&E has also engaged Public Safety Specialists (PSSs), who identify high-risk areas through on-the-ground review of PG&E's

service territory and electric assets. PG&E then incorporates those learnings into system hardening planning and project selection.

B. Decreasing Targets

In 2019, PG&E set a target of hardening all electric distribution assets in Tier 2 and Tier 3 HFTD areas (spanning approximately 7,100 miles) by approximately 2029. As part of this initial plan, PG&E set a target of hardening 150 miles in 2019 and forecasted 600 miles per year for 2020-2022. PG&E later reduced its 2020 forecast mileage to a target of 220 miles and then later PG&E reduced its 2021 target to 180 miles.

This trend of reducing system hardening mileage targets over the past couple of years does not comport with the Company's position that system hardening is the most effective wildfire mitigation measure. Using the initial 2019 Wildfire Safety Plan as a benchmark, if anything, the Monitor team would have expected to see these targets increase, not decrease, given the increasing threat of wildfires. PG&E's reasoning for decreasing the targets in 2020 from the original forecast—that the original forecasts were ambitious to begin with—is unsatisfactory, given that these were PG&E's own proposed goals. Had the Company planned and allocated sufficient resources, it could have made more progress.

C. 2021 System Hardening

For 2021-2023, PG&E's criteria for its system hardening program includes: (1) 80% of system hardening miles constructed by PG&E in 2021-2023 must be (a) located in the top 20% of the riskiest areas according to the new risk model, (b) fire rebuild miles, or (c) PSPS mitigation miles; and (2) 10% of all system hardening miles in 2021-2023 must be underground or line removal work. This year, PG&E has hardened approximately 168 miles, as of November 4, 2021. Notably, only approximately 36.5 of the 168 miles were located in the top 20% of the riskiest areas in this first year of PG&E's three year plan. Nevertheless, PG&E personnel anticipate that PG&E will harden approximately 200 total miles in 2021 (including traditional hardening in place, fire rebuild work, and PSPS mitigation work), thereby exceeding the 2021 target of 180 miles.

Out of the approximately 168 miles currently constructed, approximately 30% of the miles are either underground or line removal projects, which far exceeds PG&E's target for at least 10% of its system hardening work to be undergrounded miles (or removal of lines altogether). By the end of 2021, PG&E expects that approximately 32% of its system hardening miles will be either underground or line removal projects. These metrics represent a significant improvement and risk reduction over years past. Sustained aggregate progress in the future will also be important, in addition to percentages going forward.

D. Undergrounding Initiative

In July 2021, PG&E announced an initiative to underground approximately 10,000 miles of electric distribution lines in HFTDs. The Monitor team applauds PG&E's commitment to undergrounding to mitigate wildfire risk but notes that some serious questions and issues remain regarding PG&E's implementation of the undergrounding initiative.

For example, PG&E did not specify a timeframe by which it expects to complete the undergrounding of 10,000 miles, but indicated an intention to harden up to 1,000 miles per year as part of the program. As of October 20, 2021, PG&E expects to underground approximately 66 miles in 2021 and a total of 327 miles from 2021-2023. Notably, there is substantial skepticism among PG&E field personnel that PG&E can feasibly underground more than 500 miles per year using current technology and hardening methodologies. Other open questions and issues are discussed below, and relate to matters of permitting, resources (both personnel and financial), and diversion of resources as a result of wildfire rebuild efforts.

E. Challenges

1. Permitting

While traditional system hardening projects typically take approximately 12 to 18 months from planning to completion of construction, PG&E typically completes fire rebuild projects within a few months. PG&E personnel report that the timing discrepancy is attributable to two factors: (1) for traditional system hardening projects, cities and counties can take a very long time to review and grant permits; and (2) for fire rebuild projects, California governmental agencies assist with expediting permitting to help restore power. PG&E should attempt to work with governmental agencies to expedite permitting for traditional system hardening projects, not just those involving areas damaged by fires.

2. Scaling of the Distribution Hardening Program

PG&E personnel report that scaling up from 200-300 miles per year (i.e., 2020-2021) to approximately 1,000 miles per year in later years will likely present two substantial challenges. One challenge is that PG&E may have difficulty securing the necessary volume of qualified contractors to complete the work. Additionally, system hardening is the most expensive mitigation effort, and increasing annual system hardening funding by more than twofold could mean that other risk mitigation work receives less funding. So while PG&E makes investments into its long-term hardening program, it will remain important to ensure that near-term wildfire mitigation measures receive appropriate resources.

3. Fire Rebuild Work

Like many other types of risk mitigation work, system hardening work is often delayed or de-prioritized by annual wildfires. PG&E must divert resources to rebuild fire damaged areas, which impacts PG&E's ability to carry out hardening efforts according to its plans and risk models. In mid-2019, PG&E began counting projects built to the fire rebuild standard toward its annual system hardening goal. These projects involve replacing and rebuilding assets burned by a wildfire (including those caused by PG&E). Notably, without including the fire rebuild miles in the total system hardening miles—including those in the footprint of the Camp Fire in Butte County—PG&E would not have satisfied its annual system hardening WMP target for 2019 or 2020.

X. WILDFIRE EMERGENCY PREPAREDNESS AND RESPONSE

Since the 2017 wildfires, PG&E has worked to improve its emergency response and situational awareness capabilities to address fire risk. PG&E has made significant progress and refinements to its PSPS program, which has prevented over one thousand potential ignitions. The Company has also innovated through its enhanced power line safety settings program ("EPSS").

A. PSPS

The PSPS program is often unpopular but it is effective and has almost certainly saved lives. According to PG&E records, since PG&E began its PSPS program in 2018, it has reported roughly 1,450 damage or hazard incidents across 19 actual PSPS events, each of which could have resulted in an ignition. The Monitor team understands that a more ideal situation would be that PG&E had historically (that is, over the last generation at least) invested more in hardening infrastructure and in maintaining vegetation in a way that would obviate the need for proactive deenergization on the scale used by PG&E today. Unfortunately, however, the current state of affairs requires PG&E to preemptively deenergize assets in areas with forecasted adverse weather conditions of sufficient severity and high fire potential. The Monitor team fully acknowledges the burden PSPS places on affected customers. But again, there is little dispute that PSPS has saved lives, and potentially many lives, in the current wildfire environment.

Since launching the PSPS program in 2018, PG&E has continued to develop, improve, and automate it. For example, PG&E has: (1) enhanced the granularity and resolution of its weather and fire potential forecasting models; (2) improved its customer impact mapping accuracy; (3) utilized

PSPS impact mitigation measures; (4) improved customer notifications; (5) increased the number of Public Safety Specialists to better coordinate with external parties; (6) created the Safety and Infrastructure Protection Team to assist with field observation and mitigation efforts; (7) shortened post-event restoration times; and (8) most recently, incorporated vegetation management and asset data into its scoping decisions.

Notwithstanding this progress on the PSPS program, certain aspects of the PSPS program warrant additional attention.[4] First, during multiple 2019, 2020, and 2021 PSPS events, PG&E failed to notify all account holders at impacted service points in advance of deenergization—including critical facilities and members of PG&E's medical baseline program. The Monitor team recognizes that it may not be possible to notify every single customer, but PG&E must continue improving its notification success rates. Late or no notice is not merely an inconvenience; for some customers, especially those in the medical baseline program, notification is critical.

Second, while PG&E now offers many services to impacted customers during deenergization, including Customer Resource Centers, 55% of customers recently surveyed by PG&E indicated that they were unsure or unaware of the resources PG&E provides during PSPS events to customers with disabilities or other medical and acute needs. For these critical services to be useful, customers must know about them.

B. Enhanced Power Line Safety Settings

PG&E took quick action in the wake of the Dixie Fire to reduce ignitions by adjusting settings on line reclosers and circuit breakers to reduce fault energy flowing through lines, thereby reducing the potential for ignition events. This process is referred to as EPSS or "fast-tripping." Since the implementation of this program in late July of this year, PG&E is reporting a 46%

[4] Nothing in this report is intended to, nor should be interpreted to, conflict with or supersede any guidelines, opinions, findings, or corrective actions issued by the CPUC or any other regulator with jurisdiction over PG&E's implementation of PSPS events.

reduction in PG&E attributable ignitions in HFTDs as compared to its three year average. As a new program, there is more data to be collected and analyzed, but the early indications are that this measure, which does result in more frequent and longer outages for customers, is preventing fires.

XI. CONTINUING CHALLENGES

PG&E needs to continue to make meaningful improvements across all aspects of its operations to protect the citizens of California as well its employees and contractors. Those improvements are more challenging given the continuing challenges PG&E faces.

A. Leadership Turnover

One overarching item across the entire Monitorship is that virtually all areas of the Company have seen substantial and repeated turnover in leadership. There have been five Chief Executive Officers; six heads of Gas Operations; four heads of Electric Operations; and five heads of the Safety Organization, with the current head in an interim role, during the Monitorship. The Company also has implemented numerous changes to its organizational structure that have variously altered management and employee reporting relationships. In addition to the management, reporting, and leadership changes, there have been no less than 45 different members of the Board of Directors since 2017.

These leadership changes have an impact on the organization and can make necessary culture changes even more difficult. Employees who have been with PG&E for 20 or 30 years can become disillusioned with what they see as ever-changing direction and messaging, and a lack of continuity of programs and priorities. Those employees need to understand that the core values of safety, speaking up, and doing the right thing remain unchanged.

As an initial step, it is important that PG&E's Board of Directors focus on hiring and retaining the right set of leaders to move PG&E forward. It is important for PG&E to have real stability in the coming years in each aspect of its leadership.

B. Records Integrity

PG&E still struggles with records. PG&E needs to continue to devote substantial resources to enhancing its records, particularly in Electric Operations. Traceable, verifiable, accurate, and complete records underpin safe operations, from permitting employees to accurately understand asset health and inform repair decisions, to ensuring that vegetation issues are appropriately logged, communicated, and remediated. The lack of traceable, verifiable, accurate, and complete records was at the heart of the issues that led to the San Bruno gas explosion. In the wake of San Bruno, PG&E undertook an effort to overhaul its Gas Operations system of record to ensure its accuracy. However, no such effort was successfully implemented in Electric Operations and PG&E is still playing catch-up to achieve in Electric what it sought to do in Gas years ago—build an accurate system of record that reflects the reality of what is in the field.

C. Contractor Management

PG&E, consistent with industry practice, substantially relies on its contract workforce to perform wildfire mitigation efforts. PG&E needs to continue to focus on enhancing its relationship, communications, oversight, and expectations of its contract workforce. PG&E must also do more to try to achieve continuity of the contract workforce. Whether it be vegetation management or electric infrastructure inspections, PG&E's contract workforce has experienced high turnover in the past several years. For example, there has been a different group of contractors involved in electric equipment inspections each year since PG&E implemented its WMP. Similarly, the vegetation management contractor workforce regularly turns over. That turnover, like leadership turnover, prevents continuity in PG&E's programs, and results in a lack of familiarity and understanding of PG&E's service territory and equipment. With the high turnover, there is little opportunity to instill necessary cultural values into that workforce, including a "safety first" mentality, as described in greater detail below.

D. Long-Term Safety Projects

PG&E is demonstrating a willingness to take an unprecedented and significant step to make its infrastructure more fire resilient—such as its announcement to underground over 10,000 miles of distribution line in high threat areas. However, it will likely take at least 15 to 20 years (even assuming an ambitious and accelerated 500 miles, even 700 miles, of undergrounding per year) for these efforts to be completed. PG&E must commit to these long-term projects through its planning, budgeting and operations. It cannot put forth lofty goals and then let progress slow or deadlines slip once probation ends.

E. Near-Term Execution of Work

During those 15 to 20 years, progress on long-term projects alone will not be a panacea. Near- and intermediate-term planning and execution of other work will remain critical. The safety of the residents of PG&E's service territory requires that current PG&E wildfire mitigation efforts be executed with precision. This is not an easy task—especially given the vast contract workforce that PG&E utilizes to conduct so much of its wildfire mitigation work—but it is necessary due to the unforgiving and wildfire-prone service territory in which PG&E operates. In the vast majority of the country, the consequences of vegetation contact with a power line or the failure of electrical equipment are oftentimes reliability issues, that is, potential power outages. In PG&E's service territory, the consequences of a single misstep—a missed hazard tree, the failure to replace a corroded C-hook—can be death and destruction. Currently, as reflected by our inspections findings reported above, there are too many missteps.

Achieving flawless execution of work will take more than just technical skill and oversight of work in the field—it will require the adoption of a safety first mentality that permeates the entire organization and becomes embedded in the DNA of PG&E's employees and its contractors. Such a mentality is currently missing. A safety first mentality cannot just be a talking point at meetings or some mantra that is repeated to the point that it loses meaning with employees. For example, PG&E has a stated mission to be the safest utility in the United States—it has been saying that for some time. However, our field inspections of PG&E's vegetation management work and electric equipment continue to find issues that were missed by PG&E workers in the field, year over year. Many of these issues, like the identification of a missed hazard tree, or the assessment of pole damage, can present "close call" situations where someone not erring on the side of caution might decide to leave the risk in the field instead of mitigate the problem. PG&E must instill in its workforce, including its management, to err on the side of caution, regardless of any cost-cutting initiatives or budget targets. And PG&E must empower employees to remove the risk without being second-guessed. Too many employees have expressed skepticism about PG&E's actual commitment to safety, being able to stop jobs and deliver bad news. It does not matter if the employees are "correct" or not today; their broad perception itself is a risk factor. PG&E has attempted to change the DNA of its workforce on these issues, but it must sustain those efforts going forward.

