PACIFIC GAS AND ELECTRIC COMPANY
QUARTERLY REPORT ON 2020 WILDFIRE MITIGATION PLAN
FOR SECOND QUARTER 2021
AUGUST 2, 2021

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TABLE OF CONTENTS

CONDITION GUIDANCE 9

INSUFFICIENT DISCUSSION OF PILOT PROGRAMS

Deficiency: Electrical corporations do not describe how they will evaluate and expand the use of successfully piloted technology or which piloted technology has proven ineffective. To ensure pilots that are successful result in expansion, if warranted and justified with quantitative data, electrical corporations must evaluate each pilot or demonstration and describe how it will expand use of successful pilots.

Condition: In its quarterly report, each electrical corporation shall detail:

i. ***All pilot programs or demonstrations identified in its Wildfire Mitigation Plan (WMP);***

ii. ***Status of the pilot, including where pilots have been initiated and whether the pilot is progressing toward broader adoption;***

iii. ***Results of the pilot, including quantitative performance metrics and quantitative risk reduction benefits;***

iv. ***How the electrical corporation remedies ignitions or faults revealed during the pilot on a schedule that promptly mitigates the risk of such ignition or fault, and incorporates such mitigation into its operational practices; and***

v. ***A proposal for how to expand use of the technology if it reduces ignition risk materially.***

The first two quarterly reports that Pacific Gas and Electric Company (PG&E) filed in response to Condition Guidance-9 reported on the projects included in Section 5.1.D, New or Emerging Technologies, of PG&E's 2020 WMP. PG&E submitted the Third Quarterly Report concurrently with its 2021 WMP update, and used the section numbering from the 2021 WMP update, now Section 7.1.D, New or Emerging Technologies. Per "Action PGE-18 (Class B)" in Section 5.1.7 of the *Wildfire Safety Division Evaluation of Pacific Gas and Electric Company's First Quarterly Report* dated January 8, 2021, PG&E made a Supplemental Filing of Section 7.1.D New or Emerging Technologies on February 26, 2021 that included revised Quantitative Performance Metrics and Quantitative Risk Reduction Benefits. PG&E continues to provide updated Quantitative Performance Metrics and Quantitative Risk Reduction Benefits in subsequent quarterly reports. This Fifth Quarterly Report includes those revisions from the February 26, 2021 Supplemental Filing.

In this Fifth Quarterly Report, PG&E is initiating reporting on the following four additional new or emerging technology projects:

- Clean Generation for Public Safety Power Shutoff (PSPS);
- Electric Program Investment Charge (EPIC) 3.11B Control of behind-the-meter (BTM) Distributed Energy Resources (DER);

    NOTE: EPIC 3.11 originally included one project: Multi-Use Microgrids and it is reported on as EPIC 3.11 Multi-Use Microgrids in this report. Now there is a second project that is part of EPIC 3.11 named "Control of BTM DERs." PG&E is following a prior naming convention to refer to this project as EPIC 3.11B: Control of BTM DERs.

- Distribution Fault Anticipation (DFA); and
- Early Fault Detection (EFD).

In addition, the Wind Loading Assessments project completed in Q2 and the report on this project in this section will be the last report on this item.

In accordance with Condition Guidance-9, the project information is provided in the following standardized format arranged according to the five Condition Items noted in that deficiency, with expansion by PG&E into multiple targeted, detailed responses, including Quantitative Performance Metrics and Quantitative Risk Reduction Benefits as specified by Action PGE-18 (Class B):

Condition Item (i): All pilot programs or demonstrations identified in WMP.	
The projects are summarized in the table above and the following is the template for the detailed reporting that is provided for each project, below.	
Information Type	Description
(i).A: Project Type	Either New Technology (Commercially Available Offering) or Emerging (Pre- commercial) Technology according to the definition provided in Section 7.1.D.1 above.
(i).B: 2021 WMP Section References	The section number of this project in the New or Emerging Technologies section and/or other sections of the 2020 WMP.
(i).C: 2020 WMP Section References	The section number of this project in the New or Emerging Technologies section and/or other sections of the 2020 WMP.

