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UNITED STATES DISTRICT COURT
NORTHERN DISTRICT OF CALIFORNIA
SAN FRANCISCO DIVISION

UNITED STATES OF AMERICA, Plaintiff, v. PACIFIC GAS AND ELECTRIC COMPANY, Defendant.	Case No. 14-CR-00175-WHA **RESPONSE TO REQUEST FOR A FINAL REPORT** Judge: Hon. William Alsup

PG&E values the Court's oversight during its probation and appreciates this opportunity to address PG&E's progress in mitigating wildfire risk and improving the safety of its gas operations, as well as its remaining challenges. The Company's ongoing dialogue with the Court has led to numerous concrete actions that have made PG&E's system safer. PG&E would also like to thank the Federal Monitor for a consistently productive and constructive working relationship that has provided helpful insights, tangible improvements and valuable accountability for PG&E in both its electric and gas operations over the entire term of the probation.

Preliminary Statement

In the decade following the tragic San Bruno pipeline rupture, PG&E has transformed its gas business, which originally was the primary focus of PG&E's probation and federal monitorship. Among many other efforts, PG&E: (1) conducted a rigorous collection, review and analysis of four million records—enabling the Company to effectively conduct integrity management program work, locate mains and services and plan for construction; (2) strength-tested hundreds of miles of gas transmission pipelines and confirmed those pipelines' Maximum Allowable Operating Pressures ("MAOP"); (3) increased the ability to inspect gas transmission pipelines using state-of-the-art technology; and (4) reduced the number of third-party gas dig-ins to a level that puts PG&E's gas dig-in rate in the top quartile of gas utility companies in the United States. More opportunities for improvement remain and PG&E is continually working to improve safety outcomes through gas infrastructure modernization, investments in technology, improved asset management and new and enhanced training.

In response to the catastrophic wildfires that occurred during PG&E's probation, the Federal Monitor's and the Court's supervision expanded to PG&E's electric operations. PG&E acknowledges, deeply regrets and owns the tragic consequences of the wildfires caused by its equipment. The Company has taken a stand that catastrophic wildfires shall stop. Over the course of the past four years, PG&E's electric grid is fundamentally safer, in part due to the engagement on wildfire prevention with stakeholders such as this Court, the Federal Monitor, the CPUC and the California Governor's Office Operational Observer. At the same time, PG&E recognizes that there is more work to do to meet the extraordinary challenges facing the Company. PG&E is committed to taking bold actions to combat the threat of wildfires faced by the communities it is privileged to serve.

PG&E today is led by a board and senior management team that is new compared to those in place at the time of the San Bruno tragedy, the North Bay Fires and the Camp Fire. Since 2018, PG&E has onboarded a new set of directors, most of whom began in mid-2020. The chart below lists when each current non-executive director joined the board and highlights some of the experience each brings to PG&E.

Table 1: Non-Executive Directors Who Joined PG&E's Board Since 2018

Director	Year Joined	Experience
Robert Flexon Chair of the Board	2020	Former President and CEO of Dynegy Inc.; also served as CFO of UGI Utilities and CFO and COO of NRG
Rajat Bahri	2020	CFO of Wish, an e-commerce company
Cheryl Campbell	2019	Former Senior Vice President at Xcel Energy; also served as President and CEO of WestGas InterState
Kerry Cooper	2020	Former President and COO of Rothy's; also served as CEO of Choose Energy
Jessica Denecour	2020	Former Senior Vice President and Chief Information Officer at Varian Medical Systems
Mark Ferguson III	2020	Retired Navy Admiral who, during 38-year career, served as Commander of the U.S. Naval Forces in Europe and Africa and NATO Allied Joint Force Command
W. Craig Fugate	2020	Chief Emergency Management Officer at One Concern; previously served as Administrator of the Federal Emergency Management Agency ("FEMA") and Director of the Florida Division of Emergency Management
Arno Harris	2020	Managing Partner of AHC; formerly Executive Chair and CEO of Alta Motors and founder and CEO of Prevalent Power, Inc.
Michael Niggli	2020	Former President and COO of San Diego Gas & Electric; also served as COO of Southern California Gas and President of Sempra Generation
Dean Seavers	2020	Former President and Executive Director of National Grid
William Smith	2019	Former President of AT&T Technology Operations; previously served as AT&T's President of Network Operations
Benjamin Wilson	2020	Chairman of law firm Beveridge & Diamond PC, who served as Monitor for the Duke Energy coal ash spill remediation project and as Deputy Monitor in the Volkswagen emissions proceedings

Recognizing the need for the best thinking on operations, safety and risk, the Company has hired leaders from stable, safe and operationally excellent utilities around the country to help PG&E address the challenges of operating in a high-risk environment, including PG&E's new Chief Executive Officer (the former CEO of CMS Energy); Chief Operating Officer (the former CEO of MidAmerican Energy Company); the new head of electric operations (the former VP of Grid Development at American Electric Power); the new head of gas operations (the former VP of Gas Operations at Public Service Electric & Gas Company); the new head of electrical engineering (the former executive in charge of U.S. utility operations for AES corporation); and the new head of gas engineering (the former executive in charge of gas systems engineering at National Grid).[1] Stopping wildfires is front and center in the minds of PG&E's leaders, and they have put in place and are executing on a plan that they firmly believe will over time achieve the mission of stopping catastrophic wildfires.

PG&E believes it is on the right path, but there are no fast or fail-proof options to respond to the continuing change in climate that has occurred in Northern California. PG&E operates a vast electric infrastructure that provides power to 16 million Northern Californians, with enough electric lines to stretch from the West Coast to the East Coast and back more than 20 times. It was built to provide power to residents anywhere they chose to live in the state, including in remote and heavily forested areas. The system was built over many *decades*—it consists of millions of components and runs along many millions of trees. When the system was built, the risk from an ignition was small compared to what it is today, and it was built without a focus on wildfire risk.

Electrified power lines have always caused sparks in Northern California and across the country, principally due to trees or other objects hitting the lines or component failures. But the risks faced by potential sparking from PG&E's equipment have changed dramatically. For example, in 2012, about 15% of PG&E's service territory was in CPUC-designated high-fire threat areas.

[1] Additional information on the experience of PG&E's senior leaders who joined the Company in 2021 is set forth in Exhibit 1.

Today, less than a decade later, more than 50% of PG&E's service territory is in a High-Fire Threat District ("HFTD"), and the areas that meet HFTD criteria continue to increase. Each ignition in that extensive land area—about 35,000 square miles—has, depending on the weather, the potential to cause devastation. Further, most of California's forested land is in PG&E's service territory, meaning PG&E must contend with the majority of the 147 million trees that the United States Forest Service estimates have died in California from drought and invasive beetles.

The challenge has ratcheted up each year. For example, in 2020, wildfires burned a staggering four million acres in California, including five of the six then-largest wildfires in California's history. In 2021, large areas of the Sierras experienced their hottest summer on record, in the midst of a record-breaking drought. As a result, soil and vegetation dryness created vegetation flammability that was "off-the-charts" and was "reflected by [] extraordinary and extreme fire behavior".[2] Indeed, fuel monitoring stations in the foothills of the Sacramento Valley and the Northern Sierras registered moisture levels "lower than kiln-dried lumber, near and sometimes below the lowest levels ever recorded for the date".[3]

For the last four years, PG&E has undertaken hundreds of actions, big and small, to make its system safer and respond to the changed climate and increased risks. PG&E's Public Safety Power Shutoff ("PSPS") program is one illustration of the progress PG&E has made. In 2017, when the weather event that caused the North Bay Fires was bearing down on PG&E's service territory, PG&E did not have a PSPS program in place and thus could do little more than prepare to restore service after the windstorm had passed. Today, in response to an impending high fire-risk weather event:

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[2] *See* Daniel Swain, *Major monsoonal moisture surge to bring fairly widespread California thunderstorms (wetter south, drier north), with NorCal fire weather concerns*, WEATHER WEST (July 25, 2021), https://weatherwest.com/archives/10210.

[3] *See* Bill Gabbert, *Why are the fires in the West growing larger this year?*, WILDFIRE TODAY (Aug. 25, 2021), https://wildfiretoday.com/2021/08/25/why-are-fires-in-the-west-growing-larger-this-year/.

- an experienced PG&E team of meteorological experts uses cutting edge weather models to forecast risk across PG&E's service territory on a granular basis;
- the risk models PG&E uses to scope the event are bolstered by over 1,200 advanced weather stations PG&E has strategically installed across its service territory over the last four years;
- PG&E meteorologists select areas to de-energize and the de-energized areas can be scoped in a targeted way because of PG&E's multi-year effort to improve its models and to install 1,173 sectionalizers to allow for targeted de-energizations of circuits and transmission lines;
- customer impacts are further mitigated by large PG&E-operated generators that can keep substations powered even when the transmission lines that feed them are turned off;
- customers in the relevant areas are notified in a timely manner, after large investments in advanced database technology and improvements in the accuracy of customer and medical information;
- teams are deployed to de-energized areas to knock on doors of medically vulnerable customers who were not reached by phone or text and to open customer care centers; and
- after weather events have passed, as confirmed by the weather stations and a network of nearly 500 strategically placed high definition ("HD") cameras, PG&E leverages a fleet of more than 60 helicopters to help troublemen on the ground patrol lines to restore service as quickly as possible.

The result of these actions—which took large capital and workforce investments and countless hours to implement and iterate—is that PG&E now has infrastructure, operational processes and real-world execution experience with PSPS that allows it massively to reduce the risk of a catastrophic fire, while also reducing the impact on customers. PG&E's current PSPS models—had they been in place between 2012 and 2020—would have de-energized PG&E equipment that CAL FIRE has determined caused numerous catastrophic fires, including the fires that account for over 96% of the structures destroyed during that time period. This dramatic reduction in risk is occurring even as PG&E has made PSPS events smaller and shorter for its customers. More detail on PG&E's PSPS program, as well as its efforts to enhance asset inspections and vegetation management and to harden the system by burying 10,000 miles of high-risk lines, are set forth below.

PG&E recognizes that these programs and initiatives require great management and high-quality execution every day across its many thousands of employees and contractors. PG&E also acknowledges that there remains work to be done in the mission of cultivating at all levels of the Company and its contractors a culture of rigor, of questioning current approaches and of always having a bias for taking risk out of the system.

A core focus of the current management team is thus implementing a management operating philosophy that has been proven in multiple industries, including utilities, to increase consistency and quality—the lean management system. Every day, PG&E has over 1,300 daily operating reviews, beginning with crews closest to the work first thing in the morning and cascading up to the CEO and her direct reports. These brief 15- to 20-minute huddles provide a daily view on key performance indicators, help PG&E identify gaps and quickly develop plans to support the teams performing the work and give PG&E more visibility, control and predictability in its operations. The Company's leadership believes the lean management system will bear fruit because these leaders have successfully achieved large increases in quality and consistency using this operating system in prior organizations in the utility and automotive fields. This summer, in the midst of extreme conditions, the lean system facilitated PG&E's ability to initiate on an emergency basis Enhanced Powerline Safety Settings ("EPSS") that helped PG&E reduce the number of CPUC-reportable ignitions where EPSS was enabled dramatically, as discussed below.

We know there is more to do. Those at PG&E are acutely aware of the pointed concerns raised by this Court, and others, about PG&E's operations. We hear that criticism with open minds, understanding the ultimate aim is to help improve PG&E. Our goal is to have a learning culture that fosters openness to change and creates an environment where we can make nimble adjustments in response to a dynamic risk environment and our operational experience. We must be proactive, and we have taken safety and operational stands as an organization that are broad and forward-looking to meet the challenges ahead. These are not just words on a page or a poster; they are our commitment to make it right and make Californians safe.