F. Attention to Resources in Gas Operations

In its efforts to overcome all of these challenges, PG&E must also be cognizant of and careful of focusing too much on electric and wildfire mitigation and allowing backsliding on the progress made to date in Gas Operations. Specifically, PG&E cannot pull too many resources from Gas Operations without cannibalizing the talent necessary to maintain operations. Numerous gas leaders and managers have moved over to focus on wildfire mitigation efforts—both on a temporary and permanent basis. While that work is critically important, PG&E must ensure that there is an appropriate depth of talent and experience in Gas Operations as well.

XII. CONCLUDING REMARKS

There is no doubt that PG&E has improved during the term of the Monitorship in both Gas and Electric Operations and the Company's practices are becoming safer. Unsurprisingly, much more progress has been made on the Gas Operations side of the Company during the more than eleven years since San Bruno than in Electric Operations in the fewer years since the Wine Country wildfires of 2017. The Monitor team does not doubt the sincerity of the efforts of PG&E leaders facing these safety challenges. But results on the Electric Operations side have been inadequate and substantial additional improvement and investment is required after probation ends. Further progress will require sustained commitment in the face of real challenges. And it cannot come at the expense of cannibalizing substantial progress made in Gas Operations and Compliance and Ethics.

The first people we met with after the Monitorship effort was underway were the surviving family members of some of the San Bruno victims. They should know that the tragic deaths of their loved ones did prompt change that hopefully will spare others from experiencing the losses they and their loved ones endured from prior PG&E failings in Gas Operations. We also hope that the initial progress we have seen on the Electric Operations side will over time substantially reduce risk from wildfires and the death and destruction they can cause.

On a final note, we strongly encourage policymakers to keep an open mind about whether reforms are possible in state regulations and oversight policies. Again, we do not doubt the sincerity of efforts. But doing "more of the same" may not be enough on its own, given that often PG&E substantially complied with state mandates and goals, in important respects at least, and terrible fires, deaths, and destruction nonetheless occurred. Perhaps regulatory changes, or experiments with new approaches, may yield better results in light of recent history and learnings.

TABLE OF EXHIBITS

EXHIBIT 1: SAN BRUNO GAS EXPLOSION VICTIMS & WILDFIRE VICTIMS FROM WILDFIRES ATTRIBUTED TO PG&E BY CAL FIRE

San Bruno Gas Explosion Victims (2010)[1]

1. Lavonne Bullis, 82
2. Greg Bullis, 50
3. William Bullis, 17
4. James Franco, 58
5. Jacqueline Greig, 44
6. Janessa Greig, 13
7. Jessica Morales, 20
8. Elizabeth Torres, 81

Butte Fire (September 9 – October 15, 2015, Butte County)[2]
877 Structures Destroyed, 70,868 Acres Burned, 2 Killed

1. Owen Goldsmith, 80
2. Mark McCloud, 65

Atlas Fire (October 8, 2017 – February 19, 2018, Napa County)[3]
120 Structures Destroyed, 51,624 Acres Burned, 6 Killed

1. George Chaney, 89
2. Sally Lewis, 90
3. Charles Rippey, 100
4. Sara Rippey, 98
5. Teresa Santos, 50
6. Edward Stone, 79

Cascade Fire (October 8, 2017 – February 19, 2018, Yuba County)[4]
264 Structures Destroyed, 9,989 Acres Burned, 4 Killed

1. Stanley Coolidge, 78
2. David Patrick Culp, 76
3. Roseann Hannah, 53
4. Sandra Picciano, 77

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[1] http://www.cnn.com/2010/US/09/22/california.pipeline.explosion/index.html; https://abc7news.com/archive/7694483/; https://abc7news.com/archive/7660103/; https://www.mercurynews.com/2010/09/13/san-bruno-fire-victim-jessica-morales-20-wanted-to-be-a-fashion-designer/; https://latimesblogs.latimes.com/lanow/2010/09/81-year-old-woman-named-as-fourth-fatality-victim-in-san-bruno-gas-explosion.html.

[2] https://www.fire.ca.gov/incidents/2015/9/9/butte-fire/; https://www.kcra.com/article/coroner-80-year-old-identified-as-2nd-man-killed-in-butte-fire/6424962.

[3] https://www.fire.ca.gov/incidents/2017/10/8/atlas-fire-southern-lnu-complex/; https://www.kqed.org/forum/2010101862302/remembering-those-who-died-in-the-north-bay-wildfires.

[4] https://www.fire.ca.gov/incident/?incident=608ed849-d1ec-4b0d-a477-d1b8e9c7e6dd; https://www.kqed.org/forum/2010101862302/remembering-those-who-died-in-the-north-bay-wildfires,

Nuns Fire[5] (October 8, 2017 – February 19, 2018, Sonoma County)[6]
1,355 Structures Destroyed, 56,556 Acres Burned, 3 Killed
1. Garrett Paiz, 38
2. Lee Chadwick Rogers, 72
3. Daniel Southard, 71

Redwood Valley Fire (October 8, 2017 – February 19, 2018, Mendocino County)[7]
546 Structures Destroyed, 36,523 Acres Burned, 9 Killed
1. Irma Bowman, 88
2. Roy Bowman, 87
3. Janet Kay Costanzo, 71
4. Elizabeth Charlene Foster, 64
5. Jane Gardiner, 83
6. Kai Shepherd, 14
7. Kressa Shepherd, 17
8. Steve Bruce Stelter, 56
9. Margaret Stephenson, 86

Camp Fire (November 8-15, 2018, Butte County)[8]
18,804 Structures Destroyed, 153,336 Acres Burned, 84 Killed
1. Joyce Acheson, 78
2. Herbert Alderman, 80
3. Teresa Ammons, 82
4. Rafaela Andrade, 84
5. Carol Ann Arrington, 88
6. Julian Binstock, 88
7. David Bradburd, 70
8. Cheryl Marie Brown, 75
9. Larry Alan Brown, 72
10. Richard Clayton Brown, 74
11. Andrew Burt, 36
12. Joanne Caddy, 75
13. Barbara Jean Carlson, 71
14. Vincent Mario Carota, 65
15. Dennis Clark Jr., 49
16. Evelyn Cline, 81
17. John Arthur Digby, 78
43. T.K. Huff, 71
44. Gary Lee Hunter, 67
45. James Warner Kinner, 83
46. Warren Lessard, 68
47. Dorothy Lee Mack, 88
48. Sara Magnuson, 75
49. Joanne Dolores Malarkey, 90
50. John Malarkey, 89
51. Christopher Maltby, 69
52. David William Marbury, 66
53. Deborah Morningstar, 65
54. Helen Pace, 84
55. Joy Porter, 72
56. Beverly Powers, 64
57. Robert Quinn, 74
58. Joseph Rabetoy, 39
59. Forrest Rea, 89

[5] Note that CAL FIRE reports the Nuns fire along with the Adobe, Norrbom, Pressley, Partrick, and Oakmont fires, collectively also referred to as the "Central LNU Complex" fires.

[6] https://www.fire.ca.gov/incidents/2017/10/8/nuns-adobe-norrbom-pressley-partrick-fires-oakmont-central-lnu-complex/; https://www.kqed.org/forum/2010101862302/remembering-those-who-died-in-the-north-bay-wildfires.

[7] https://www.fire.ca.gov/incidents/2017/10/8/redwood-valley-fire-mendocino-lake-complex/; https://www.kqed.org/forum/2010101862302/remembering-those-who-died-in-the-north-bay-wildfires.

[8] https://www.fire.ca.gov/incidents/2018/11/8/camp-fire/; https://www.buttecounty.net/Portals/30/CFReport/PGE-THE-CAMP-FIRE-PUBLIC-REPORT.pdf?ver=2020-06-15-190515-977; http://extras.chicoer.com/campfireremembrances/.

18. Gordon Dise, 66
19. Paula Susan Dodge, 70
20. Randall Paul Dodge, 66
21. Andrew James Downer, 54
22. Robert John DuVall, 76
23. Paul Ernest, 72
24. Rose Farrell, 99
25. Jesus Pedro Fernandez, 48
26. Jean Forsman, 83
27. Ernest Foss, Jr., 63
28. Elizabeth Gaal, 80
29. Sally Gamboa, 69
30. James Doyle Garner, 63
31. Richard Jay Garrett, 58
32. William Godbout, 79
33. Shirley Haley, 67
34. Dennis Hanko, 56
35. Anna Irene Hastings, 67
36. Jennifer Lynn Hayes, 53
37. Christina Heffern, 40
38. Ishka Heffern, 20
39. Matilde Heffern, 68
40. Dorothy Lee-Herrera, 93
41. Louis Herrera, 86
42. Evva Holt, 85
60. Vernice Mathilda Regan, 95
61. Ethel Colleen Riggs, 96
62. Lolene Rios, 56
63. Gerald Rodrigues, 74
64. Frederick Salazar Jr., 76
65. Phyllis Salazar, 72
66. Sheila Santos, 64
67. Ronald Schenk, 74
68. Berniece Schmidt, 93
69. John Sedwick, 82
70. Donald Shores, 70
71. Kathy Lynn Shores, 65
72. Judith Sipher, 68
73. Larry Smith, 80
74. Russell Stewart, 63
75. Victoria Taft, 67
76. Shirlee Teays, 90
77. Joan Carol Tracy, 82
78. Ellen Walker, 72
79. Donna Ware, 86
80. Isabel Webb, 68
81. Marie Wehe, 78
82. Kimberly Wehr, 53
83. Carl James Wiley, 77
84. David Young, 69

Zogg Fire (September 27 – October 13, 2020, Shasta County)[9]
204 Structures Destroyed, 56,338 Acres Burned, 4 Killed

1. Karin King, 79
2. Alaina Rowe McLeod, 46
3. Feyla McLeod, 8
4. Kenneth Vossen, 52

Dixie Fire (July 13 – Oct. 25, 2021, Butte, Plumas, Lassen, Shasta, and Tehama Counties)[10]
1,329 Structures Destroyed, 963,309 Acres Burned, 1 Killed

1. Marcus Pacheco, 53 (complications from COVID-19)

[9] https://www.fire.ca.gov/incidents/2020/9/27/zogg-fire/; https://www.latimes.com/california/story/2020-10-22/zogg-fire-lives-lost-shasta-county-california-wildfire.

[10] https://www.fire.ca.gov/incidents/2021/7/13/dixie-fire/; https://www.fs.usda.gov/inside-fs/memorial/remembering-marcus-pacheco. There has been no public report from CAL FIRE attributing the Dixie Fire to PG&E, and the Monitor team takes no position on fire cause or origin. This fire is included here due to the significant media and other attention on PG&E's equipment and the Dixie Fire.

EXHIBIT 2: FIFTEEN ORIGINAL TECHNICAL GAS ORDER REQUIREMENTS (DKT. 916)

Requirement One

Implementation of policies and procedures sufficient to comply with CPUC Decision 16-09-055 (effective Sept. 30, 2016) relating to the handling of safety citations and timely reporting of self-identified potential violations.

Requirement Two

Completion of the collection and organization of the necessary pipeline strength test records and pipeline features information for validation of the Maximum Allowable Operating Pressure for PG&E's gas transmission pipeline, consistent with the NTSB's recommendations for maintaining asset records to a "traceable, verifiable, and complete" requirement, and in accordance with CPUC Resolution L-410 (Jan. 13, 2011), Decision 11-06-017, and Decision 12-12-030.

Requirement Three

Confirmation of satisfactory strength testing of at least 500 miles of gas transmission pipelines in 2017 and 2018.

Requirement Four

Upgrading and/or retrofitting approximately 300 miles of gas transmission pipelines to accommodate in-line inspection tools in 2017 and 2018.

Requirement Five

Consistent with CPUC Decision 15-04-024, Appx E at 1 (San Bruno OII Remedy 4), implementation of Integrity Management procedures that ensure where data is missing, direct the Company to use conservative, supportable assumptions as required by ASME B31.8S.

Requirement Six

Consistent with CPUC Decision 15-04-024, Appx E at 1 (San Bruno OII Remedy 3), completion of records search to include gas transmission pipeline historical leak data into a single database of transmission leak record data.

Requirement Seven

Consistent with CPUC Decision 15-04-024, Appx. E at 1 (San Bruno OII Remedy 2), implementation of Integrity Management procedures sufficient to ensure that the data gathering processes, the data elements collected and reviewed, and company data sources meet the requirements of 49 CFR Part 192.917(b) and ASME B31.8S.

Requirement Eight

Consistent with NTSB Recommendation P-11-29, implementation of Integrity Management revisions to include (1) a revised risk model, reflecting actual recent data on leaks, failures, and incidents; (2) consideration of defect and leak data for the life of each pipeline; (3) revised risk methodology to ensure assessment methods are selected for each pipeline segment; and (4) improved self-assessment that adequately measures whether the program is effectively assessing and evaluating the integrity of each covered segment.

Requirement Nine

Implementation of policies and procedures that address threats caused by vegetation and structural encroachments on gas transmission pipelines.