<table>
<tr><td>(i).D: Project Objective and Summary</td><td>A summary of the project, including its wildfire mitigation-related objective and an indication of whether the project is progressing toward broader adoption, if known. For many new or emerging technology projects, it is not clear until late in the project lifecycle whether the results indicate that the technology is appropriate to be broadly adopted.</td></tr>
<tr><td>(i).E: Utility Wildfire Mitigation Maturity Model (UWMMM) Categories & Capabilities Potentially Impacted</td><td>PG&E is providing one or more UWMMM Categories and Capabilities potentially impacted, where anticipated. Due to the nature of new and emerging technology project developments, these potential Categories and Capabilities are subject to change.</td></tr>
<tr><td colspan="2">Condition Item (ii): Status of the pilot, including where pilots have been initiated and whether the pilot is progressing toward broader adoption.</td></tr>
<tr><td>Information Type</td><td>Description</td></tr>
<tr><td>(ii).A: Project Phase</td><td>The project phase is reported according to the following definitions:
<table>
<tr><td>Project Phase</td><td>Definition</td></tr>
<tr><td>Initiation</td><td>Project purpose and benefits defined
Initial scope, schedule, budget
Sponsor, stakeholders, project team defined</td></tr>
<tr><td>Planning</td><td>Business case including refined scope, schedule, budget and approvals
Benchmarking for non-duplication, lessons learned, and industry best practices</td></tr>
<tr><td>Design/ Engineering</td><td>Detailed design, technical requirements, coordination
Contracting</td></tr>
</table></td></tr>
</table>

	Staging	Review and confirmation of project alignment with purpose, benefits, scope, budget, schedule Key success factors defined
	Build/Test	Build, test, and demonstration Evaluation to defined metrics
	Closeout	Path to production revised Lessons learned documented Decommissioning completed Final report
	Continuous Improvement	Optional phase that some projects progress to when there is project-related continuous improvement activity post Closeout.
(ii).B: Project Status	A summary of the current state of the project, with activity indicative of whether the project is progressing toward broader adoption. For many new or emerging technology projects, it is not clear until late in the project lifecycle whether the results indicate that the technology is appropriate to be broadly adopted.	
(ii).C: Project Location	For field-based projects the general location is provided. For software or analytics-only projects, the area the project applies to is provided, such as to High Fire Threat Districts (HFTD) or systemwide.	
Condition Item (iii): Results of the pilot, including quantitative performance metrics and quantitative risk reduction benefits.		
Information Type	Description	
(iii).A: Results to Date	Results of pilot projects are provided through Q2 2021. Project results for prior quarters are included, either labeled by quarter or as Prior Results that may extend to the origin of the project. Results for pilot projects in phases preceding the Closeout phase, as defined in (ii).A, are preliminary and subject to change.	
(iii).B: Lessons Learned	Lessons learned for pilot projects are technological learnings, findings, and key takeaways to inform a path to production. Lessons learned can also be barriers, issues, risk, or obstacles that if not solved could jeopardize the path to production. Lessons learned provided for projects in phases preceding the Closeout phase, as defined in (ii).A, are preliminary and subject to change.	
(iii).C: Quantitative Performance Metrics	Quantitative performance metrics, along with preliminary corresponding performance targets, are provided for the projects in this portfolio, where appropriate. In subsequent quarterly and annual updates, and as these projects progress, PG&E will refine these quantitative performance metrics, the performance targets associated with these metrics, and identify performance against these metrics as they become available. In addition, several of the projects in this portfolio, including but not limited to foundational projects, are evaluated on a delivered feature set or pass/fail basis. In such cases, non-quantitative or minimum deliverable criteria are provided and identified as such. Performance measures are provided for the evaluation of the effectiveness of the technology during the project specifically, and do not extend beyond to any eventual uses of the technology if subsequently deployed.	