Without minimizing what is left to do, PG&E firmly believes it has demonstrated that the Company is pushing hard to stop wildfires; that the Company is objectively making financial investments in wildfire safety that are massive and unprecedented (approximately $12 billion in capital expenditures and expenses over the past five years); and that the actions of the Company, which is made up of 25,000 individuals who live and work in the communities it serves, have made a major difference in reducing wildfire risk. Those employees (along with an additional 15,000 contractor partners, many of whom share hometowns with our employees) have dedicated their careers to improving PG&E and making its system safer for their loved ones and all its customers. Vilifying them and threatening to criminalize the exercise of professional judgment or the making of honest mistakes serves neither safety nor fairness, and instead severely detracts from PG&E's efforts to bring the skills of the best and brightest to bear on stopping wildfires. We are all in this together.

The Company looks forward in the years ahead to carrying through on its obligation to deliver clean energy *safely* to its customers.

Electric Operations

Between 2017 and 2020, approximately 44% of CPUC reportable ignitions in PG&E's HFTD areas were caused by vegetation contact with electric equipment and approximately 27% were caused by equipment failures. (The remaining 29% of ignitions were caused by third-party actions, animals and various other causes.) The catastrophic wildfires that CAL FIRE has attributed to PG&E equipment were also caused by vegetation and equipment failures, including the Butte Fire, the Atlas Fire, the Camp Fire, the Kincade Fire and the Zogg Fire. As a result, PG&E's wildfire mitigation efforts are focused on preventing ignitions caused by millions of trees that surround its lines in HFTD areas and from equipment failures from its millions of equipment components. The principal programs in PG&E's multi-layered defense—vegetation management, enhanced asset inspections, system hardening, EPSS and PSPS—are discussed below. In addition to discussing the progress in each program, PG&E also highlights the numerous areas for continued improvement in each program that the Company continues to address.

1. EPSS

During the 2021 fire season, PG&E's service territory faced unprecedented conditions. As one climate scientist at UCLA's Institute of the Environment and Sustainability wrote in late July 2021, a combination of intense heat and extreme drought created highly dangerous and previously unseen conditions:

> Some areas across the NorCal interior are continuing to experience their *hottest summer on record* to date, and this is in the midst of an *extreme to record breaking drought* in the same region. As a result, soil and vegetation dryness are now approaching or have already reached record levels–not just for the calendar date, but for any time of year. This has yielded vegetation flammability that is similarly off-the-charts. And that's reflected by the extraordinary and extreme fire behavior being almost continuously observed on large fires like the Dixie Fire, currently burning in (primarily) Plumas County at the moment, even in the absence of extraordinary ambient fire weather conditions.[4]

CAL FIRE similarly reported that firefighters experienced conditions this summer that they had never seen before:

> Under these drought conditions, wildfires are burning rapidly with extreme severity and have traveled up to 8 miles in a single day. Fuel conditions are much worse than previous years and along with wind is causing much greater fire spread. Firefighters are experiencing conditions never seen before, such as increased spread rates, spotting and active nighttime burning.[5]

The impacts of this record-breaking weather were observed by PG&E. In mid-July, the total year-to-date number of CPUC reportable ignitions caused by PG&E equipment was approximately 40% higher than in 2020.

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[4] Swain, *supra* note 2 (emphasis added).

[5] *Dixie Fire Update – August 24 – 7 pm*, Incident Information System (Aug. 24, 2021), https://inciweb.nwcg.gov/incident/article/7690/64705/.

On July 28, 2021, PG&E implemented the EPSS program, which focuses on adjusting the sensitivity of protection devices, such as line reclosers and circuit breakers, on certain power lines to de-energize them more rapidly in the event of a disturbance to help prevent potential ignitions. This involves increasing the sensitivity at which protective devices will automatically turn off power in the event of a phase or ground fault exceeding minimum to trip thresholds, thereby reducing the potential energy that is released from an arc that is created as a result of certain faults. Protective device settings need to balance the risk of de-energizing for disturbances that represent a true threat to the line versus causing outages for every disturbance on the system, given that temporary disturbances occur frequently (for example, due to load changes). In effect, PG&E re-set the settings on higher risk lines to trade off reliability for safety given the extreme conditions. In addition to detecting faults more quickly, EPSS-enabled circuit breakers and line reclosers were set to respond to qualifying faults with three-phase protection, *i.e.*, to de-energize all three phases where the fault may not have been sufficient to cause all three fuses to operate.

This change in protocols in the midst of fire season was not something that was mandated or suggested to PG&E by regulators, observers or other third parties. It was taken on PG&E's own initiative as part of the Company's commitment to take the steps necessary to stop catastrophic wildfire ignitions in an environment of dramatically increasing risk and demonstrated PG&E's bent toward prioritizing safety.

The results of the EPSS programs were eye-opening and significantly exceeded expectations. PG&E implemented EPSS settings on circuit devices across more than 11,500 HFTD miles, or approximately 45% of distribution lines in HFTDs. Prior to the change in settings, CPUC reportable ignitions in HFTDs were running significantly higher than prior years. But, notwithstanding the extreme conditions, after EPSS was initiated, CPUC reportable ignitions were reduced by about 80% on EPSS enabled circuits compared to the prior three-year average. Based on these results, PG&E believes it has added a powerful new tool to its kit for stopping catastrophic wildfires.

But, as anticipated, those averted ignitions have unfortunately impacted our customers' electric reliability. Indeed, a direct consequence of increasing the sensitivity of protective device settings is more frequent and longer outages for some of our customers in parts of our service area, outages that pose a particular hardship because they are unplanned. PG&E recognizes that it could have done a better job of communicating these changes to customers before they were implemented. After implementing the EPSS program, PG&E held more than a dozen informational webinars for communities experiencing these outages and heard first-hand from customers who had experienced hardships as a result of EPSS. PG&E heard the concerns raised by its customers and the CPUC and has taken a number of steps to mitigate the impacts from EPSS, including adjusting settings in a more coordinated and individualized manner to reduce outages, utilizing helicopters to more rapidly check lines that have tripped, installing animal protection on equipment and targeted asset hardening. Further, after the recent rains in Northern California, PG&E restored many EPSS circuits to their normal settings to increase customer reliability without increasing wildfire risk.

Given the demonstrated efficacy of EPSS, next year PG&E intends to expand the development of EPSS settings across all HFTD circuits, while minimizing and mitigating power loss impacts on our customers by applying learnings from 2021 and optimizing our device settings at the outset.

2. Public Safety Power Shutoffs

As noted above, when high winds were forecast in Northern California in advance of the catastrophic October 2017 North Bay Fires, PG&E did not have in place a process to de-energize power lines in response to forecasted weather conditions. PG&E's power grid was not designed or configured to implement preemptive power shutoffs, nor were there processes in place for notifying customers prior to such shutoffs or for re-energizing power lines after a weather event had passed.

Today, PG&E has put in place and continued to improve a state-of-the-art program that PG&E believes is a highly effective risk mitigation tool. Based on PG&E's analysis, had the 2021 PSPS model been in place between 2012 and 2020, it would have prevented the fires that caused the destruction of 96% of the structures that were destroyed by fires that have been attributed by CAL FIRE to PG&E's equipment during that time period. Moreover, by combining PSPS with EPSS, PG&E believes the two will serve as a robust fire prevention combination.

The PSPS program is driven by data showing that, historically, the largest and most catastrophic fires have occurred towards the end of fire season when the vegetation is dry and there are strong Diablo windstorms. PG&E's PSPS program has been honed—with improvements each year from the program's inception in late 2017 to the present—to better target these dry, low-humidity and high-wind scenarios that create extreme fire risk, while minimizing the number of customers left without power. Below, PG&E lays out the incremental progress that it has made each year from the PSPS program's inception in late 2017 to now.

PG&E has not made this progress alone. Input and interactions from numerous stakeholders have been invaluable to PG&E's ability to develop the PSPS program to its current state today. PG&E has been in constant contact with the CPUC, public safety partners and local communities, particularly with respect to implementing effective customer notifications and minimizing, where possible, the negative customer impacts of de-energization. Likewise, PG&E has benefited from suggestions from this Court, which PG&E believes have led to concrete improvements and wildfire risk mitigation, such as the integration of information relating to outstanding high-risk vegetation tags and the relative number of trees tall enough to fall into PG&E's lines.

Development for the 2018 Fire Season. The PSPS program that PG&E developed and put in place for the 2018 fire season involved the use of the PG&E Operational Mesoscale Modeling System ("POMMS") model to forecast weather conditions for each three kilometer-by-three kilometer area, or "grid cell", in PG&E's service territory. Using Red Flag Warnings issued by the National Weather Service ("NWS") and forecast wind speeds, humidity levels, moisture contents in vegetation as well as other weather-related information, PG&E determined whether to de-energize a grid cell. PG&E developed predictive models to determine when to de-energize to mitigate fire risk, including by creating the Fire Potential Index ("FPI") to rank fire danger based on historical fire occurrences and relying on the Storm Outage Prediction Model to forecast outages based on historical outages.

In 2018, PG&E installed 201 weather stations to increase its ability to forecast extreme fire risk conditions. And to detect ignitions more quickly when they do occur as well as to expedite the re-energization process, PG&E installed nine HD cameras.

Improvements for the 2019 Fire Season. Each year since 2018, PG&E has invested significant time and resources both to improve the PSPS program's ability to mitigate fire risk and to decrease the detrimental effect that prospective de-energizations have on PG&E's customers. As part of its process of improving fire-risk modelling, PG&E frequently subjects its PSPS models to rigorous testing based on recent and historical fire occurrences to ensure that the models would prevent catastrophic wildfires. Each year, PG&E evaluates how well its weather and other PSPS models operate, incorporates the weather and fire data for that year and makes decisions about what improvements should be made to the models in advance of the next fire season. Using historical fire occurrence and customer outage data, PG&E then validates that these changes would result in models that are improved with respect to their ability to target and mitigate the risk of catastrophic fires.

For the 2019 fire season, PG&E expanded the scope of lines considered for a PSPS from circuits at 70 kV or below that traversed Tier 3 HFTDs to include all circuits that traversed either Tier 2 or Tier 3 HFTDs—ultimately increasing the number of circuit miles subject to potential de-energization four-fold from approximately 7,370 to 30,700. As PG&E expanded the scope of its PSPS program, it also expanded the information that it considered in determining fire risk. For example, PG&E developed a risk-based process called the Operability Assessment ("OA") to assess the wildfire risk of individual structures on its transmission lines and developed a new model for calculating the probability of an outage, the Outage Producing Winds ("OPW") model.

In 2019, PG&E installed an additional 426 weather stations and 124 HD cameras, bringing the total numbers installed since 2017 to 627 weather stations and 133 HD cameras. PG&E also installed 228 sectionalizing devices to allow for targeted de-energizations of power lines.

Improvements for the 2020 Fire Season. For the 2020 fire season, PG&E enabled more precise PSPS event boundaries by updating the POMMS model and converting it from a three kilometer forecast to a higher resolution two kilometer forecast. PG&E also incorporated a number of other changes to increase the accuracy of its weather forecasts based on recommendations from two independent groups of experts. As part of the development of the updated POMMS model, PG&E employed the National Center for Atmospheric Research's Model Evaluation Tool ("NCAR MET") to ensure the efficacy of the updated model, both by looking to see how well it forecast weather conditions in the past as well as how well it was forecasting weather conditions as they arose. PG&E's analysis of the changes to the POMMS model has confirmed that it produces more accurate forecasts over a longer time horizon than the previous model, including in connection with high-impact weather events.