Requirement Ten

Implementation of processes and procedures that for each segment of gas transmission line in High-Consequence Areas, enable PG&E to calculate the expected life of the pipe using a fracture control analysis that (1) estimates maximum flaw sizes remaining after inspections and/or strength testing; (2) estimates potential crack growth rate based on the past history of and potential pressure cycles; (3) assesses the remaining life calculations; and (4) determines appropriate methods of reassessment and frequency of reassessment of each such segment.

Requirement Eleven

Consistent with CPUC Decision 15-04-024, Appx. E at 2 (San Bruno OII Remedy 6), implementation of policies and procedures such that relevant data is incorporated in threat identification and assessment procedures for both covered and non-covered segments, including but not limited to potential manufacturing and construction threats, and leak data.

Requirement Twelve

Consistent with CPUC Decision 15-04-024, Appx. E at 2 (San Bruno OII Remedy 9), implementation of threat identification and assessment procedures such that High-Consequence Areas are prioritized consistent with 49 CFR Part 192.917(e)(3)-(4).

Requirement Thirteen

Implementation of policies designed to incorporate changed circumstances into assessment methodologies and prioritization, including Risk Management Procedure 16 ("Threat Identification") and TD 4810B-001 ("Changes to Integrity Management Pressure Testing Requirements for Unstable Manufacturing Threats"), consistent with ASME B31.8S.

Requirement Fourteen

Consistent with CPUC Decision 15-04-024, Appx. E at 2 (San Bruno OII Remedy 8), cessation of regularly increasing pipeline pressure up to a "system MAOP" to eliminate the need to consider manufacturing and construction threats, and analysis of segments that were subjected to the planned pressure increases to determine the risk of failure from manufacturing threats under 49 CRF Part 192.917(e)(3), including review of strength-testing of all segments identified as having an unstable manufacturing threat.

Requirement Fifteen

Consistent with CPUC Decision 15-04-024, Appx. E at 2 (San Bruno OII Remedy 10), implementation of threat identification and assessment policies and procedures such that cyclic fatigue and other loading conditions are incorporated into segment-specific threat assessments and risk ranking algorithm, including review of risk management procedures for appropriate treatment of cyclic fatigue and loading.

EXHIBIT 3: PG&E CONDITIONS OF PROBATION

April 3, 2019 Order, Dkt. 1040

- **Condition 1:** PG&E must fully comply with all applicable laws concerning vegetation management and clearance requirements, including Sections 4292 and 4293 of the California Public Resources Code, CPUC General Order 95, and FERC FAC-003-4.

- **Condition 2:** PG&E must fully comply with the specific targets and metrics set forth in its wildfire mitigation plan, including with respect to enhanced vegetation management. Compliance with these targets and metrics, however, will not excuse any failure to fully comply with the vegetation laws as required in paragraph 1.

- **Condition 3:** The Monitor shall assess PG&E's wildfire mitigation and wildfire safety work, including through regular, unannounced inspections of PG&E's vegetation management efforts and equipment inspection, enhancement, and repair efforts. The inspections will include both inspections of segments of power lines where PG&E has conducted its enhanced vegetation management efforts pursuant to its wildfire mitigation plan, as well as areas where enhanced vegetation management has yet to occur. The inspections will further include field interviews and questioning of PG&E employees and contractors.

- **Condition 4:** PG&E shall maintain traceable, verifiable, accurate, and complete records of its vegetation management efforts. PG&E shall report to the Monitor on the first business day of every month on its vegetation management status and progress, and make available for inspection all related records at the Monitor's request.

- **Condition 5:** PG&E shall ensure that sufficient resources, financial and personnel, including contractors and employees, are allocated to achieve the foregoing. If PG&E cannot find enough contractors, then PG&E must hire and train its own crews to trim and remove trees. To ensure that sufficient financial resources are available for this purpose, PG&E may not issue any dividends until it is in compliance with all applicable vegetation management requirements as set forth above.

May 14, 2019 Order, Dkt. 1070

- **Condition 6:** By no later than July 15, 2019, the PG&E Board of Directors, PG&E's Chief Executive Officer and certain other PG&E senior executive leaders, the Monitor, and Probation shall visit Paradise and San Bruno to gain a firsthand understanding of the harm inflicted on those communities and meet with victims and other stakeholders, such as fire-fighting personnel and/or city officials.

- **Condition 7:** A committee of the PG&E Board of Directors shall assume responsibility for tracking progress against PG&E's Wildfire Safety Improvement Plan, as approved by the California Public Utilities Commission, and the new terms of probation imposed on April 3 regarding wildfire safety. The committee is to report in writing to the Board at least quarterly, and also present orally to the Board at least quarterly, PG&E's progress in meeting the terms of the approved Wildfire Safety Improvement Plan and the April 3 terms of probation and, to the extent there are shortfalls, how PG&E will address the shortfalls.

August 7, 2020 Order, Dkt. 1243

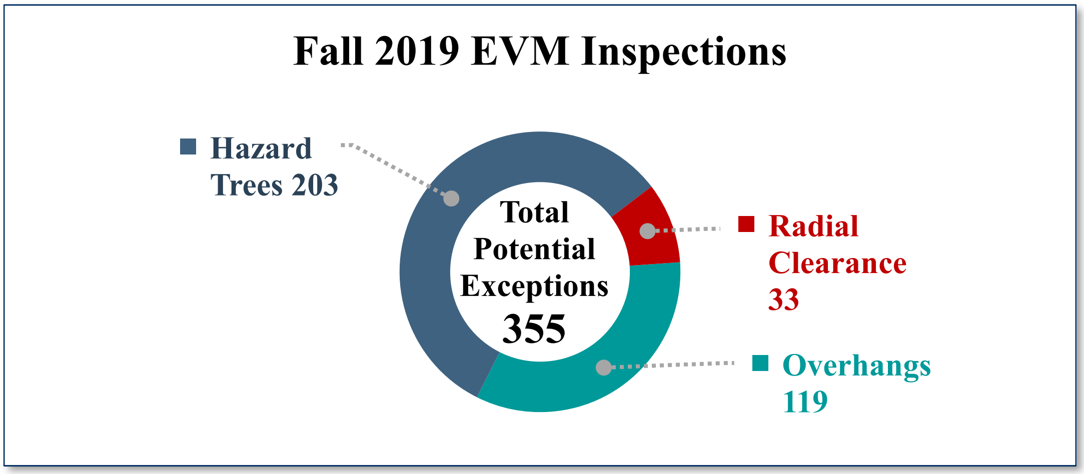
- **Condition 8:** Vegetation Condition: PG&E shall, by September 1, 2020, staff an in-house vegetation management inspection manager to oversee a number of workforce resources who will provide in-field oversight of all stages of the vegetation management process, including the enhanced vegetation management program work, to be deployed throughout PG&E's territory, including High Fire-Threat Districts (HFTDs). By the end of September 2020, PG&E will extend offers to 10 in-house field supervisors and/or inspectors, an additional 10 inspectors by the end of November, and the remaining approximately 10 inspectors by the end of January 2021. The inspectors shall conduct in-field oversight of PG&E contractors while the work is being performed, verifying and correcting any deviation from applicable scopes of work pursuant to PG&E policies and legal requirements. The inspectors shall also oversee pre-inspectors to help ensure they are clearly marking and designating trees for trimming and removal, and that tree-trimming contractors are appropriately performing their duties. Deviations from applicable scopes of work shall also be accurately recorded and reported to PG&E and the Monitor team to be used for, among other things, ongoing training of PG&E's contract workforce.

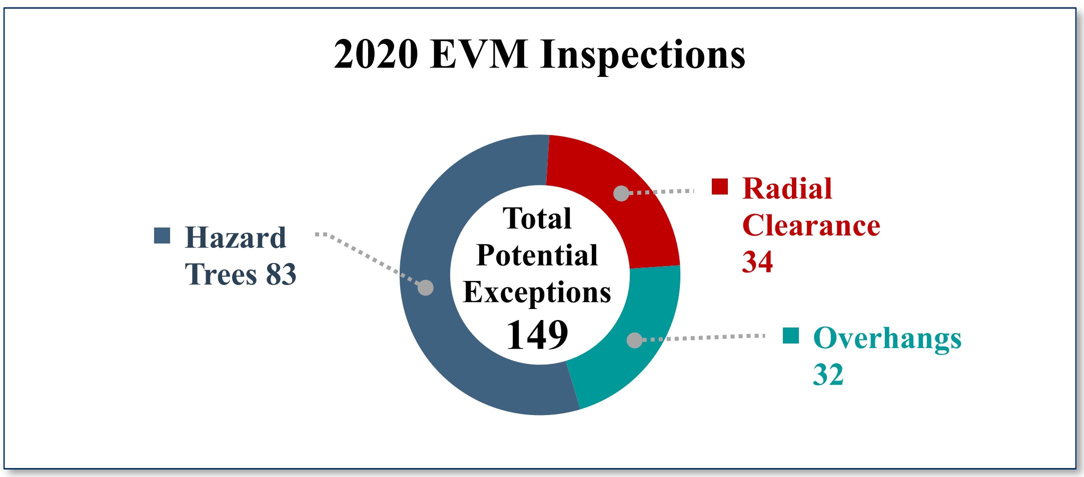
- **Condition 9:** Asset Age Condition: For certain critical transmission tower components in High Fire-Threat Districts, the failure of which may result in an ignition, PG&E shall conduct a reasonable search and, where available, record the age and date of installation of those components. For all other such critical transmission components and where asset-age records are not reasonably available, PG&E shall make conservative assumptions of such ages and dates of installation. PG&E shall also implement a program to determine the expected useful life of critical components factoring in field conditions and incorporate that information into its risk-based asset management programs. PG&E shall begin this effort (or supplement any existing or planned initiatives) immediately and provide monthly progress reports to the Monitor team.

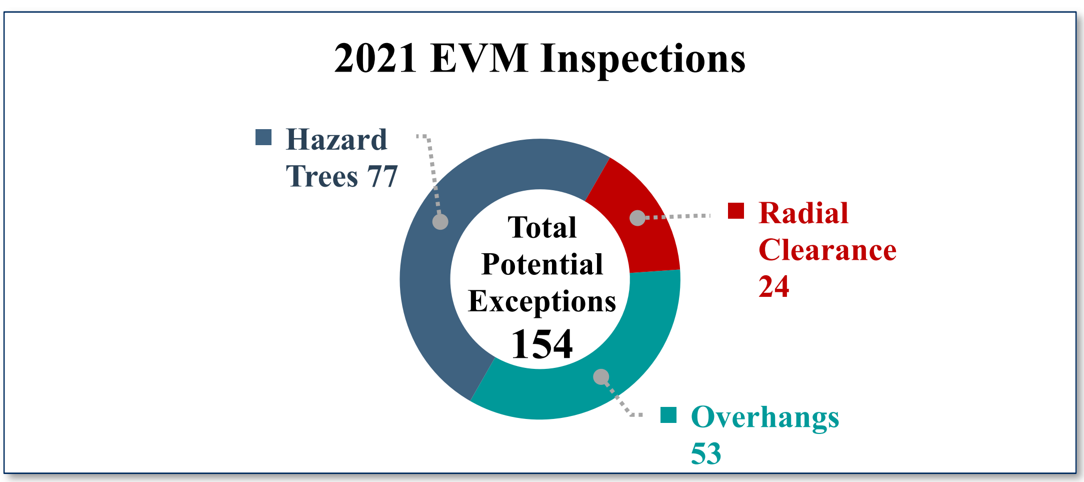
- **Condition 10:** Transmission Inspection Program Condition: PG&E shall, by the end of 2020, supplement its transmission-asset inspections program to include the following measures: (1) hire a crew of in-house and/or contract inspectors, independent from inspectors conducting transmission inspections, to oversee in the field transmission inspections while they are being conducted; (2) going forward, and subject to CAISO clearances and/or other external dependencies, revise the material loss threshold for the replacement of cold-end hardware (including C-hooks and hanger plates) in HFTDs to create a 90-day replacement requirement for such hardware with an observed material loss approaching 50%; and (3) make the prior two years of inspection reports available to transmission post-inspection review teams starting in 2021, and one year of inspection reports available in 2020.

EXHIBIT 4: EVM INSPECTION STATISTICS

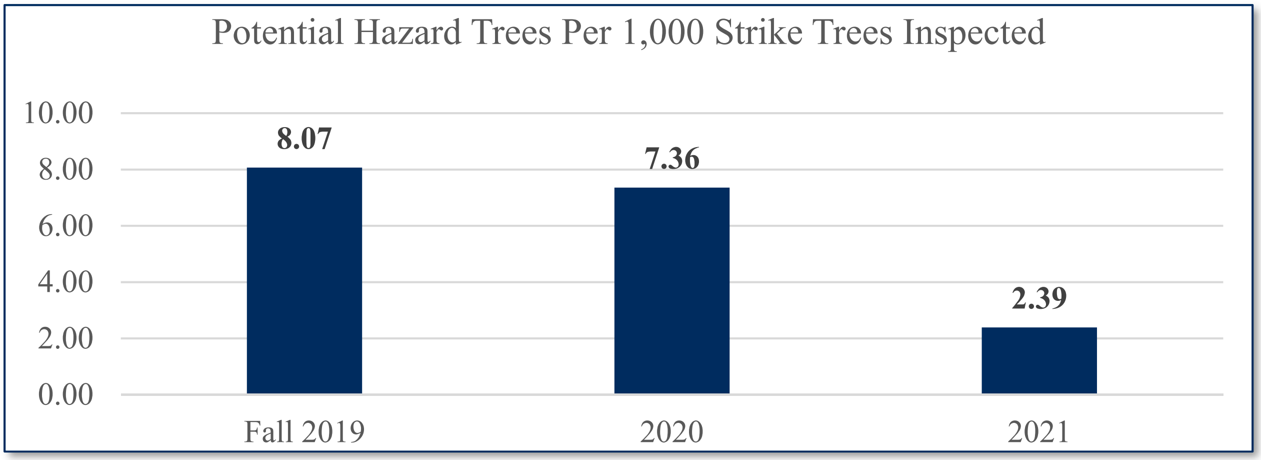
For Monitor team inspections of EVM areas from 2019-2021, the three graphs below show the number of potential exceptions observed.