(iii).D: Quantitative Risk Reduction Benefits	Quantitative risk reduction benefits that may result from adoption and deployment of the technology are provided for projects in this portfolio, as appropriate. The risk model used to calculate the potential quantitative risk reduction benefits is PG&E's Enterprise Risk Model for which the wildfire risk assessment and bowtie analysis is described in Section 4.2(b) of the 2021 WMP. The estimated potential risk scores provided for individual projects range from 13 to 6,302 and are in relation to the baseline risk score of approximately 25,000. For further explanation, please see Section 4.2(b). Note that the estimated potential risk reduction is calculated for each technology independent of the effects of other technologies working on the same geography or asset. This is further explained in the document "RSE Lite Methodology WMP 2021.pdf" submitted with the 2021 WMP. The estimated risk reduction considers the total potential risk reduction impact at full technology deployment (e.g., system-wide, Tier 2 and 3 HFTD, or specific types of distribution circuits) depending on the specific assets or geographic scope where the technology is applicable, and independently of any other risk reduction projects. In order to normalize the variations in scope for technology deployment, estimated potential risk reduction is normalized per mile in the results. Along with the calculated benefits provided using this methodology, the underlying assumptions and short explanations are provided as needed. There is inherent uncertainty in the assumptions and estimates that are developed to create the quantitative risk reduction benefits. Risk reduction benefits should be viewed as initial potential estimates if the technology is proven successful and will be refined in subsequent updates, as assumptions around the types of assets impacted, the applicable scope of deployment, and the effectiveness of the technologies are refined. Projects classified as foundational do not lend themselves to the calculation of a quantitative risk reduction benefit. Instead, these projects enable other technology projects to build on foundations to potentially provide quantitative risk reduction benefits. In these foundational project cases, there is an explanation of either specific projects that are built upon the foundation that may provide quantitative risk reduction benefits or a general qualitative explanation of risk reduction benefits that may be provided in the future.
Condition Item (iv): How the electrical corporation remedies ignitions or faults revealed during the pilot on a schedule that promptly mitigates the risk of such ignition or fault and incorporates such mitigation into its operational practices.	
Information Type	Description
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	If the project, in any phase, identifies a potential ignition or fault risk condition (e.g., an in-field asset condition or configuration issue, or a vegetation issue), the potential condition is reported and validated against current PG&E preventive and corrective maintenance guidelines and treated in accordance. In addition, a general statement of such activity is provided in this response.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	Typically, methods to incorporate ignition or fault risk mitigation findings into operational practices are revealed toward the end of the projects as part of the lessons learned and other recommendations in the Closeout documentation. However, if PG&E identifies such risk mitigation methods to inform proposed changes to operational practices, including prior to the conclusion of the project, they will be included in this response.

Condition Item (v): A proposal for how to expand use of the technology if it reduces ignition risk materially.	
Information Type	Description
(v).A: 'End Product' at 'Full Deployment' and Location	For this response PG&E is providing the anticipated use of the technology, including anticipated locations, should the technology be proven to be successful and subsequently put into production. Given that the projects are in varying phases of development and precommercial technologies are inherently uncertain, this response is based upon our current understanding of the technology and its applicability to PG&E operations, and subject to change. Early stage projects may not have a clear strategy for the 'end product' at 'full deployment', while others such as those in the Continuous Improvement phase may have already been deployed.

Forward-looking statements detailed through this section, including but not limited to project next steps, expected results, and potential quantitative risk reduction benefits, are subject to change due to the evolving nature of technology and drivers of system and public safety risk.

The projects described below are organized by Program Areas.

<u>Program Area</u>: Situational Awareness and Forecasting – New or Emerging Technologies

PG&E is deploying a set of complementary tools to better assess and more accurately locate, often in near real time, environmental events and grid conditions that pose a danger to the grid so that critical issues may be dealt with as quickly as possible to avoid the risk of catastrophic wildfires. Below are potential mitigations leveraging new or emerging technologies; for additional information reference Section 7.3.2.

SMARTMETER PARTIAL VOLTAGE DETECTION

(i).A: Project Type	Emerging (Pre-commercial) Technology
(i).B: 2021 WMP Section References	7.1.D.3.1. This project is also described in Section 7.3.2.2.2: Situational awareness and forecasting – SmartMeter Partial Voltage Detection (Formerly Known as Enhanced Wires Down Detection).
(i).C: 2020 WMP Section References	5.1.D.3.4