In addition to updating the POMMS model, PG&E also updated both the OPW model to take into account additional outage data and the FPI model to increase the alignment of PG&E's identification of fire risk with agency forecasts and warnings by taking into account whether a Red Flag Warning has been issued by the NWS. Furthermore, PG&E created a new model based on the outputs of the OPW model and FPI model called the Large Fire Probability ("LFP") model to determine when to de-energize lines to mitigate fire risk. PG&E also created separate criteria for de-energization called "Black Swan" criteria to de-energize circuits when the risk of ignition is low, but the consequence of an ignition would be high due to high winds.

In 2020, PG&E installed an additional 378 weather stations, 216 HD cameras and 657 sectionalizing devices, bringing the total numbers installed since 2017 to 1,005 weather stations, 349 HD cameras and 885 sectionalizing devices.

Because PSPS events result in significant impacts on customers who lose power, PG&E deployed in 2020 a number of other means to mitigate those impacts on customers. For example, PG&E secured 450 megawatts of temporary generation to support substations and critical customers such as hospitals, water and wastewater plants, emergency response personnel such as fire and police stations, and telecommunications providers. For customers who were de-energized during a 2020 PSPS event, PG&E also reduced the amount of time that they were without power. Using the two kilometer-resolution weather modeling, PG&E was able to declare weather "all clears" on a more granular level than in 2019, allowing PG&E to begin restoration patrols sooner. To expedite the rate at which restoration patrols could be conducted, PG&E also analyzed optimal routing methods for such patrols, nearly doubled the number of helicopters dedicated to such patrols (from 35 in 2019 to 65 in 2020) and commissioned two airplanes with specialized equipment that allowed such patrols of transmission lines to occur at night. Through these efforts, PG&E reduced the aggregate average outage duration after the "all clear" from approximately 17 hours in 2019 to approximately 10 hours in 2020, or a reduction of 41%. PG&E also improved its notification systems to customers, ultimately notifying over 99% of its Medical Baseline customers who were in the final scope of de-energization prior to the de-energization event, despite the fact that weather shifts *during* PSPS events altered the de-energization footprints in every 2020 event.

During 2020, the Zogg Fire tragically resulted in four fatalities. PG&E's 2020 models did not call for the de-energization of the area where the Zogg Fire ignited, though other areas in Shasta County were de-energized. In response, PG&E again changed the PSPS model for the 2021 fire season (discussed below), and PG&E believes that as a result of those changes, the 2021 PSPS model would have called for the de-energization of that area and would have prevented the ignition of the Zogg Fire.

Improvements for the 2021 Fire Season. For the 2021 fire season, following discussions with this Court, PG&E's models now take into account the relative amount of Tree Overstrike (the approximate linear distance of trees that are tall enough to fall on PG&E lines, as estimated based on aerial Light Detection and Ranging ("LiDAR") scans) as well as outstanding high-priority vegetation and asset maintenance tags. PG&E's PSPS models initially incorporated Tree Overstrike as an independent trigger for de-energization, but by using machine-based learning, PG&E was able to integrate a given grid cell's Tree Overstrike into the broader calculation of the probability of an outage and associated potential ignition.

PG&E also replaced the LFP model with the Catastrophic Fire Probability ("CFP") model. For distribution circuits, the CFP model, like the LFP model, assesses the probability of an outage and potential ignition together with the potential consequence of a resulting fire by using the outputs of other models. An updated instance of the FPI model uses satellite-based fire detections and machine learning to predict the probability of rapidly growing and not easily controlled fires. And the new Ignition Probability Weather ("IPW") model uses the probability of an outage predicted by the OPW model to predict the probability of an *ignition*, using known outage-to-ignition ratios for specific outage causes (*e.g.*, vegetation, equipment failure, animal/third-party contacts).

This year, as of September 30, 2021, PG&E has installed an additional 272 weather stations, 132 HD cameras and 288 sectionalizing devices. In total, since 2017, PG&E has installed 1,277 weather stations, 481 HD cameras and 1,173 sectionalizers.

PG&E's work on its PSPS program is not finished. But PG&E believes that it has the infrastructure in place for a successful PSPS program to significantly mitigate the risk of catastrophic wildfires. In 2022, the program will be entering its fifth fire season, and it will remain subject to PG&E's continual examination of all aspects of the program, including the performances of its models, power-restoration teams and customer notification processes. For example, PG&E expects that each year it will evaluate potential changes to its program to make the program's targeting of wildfire risk more effective, including by altering the models' parameters, incorporating additional data or making other changes, and that any such changes would be subject to a robust weather-backcasting analysis to confirm that the models would have effectively prevented catastrophic wildfires.

3. Updated Risk Model to Guide Initiatives

In 2018, PG&E developed an initial wildfire risk model—the 2019-2020 Wildfire Risk Model—to prioritize circuit levels where the highest wildfire risk existed, leveraging a relative risk ranking. The risk ranking was based on two components: risk ignition probability and wildfire consequence. In other words, the wildfire risk model sought to quantify the risk of wildfire on a relative basis as represented by the probability of ignitions associated with electric grid infrastructure combined with the consequences if that ignition propagates into a wildfire. In 2020, PG&E developed the 2021 Wildfire Distribution Risk Model to improve both parts of that calculation. PG&E contracted with Energy and Environmental Economics to perform an independent, third-party review of PG&E's 2021 Wildfire Distribution Risk Model, which found that the model is appropriately designed for its stated goals, that it represents an improvement to PG&E's prior model, and that it is a meaningful step above the industry standard approach.

The ignition probability portion of the 2021 Wildfire Distribution Risk Model has been advanced into a more comprehensive assessment of probabilities for two of the most significant utility-caused ignition drivers: vegetation contact and conductor failure. Future modeling efforts will add other drivers.

The wildfire consequence portion of the 2021 Wildfire Distribution Risk Model focuses on impact measures such as acres, number of structures and variables describing the nature of the fire such as flame length and rate of spread. The key improvement for the 2021 Wildfire Distribution Risk Model is tied to the advanced modeling capabilities of the Technosylva fire simulation tools, which derive fire propagation and consequence outcomes based on available fuels, topography and weather as well as buildings and population locational data. The prior risk model provided simulations that relied heavily on the concentration of fuels to determine the potential for an ignition to propagate to a wildfire. The Technosylva simulation tool improves on this capability by modeling what fire science refers to as "ladder fuels" whereby an ignition will propagate from low fuels such as grass and brush to increasingly denser fuels leading to treetop, as well as updated ground fuels, buildings and population data layers. The result is a more accurate representation of the potential consequences of wildfire.

The updated 2021 Wildfire Distribution Risk Model has produced more comprehensive, updated results in terms of which assets and locations in our system are most appropriate to target. To ensure alignment across the Company on governance, accountability and support of the implementation of PG&E's updated wildfire risk model, a new governance committee, the Wildfire Risk Governance Steering Committee ("WRGSC"), was established in late 2020.

Chaired by PG&E's Chief Risk Officer, the WRGSC incorporates leaders from Electric Operations, Risk and Internal Audit and other teams. Representatives from PG&E's Federal Monitor as well as the Operational Observers from the governor's office also attend these meetings. The WRGSC reviews and approves the workplans for the most critical wildfire risk mitigation programs to ensure they are in alignment with the current approved risk model. Additionally, as part of implementing the lean operating system, regular reporting of work completion, quality results and trends are conducted in the daily, weekly and monthly operating reviews held by the Chief Risk Officer.

As PG&E has shifted project execution to align with the new risk model outcomes, some previously identified projects have been deferred to later years and newly identified projects are being aggressively pursued to reduce risk as quickly and safely as feasible. Vegetation management and system hardening are two areas where the Company's work has shifted in response to the improved risk modeling. The amount of risk reduction has increased, but that is not necessarily reflected in the number of miles of work performed. For example, the number of miles completed as part of PG&E's Enhanced Vegetation Management ("EVM") program between 2020 and 2021 is roughly the same, but because high risk areas have been more rigorously targeted, the number of higher risk trees removed will increase significantly from 167,765 in 2020 to a forecasted 252,542 in 2021. For system hardening, the amount of miles hardened in 2021 will be less than originally planned for 2021, as PG&E stopped previously selected projects and started different projects in alignment with our updated risk model. But the 180 miles of work performed in 2021 represents a 58% increase in risk reduction compared to the previously planned work based on PG&E's risk scoring.

4. Vegetation Management

Before the 2017 North Bay Fires, PG&E's Vegetation Management ("VM") program was designed to comply with state regulations, which included clearances around trees and removal of hazard trees. PG&E's VM program did not have initiatives that specifically focused on wildfire risk. At that time, the VM program followed industry standards: it primarily relied on one annual routine inspection to identify trees for trimming or removal with additional patrols in areas experiencing drought conditions; patrol schedules were based on operational efficiency rather than wildfire risk; there was no group assigned to coach inspectors; and work that was completed was not subject to work verification.

As discussed above, the increased number of dead and dying trees, expanded drought conditions and hotter temperatures have significantly increased the risk of a catastrophic wildfire in the event of an ignition. In response to this risk, PG&E has made and is continuing to make unprecedented investments to address hazard and higher risk trees near its power lines by increasing spending on vegetation management and increasing the number of internal and external resources available to inspect and work the trees in its service territory. Between 2017 and 2021, PG&E increased spending on vegetation management from approximately $440 million a year to approximately $1.4 billion, representing an over 200% increase. The total number of employees and contractors dedicated to vegetation management rose from 4,446 in 2019 to 10,265 in 2021, including the addition of one officer and seven director positions. These unprecedented monetary and workforce investments have resulted in a significant amount of additional work: in 2021, PG&E has removed or trimmed over 1.63 million trees as of October 31, and forecasts it will remove or trim 1.82 million trees in total by year-end, a 20% increase over the 1.52 million trees worked in 2019.

PG&E believes that its financial investments and efforts on wildfire mitigation are more aggressive than any other utility in the country. That effort and funding has facilitated a number of enhancements, including the highest risk circuit protection zones ("CPZs") being subject to EVM. Additional enhancements include:

- Subjecting all miles in HFTDs to both a routine and a CEMA[6] patrol;
- Subjecting work in HFTDs to work verification to help provide consistency and quality;

[6] Catastrophic Event Memorandum Account ("CEMA") patrols are conducted primarily to inspect for dead, dying or diseased trees and are performed in addition to PG&E's routine patrols, which also inspect for dead, dying or diseased trees. CEMA patrols are mid-cycle patrols scheduled approximately six months before or after the routine patrol on all overhead primary and secondary distribution facilities.

- Prioritizing patrol schedules based on wildfire risk;
- Enlisting corps of inspectors to provide hands-on coaching to VM inspectors in the field during their patrols;
- Increasing the amount of contractor training available through training courses and in-field testing designed to measure knowledge of the inspection process;
- Deploying new technology to assist pre-inspectors with identification of trees that have strike potential or need to be removed or worked under EVM, including the Tree Assessment Tool ("TAT");
- Entering a Letter of Agreement ("LOA") with International Brotherhood of Electrical Workers ("IBEW") to improve workforce retention, as well as quality and consistency of inspections;
- Establishing a program to manage wood remaining post-tree work in fire-impacted areas;
- Standing up EVM and Quality Command Centers and using lean management techniques to bolster data transparency and efficient operational responses; and
- Leveraging VM tags to inform PSPS events based on the status of the highest priority work across VM departments.

PG&E describes the evolution and enhancement of its VM programs during the course of this probation below.