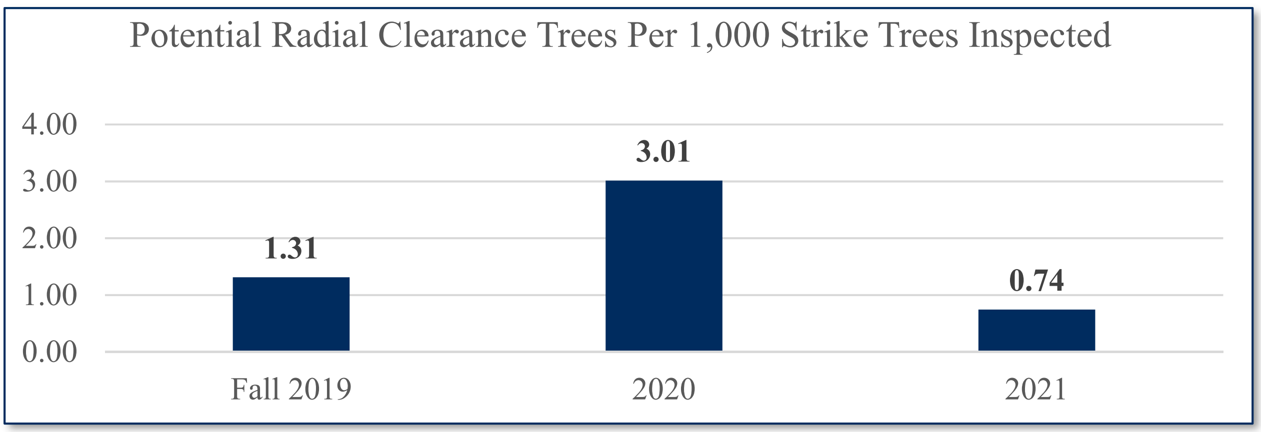






For Monitor team inspections of EVM areas from 2019-2021, the first graph shows the number of potential hazard trees observed per 1,000 strike trees inspected, the second graph shows the number of potential radial clearance issues observed per 1,000 strike trees inspected, and the third graph shows the number of potential overhang trees observed per 1,000 strike trees inspected.





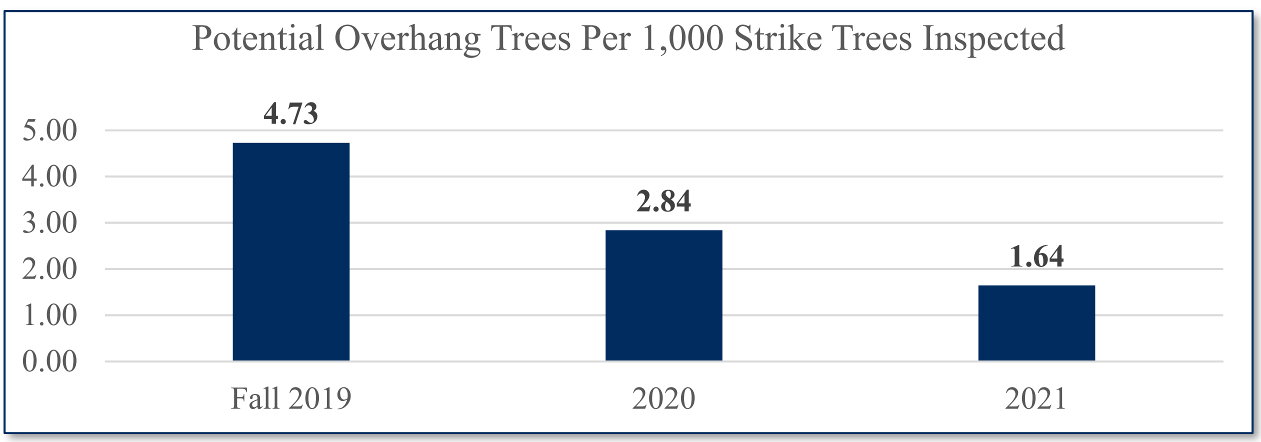
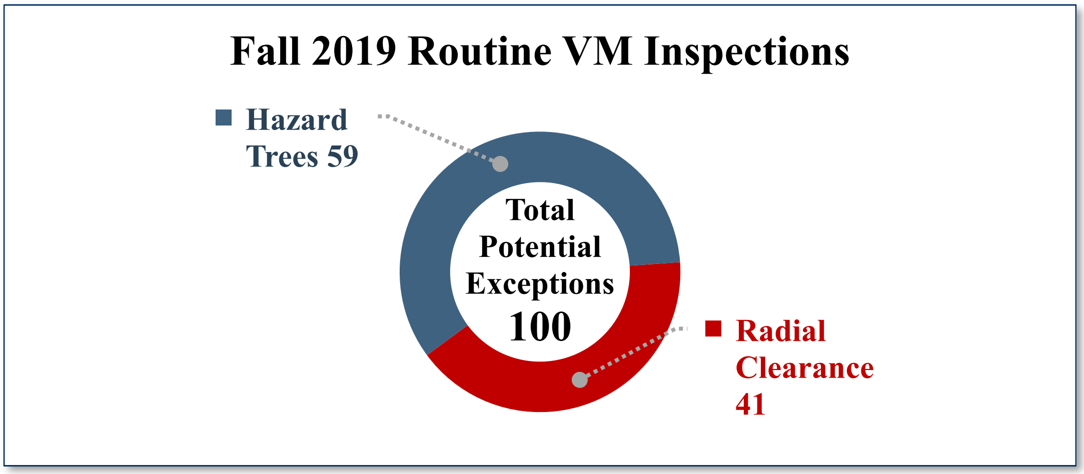
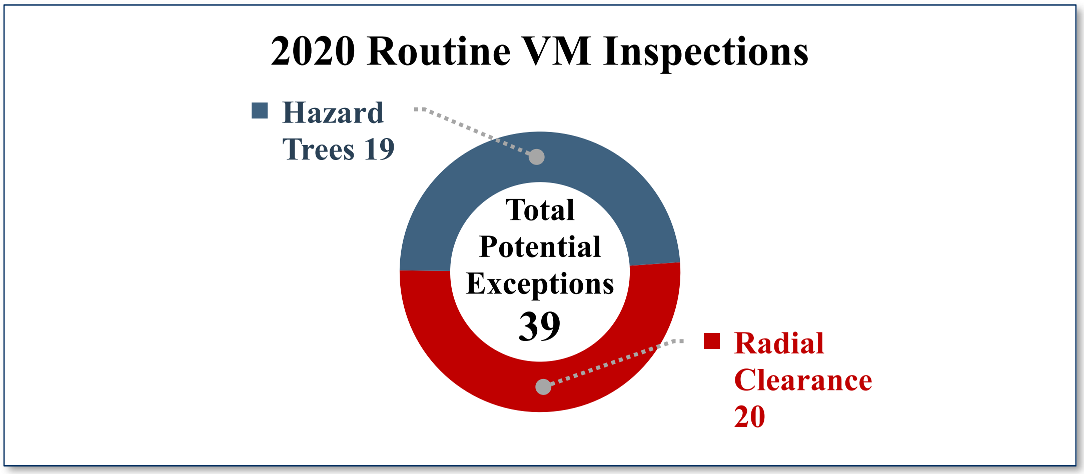
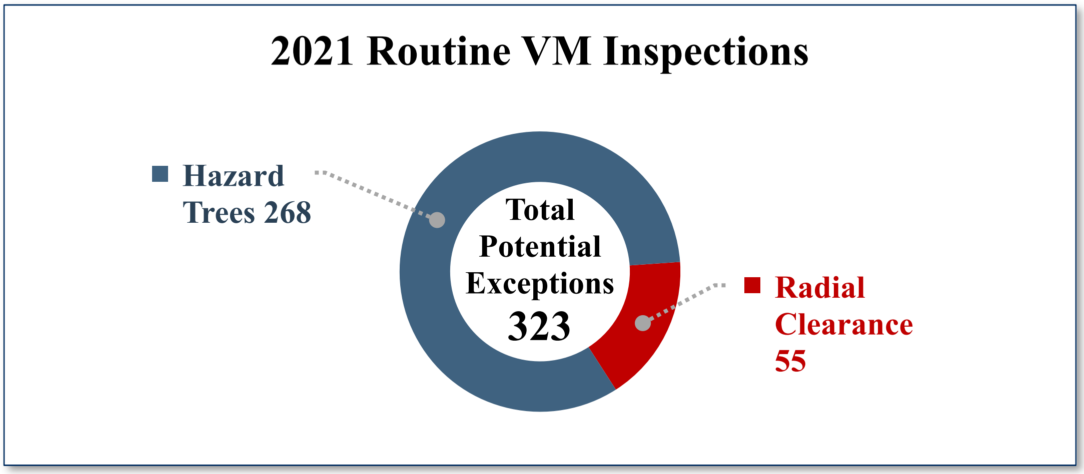


EXHIBIT 5: ROUTINE VM INSPECTION STATISTICS

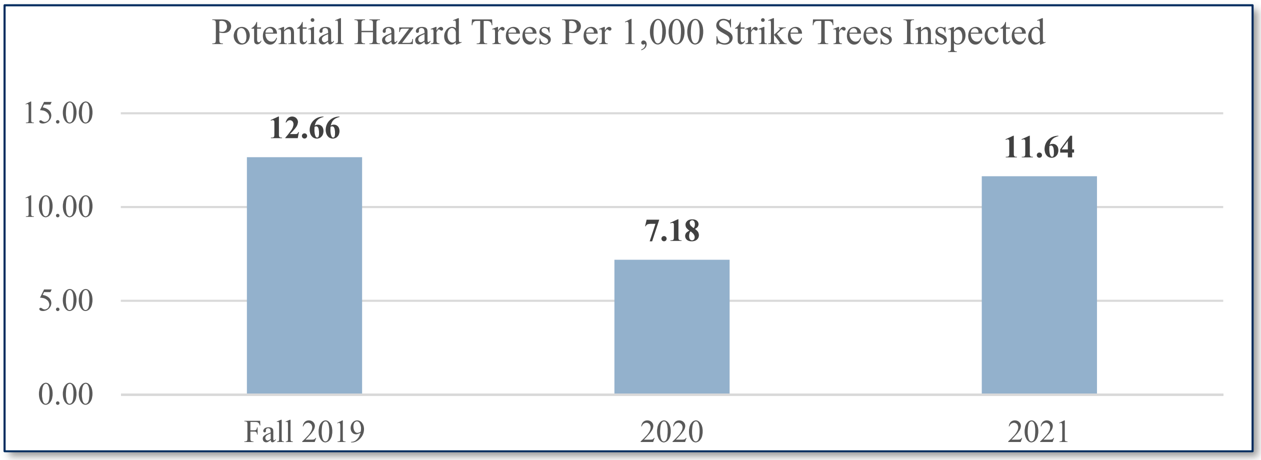
For Monitor team inspections of Routine VM areas from 2019-2021, the three graphs below show the number of potential exceptions observed.







For Monitor team inspections of Routine VM areas from 2019-2021, the first graph shows the number of potential hazard trees observed per 1,000 strike trees inspected, and the second graph shows the number of potential radial clearance issues observed per 1,000 strike trees inspected.