(i).D: Project Objective and Summary	PG&E's EPIC 1.14: Next Generation SmartMeter Telecom Network Functionalities project demonstrated that the SmartMeter Telecommunications Network can support a variety of both present and future smart grid applications and devices, including using multiple types of outage reporting data from the SmartMeter network to better identify and differentiate wire down type outages and share information with distribution management systems (DMS) more effectively. The SmartMeter Partial Voltage Detection (formerly known as Enhanced Wires Down Detection) project builds on this work to assess the ability to use SmartMeter technology to locate and identify partial voltage conditions to enable faster response to grid issues. A partial voltage condition can indicate the occurrence of a potentially hazardous distribution grid condition, including hazards that can contribute to wildfire risk. PG&E has enabled Single-Phase SmartMeters to send real-time alarms to the DMS under partial voltage conditions (25-75 percent of nominal voltage). Prior to implementation, SmartMeters electric meters could only provide real-time alarms for the outage state. For Three-Wire distribution systems, the partial voltage condition indicates one phase feeding the transformer has low voltage or no voltage. This enhanced situational awareness can help detect and locate the area boundaries between meters encountering normal voltage and those encountering partial voltage. This allows operators to detect and locate partial voltage line sections more quickly to enable faster response to potential wires down, open jumpers, or loss of phase(s) due to unganged fuse operation. Phase 1 partial voltage detection technology has proven successful on 3-Wire distribution systems where transformers are connected line-to-line, and loss of phase results in a partial voltage condition whereby the communication card can detect and then send alerts to the DMS during the event. Phase 1 of this project completed in 2019 included implementation on 4.5 million single phase SmartMeter electric meters covering 25,597 line miles of Tier 2 and Tier 3 HFTD areas. Phase 2 of this project is underway. It applies to ~411,000 (originally ~365K) 3-phase SmartMeter electric meters and relies upon the implementation of firmware detection of partial voltage conditions. The Phase 2 technology is intended to alert on partial voltage conditions on 4-Wire systems where transformers are connected line-to-neutral.
(i).E: Utility Wildfire Mitigation Maturity Model (UWMMM) Categories & Capabilities Potentially Impacted	F. Grid operations and protocols: 27. Protective equipment and device settings
(ii).A: Project Phase	Phase 1: Closeout (~4.5M single-phase meters have been in production since 2019). Phase 2: Design/Engineering (~411K three-phase meters in scope).
(ii).B: Project Status	Phase 1 is in production and has been deployed to ~4.5M meters system-wide. Phase 2 is in production and has been deployed to ~411K meters system-wide.

(ii).C: Project Location	Phase 1: Tier 2 & 3 HFTDs were initially targeted; now deployed systemwide. Phase 2: Tier 2 & 3 HFTDs were initially targeted; now deployed system-wide.
(iii).A: Results to Date	Q2 2021 Phase 2 Project Results: Completed deployment in June and is in production. Q1 2021 Phase 2 Project Results: SmartMeter firmware general release received from vendor. Regression testing started. PG&E was awarded United States (U.S.) Patent No. 10,877,083 on method of using partial voltage condition on 3 wire circuits to detect and localize wire down and other partial voltage conditions. Q3 2020/Q4 2020 Phase 2 Project Results: Meter firmware vendor contract finalized. Design of DMS data presentation for operator use. SmartMeter firmware functionality testing complete SmartMeter firmware deployment planning complete
(iii).B: Lessons Learned	In Phase 1, it was discovered that some abnormal SmartMeter electric meter conditions (e.g., failed power supply) can produce false positive partial voltage alerts. PG&E had to address these false positives by applying filtering strategies to prevent presentation to operators through the DMS. In Phase 2, it was discovered that the filter needed to be reassessed because the system was alerting not just on primary open conductor issues, but also secondary or individual service issues that needed to be corrected through other means.
(iii).C: Quantitative Performance Metrics	Detection, analysis, and reporting of open jumpers, partial operation of unganged fuses, and wire down events. Target false positive rate: near zero though it is not possible to get to zero due to operational conditions and technical limitations. Actual Results: Not available at this time. Number of minutes from the report of an event in advance of when a report would otherwise have been first received through existing processes. Target: Non-zero (any improvement in accurate advanced notice of an event contributes to risk reduction). Actual Results: Not available at this time.