PG&E recognizes that it must continue to take steps to further improve its VM efforts. As observed by the Federal Monitor, PG&E knows that it must continue to drive a culture of rigor and a bias for taking risk out of the system throughout all levels of the organizations, including contractors. The steps that PG&E will be taking next—including an ambitious, unprecedented effort to attempt to move to 360-degree visual assessments of all strike trees in HFTDs—are further described below. But even with this far greater effort on VM, and an over 200% increase in spending, it is operationally infeasible to cut away all of the risk associated with the trees surrounding its power lines. The immense challenge posed by the approximately 8 million strike trees in HFTDs around PG&E's power lines in this climate cannot be overstated. Each of these 8 million trees is potentially capable of causing a wildfire; identifying which trees pose a heightened risk is a judgment call that depends on often subjective assessments. Further, there are only so many highly qualified experts available, and even experts can disagree on which trees are hazardous; the identification of hazard trees is both subjective and not guaranteed to capture every tree at risk of failing. Moreover, the environment is dynamic; trees in compliance with state law and PG&E regulations one day might not be in compliance the next day. These dynamics are part of the reason that PG&E believes that PSPS and enhanced power line settings are important risk backstops to its VM efforts.

EVM. As outlined in prior filings with the Court, over the last three years, PG&E has launched from scratch an EVM program that goes beyond compliance with state law to reduce wildfire risk. The EVM program includes radial clearances, overhang trimming and a more objective assessment of trees with the potential to strike PG&E's power lines that targets not only hazard trees but also healthy, sound trees that present a higher risk of falling into the line.

Since its inception in 2018-2019, PG&E has completed over 5,800 miles of EVM and removed or trimmed over 605,100 trees as part of this program alone. Furthermore, as of September 30, 2021, following an emphasis on working the highest risk miles, over 97% of EVM work in 2021 has been completed on the highest 20% of CPZs.

For each line mile subject to the EVM program, pre-inspectors perform two phases of inspections. During a Phase 1 inspection, pre-inspectors identify for removal or trimming any vegetation that encroaches on a 12-foot radial clearance of PG&E's power lines or that overhangs above the conductor or within the 4-foot zone extending on either side of the conductor, as well as any dead, dying or diseased trees that pose a risk to PG&E's facilities. During a Phase 2 pre-inspection, pre-inspectors inventory and perform a tree assessment of any tree tall enough to strike PG&E equipment. For every potential strike tree, EVM pre-inspectors are trained and instructed to record, among other things, the tree species, diameter, height, health, prescribed work (or whether no work is prescribed) and the status of that work. After identifying a vegetation point and inputting the requisite information, EVM pre-inspectors are instructed to use the TAT—a tool developed by arborists for the EVM program to provide more objective assessments—to determine whether and what work should be prescribed for that tree.

All work prescribed under EVM is subject to PG&E's 100% work verification process. No line mile is marked as complete under PG&E's EVM program until that mile has been subject to both phases of pre-inspection and tree work under the EVM program scope and has been verified as complete to EVM standards by PG&E's Work Verification ("WV") team.

Before starting work on EVM, in addition to threshold requirements, both pre-inspectors and work verification personnel are required to take approximately 10 hours of web-based trainings created by PG&E for the EVM program, including an introductory-level course called Veg-0100: Vegetation Management for Inspectors and an EVM-specific course called Veg-0410: EVM Scope – Experienced Vegetation Patrollers. The Veg-0100 course is designed to review safety protocols, introduce contractors to PG&E procedures and to educate the contractors on the role they play in reducing wildfire risk. Contractors must pass the simulated VM inspection portion of Veg-0100 before they are eligible to enroll in and complete Veg-0410, the EVM-specific training course. Veg-0410 is designed to explain the scope of the EVM program, the process of conducting an EVM inspection and how to use the Collector App.

In 2020, the Federal Monitor found that PG&E was inadequately prioritizing the highest risk EVM work. The CPUC subsequently placed PG&E into Step 1 of the Enhanced Oversight and Enforcement Process ("EOE Process").[7] On May 6, 2021, PG&E submitted a

[7] Resolution M-4852, Placing Pacific Gas and Electric Company into Step 1 of the "Enhanced Oversight and Enforcement Process" Adopted in Decision 20-05-053 (CPUC Apr. 15, 2021), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M367/K731/367731890.PDF. Commission Decision 20-05-053 gave the CPUC approval of PG&E's bankruptcy plan of reorganization with conditions and modifications and established an EOE Process allowing the CPUC to take additional steps to ensure PG&E is improving its safety performance if specific "triggering events" occur. Decision 20-05-053, Approving Reorganization Plan (CPUC May 28, 2020), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M338/K816/338816365.PDF. The steps range from Step 1, which contains enhanced reporting and oversight requirements, to Step 6, involving the potential revocation of PG&E's ability to operate as a utility in California.

Corrective Action Plan ("CAP") to the CPUC as part of the EOE Process, which contained comprehensive plans for all 14 deficient elements identified in PG&E's 2020 EVM work, including prioritization of the highest-risk CPZs. PG&E's 2021 EVM scope of work was developed using the EVM tree-weighted prioritization list, which is based on the 2021 Wildfire Distribution Risk Model with several modifications specifically intended to address vegetation risk. PG&E completed 57% of 2021 EVM work by September 1, 2021, exceeding its CAP commitment to complete 47% of 2021 EVM work by this date. As of September 2021, PG&E has also completed 97% of EVM work in the highest 20% of CPZs, exceeding its goal identified in its Revised 2021 Wildfire Mitigation Plan to perform at least 80% of 2021 EVM work on the highest 20% of the risk-ranked miles.

Still, PG&E is constantly re-evaluating and revising its EVM scope of work. Since August 2021, PG&E has added five CPZs to the scope of work based on vegetation-related events and ignitions tracked in real-time. PG&E has also successfully resolved more than 260 miles previously constrained due to customer refusals or non-contacts, land or environmental holds, permitting or fire impacts, leaving 406 constrained miles remaining as of September 30, 2021, which PG&E is working to resolve. Additionally, PG&E has reaffirmed the commitments it made in 2019 and 2020 to cities, counties and agencies to conduct work in areas that had high-risk rankings under previous risk models. As such, PG&E has added five CPZs to the plan as an additional undertaking that will not detract from PG&E's goal of 80% of the EVM work being performed in the top 20% risk-ranked CPZs.

Notwithstanding the large investment PG&E has made in its EVM program, PG&E recognizes that due to the highly resource-intensive nature of EVM, PG&E can only patrol a fraction of its service territory under the EVM program in any given year. PG&E is thus also focused on enhancing its routine vegetation management program, as discussed below.

Routine VM. PG&E's routine VM program inspects all of its approximately 100,000 miles of overhead electric distribution facilities at least annually to identify and clear vegetation that might grow or fall into utility equipment. As part of this program, pre-inspectors perform scheduled inspections on all overhead primary and secondary distribution facilities to

(1) maintain radial clearance between vegetation and conductors by identifying trees that will encroach within the minimum distance requirements imposed by federal law, state law or PG&E procedures; and (2) identify dead, dying or diseased trees and other hazard trees that pose a risk to PG&E facilities. PG&E forecasts that it will work approximately 1.5 million trees in 2021 as part of its routine VM program.

This year, in response to a condition of probation agreed upon by PG&E and the Federal Monitor, PG&E stood up its Vegetation Management Inspector ("VMI") program, now known as Construction Management. The organization includes PG&E-employed supervisors and management and 95 Senior Vegetation Management Inspectors ("SVMIs"), formerly known as Vegetation Management Inspectors ("VMIs"), including 30 employed by PG&E. One of several areas of focus for the SVMIs is spending time accompanying routine VM pre-inspectors in the field during their patrols, providing hands-on, in-the-field coaching and oversight of their work. PG&E anticipates that this significant investment in coaching routine inspectors will result in higher quality and more consistent outcomes across routine VM patrols over time.

To further improve the quality of VM patrols, and to promote a sustainable workforce, PG&E also established a new LOA with the IBEW on June 8, 2021. The IBEW Local 1245 represents nearly 20,000 members. This LOA provides that contractors performing VM inspection work for PG&E must become signatories to the IBEW union and will be classified as VMIs or SVMIs. The LOA also includes training and enhanced oversight, providing for increased public and member safety in the field.

PG&E has also started to move to a 100% work verification model in its routine VM program in HFTDs, similar to the model used for PG&E's EVM program. This model means that once a line has been pre-inspected by a VM contractor, and that contractor's tree crews have completed the work prescribed on the line, an inspector from a different contractor will walk the line and perform a second, independent patrol to assess whether the line is fully compliant with state law. If any further work is deemed necessary by this second, independent set of eyes, it will be prescribed and resolved by work execution teams. Given the scope of PG&E's routine VM program, this move toward 100% work verification required a significant investment in additional resources. In 2021, PG&E tripled its work verification workforce by adding 200 additional inspectors to perform this work. Between PG&E's routine VM patrol and mid-year CEMA patrol, all miles in HFTDs are subject to at least two patrols each year to verify compliance, and all routine work in HFTDs is in the process of being subject to 100% work verification to help provide consistency and quality.

This year, PG&E also began deploying where feasible the use of vehicle-based LiDAR technology as yet a further check on the quality of its VM patrols in HFTDs. Vehicle-based LiDAR scans following a routine inspection and its associated tree are meant to help objectively confirm that the required clearance around the conductors has been achieved.

Looking forward, major challenges remain. Notwithstanding the billions of dollars in investments PG&E has made with respect to its VM programs, all it takes is one tree out of the many millions surrounding PG&E's lines to fail and cause a wildfire. Facing that reality, PG&E has—as catalogued above—taken numerous steps to increase consistency and objectivity in PG&E's VM patrols to remove risk, including use of the TAT for EVM and 100% work verification. Yet, as the Federal Monitor has noted to PG&E, given the sheer number of trees in PG&E's service territory, making the right calls 99% of the time on which trees to remove and not remove still leaves many trees near the lines that could start a fire. PG&E thus plans to carry through the improvements introduced in 2021 and has set a highly ambitious goal to shift to 360-degree visual assessments of potential strike trees in overhead distribution miles in HFTDs. The intention of this assessment is to identify potential integrity issues, such as signs of defect, disease or any other visible condition that contributes to the tree's likelihood of failure and ability to strike overhead conductors. This will result in more thorough inspections and increase the likelihood of identifying visible indicators of failure potential. Implementation of the program will require pre-inspectors to conduct a 360-degree visual assessment of all sides of trees having strike potential. If the assessment determines that the tree requires work, the work will be prescribed following existing processes. This approach is industry-leading, as the typical industry approach entails inspecting trees from the utility's right of way and conducting closer inspections only if warranted by the inspector's observations. PG&E

plans to formalize 360-degree visual assessments as part of routine pre-inspection patrols during 2022, though doing so presents challenges in recruiting a sufficient number of qualified foresters given the more time-intensive nature of the patrols. Notwithstanding the challenges, PG&E is focused on embarking on this approach.

An additional focus for PG&E has been to increase oversight and engagement with the contractors supporting VM work. The Construction Management team within VM helps to manage and oversee contractor (vendor) relationships and contractor safety. Examples of the tasks and initiatives led by this team include providing direct in-field support and feedback to crews; establishing a dedicated safety observer job role (Senior VMI) to provide real-time feedback and to prevent potential safety incidents; validating that contractors have received appropriate training; conducting contractor performance feedback sessions on a monthly basis, which include report cards on productivity and quality; and partnering with local educational institutions, including Butte County College, to identify qualified recruits.

Looking past next wildfire season, PG&E is assessing additional potential improvements in its VM programs. PG&E has initiated work on technology implementation to move disparate processes and programs onto one unified platform to enable comprehensive VM execution with access to informative and transparent data. In addition, PG&E is considering and evaluating a potential transition away from having separate EVM, routine VM and CEMA programs to having one VM program that conducts two patrols per year on all HFTD lines and one patrol per year on non-HFTD lines. The program being evaluated would incorporate operational learnings and elements from the EVM program in a manner that enables the Company to implement a rigorous VM program across its entire HFTD footprint every year.