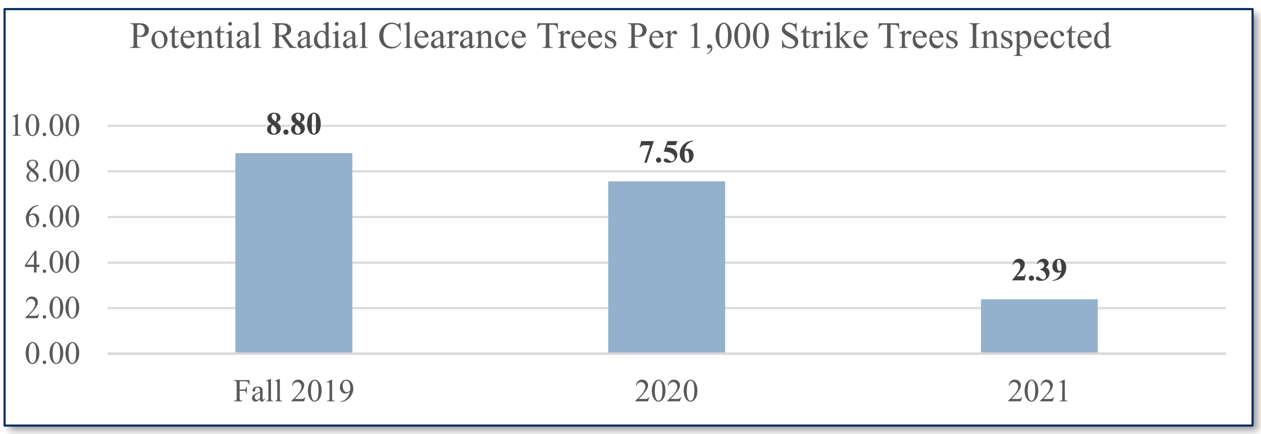


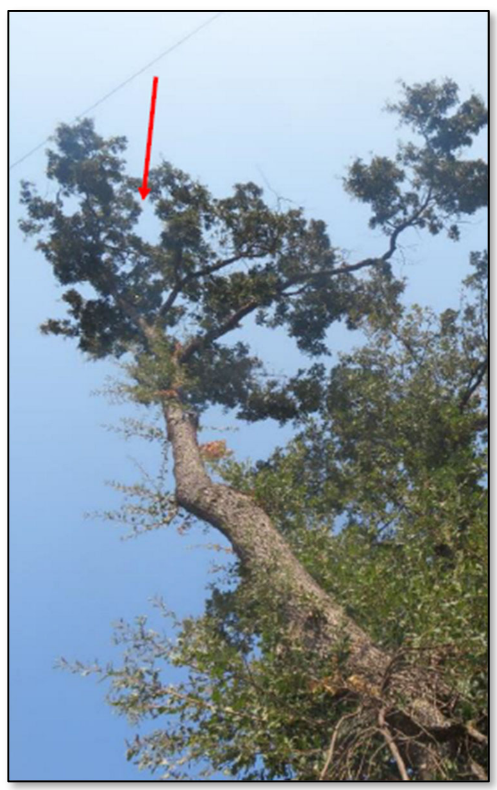
EXHIBIT 6: HAZARD TREES

Below is a hazard tree with fire damage identified by the Monitor team.

Below is a hazard tree that was dead or dying identified by the Monitor team.

Below is a hazard tree with decayed cavities identified by the Monitor team.

Below is a hazard tree with poor taper identified by the Monitor team.

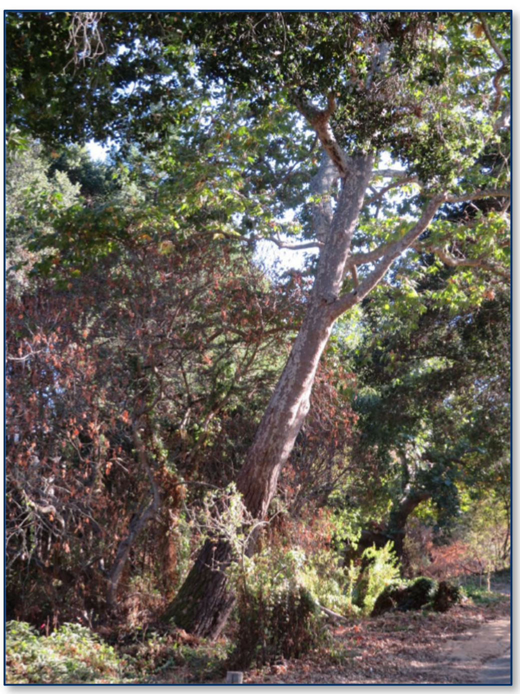


Below is a hazard tree with branch dieback and decayed cavities identified by the Monitor team.

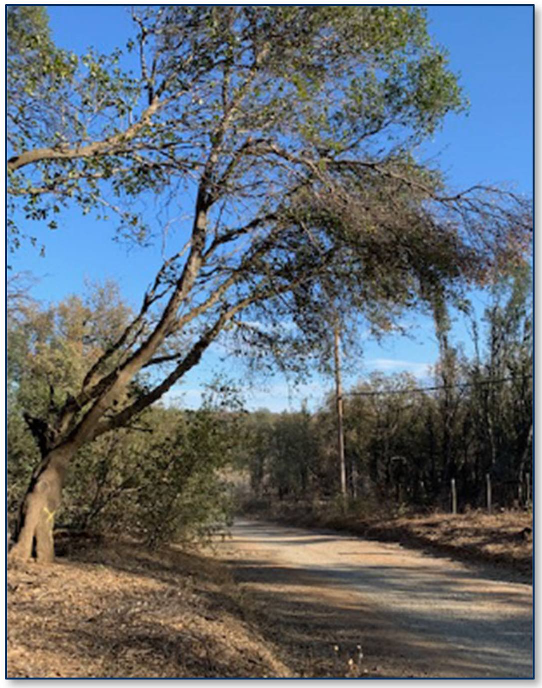
Below is a hazard tree with exposed roots identified by the Monitor team.

Below is a hazard tree with mechanical damage identified by the Monitor team


Below is a hazard tree uprooting at the base identified by the Monitor team.




Below is a hazard tree with cavities, heart rot, and cracking identified by the Monitor team.



Below is a hazard tree with cavities and rotting identified by the Monitor team.

Below is a hazard tree with severe lean towards primary conductor identified by the Monitor team.

EXHIBIT 7: VM RISK PRIORITIZATION STATISTICS

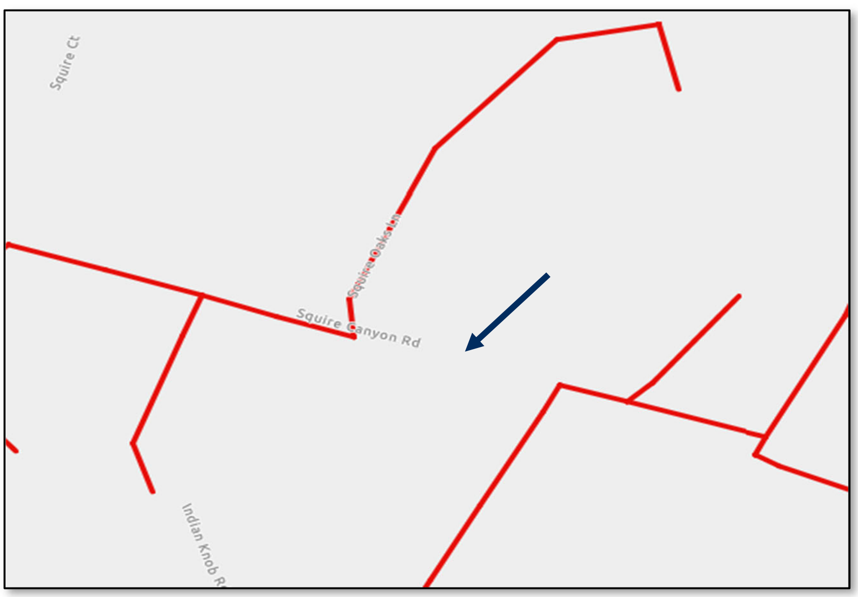
The chart below shows the percentage of EVM mileage in 2019-2021 completed in the top 10% of risk-ranked HFTD circuit miles, according to PG&E's stated risk models in those years.

	2019	2020	2021 YTD
Total EVM Work Verification Pass Miles	2,499.29	1,877.94	1,303.96
EVM Work Verification Pass Miles Within the Top 10% of HFTD Miles on the Stated Risk Model	463.94	118.93	1,079.83
Percentage of EVM Work Verification Pass Miles Within the Top 10% of HFTD Miles on the Stated Risk Model	18.6%	6.3%	82.8%

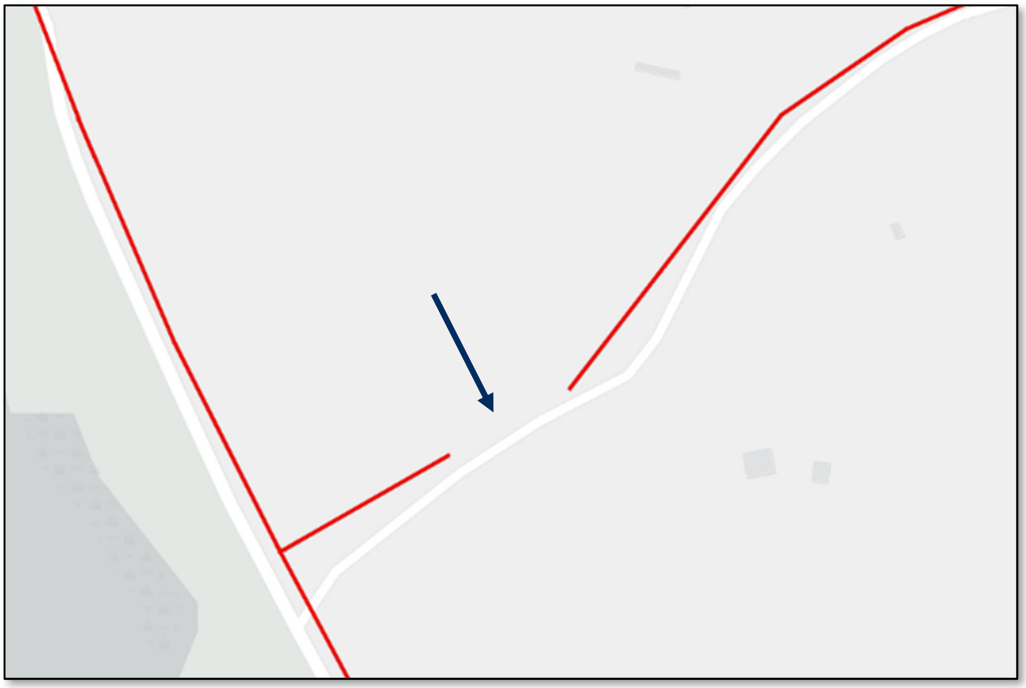
EXHIBIT 8: VM MAP INACCURACIES

On CIP_BF126-A14_638206, the actual location of a pole (blue circle with white arrow) was ~200 feet away from the location of that pole on the Arc Collector map (red circle).

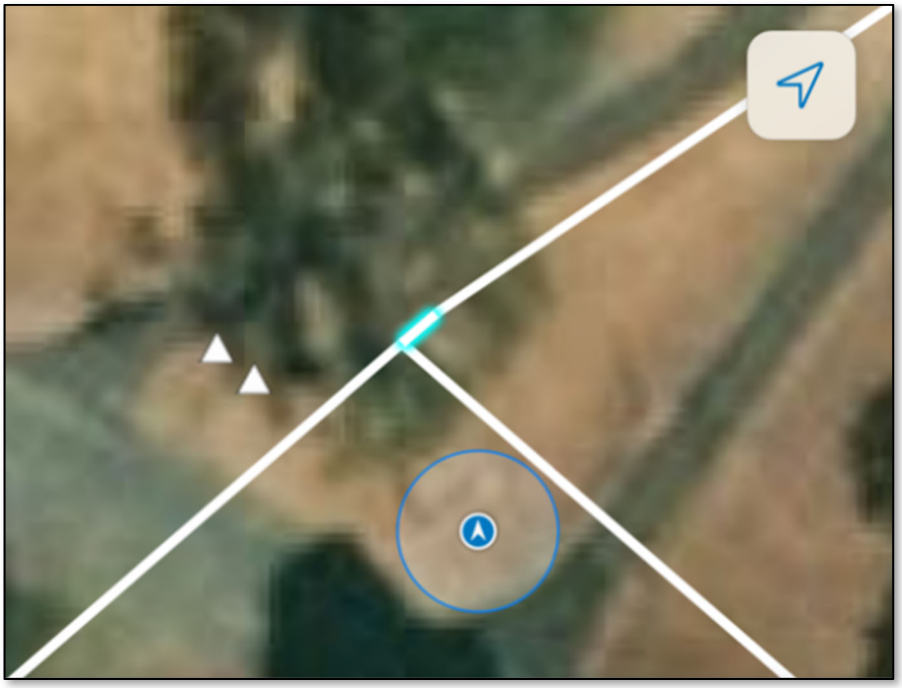
Near CIL_AY138-L08_143892, the Monitor team informed PG&E on 10/30/20 of a radial clearance issue on a segment that was missing from the Arc Collector map. That segment is still missing in 2021.



Near CIE_AJ120-I16_1746168, a segment was observed as missing from the Arc Collector map.



CIE_B127-B19_1727589 is a seven-foot long segment that does not correspond to a full span of primary conductor.



CIE_AO108-B15_1774125 (and the adjacent L-shaped segment) do not exist in the field.

CIE_AP120-K24_1757184 appears curved on Arc Collector, but the segment is a straight line in the field.

EXHIBIT 9: INCONSISTENT VM DATA

Near CIE_AJ120-K23_1744484, the Monitor team observed five trees that had been marked as "Tree Work Complete," but the Monitor team observed that the prescribed tree work had not been performed.