(iii).D: Quantitative Risk Reduction Benefits	Estimated Potential Risk Reduction Score: 265. Risk Drivers: Equipment Failure, Vegetation. Deployment Scope Assumption: System-wide. The risk mitigation potential is driven by a 7 percent estimated effectiveness in the ability to reduce the likelihood of wildfire ignition risk through faster response time due to partial voltage and/or wire down conditions.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	As both phases of this project are now in production, current operational practices have been modified to include the functionality as described in this section (there are no additional findings).
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	The methodology is to display filtered partial voltage alerts on transformers in DMS maps, which allows operators to be alerted of partial voltage conditions and visualize the boundaries between full voltage, partial voltage and complete outage sections of the distribution system. Integration into the Outage Management Tool will summarize SmartMeter partial voltage alert counts in an informational table presentation for current outages. The enhanced situational awareness can help operators detect and locate partial voltage line sections more quickly to enable faster response to potential wires down, open jumpers, or loss of phase(s) due to unganged fuse operation.
(v).A: 'End Product' at 'Full Deployment' and Location	The end product is that the partial voltage detection firmware will be deployed to all compatible PG&E SmartMeter electric meters system-wide, with system optimization completed, and functionality integrated into the DMS and Outage Management Tool, as described in (iv).B above.

LINE SENSOR DEVICES

(i).A: Project Type	New Technology (Commercially Available Offering)
(i).B: 2021 WMP Section References	7.1.D.3.2. Also Section 7.3.2.2.5: Situational Awareness & Forecasting – Line Sensor Devices
(i).C: 2020 WMP Section References	5.1.D.3.5
(i).D: Project Objective and Summary	Line Sensors are primary conductor-mounted devices that continuously measure current in real-time and report events as they occur, and in some cases the current waveform of grid disturbances. These line sensors are next-generation fault indicators with additional functionality and communication capabilities. Line Sensor technology can reduce wildfire risk and improve public safety by continuous monitoring of the grid, performing analytics on captured line disturbance data, identifying potential hazards, and when necessary dispatching field operations to proactively patrol, maintain, and repair discovered field conditions or assets on the verge of failure.
(i).E: Utility Wildfire Mitigation Maturity Model (UWMMM) Categories & Capabilities Potentially Impacted	F. Grid operations and protocols: 27. Protective equipment and device settings
(ii).A: Project Phase	Build/Test
(ii).B: Project Status	Line sensors have been deployed on 85 circuits covering a total of 6,949 circuit miles in Tier 2 & 3 HFTDs. On a daily basis, the data from these sensors are being used to investigate the source of unknown cause outages. Line sensor deployment on a minimum of 25 additional circuits is targeted for completion in 2021. PG&E continues to engage with other California and international utilities to discover and assess alternatives for monitoring technology.
(ii).C: Project Location	Tier 2 & 3 HFTDs in the North Bay, Sonoma, North Valley, Humboldt, Yosemite, De Anza, Los Padres, Central Coast, and Sierra divisions.

(iii).A: Results to Date	Q2 2021 Deployed line sensors on 25 additional circuits covering 2,052 line-miles in Tier 2 & 3 HFTDs. Q1 2021 Line sensors for the planned 2021 deployment ordered and contract team engaged to manage deployment and commissioning. Q3 2020/Q4 2020 Developed line risk evaluations based on line sensor and other data for select HFTD circuits to calculate location of potential issues. Informed field operations for further inspection, assessment, and maintenance. Improved analytics methods and automation.
(iii).B: Lessons Learned	When combined with other data sources, line sensor devices contribute valuable data to enable proactive condition detection. Inputs from other sensors and systems as well as analytics are required to improve accuracy and results.
(iii).C: Quantitative Performance Metrics	Percentage (%) of the events detected by sensors (e.g., grid disturbances from vegetation contact or line slap) resulting in identification of wildfire risk conditions requiring preventative action. Target: ≥50% Actual Results: 42 percent (7 events investigated with 3 risk issues found).
(iii).D: Quantitative Risk Reduction Benefits	Estimated Potential Risk Reduction Score: 2004 NOTE: This Estimated Potential Risk Reduction Score is for the combination of this Line Sensor Devices project and the DFA project also reported on in this section, as the technologies of these two projects work in concert to detect where the fault was located (Line Sensor Devices) and when the fault occurred (DFA). Risk Drivers: Equipment Failure, Vegetation, Consequence of Fire. Deployment Scope Assumption: Distribution lines in Tier 2 & 3 HFTDs. This initiative, in concert with DFA as previously described, reduces the likelihood of ignition and consequence of fire risk, specifically mitigating the equipment failure, vegetation drivers and financial, safety, and reliability consequences. The risk mitigation potential is driven by an overall ~7% effectiveness estimated by subject matter experts.