5. Asset Inspections

During the probation period, PG&E completed an overhaul of its asset inspections program that has resulted in a significant mitigation of the wildfire risk posed by PG&E's equipment. This overhaul was implemented in an intense sprint of work in 2019 following the tragic Camp Fire, which resulted from a failed C hook on one of PG&E's transmission towers. In short, PG&E's

program for asset inspections went from one that was not originally designed with wildfire risk in mind to one that is now squarely centered around wildfire risk mitigation and is far more thorough, standardized, digitized and verifiable. In addition to a fundamental shift in focus, PG&E has also committed large amounts of resources to enhance its inspections program, increasing spending on its asset inspections program from approximately $45 million in 2017 to over $230 million thus far in 2021. While many challenges remain, the PG&E of today is a fundamentally different company with respect to asset inspections in HFTDs than it was at the start of the probation period.

Asset Inspections at the Start of the Probation Period. In 2017 and 2018, PG&E's program for inspecting its transmission and distribution assets was designed based on an industry-standard time cycle approach that complied with applicable rules and regulations, such as those set forth in General Orders 95 and 165. This approach was not oriented toward wildfire risk. Assets were treated the same regardless of where in its service territory they were located and what the wildfire risk profile of those assets might be. For overhead transmission circuits, for example, PG&E's Electric Transmission Preventive Maintenance Manual ("EPTM") required that, consistent with applicable rules and regulations, most of PG&E's overhead transmission lines be subject to a detailed ground inspection once every five years, with inspections in the intervening years being limited largely to aerial patrols. These requirements were the same for transmission assets in Tier 3 HFTD areas as they were for assets in non-HFTD areas.

These asset inspections did not attempt to utilize the latest available technology to enhance the reliability and effectiveness of such inspections. Instead, even detailed inspections of assets were largely ground-based, with inspectors using binoculars to visually inspect structures regardless of the height of the structure. Inspections were also exception-based, meaning findings had to be documented by inspectors only if a corrective action was determined to be necessary. Required maintenance was heavily dependent on the judgment of individuals performing inspections in the field. PG&E's records for asset inspections and corrective actions were also paper-based, further contributing to challenges in maintaining consistency throughout its system and verifying findings of the local crews responsible for performing these inspections.

In 2017, PG&E spent just over $45 million to conduct approximately 485,000 distribution and 72,000 transmission inspections, and spent nearly $250 million on asset maintenance and repairs. In 2018, PG&E spent just over $50 million to conduct approximately 455,000 distribution and 65,000 transmission inspections, and spent over $365 million on asset maintenance and repairs.

2019 Wildfire Safety Inspections Program. PG&E's emphasis on asset inspections fundamentally shifted after the devastating 2018 Camp Fire, when PG&E created its Wildfire Safety Inspections Program ("WSIP") to perform enhanced inspections on all transmission, distribution and substation assets in Tier 2 and Tier 3 HFTD areas prior to the start of the 2019 wildfire season. WSIP was an industry-leading, risk-informed inspections program that PG&E developed on an intense schedule that required day and night work from a cross-functional PG&E team and external subject-matter experts to fundamentally enhance inspections in HFTD areas. In contrast with the utility industry-standard programs in place at the start of the probation period, WSIP followed a risk-based approach, basing inspections procedures on a Failure Mode and Effects Analysis ("FMEA") that focused attention on points of failure on electric assets that could lead to fire ignition and allowed for the development of inspection methods that could more reliably identify those conditions. The goal of the WSIP program was to identify and quickly remediate the most serious conditions in areas that were the most likely to lead to catastrophic wildfires in the event of an ignition, with the program representing a significant upgrade in the safety and reliability of PG&E's transmission and distribution systems.

Under WSIP, steel transmission towers were subject to both climbing inspections and aerial inspections (by helicopter, drone or aerial lift). Climbing inspections were performed by Qualified Electrical Workers, who completed electronic checklists to document findings for all components identified in the FMEA on an inspected structure, and took photographs of specific components on each transmission structure, regardless of whether an abnormal condition was identified on the equipment. Aerial inspections were conducted by using drones or helicopters to take high-resolution photographs from multiple angles that were then reviewed by a Drone Inspection

Review Team ("DIRT") with collective knowledge and backgrounds in transmission maintenance and engineering. Following both climbing and aerial inspections, identified conditions were reviewed and prioritized for repair by a Centralized Inspection Review Team ("CIRT") composed of personnel with collective experience in engineering, inspections and maintenance. Distribution poles were subjected to detailed ground inspections, likewise using electronic checklists to document findings for components identified in the FMEA.

WSIP inspectors, guided by the electronic checklists developed based on the FMEA, were required to take high-definition photographs of components most likely to contribute to wildfire ignitions. These inspections, documented with electronic checklists and with verifiable records regardless of whether a corrective action was deemed necessary, were a significant shift from the exception-based, paper-recorded inspections that were standard at the time. As discussed further below, this shift in 2019 to electronic records and the collection of high-definition photographs of its assets year after year have built up a considerable amount of high quality data about its transmission and distribution systems, which have recently allowed PG&E to explore the use of advanced technology such as artificial intelligence and machine learning to further enhance its asset inspections and mitigate wildfire risk.

The results of the WSIP program as compared to its prior asset inspection efforts are staggering. In total, 49,715 transmission towers and 694,250 distribution poles were inspected as part of PG&E's WSIP program, with PG&E investing over $230 million to complete such inspections. By December 31, 2019, PG&E's WSIP inspections had identified approximately 62,000 repairs to be made on its transmission assets and over 225,000 repairs to be made on its distribution assets, with PG&E spending over $1.13 billion in 2019 on asset maintenance and repairs. Perhaps most importantly, over 1,000 conditions requiring immediate attention were identified during these inspections and remediated, while over 10,000 additional conditions requiring expedited attention were identified and remediated. Finding these exigent conditions through these enhanced inspections and repairing them improved the safety profile of PG&E's equipment in a fundamental manner.

Asset Inspections in 2020 and Beyond. Starting in 2020, PG&E incorporated the enhanced inspection processes and tools developed for the WSIP program into its routine compliance inspection and maintenance program, adopting risk-informed maintenance cycles so that facilities in Tier 3 HFTDs would be subjected to these enhanced inspections annually, and assets in Tier 2 HFTDs would be subjected to enhanced inspections on a three-year cycle. These "enhanced inspections" generally refer to the use of digital checklists, documentation of asset features, capture of standard imagery, and centralized review of inspection findings, as well as work quality monitoring. This includes ground, climbing and aerial inspection collection methods in transmission and distribution, whether in HFTDs or otherwise.

In 2020, PG&E completed inspections of 26,282 transmission structures and 339,728 distribution structures in HFTDs using these enhanced techniques, with a combined total of 736,588 transmission and distribution inspections conducted throughout its system. So far in 2021, over 500,000 transmission and distribution structures in HFTDs have been subjected to enhanced inspections, with more than 870,000 combined inspections throughout PG&E's transmission and distribution systems. In total, PG&E invested $300 million on asset inspections and $665 million on asset maintenance and repairs in 2020, and has spent over $230 million on asset inspections and $580 million on asset maintenance and repairs thus far in 2021.

PG&E's asset inspections program benefited from thoughtful and helpful feedback from the Court and the Federal Monitor. For example, following the institution of the Court's "Transmission Inspection Program Condition", PG&E created the "Inspection Review Specialist" position at the end of 2020 to hire inspectors to oversee field transmission inspections. PG&E currently has 37 full time employees and contractors in the position, and in 2021 PG&E Inspection Review Specialists conducted quality control and work verification inspections of over 2,950 ground-based transmission inspections and reviewed 62,868 aerial transmission inspections.

PG&E likewise is complying with the Court's "Asset Age Condition" of probation requiring, among other things, that PG&E record or estimate the age and date of installation of components of transmission towers in HFTD areas that may result in ignitions should they fail.

While initial implementation of some aspects of its program to comply with this condition were slower than PG&E would have liked, PG&E is now on track to record the asset age for critical components on 50 transmission circuits by the end of 2021 and is aiming to record the asset age of such components of all 550 transmission circuits in HFTD areas by the end of 2022. PG&E's program also includes an effort to search historical asset records, engineering drawings and other information to provide new, quality data fields into the system of record. This will provide better data to the various asset health and risk models, improving granularity and reducing the number of assumptions needed to be made around fields such as asset age. Furthermore, as part of its effort to comply with the portion of the Asset Age Condition requiring PG&E to implement a program to determine the expected useful life of critical components, PG&E has identified 47 components to incorporate into its "Useful Life Model" that will eventually model the useful life for such components based on eight high-priority threats such as wind, fatigue, corrosion and mechanical wear. PG&E also is now on track to complete its model for all 47 components for the wind hazard—which PG&E has been prioritizing—by the end of Q1 2022, with modeling for other hazards set to occur later in 2022.

In terms of opportunities for improvement, PG&E is working to improve the consistency of its asset inspections. In 2021, the Federal Monitor team sent their own independent inspectors to review PG&E's inspection findings and provided PG&E with exception reports that identified conditions identified by independent inspectors that were not identified by PG&E inspectors. PG&E has been working closely with the Federal Monitor to analyze these exception reports to identify tendencies and prioritize exception findings based on wildfire risk to ensure that PG&E identifies and remediates the most critical shortcomings of its inspections first. As just one example of PG&E's efforts in this regard, data from the Federal Monitor showed that just 3% of inspectors accounted for 22% of missed conditions, and PG&E has taken steps to ensure that those inspectors will not perform any work for PG&E in the future. Relatedly, but independent of the Federal Monitor's work, in 2021 PG&E established its new System Inspection Quality Control program, which is designed to perform independent quality control inspections of distribution and transmission assets in HFTD areas. PG&E is on pace to complete 30,000 quality control inspections through this program in 2021. Findings from these inspections thus far have shown that, consistent with the Federal Monitor's own findings, PG&E has substantial room for improvement in terms of the consistency of its asset inspections. The System Inspection Quality Control program will both lead to high-risk assets being re-reviewed, increasing the likelihood that conditions capable of leading to ignitions are identified, and will provide PG&E with important data that will inform continued refinements to its asset inspections program, such as by identifying components or conditions that inspectors have the most difficulty with assessing so that training can emphasize those components and conditions moving forward. Importantly, this work will continue after the end of the probation period, meaning an independent team at PG&E will continue the important work that the Federal Monitor has conducted to ensure the quality and consistency of PG&E's asset inspections.

PG&E's efforts to improve the quality of its inspections program are also continuing. As one example, PG&E will pilot inspection technology to target difficult-to-detect failure modes. For instance, by conducting enhanced inspections since 2019 that utilize the completion of electronic checklists and require the collection of high-resolution images of various components on its transmission and distribution structures, PG&E has developed a massive database of high-resolution images of its assets. As PG&E inspectors have marked up those images through PG&E's Sherlock web application, those markups have been fed into computer vision models that are trained to classify photos, identify asset components and search for components in an automated fashion. This program is already being used to flag select images for inspectors—such as woodpecker damage, C-hook wear and birds' nests—and inspectors are then able to label data and provide feedback on predictions, which improves the models over time while reducing the inspection time and increasing inspection quality.