Vegetation Point RW: SALMON CREEK 1101

Tree Assessment Tool

Auto ID	VP_AJ120-K23_1830914_2021
Circuit Name	SALMON CREEK 1101
Unique Parcel ID	LP_AJ120-K23_843892
Nearest Conductor Segment ID	CIE_AJ120-K23_1744484
Veg Point Status	Tree Work Complete
Work Verification Status	
Tree DBH - Inches	17
Tree height - Feet	33
Dead or Clearly Dying	No
Redwood Exception	No
TAT Assessment Result	Abate
HTRS Tree Matrix Score	
HTRS Impact Matrix Score	
PI Prescription	F2B_FP-Rmv2 B .1SP/S/o/P27, ABV RD, X-Stem (3). More than 25• lean towards facilities;

The below vegetation point record shows a tree with a Tree Assessment Tool result of "Abate" but a Status of "No Work Required Under EVM." The map shows 1,541 vegetation point records in Arc Collector with the same discrepancy between the Tree Assessment Tool result and the Status.

Vegetation Point RW: DIAMOND SPRINGS 1105

Tree Assessment Tool

Auto ID	VP_AX119-B22_2016813_2021
Circuit Name	DIAMOND SPRINGS 1105
Unique Parcel ID	LP_AX119-B23_956106
Nearest Conductor Segment ID	CIE_AX119-B22_1802227
Veg Point Status	No Work Required Under EVM
Work Verification Status	
PI Company	[redacted]
Species	Interior Live Oak
Tree DBH - Inches	12
Tree height - Feet	43
Dead or Clearly Dying	No
Redwood Exception	No
TAT Assessment Result	Abate

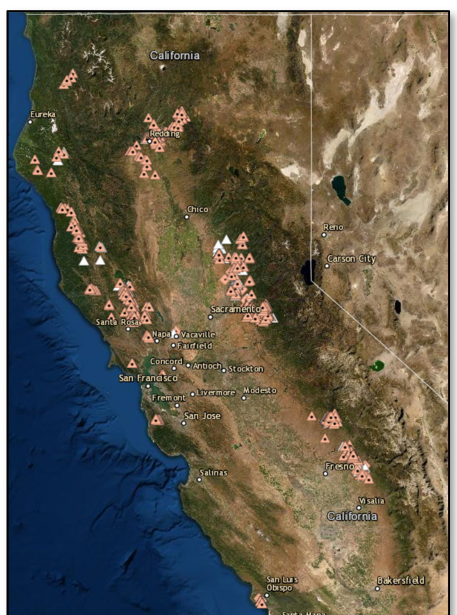
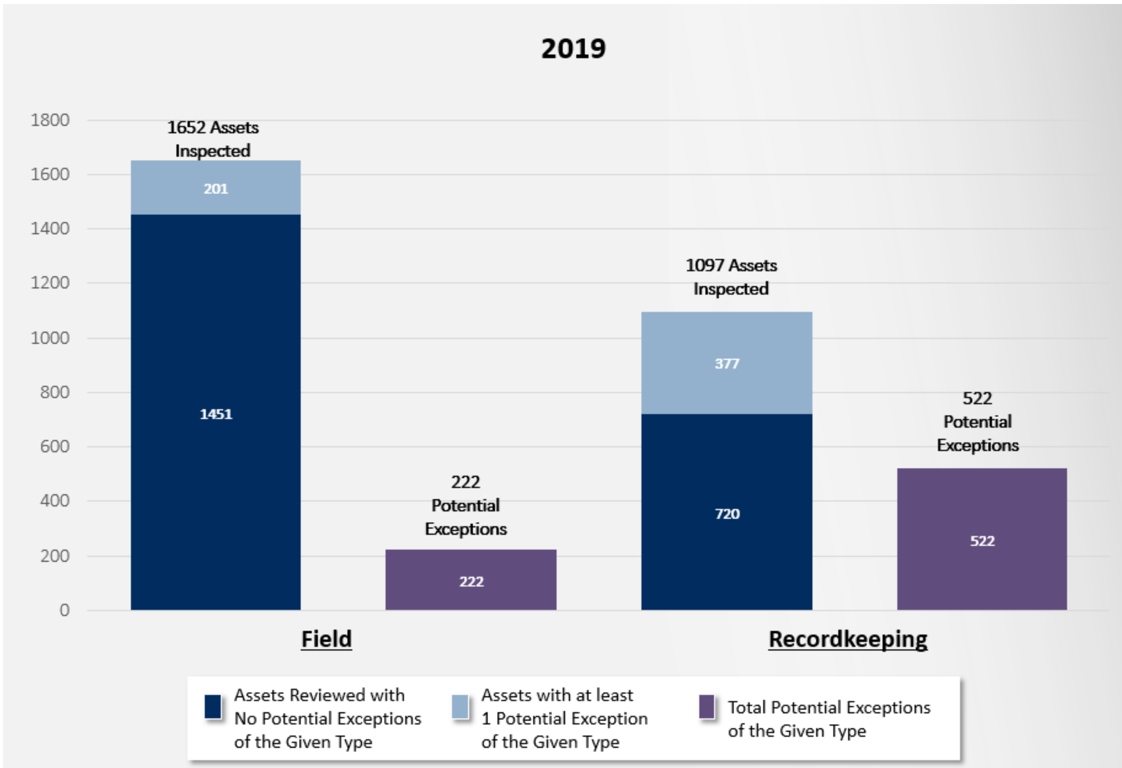
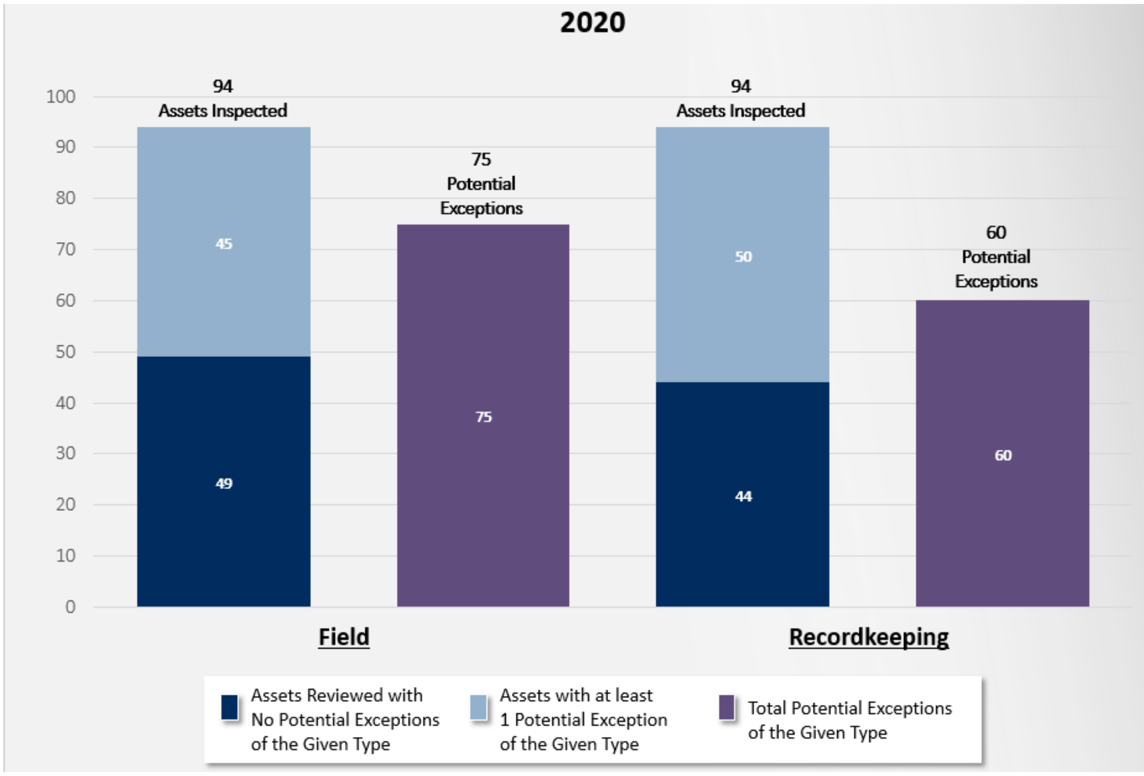
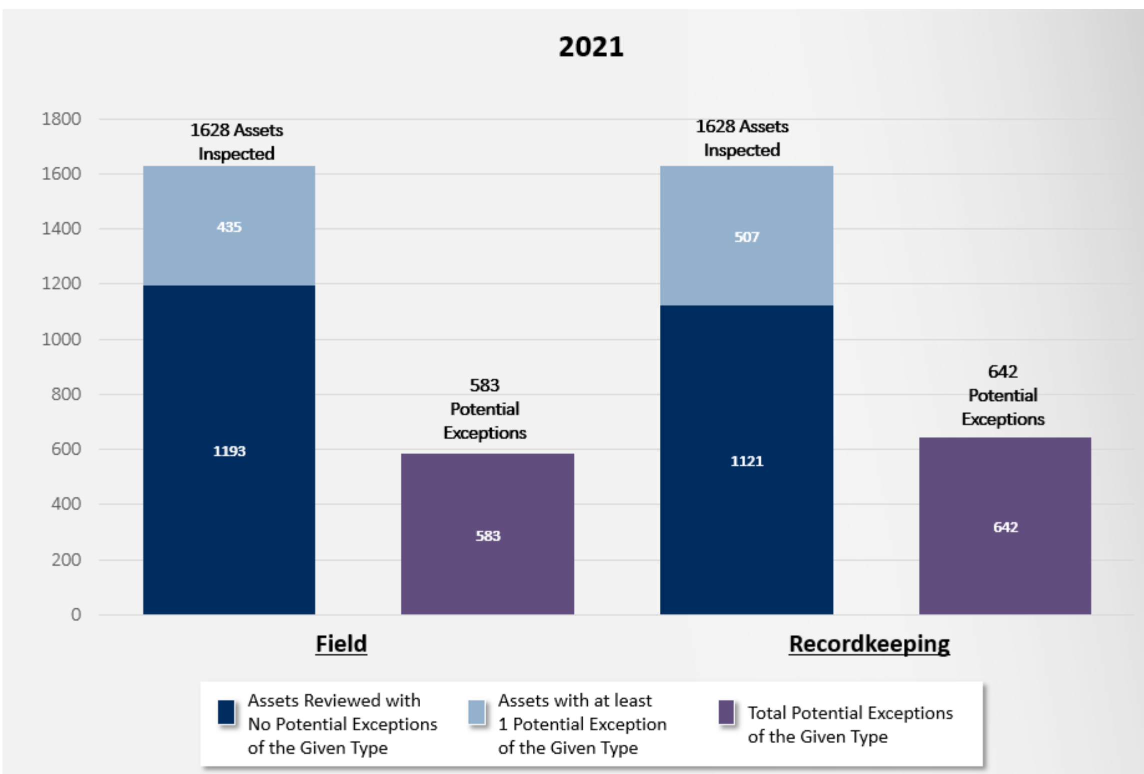


EXHIBIT 10: REVIEW OF DISTRIBUTION INSPECTION FINDINGS (2019 - 2021)

The graphics below show the number of distribution inspections reviewed by the Monitor team each year, as well as the number of potential exceptions recorded.




2020
100
90
80
70
60
50
40
30
20
10
0
94
Assets Inspected
45
49
75
Potential
Exceptions
75
94
Assets Inspected
50
44
60
Potential
Exceptions
60
Field
Recordkeeping
Assets Reviewed with No Potential Exceptions of the Given Type
Assets with at least 1 Potential Exception of the Given Type
Total Potential Exceptions of the Given Type


2021
1800
1600
1400
1200
1000
800
600
400
200
0
1628 Assets Inspected
435
1193
583
Potential
Exceptions
583
1628 Assets Inspected
507
1121
642
Potential
Exceptions
642
Field
Recordkeeping
Assets Reviewed with No Potential Exceptions of the Given Type
Assets with at least 1 Potential Exception of the Given Type
Total Potential Exceptions of the Given Type

The tables below show the number of potential exceptions recorded by the Monitor team for the most prevalent field conditions (i.e., those that should have been identified by an inspector per PG&E guidance) on distribution structures.