PG&E has also successfully launched its "Data Analytics for Predictive Maintenance" project, also referred to as "Epic 3.20"[8], which develops analytical models using machine learning based on existing PG&E data sets to predict electric distribution equipment failures so that corrective action can be taken before failure occurs. Among other successes, the project has developed an analytical model focusing on ignition risks and catastrophic failures associated with near-failure distribution transformers—a significant cause of ignitions within PG&E's system—accurately predicting transformer anomalies posing an imminent wildfire risk in 72% of the 125 field reviews conducted in this phase of the program.

PG&E also performs annual assessments of its asset inspections programs to continually determine and address areas for improvement. For example, in 2020 the programs reviewed and updated the 2019 WSIP checklist software tool, checklist wording, question formatting, software tool performance and reference materials to guide more consistent and repeatable results. For 2021, a similar retrospective assessment was performed. Revisions in all overhead inspection checklists to refine the flow and wording, as well as to address gaps in content from prior cycles, such as presence of non-exempt equipment, and new criteria for cold end hardware degradation (C-hooks) were completed as a result. Annual refresher trainings were delivered in 2020, and revised orientation trainings were prepared for both incumbent and new inspection personnel in 2021. Finally, analytics and trending of conditions found through enhanced inspection will continue to inform future condition-based inspection cycles.

6. Records

One aspect of PG&E's wildfire mitigation programs that PG&E is committed to improving is the quality of its records. PG&E recognizes that incomplete or inaccurate records can have serious safety implications and that, in the past, its records have fallen short. Among other

[8] PG&E's Electric Program Investment Charge ("EPIC") program was established by the CPUC in 2011 and provides PG&E with the opportunity to demonstrate the value of emerging technologies that could advance a broad array of objectives including wildfire safety, grid safety, resiliency and reliability as well as customer enablement, and integration of renewable and distributed energy resources.

things, PG&E is addressing the quality of records by being consistent in its messages to employees and contractors that the quality of PG&E's records is critical and by moving from paper records to digitized records. Paper processes require manual oversight and checking, are relatively difficult to control, and the data in paper records cannot be easily aggregated for systemic trends or statistical analysis. Digital records, on the other hand, can be structured to be more complete and consistent (*e.g.*, requiring fields to be filled in for completeness and providing standard drop-down responses for consistency), and are far more verifiable and analyzable. Today, numerous wildfire mitigation related activities, such as PSPS, detailed equipment inspections, enhanced vegetation management and system hardening have fully shifted to using electronic record-keeping systems, and PG&E is working to shift more programs to fully digital records.

While more work remains to be done, the benefits of this shift to digital records is already providing benefits. For example, as PG&E's detailed asset inspections moved from paper records to digital records, it made the records far more accurate, complete and verifiable. Inspections are scoped and completed at the asset-level using equipment records from enterprise systems to confirm exactly which locations require detailed inspection. Completions are recorded back into those same systems with positive confirmation that every location was visited. To confirm that an inspector visited a particular transmission tower, it is straightforward to pull up the records and digital photographs from the inspection and to examine the associated metadata of the photographs that show the location and time the photographs were taken. The inspection records also benefit from electronic checklists that have required fields and have standard drop down menus. But beyond these immediate benefits, the digital records have facilitated numerous additional enhancements described above, including the Transmission Overhead Asset Information Collection effort and PG&E's efforts to use the multitude of photographs and digital records associated with the inspections to train artificial intelligence and computer vision programs to examine the photographs and to flag potential concerns for human review.

As another example, in the context of vegetation management, PG&E historically relied on paper Hazard Tree Rating System ("HTRS") forms to help guide inspectors in the field in deciding whether to abate a tree. Starting in March 2020, inspectors in the EVM program began evaluating trees using PG&E's digitized Tree Assessment Tool ("TAT"), which replaced the HTRS. TAT is a tool that evaluates an individual tree's likelihood of failing and indicates whether to abate the tree. Developed in conjunction with expert arborists, TAT incorporates historical data on tree failures, regional species risk and local wind gust data and assesses different components of an individual tree's health and risk of falling into PG&E lines or equipment. The TAT is completely digital, and field employees can input data directly into a mobile platform that immediately generates a risk mitigation determination. The record of the determination is then digitally stored and available for retrieval.

PG&E will continue pushing to digitize its wildfire-mitigation related records and to monitor our data, records and processes to identify and resolve gaps.

7. Undergrounding and Other System Hardening

One component of PG&E's wildfire mitigation efforts is system hardening. System hardening entails replacing or eliminating existing distribution lines in HFTDs and installing stronger and more resilient equipment. Hardening methods include replacing bare overhead conductor with covered conductor and installing stronger poles, removing the line and serving our customers through remote grids, or converting the line from overhead to underground.

Between 2019 and September 30, 2021, PG&E has hardened 638 miles of high-risk distribution miles. PG&E believes that its system hardening efforts between 2019 and 2021 have made a significant difference, both by reducing ignition risk on 638 miles and by reducing customer impacts from PSPS events through strategic hardening projects. PG&E is mindful, however, that over three years its system hardening efforts have touched less than 3% of PG&E's miles in HFTDs—in part due to the very operationally intensive nature of system hardening, and the planning and permitting involved. Moreover, short of undergrounding, hardened lines are more resistant to ignition, but still pose a risk.

These constraints, as well as the operational knowledge gained over the last three years, informed PG&E's recent announcement of its commitment to underground 10,000 miles of electric distribution lines in HFTDs. For a sense of scale, the 10,000 miles are the equivalent of approximately 11 round trips from Chico to Los Angeles, or almost halfway around the world. This will be one of the largest infrastructure projects in California history, and an unprecedented effort by a utility.

PG&E and its leadership team expect this undergrounding plan to provide significant benefits for PG&E's customers, stakeholders and the entire State of California. The most important of those benefits is that undergrounding overhead electric wires will eliminate ignition risks from vegetation or wind-induced equipment failures in those areas. Thus, by undergrounding the riskiest portion of PG&E's system (where a disproportionate amount of the risk resides), PG&E can substantially reduce wildfire risk. Undergrounding overhead electric lines will also help reduce the need for vegetation management, which currently costs PG&E up to $1.4 billion a year and involves the removal of large numbers of trees near distribution lines—as PG&E moves more of its electric system underground, it will be able to move funding from vegetation management to the undergrounding process and leave more of California's trees untouched. Further, the undergrounding of 10,000 miles of overhead electric lines will have a variety of additional benefits, including cutting down on the need for PSPS events and increasing reliability. For example, PG&E recently completed a four-mile undergrounding project in Santa Rosa that mitigates the risk of an ignition, while also preventing 11,000 customers from experiencing repeated PSPS events in the future.

PG&E is currently engaged in extensive efforts to prepare for this project and to learn from previous undergrounding projects, including undergrounding work between 2018 and 2020 in the high fire-threat areas of Alameda, Contra Costa, Nevada and Sonoma Counties and the undergrounding of power lines in Butte County following the Camp Fire. By engaging in those projects and reviewing the results and processes, PG&E has been able to focus on improving cost effectiveness by implementing new planning systems and strategies, utilizing new materials and new equipment, bundling undergrounding work into larger blocks and partnering with natural gas projects and phone and internet providers to share costs. PG&E has solicited information from 40 engineering and construction firms for the project and has put out an open call to action to academia and environmental groups to assist in the process of developing a safer, more efficient electric system for the State of California. PG&E looks forward to engaging with its customers, regulators, governmental partners, tribal leaders and wildfire safety specialists to move this project forward.

Table 2: Summary of Key Improvements to PG&E's Wildfire Mitigation Efforts

Year	Key Improvements	Key Measures Taken
2019	• Expanded PSPS scope to include all circuits traversing Tier 2 and Tier 3 HFTDs • Developed the Operability Assessment • Replaced the Storm Outage Prediction Model with the Outage Producing Winds ("OPW") model • Implemented 100% work verification with respect to EVM program • Increased the amount of contractor training available through training courses and in-field testing • Updated Collector application to improve EVM data collection process	• 426 weather stations installed (in addition to 201 in 2018) • 124 HD cameras installed (in addition to 9 in 2018) • 228 sectionalizers installed • 1.5 million trees worked • 743,000 assets inspected • 171.6 miles of system hardened
2020	• Improved the resolution of the PG&E Operational Mesoscale Modeling System ("POMMS") and OPW models from 2 kilometers to 3 kilometers • Updated the OPW model to consider new data • Updated Fire Potential Index ("FPI") in light of Red Flag Warnings • Developed the Large Fire Probability ("LFP") model • Developed Black Swan Criteria	• 378 weather stations installed • 216 HD cameras installed • 657 sectionalizers installed • 1.9 million trees worked • 736,000 assets inspected • 324.1 miles of system hardened
2021	• Replaced the LFP model with the Catastrophic Fire Probability model • Replaced the OPW model with the Ignition Probability Weather model • Updated FPI to use satellite data and machine learning • Replaced Black Swan criteria with Catastrophic Fire Behavior criteria	• 272 weather stations installed • 132 HD cameras installed • 288 sectionalizers installed

Year	Key Improvements	Key Measures Taken
	• Added consideration of Tree Overstrike and outstanding high-priority vegetation and asset maintenance tags • Implemented VMI program to provide hands-on, in-the-field coaching and oversight of routine pre-inspectors' work • Prioritized highest risk EVM work • Expanded 100% work verification to routine VM program for HFTDs • Deployed vehicle-based LiDAR scans following routine VM inspections • Introduced goal to shift to 360-degree visual assessments of potential strike trees in overhead distribution miles in HFTDs.	• 1.6 million trees worked (as of Oct. 31) • More than 870,000 assets inspected • 124.7 miles of system hardened (as of Sept. 30)
Total		• 1,277 weather stations installed • 481 HD cameras installed • 1,173 sectionalizaers installed • 5.2 million trees worked • More than 2.35 million assets inspected • 638 miles of system hardened

Gas Operations

As mentioned above, following the tragic San Bruno gas pipeline explosion in September 2010, PG&E took significant steps to improve its gas operations. Among other things, PG&E collected, reviewed and performed an engineering analysis on four million records from the Company's field offices and loaded the information into PG&E's gas transmission geographic information system for digital accessibility through a geospatial view, enabling PG&E to effectively conduct integrity management program work, locate mains and services and plan for construction. PG&E also conducted a pipeline centerline survey of 6,750 miles of gas transmission pipeline using precise mapping tools with Global Position System ("GPS") coordinates and entered the GPS coordinates into PG&E's gas transmission geographic information system for digital accessibility through a geospatial view, which allows PG&E to accurately locate and monitor its gas transmission pipelines. Through these and other efforts, PG&E has met 11 of the 12 safety recommendations from the National Transportation Safety Board's 2011 report on the San Bruno incident, with one recommendation related to strength testing short lengths of gas transmission pipes remaining open and PG&E's progress ongoing and considered acceptable by the NTSB. Additionally, PG&E was the first company in the United States to meet the rigorous safety standards outlined in American Petroleum Institute Recommended Practice (API RP 1173), as verified by third-party auditor Lloyd's Register after their assessment of PG&E's Pipeline Safety Management System ("PSMS") against API RP 1173. Although some of the Company's changes were slower than it preferred at times, PG&E has now transformed its entire gas business, including, but not limited to, modernizing infrastructure, improving asset management and investing in technology and research and development.

1. PG&E's Progress in Improving Public Safety in Gas Operations

During the period of its probation, PG&E has made considerable progress in improving public safety in its gas operations in a myriad of ways. Some of the most significant improvements include: (1) strength testing hundreds of miles of gas transmission pipelines and confirming the pipelines' Maximum Allowable Operating Pressures ("MAOP"); (2) increasing the inspectability of gas transmission pipelines using state of the art technology; and (3) reducing the number of third-party gas dig-ins.[9]

Improvement 1: Strength Testing Gas Transmission Pipelines. It is widely understood within the gas transmission industry that hydrostatic testing—or strength testing using water or another medium—is an effective method to detect pipeline defects that could subsequently cause a rupture or leak. Since January 2017, PG&E has strength tested approximately 709 miles of previously untested transmission pipelines, bringing the total amount of PG&E transmission pipeline

[9] For a more comprehensive summary of key improvements in gas operations, please see Exhibit 2.

with traceable, verifiable and complete records of strength testing to approximately 6,175 miles, or 94% of PG&E's total transmission pipeline system. PG&E's strength testing process, which required an investment of approximately $760 million since the start of probation, involves taking a pipeline out of service, clearing it of gas, cleaning it internally and then filling it—typically with water—to pressures consistent with industry guidelines to ensure the pipeline can withstand the necessary pressure. PG&E then repairs any defects uncovered during this process. This process also results in a test record that confirms the pipeline's MAOP (the highest operating pressure the pipe can safely withstand), which enables PG&E to safely operate the pipeline at a pressure not to exceed the value established through the strength test.

Improvement 2: Increasing the Inspectability of Gas Transmission Pipelines. Although strength testing is an effective way to detect existing pipeline defects that could subsequently cause a rupture or leak, such testing does not provide important granular information about the specific nature of the defect that caused a pipeline to fail a pressure test—*e.g.*, whether the defect was a crack or corrosion—or whether defects exist in a pipe despite the fact the pipeline passed the pressure testing. Obtaining that level of detail requires conducting an in-line inspection ("ILI"), which is the most reliable pipeline integrity assessment tool currently available to natural gas pipeline operators to assess the internal and external condition of transmission line pipe.

PG&E uses technologically advanced pipeline inspection gauges ("PIGs"), often referred to as "smart pigs," to evaluate the condition of transmission pipe so any issues (*e.g.*, corrosion, cracks and pipe deformation) are identified and appropriate action taken. Prior to running an ILI tool in a pipeline, the pipeline must be made "piggable," which means equipment must be installed to insert and remove the ILI tool and pipeline structures that would obstruct the passage of the ILI tool must be replaced. Once a pipeline is made piggable, an ILI tool is used to collect certain data about the pipe, which is then analyzed for pipeline anomalies. Any identified irregularities are examined and repaired as necessary. The information from this work is also used to generate mitigation measures to improve the long-term safety and reliability of the gas pipeline. As of October 2021, approximately 1,915 miles of PG&E's gas transmission pipeline is piggable, up from 665 miles of gas transmission pipeline in 2016—an effort requiring an investment of approximately $655 million.

Taken together, strength testing—which establishes the pipeline's integrity baseline—and conducting ongoing in-line inspections—which continues to ensure integrity of the pipeline going forward—is one of the most effective methods to maintain the integrity of gas transmission pipelines.

Improvement 3: Reducing the Number of Third-Party Gas Dig-Ins. A dig-in is an event that results in a need to repair or replace an underground gas facility due to excavation damage (*e.g.*, an excavator hits a gas line with a back-hoe loader). The "dig-in rate," or dig-ins per 1,000 Underground Service Alert ("USA") tickets (which are documents individuals submit in advance of an excavation project to request that a utility locate and mark underground lines at a worksite, home, or project), is an important safety metric since each dig-in has the potential to harm people and/or property. PG&E's Gas business experienced 2.02 dig-ins per thousand USA tickets in 2016, the year before the probation period started, down from a high of 2.75 dig-ins per thousand USA tickets in 2013 and putting the Company in the second quartile of gas utility companies in the United States. By the end of 2020, the Company's Gas dig-in rate had dropped to 1.05 per thousand USA tickets, a decline of almost 50% in four years. PG&E's Gas dig-in rate has been in the top quartile (*i.e.*, the quartile with the lowest number of dig-ins) of gas utility companies in the United States every year since 2018.

This reduction is the result of a concentrated focus in gas operations to implement programs aimed at significantly decreasing the dig-in rates over the last five years. These programs include, among others: (1) PG&E's Dig-in Reduction Team ("DIRT"), which deploys investigators to examine dig-ins, patrol active excavations and intervene when unsafe excavation activities are identified; and (2) PG&E's Pipeline Patrol, which uses aerial and ground patrols of gas pipelines to identify excavation and construction activity in the vicinity of gas facilities and notifies DIRT when necessary so DIRT can perform the work noted above as appropriate. These efforts required an investment of approximately $257 million between 2016 and the end of 2020.

2. Opportunities for Continued Improvement

Despite the success PG&E has had in improving its gas operations over the period of probation, there are opportunities for continued improvement. As noted above, the Company is mindful of the risk inherent in having the level of senior leadership turnover that has occurred over the past several years. PG&E has addressed this challenge in its gas operations by recruiting committed, talented and experienced leaders from large gas companies outside of California to bring a fresh perspective to PG&E's gas operations. Such leaders include Joe Forline—who spent 35 years at New Jersey's largest provider of electric and natural gas service, Public Service Electric & Gas Company ("PSEG"), ultimately serving as PSEG's Vice President of Gas Operations for five years—and Janisse Quiñones, who has over 20 years of engineering and utility experience and most recently served as Vice President of Gas System Engineering at National Grid, where she was responsible for the engineering and design of natural gas distribution, transmission and infrastructure projects for National Grid's U.S. territory.

Another challenge PG&E's gas operations faces relates to its gas transmission pipeline As-Built process. Since approximately 2019, all construction work done on PG&E's transmission pipelines flows through the Company's gas transmission pipeline As-Built process, which, at a high level includes the following steps, among others: (1) the construction crew performs the work; (2) Quality Control ("QC") reviews the work; (3) the engineering department reviews the drawings of the work done against the original drawings to ensure any deviations were appropriate; and (4) the Company's systems of record (*e.g.*, GIS, SAP, Documentum) are updated. If any inconsistency is observed during the As-Built process, which would indicate a potential quality concern, the As-Built package is sent back to the construction crew to review and correct any defects.

The Company has been working to decrease the cycle time (*i.e.*, make the process faster) and decrease the number of potential quality issues primarily through multiple weekly cross-functional meetings and tracking relevant metrics, but recognizes there is still work to be done. Accordingly, PG&E has deployed a digital As-Built solution, leveraging tablets, digital smart-forms, barcodes, locating equipment and a Real Time Kinematics ("RTK") network deployed across the service territory to enable asset traceability and high accuracy GPS for Gas Distribution mains and services. PG&E is already seeing quantifiably fewer quality control errors by comparison to traditional paper As-Built records. Given these positive results, the Company is initiating a digital As-Built solution pilot for Gas Transmission projects as well. The digital solution is also contributing to the reduction in annual dig-ins attributed to inaccurate facility records. The Company continues to make progress toward clearing a backlog of work that was completed prior to 2018 that still needs to go through the As-Built process.

3. Requirements Enumerated in January 2017 Order

On January 31, 2017, PG&E was ordered to retain a Federal Monitor as a condition of the Company's probation to ensure the Company's completion of 15 enumerated requirements ("Order Requirements"), which are aimed at maintaining the safety of its gas transmission pipeline system. PG&E agrees with the perspective the Federal Monitor shared with the Company over the course of probation that PG&E: (1) has completed the requirements that have a set deadline within the required period of time; and (2) for those requirements without a set deadline, that PG&E has progressed adequately to satisfy the requirement. Exhibit 3 sets out certain of the measures PG&E has taken to satisfy the requirements.

Conclusion

PG&E thanks the Court for the opportunity to share the various ways in which we have continued to make our system safer and areas for further improvement, and for its continued engagement over the course of the probation period. PG&E has taken a stand that everyone is always safe and that catastrophic wildfires shall stop. Our work is far from finished, but PG&E plans to deliver on these stands by building upon past progress and leading one of the greatest infrastructure reinventions in history. Throughout this reinvention, we will continue to work with stakeholders, our regulators and our communities on how best to safely serve them in the years ahead.

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Respectfully Submitted,

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Exhibit 1

Senior Leaders Who Joined PG&E[1] in 2021

Name	Position	Experience
Patti Poppe	CEO	Former president and CEO of CMS Energy where she also served as SVP of Distribution Operations, Engineering and Transmission, among other roles.
Joe Bentley	SVP, Electric Engineering	Former SVP, U.S. Utility Operations for AES Corporation.
Julius Cox	EVP, People, Shared Services & Supply Chain	Former Chief Human Resources Officer at American Electric Power and Chief Transformation Officer at Dynegy.
Joe Forline	SVP, Gas Operations	Former VP of Gas Operations at Public Service Electric & Gas Company (PSE&G).
Jason Glickman	EVP, Engineering, Planning & Strategy	Former Partner and Global Head of Utilities and Renewables at Bain & Company.
Carla Peterman	EVP, Corporate Affairs	Former SVP of Strategy and Regulatory Affairs at Southern California Edison; previously served a six-year term as a Commissioner of the California Public Utilities Commission.
Janisse Quiñones	SVP, Gas Engineering	Former VP of Gas Systems Engineering at National Grid.
Marlene Santos	EVP, Customer & Communications	Former President of Gulf Power Company.
Wade Smith	SVP, Electric Operations	Former SVP, Grid Development at American Electric Power.
Adam Wright	EVP, Operations	Former President and CEO of MidAmerican Energy Company, a Berkshire Hathaway Energy Company.

[1] For purposes of this chart, "PG&E" can refer to either PG&E Corporation or Pacific Gas and Electric Company.

Exhibit 2

Gas Operations Key Improvements

Demonstrated progress and continued focus on gas system safety since 2010, achieving industry-leading gains in process safety, asset management, and technology innovation.

Industry Recognitions and Certifications

PAS 55 / ISO 55001	Best-in-Class Asset Management
API RP 754	Process Safety Performance Indicators
API RP 1173	Pipeline Safety Management Systems

Opened state-of-the-art facilities

- Gas Control Center, San Ramon
- Gas Safety Academy, Winters
- Gas Safety and Innovation, Dublin

	2010	2021 YTD [2]
GAS ODOR RESPONSE TIMES		
Average response time in minutes	33.3	20.5 [3]
Percent response within 60 minutes	94.4%	99.5%
SCADA VISIBILITY AND CONTROL POINTS		
Transmission pressures and flows	1,300	2,510
Transmission control points	870	1,019
Distribution pressures and flows	290	4,526
LEAK BACKLOG		
Grade 2 open leak average duration (Target: 150 days)		89 days
DIG-IN REDUCTION		
Third party gas dig-ins/1,000 USA tickets	3.5	0.95 [3]

	2010	2011-21 [2]
GAS TRANSMISSION		
Miles of pipeline replaced	9	>277
Miles of pipeline strength tested	0	>1548
Miles of pipeline made piggable	130	>1,915
Automated valves installed	0	390
GAS DISTRIBUTION		
Miles of main replaced [1]	27	>1,152

[1] In 2014, all known remaining cast-iron pipe was decommissioned
[2] Data through October 2021
[3] First quartile performance

Exhibit 3

Measures Taken By PG&E to Satisfy Order Requirements
Related to the Safety of its Gas Transmission Pipeline System

Order Requirement	Measures Taken by PG&E to Satisfy Order Requirement
Order Requirement 1: 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.	• PG&E implemented policies to comply with the evolving regulations on self-reporting potential violations to the CPUC. • PG&E holds a weekly "Quorum" meeting, attended by the Federal Monitor, during which PG&E engineers, legal professionals and compliance professionals determine whether potential non-compliance events are reportable. If the Quorum meeting participants decide a potential non-compliance event poses a significant safety threat to the public, that event will be reported to the CPUC's Safety and Enforcement Division ("SED") each month. Violations that the Quorum determines do not require a self-report to the SED but nonetheless should be reported to the CPUC are included in the Company's quarterly summary report to the CPUC. • Additionally, PG&E's Gas Regulatory Compliance team leverages this data to identify compliance trends.
Order Requirement 2: 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 ("MAOP") for PG&E's gas transmission pipeline, consistent with the National Transportation Safety Board's ("NTSB") 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.	• During its MAOP Validation project, PG&E collected, reviewed and performed an engineering analysis on four million records from the Company's field offices. Data was taken from those records, entered into a spreadsheet (called "pipeline features lists" or "PFLs") and ultimately loaded into PG&E's gas transmission geographic information system ("GT-GIS") for digital accessibility through a geospatial view. The PFLs and GT-GIS enable PG&E to validate the MAOP using PG&E's historic and recent records. • Through cross-functional meetings and technological investments, PG&E continues to prioritize and improve the cycle time and quality of the As-Built records that are used both to update PG&E's gas transmission geographic information system and to maintain the integrity of PG&E's system. • To comply with the applicable regulations, PG&E continues to strength test and re-confirm the transmission pipelines' MAOP for previously untested pipelines and, as of October 2021, has strength tested 6,175 miles, or 94% of PG&E's total transmission pipeline system.