Top Field Conditions - 2019

Condition	# of Conditions Identified
Poles: Is pole damaged, broken, burnt, or showing signs of cracking or decay?	50
Guys/Anchors: Is guy/anchor broken, damaged, corroded, covered by vegetation, or overgrown; or is soil eroded, or guy/anchor graded or buried; or is there strain or abrasion?	36
Tree/Vine: Is there improper clearance on conductor, pole or cross arm due to vegetation?	28
Connector: Are mini-wedge or Insulink connectors used in primary conductors? Or is there an incorrect use of secondary connectors (mini-wedge or Insulink) in primary conductor?	14
Guys/Anchors: Does pole have any unbalanced or unsupported strain at primary or communication level? Are necessary guys missing or loose?	13

Top Field Conditions - 2020

Condition	# of Conditions Identified
Conductor: Conductor has splices tied in within 2' of insulator preventing free movement of splice with conductor	18
Structure: Pole broken, damaged, burnt, deformed, corroded, gunshot, or showing signs of cracking, rotten or decay	8
Anchor and Guys: Guy wire broken, damaged, clearance issues, corroded, covered by vegetation, overgrown, strain or abrasion	8
Hardware and Framing: Hardware Framing molding missing, broken, damaged, or loose	4
Vegetation: Tree causing strain or abrasion to secondary or service	4

Top Field Conditions - 2021

Condition	# of Conditions Identified
Structure: Pole broken, damaged, burnt, deformed, corroded, gunshot, or showing signs of cracking, rotten or decay	164
Vegetation: Support Structure with non-exempt equipment, has dried ground vegetation within 10' radius of Support Structure base	55
Conductor: Conductor has splices tied in proximity to insulator preventing free movement of splice with conductor	53
Anchor and Guys: Guy wire broken, damaged, clearance issues, corroded, covered by vegetation, overgrown, strain or abrasion	37
Hardware and Framing: Tap clamps installed incorrectly	34

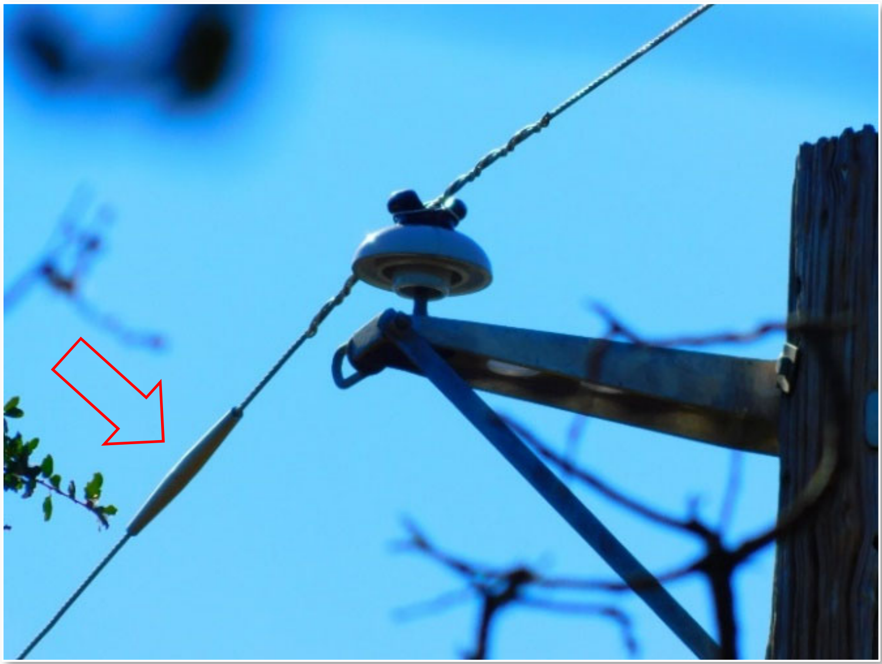
The graphics below show conditions identified by the Monitor team in its review of distribution inspections.

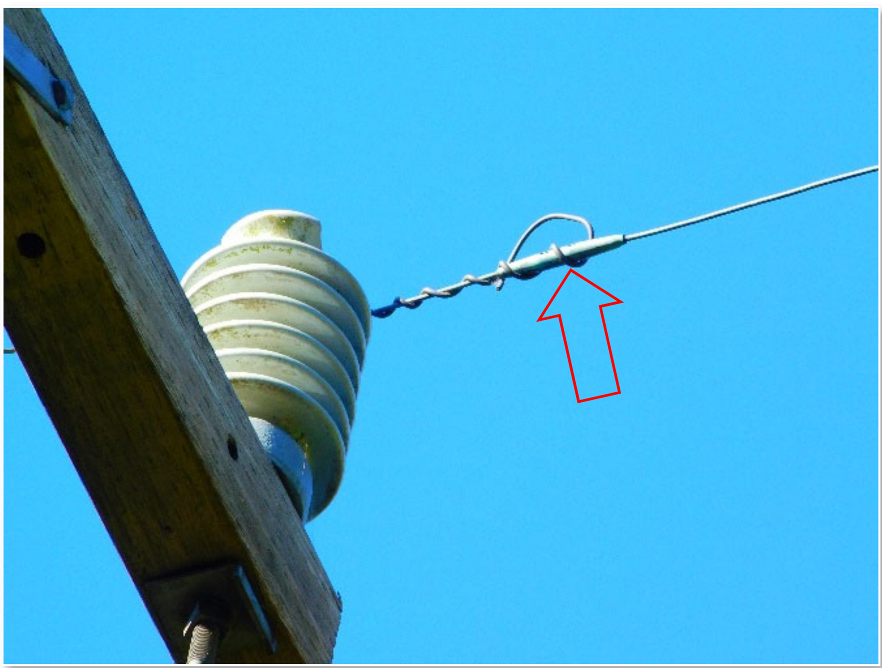
Below is a severely damaged crossarm the Monitor encountered in a Tier 3 HFTD. The Monitor team immediately reported this condition to PG&E, which then dispatched a field team that arrived on site within approximately two hours.

Below is a pole with severe cracking and decay that the Monitor team found in a Tier 2 area and immediately reported to PG&E. The Monitor team confirmed that PG&E replaced the pole the same day.

Below are floating conductors the Monitor team identified in Tier 3 areas and immediately reported to PG&E.

Below are conductors the Monitor team identified with splices tied in within 2’ of an insulator.

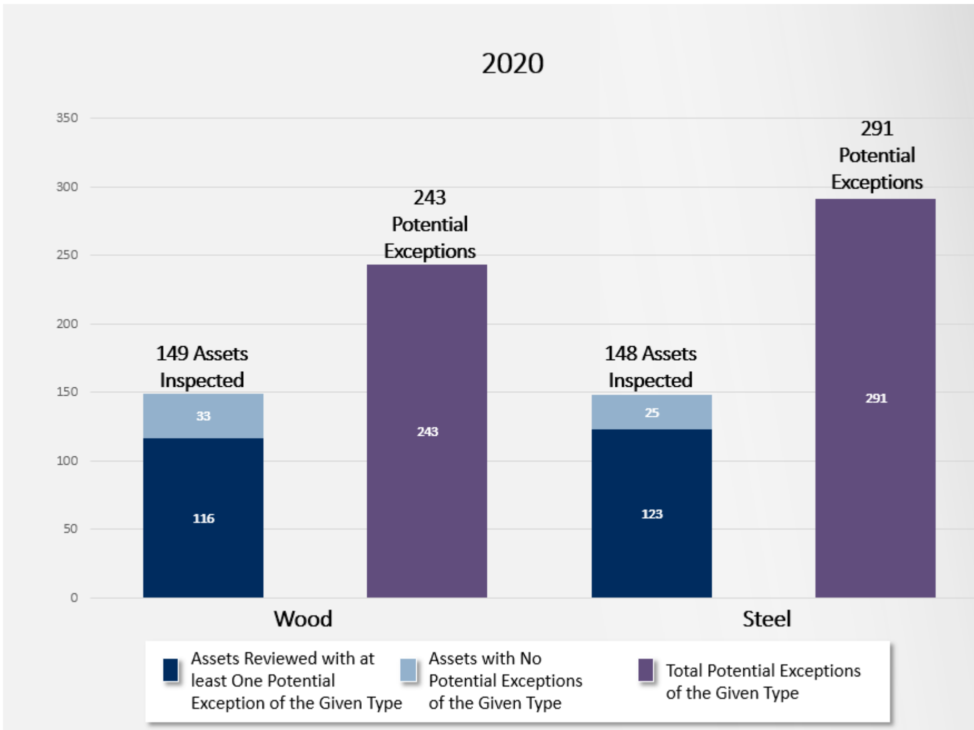


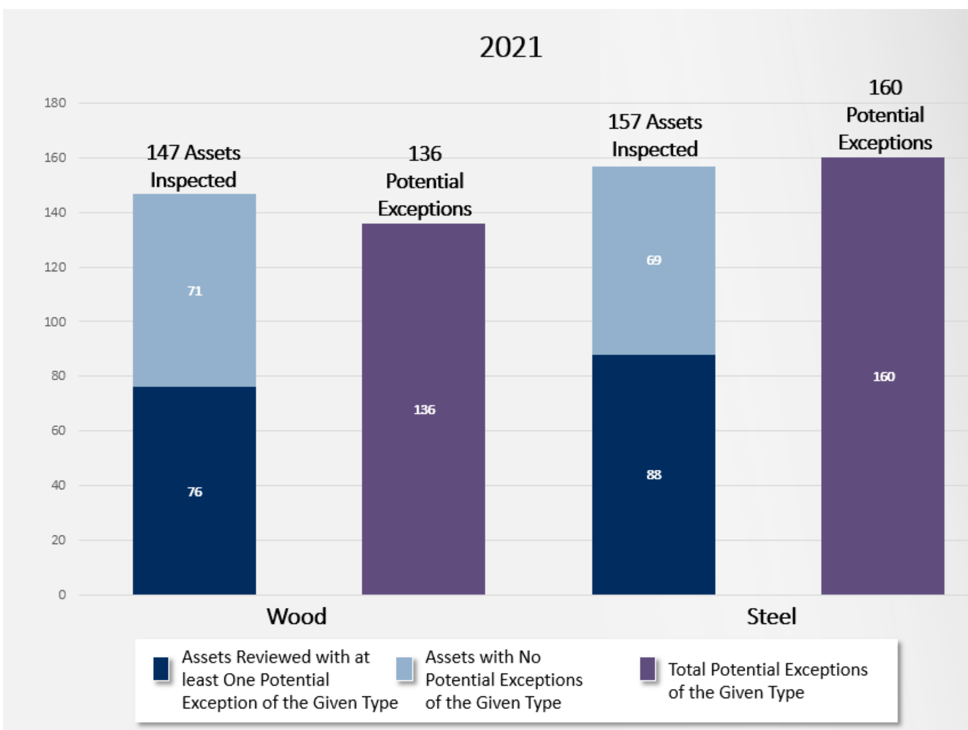


Below are examples found by the Monitor team where the guy wire was overgrown by vegetation.

EXHIBIT 11: REVIEW OF TRANSMISSION INSPECTION FINDINGS (2020 - 2021)

The graphic below shows the number of transmission inspections reviewed by the Monitor team each year, as well as the number of potential exceptions recorded.





The tables below show the number of potential exceptions recorded by the Monitor team for the most prevalent conditions in transmission steel and wood structures in 2020 and 2021.

Top Steel Structure Conditions - 2020

Condition	# of Conditions Identified
Structure Location: Is the structure in a rural area and within 600 ft of a frequently traveled road/trail?	68
Structure Location: Is the structure in a rural area and within 600 ft of a dwelling or camp?	31
Steel Structure: Steel Structure Hardware Loose or missing	18
Insulators: Insulators' hardware cold-end in poor condition (e.g. C-hook)	17
Steel Structure: Insulator hanger (eye) plate in poor condition	13

Top Steel Structure Conditions - 2021

Condition	# of Conditions Identified
General: Rural area and structure within 600 ft of a frequently traveled road/trail	23
Conductors & Insulators: Is there OPGW or Shield Wire Present?	21
Steel Structure: Steel Structure hardware loose or missing (e.g vibrating members)	9
General: Vegetation present?	7
General: High voltage signs missing, damaged, or installed incorrectly (see E.D. 022168 further details see GO 95)	7

Top Wood Structure Conditions - 2020

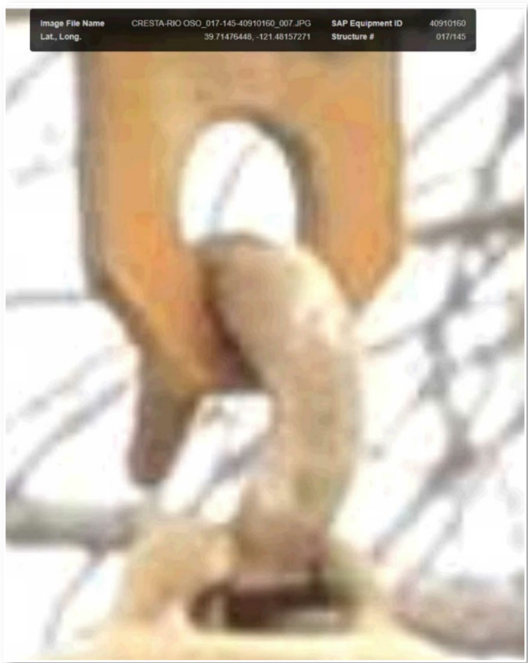
Condition	# of Conditions Identified
Structure Location: Is the structure in a rural area and within 600 ft of a frequently traveled road/trail?	58
Structure Location: Is the structure in a rural area and within 600 ft of a dwelling or camp?	31
Non-Steel Structure: Pole-top damage or split-top	22
Non-Steel Structure: Breaks or cracks or split in pole	18
Non-Steel Structure: Bird, animal or insect damage (e.g., woodpecker)	12

Top Wood Structure Conditions - 2021

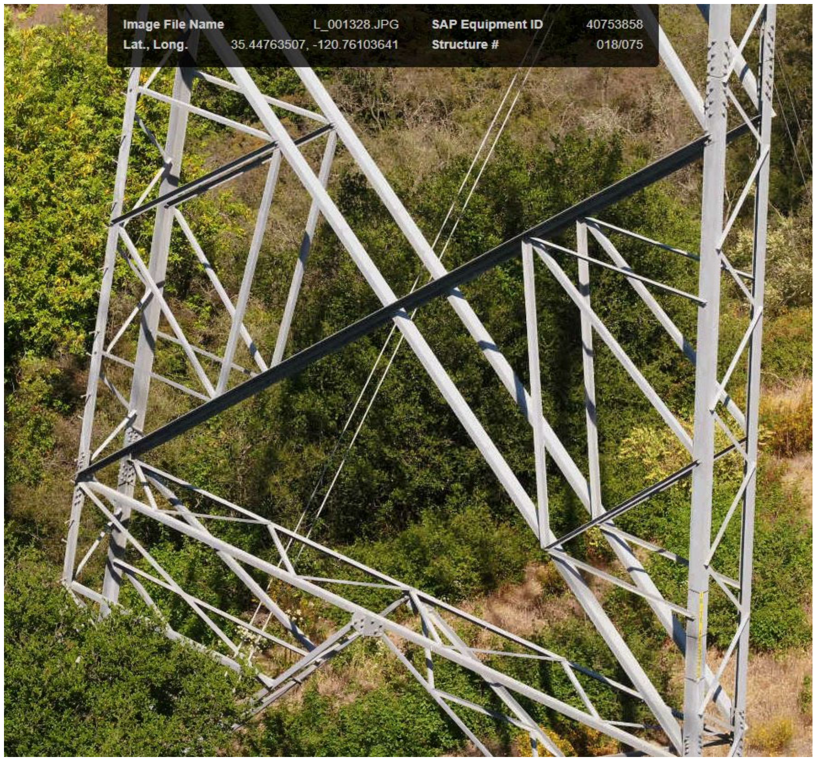
Condition	# of Conditions Identified
General: Rural area and structure within 600 ft of a frequently traveled road/trail	29
General: Rural area and within 600 feet of a dwelling or camp	11
Non-Steel Structure: Does this structure have a guy?	11
General: High voltage signs missing, damaged, or installed incorrectly (see E.D. 022168 further details see GO 95)	10
Conductors & Insulators: Polymer	7
General: Distribution underbuilt present	7

The graphics below show conditions identified by the Monitor team in its review of transmission inspections.