Order Requirement	Measures Taken by PG&E to Satisfy Order Requirement
Order Requirement 3: Confirmation of satisfactory strength testing of at least 500 miles of gas transmission pipelines in 2017 and 2018.	• PG&E's policies and procedures regarding strength testing are consistent with industry practices and comply with the requirements of 49 C.F.R. Part 192, Subpart J. • PG&E successfully strength tested over 530 miles of its gas transmission pipelines in 2017-2018—253 miles in 2017 and 286.7 miles in 2018—thus exceeding Order Requirement Three's mandate to strength test at least 500 miles during that same time period. The Company strength tested an additional 170 miles of gas transmission pipelines from 2019-2021 and plans to strength test an additional 66 miles in 2022.
Order Requirement 4: Upgrading and/or retrofitting approximately 300 miles of gas transmission pipelines to accommodate in-line inspection tools in 2017 and 2018.	• PG&E successfully upgraded almost 400 miles of its transmission pipelines to accommodate in-line inspection tools in 2017–2018—154.4 miles in 2017 and 243 miles in 2018—far exceeding Order Requirement Four's obligation to upgrade 300 miles of its transmission pipelines in those same years. As of October 2021, approximately 1,915 miles of gas transmission pipelines had been upgraded to accommodate in-line inspection tools.
Order Requirement 5: 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.	• Between 2018-2020, PG&E enhanced its integrity management program by implementing projects under a Data Therapeutics Program aimed at improving data quality, data availability, data acquisition (where missing) and data delivery efficiencies. • In addition to doing yearly analyses to ensure that the Company is using the most conservative assumptions where relevant data is missing, PG&E is also working to reduce the number of pipelines that have missing data and therefore require an assumption in the first place by, among other things, examining pipelines with unknown features to determine known specifications.

Order Requirement	**Measures Taken by PG&E to Satisfy Order Requirement**
Order Requirement 6: 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.	• All of PG&E's transmission leak record data is now stored in PG&E's internal database built on a SAP platform. Specifically, after a gas transmission leak is identified, it is marked and logged into the Digital Catalyst mobile inspect application, at which time a SAP notification number is auto generated and attributed to the leak and the leak data (*i.e.*, location, percentage of gas found and type of equipment involved) is automatically transferred into SAP. All activities related to repairing the leak are also logged in SAP, until the leak is repaired and the leak record is closed, at which time the leak data is added to PG&E's risk model, designed to predict the likelihood of different leaks across PG&E's transmission system. • Once a month, a SQL query is run in SAP to identify leaks that may be relevant for CPUC reporting or risk assessment, and engineers review the leaks to identify transmission leaks that are significant, which are then are logged in the "Master Leak List."
Order Requirement 7: 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.	• PG&E's Asset Knowledge Management team has implemented projects to improve the quality and availability of the Company's data in its gas transmission geographic information system to comply with applicable regulations. These efforts include digitizing field inspection and pipeline property data, and building a database to effectively integrate field data from in-line inspections into PG&E's records. • PG&E now collects data from additional sources to incorporate into its risk management procedure. As part of PG&E's threat identification process, data gathered from internal sources (such as design, inspection, operational and maintenance records) and external sources (such as the United States Geological Survey or industry failure data) are aggregated and then used to evaluate transmission pipeline segments.

Order Requirement	**Measures Taken by PG&E to Satisfy Order Requirement**
Order Requirement 8: 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.	• At the beginning of each year, PG&E initiates an organized process to evaluate and update its Transmission Integrity Management Program ("TIMP") risk model. For each threat included in the TIMP risk model, there is a threat-specific steering committee composed of subject matter experts, risk engineers and gas technical specialists. The threat-specific steering committees meet at the beginning of the year to discuss lessons learned in the prior year, the current outputs of the risk model, and proposed adjustments to the portion of the risk model related to that steering committee's area of responsibility. • As the Federal Monitor has noted, the TIMP risk model has significantly improved in the past several years, including: the addition of weekly progress reviews of the Company's annual risk assessment schedule, earlier engagement with subject matter experts, improved documentation and formalization for incorporating feedback from experts, increased resource allocation for data gathering and integration of field findings, and the ability to evaluate the effects of potential risks to the Company's system. • The annual update process is also driven by initiatives in a five-year risk road map that identifies key performance indicators and a plan for improvement. Annual goals and status updates are reviewed during quarterly meetings. • PG&E also made key procedural updates to its threat identification process, TIMP risk algorithm and gas transmission integrity management program, among others.

Order Requirement	**Measures Taken by PG&E to Satisfy Order Requirement**
Order Requirement 9: Implementation of policies and procedures that address threats caused by vegetation and structural encroachments on gas transmission pipelines.	• PG&E has completed 99% of the work outlined in its Community Pipeline Safety Initiative, which included removing structures, trees and brush that pose a safety concern because they are located too close to a pipeline. PG&E continues to work with the approximately five remaining communities to develop plans for the remaining 1% of work. • PG&E has developed and implemented a routine Maintenance Program (Gas Transmission Vegetation Management), which includes routinely patrolling the area above the gas transmission pipelines and addressing any new vegetation or structures identified that pose a safety concern (*e.g.*, trees located too close to a pipeline, which can cause damage to the pipe, potentially leading to corrosion and leaks).
Order Requirement 10: 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.	• PG&E implemented a Utility procedure, TD-4811P-02, "Fatigue Life Evaluation of Gas Transmission Pipeline," in response to this requirement. The procedure addresses each of the four enumerated items and informs how to evaluate the remaining life of gas transmission pipeline segments by analyzing the minimum time to failure due to in-service fatigue crack growth as a result of operational pressure cycling. • PG&E also has a Utility procedure, TD-4810P-25, "In-line Inspection ("ILI") Crack Acceptance," that provides guidance on how to establish response requirements for crack detection, defines which reported anomalies require excavation and examination, gives instructions on performing field examinations when validating a crack detection report and provides direction on accounting for crack growth. • PG&E prefers, where available, to utilize ILI tools to detect crack or crack-like flaws in order to calculate the remaining life of a pipeline. When collecting data via ILI is not feasible or available, PG&E utilizes strength test data to determine remaining life where appropriate.

Order Requirement	**Measures Taken by PG&E to Satisfy Order Requirement**
Order Requirement 11: 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.	• PG&E recently revised its Threat Identification procedure to include industry research, integration of field findings and lessons learned. The procedure, which was published on September 15, 2021, was updated to integrate an improved risk assessment and response approach for threats requiring integrity assessments (e.g., differentiating between leak versus rupture scenarios for crack and crack-like defect threats). • PG&E has also revised its Continual Evaluation procedure—which is designed to identify systematic, operational and environmental changes that may potentially affect the magnitude of risks and threats to a pipeline segment—to include revised remaining life calculation language and integration of crack-like indications from pipeline defect assessment forms. • PG&E has also developed an improved five-year risk road map that outlines risk assessment and threat identification improvements, with a plan to implement field validation digs to improve threat assessments and potentially change threat levels.

Order Requirement	**Measures Taken by PG&E to Satisfy Order Requirement**
Order Requirement 12: 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 ("HCAs") are prioritized consistent with 49 CFR Part 192.917(e)(3)¬(4).	• Federal law requires PG&E to identify which of its pipelines are in HCAs and, as of 2020, Moderate Consequence Areas ("MCAs"). This categorization depends in part on the composition of the area around the pipeline, including the number and proximity to the pipeline of buildings intended for human occupancy. In response to Order Requirement 12, PG&E now conducts an annual system-wide MCA and HCA analysis, which includes analyzing potential changes to prior HCA and MCA determinations to evaluate whether the area around the pipeline has changed in such a way that the pipeline needs to be reclassified. PG&E has various policies designed to enable the Company to accurately designate consequence areas and evaluate for change. • PG&E has also integrated new processes and technology to make accurate consequence designations. The updated process includes more detailed (and focused) desktop review for changes in human occupancy in the area around the pipeline and includes field verification if desktop review is inconclusive for occupancy or if a structure that is within the area around the pipeline's type or use changes. PG&E's review of such changes can result in either confirming the existing consequence area or reducing or removing the extent of a consequence area.
Order Requirement 13: Implementation of policies designed to incorporate changed circumstances into assessment methodologies and prioritization, including Risk Management Procedure 15 ("Threat Identification") and TD 4810B-001 ("Changes to Integrity Management Pressure Testing Requirements for Unstable Manufacturing Threats"), consistent with ASME B31.8S.	• In response to this requirement, PG&E updated the Company's Continual Evaluation procedure to include a section related to lessons learned from external industry events (e.g., impactful leaks, failures, or ruptures) that occur on transmission pipeline assets. Although external events do not occur on PG&E assets, there may be information related to the event that PG&E had not considered in evaluating its own similar assets. • To ensure the Company continues to monitor these events, PG&E also established a dedicated team that meets quarterly to review recent external industry events and the related lessons learned.

Order Requirement	Measures Taken by PG&E to Satisfy Order Requirement
Order Requirement 14: 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 CFR Part 192.917(e)(3), including review of strength-testing of all segments identified as having an unstable manufacturing threat.	• Prior to the start of the probation period, PG&E's method for determining whether a pipeline had an unstable manufacturing threat included utilizing historical data and intentionally increasing the pipeline's pressure up to the maximum allowable operating pressure. PG&E has reviewed all historical pipeline routes that were subjected to the planned pressure increases and has confirmed through records review of post construction traceable, verifiable and complete test records that those segments are stable. PG&E ceased the practice of planned pressure increases to stabilize the manufacturing and construction threats and now requires all covered segments to be subjected to a post construction pressure test to a minimum of 1.25x MAOP in response to Order Requirement Fourteen. • PG&E now has a risk review process for evaluating pressure restorations or uprates prior to allowing pressure to be restored or a pipeline to be uprated that includes strength testing pipelines in order to stabilize manufacturing or construction related defects.
Order Requirement 15: 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.	• PG&E has updated and improved its cyclic fatigue evaluation procedure, TD-4811P-02, to include data from in-line inspection and strength test assessments, and to apply current industry evaluation models and growth rate parameters. • PG&E's cyclic fatigue analysis results are incorporated into its threat identification and risk assessment processes per Utility procedure TD-4810P-16 ("Threat Identification") and TD-4810P-01, Attachment 3 ("Transmission Integrity Management Program Risk Algorithm for Steel Pipe"). • PG&E's cyclic fatigue procedure and all other associated risk assessment, threat identification and continual evaluation procedures are reviewed annually for continued improvements.