Below is a transmission structure on which the Monitor team observed a partially deteriorated C-hook and hanger plate.



Below are structures the Monitor team identified that appeared to have vegetation present where PG&E inspectors did not note it.



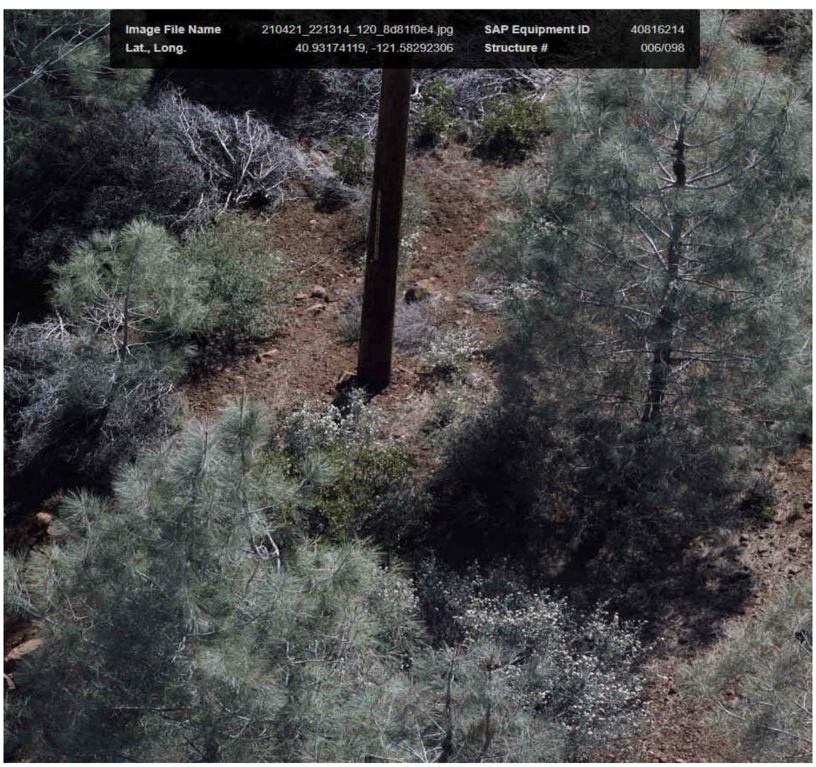


EXHIBIT 12: INCREASING BACKLOG OF INFRASTRUCTURE-RELATED REMEDIATION WORK

This graphic shows the increasing backlog of outstanding transmission and distribution tags through June 2021.

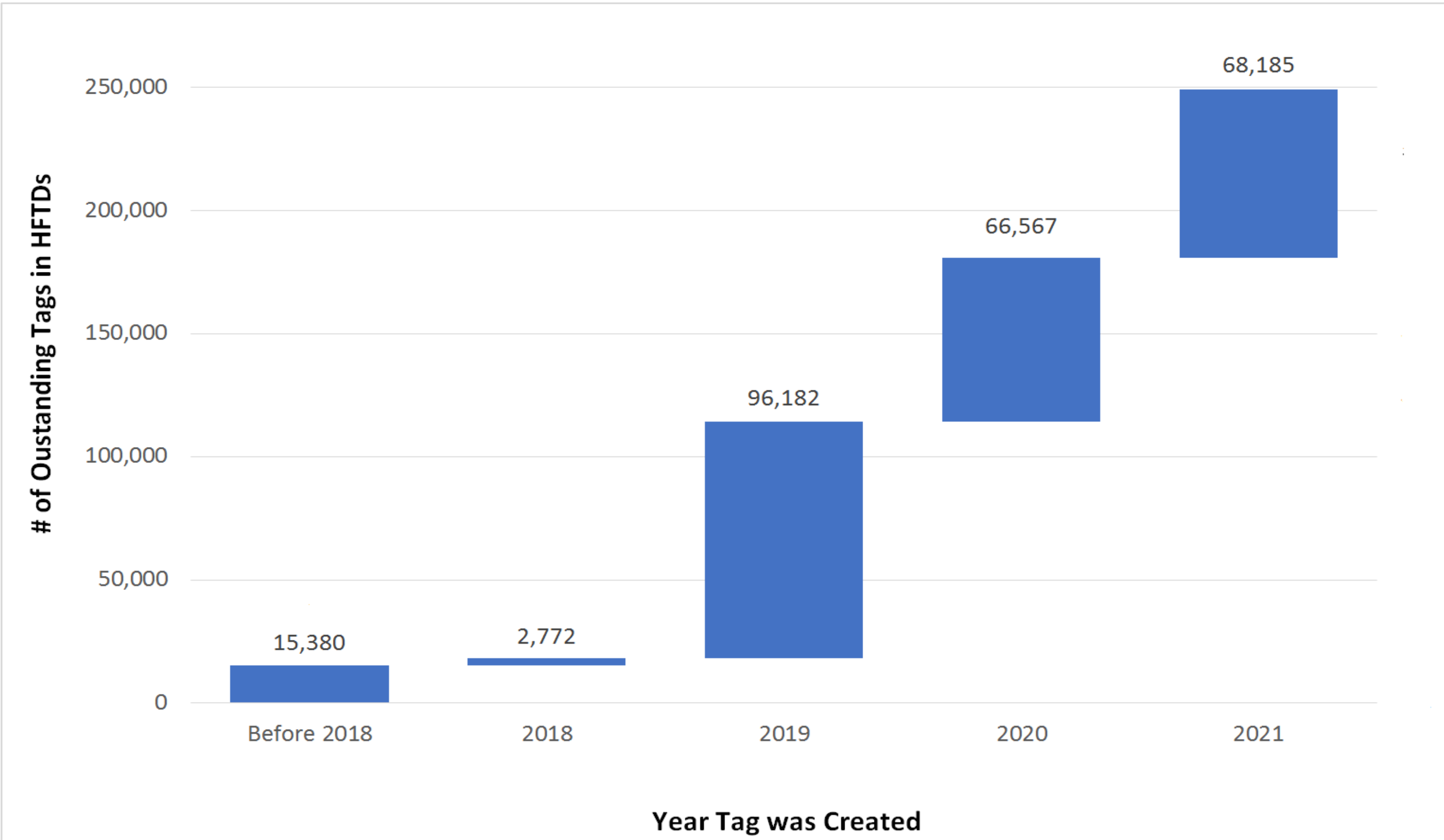


EXHIBIT 13: PENDING, UNRESOLVED INFRASTRUCTURE-RELATED TAGS

This table shows the pending, unresolved ("open") tags by repair tag priority that had not been addressed by June 30, 2021. Priority A tags are generated for conditions that require immediate mitigation and a full repair within 30 days. Priority B tags must be remediated within 90 days. Priority E and F tags must be remediated within one year (six months if in HFTD Tier 3) and five years, respectively. Priority H tags, which are only in distribution, refer to tags related to system hardening or proactive removal projects. WSIP refers to PG&E's 2019 Wildfire Safety Inspections Program, which was an accelerated ignition-based inspection program that evaluated every PG&E asset in areas of extreme (Tier 3) and elevate (Tier 2) wildfire risk, as defined by the CPUC HFTD map. Therefore, WSIP tags refer to tags identified through WSIP as opposed to PG&E's subsequent inspections.

Asset Type	Inspection Source [8,12]		Total Created Tags (21Q2)[1, 14] (carry-forward from Table 3)						Tags Closed (C)[13] (data as of 06/30/21)						Total Open Tags (O = 21Q2-C)[2] (data as of 06/30/21)					
			A[10]	B	E	F	H[11]	Sub-total	A[10]	B	E	F	H[11]	Sub-total	A[10]	B [15]	E	F	H[11]	Sub-total
Electric Distribution	HFTD	WISP	996	8,630	174,557	10,016	11,030	**205,229**	996	7,586	105,355	6,458	4,383	124,778	-	1,044	69,202	3,558	6,647	80,451
	HFTD	Non-WISP	11,134	21,795	107,265	26,671	1,024	**167,889**	11,075	13,573	15,741	3,288	158	43,835	59	8,276	92,268	39,339	1,665	141,607
	Non-HFTD / Non-WSIP		35,713	32,126	139,956	49,444	46	**257,285**	35,602	28,501	29,736	4,038	6	97,883	111	3,665	110,936	113,575	59	228,346
	Subtotal		**47,843**	**62,551**	**421,778**	**86,131**	**12,100**	**630,403**	**47,673**	**49,660**	**150,832**	**13,784**	**4,547**	**266,496**	**170**	**12,985**	**272,406**	**156,472**	**8,371**	**450,404**
Electric Transmission	HFTD	WISP	69	4,344	42,992	5,186	-	**52,591**	69	4,336	40,972	3,869	-	**49,246**	-	8	2,020	1,317	-	**3,345**
	HFTD	Non-WISP	688	3,453	20,125	12,920	-	**37,186**	688	2,696	8,568	3,851	-	**15,803**	-	758	11,819	9,091	-	**21,668**
	Non-HFTD / Non-WSIP		1,393	9,414	41,321	19,925	-	**72,053**	1,392	8,994	16,368	4,513	-	**31,267**	1	420	25,194	15,479	-	**41,094**
	Subtotal		2,150	17,211	104,438	38,031	-	**161,830**	**2,149**	**16,026**	**65,908**	**12,233**	**-**	**96,316**	**1**	**1,186**	**39,033**	**25,887**	**-**	**66,107**
Electric Substation	HFTD	WISP	107	728	2,828	-	-	**3,663**	107	728	2,791	-	-	**3,626**	-	-	37	-	-	**37**
	HFTD	Non-WISP	509	1,894	6,266	119	-	**8,788**	508	1,620	3,924	15	-	**6,067**	1	274	2,343	117	-	**2,735**
	Non-HFTD / Non-WSIP		1,501	5,281	11,897	166	-	**18,845**	1,500	5,056	10,080	56	-	**16,692**	1	225	1,825	126	-	**2,177**
	Subtotal		2,117	7,903	20,991	285	-	**31,296**	2,115	7,404	16,795	71	-	**26,385**	**2**	**499**	**4,205**	**243**	**-**	**4,949**
Grand Total	HFTD	WISP	1,172	13,702	220,377	15,202	11,030	**261,483**	1,172	12,650	149,118	10,327	4,383	**177,650**	-	1,052	71,259	4,875	6,647	**83,833**
	HFTD	Non-WISP	12,331	27,142	133,656	39,710	1,024	**213,863**	12,271	17,889	28,233	7,154	158	**65,705**	60	9,308	106,430	48,547	1,665	**166,010**
	Non-HFTD / Non-WSIP		38,607	46,821	193,174	69,535	46	**348,183**	38,494	42,551	56,184	8,607	6	**145,842**	113	4,310	137,955	129,180	59	**271,617**
	Subtotal		**52,110**	**87,665**	**547,207**	**124,447**	**12,100**	**823,529**	**51,937**	**73,090**	**233,535**	**26,088**	**4,547**	**389,197**	**173**	**14,670**	**315,644**	**182,602**	**8,371**	**521,460**

[12] W = WSIP, NW = Non-WSIP, NH/NW = Non-HFTD/Non-WSIP

[13] Closed tags include cancelled, deleted, or tags moved out of scope, in addition to physically completed work; reflects new tags closed since January 1, 2019.

[14] Created Tags reflects the summation of tags open and closed since January 1, 2019, consistent with prior quarterly reports, and not does reflect open tags created prior to 2019.

[15] All B tags initially identified through the WSIP were completed by year 2020; open WSIP B tags reflected below are tags that have had their priority upgraded since the tags were created.

Source: PG&E Q2 2021 Compliance Plan Quarterly Update, dated August 16, 2021