(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	When a suspected high-risk condition is found by the Line Sensor Device team, the local restoration team is alerted and dispatched to patrol and rectify the situation as needed.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	PG&E is using data provided by line sensor technologies to bolster asset health and performance through a three-step process: (i) Collecting line sensor data attributes on disturbances to create a database of disturbance signatures for disturbance evaluations; (ii) Detecting disturbance information from Tier 2 and Tier 3 HFTDs and matching the captured disturbance data against the signature database to determine if a distribution line risk is likely to materialize as a hazard; (iii) Matching line sensor data attributes on line risks in a manner in which they can be evaluated in the distribution network model software to estimate the location of the line risk for proactive field patrol, inspection, and repair, if necessary, before failure to reduce risk and improve system safety.
(v).A: 'End Product' at 'Full Deployment' and Location	This product is one component of a set of grid sensor technologies (as described in 7.3.2.2 Continuous Monitoring Sensors) that, as a set, are optimized to support and complement each other. This product would be deployed to circuits in Tier 2 & 3 HFTDs and would be integrated into Distribution Control Center (DCC), Maintenance, and Field Operations functions to support faster fault identification (including location data) for proactive maintenance prior to high fire risk periods.

EARLY FAULT DETECTION

(i).A: Project Type	New Technology (Commercially Available Offering)
(i).B: 2021 WMP Section References	7.3.2.2.3
(i).C: 2020 WMP Section References	5.3.2.2.5
(i).D: Project Objective and Summary	The EFD project utilizes distributed sensors near transmission or distribution lines to detect radio frequency signals that are generated by potential latent or incipient issues in their early stages with the intent to be able to remove many of the conditions that can cause wildfires. EFD may also be able to more quickly detect and locate aggressively failing components during high-risk conditions and allow field crews and fire protection personnel to more immediately respond to and minimize wildfire risks.
(i).E: Utility Wildfire Mitigation Maturity Model (UWMMM) Categories & Capabilities Potentially Impacted	F. Grid operations and protocols: 27. Protective equipment and device settings
(ii).A: Project Phase	Design/Engineering
(ii).B: Project Status	Deployment planning including contract negotiation, coordination with PG&E's Standards team, and the development of engineering processes.
(ii).C: Project Location	Distribution circuits with more than 3 line miles within Tier 2 or 3 HFTDs.
(iii).A: Results to Date	Q2 2021 No results this quarter as the deployment is currently being planned.
(iii).B: Lessons Learned	None so far.
(iii).C: Quantitative Performance Metrics	Percentage (%) of the events detected by sensors resulting in identification of wildfire risk conditions requiring preventative action. Target: ≥50% Actual Results: To be provided as available from assessment data.
(iii).D: Quantitative Risk Reduction Benefits	Estimated Potential Risk Reduction Score: 6302 Risk Drivers: Equipment Failure, Vegetation, Consequence of Fire. Deployment Scope Assumption: Distribution lines in Tier 2 & 3 HFTDs. This initiative reduces the likelihood of ignition and consequence of fire risk, specifically mitigating the equipment failure, vegetation drivers and financial, safety, and reliability consequences. Ko0ect matter experts.

(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	When a suspected high-risk condition is found by the project team, the local restoration team is alerted and dispatched to patrol and rectify the situation as needed.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	PG&E is using data provided by continuous monitoring sensor technologies such as EFD to bolster asset health and performance in the distribution network model software to estimate the location of the line risk for proactive field patrol, inspection, and repair, if necessary, before failure in order to reduce risk and improve system safety.
(v).A: 'End Product' at 'Full Deployment' and Location	This product is one component of a set of grid sensor technologies (as described in 7.3.2.2 Continuous Monitoring Sensors) that, as a set, are optimized to support and complement each other. This product would be deployed to circuits in Tier 2 & 3 HFTDs and would be integrated into DCC Maintenance, and Field Operations functions to support faster fault identification (including location data) for proactive maintenance prior to high fire risk periods. The intent is to deploy EFD (along with DFA) sensors on a total of 600-800 circuits in Tier 2 and Tier 3 HFTD areas, mitigating 28,000 total line miles (20,200 miles in Tier 2, 7,800 miles in Tier 3).

DISTRIBUTION FAULT ANTICIPATION

(i).A: Project Type	Emerging (Pre-commercial) Technology
(i).B: 2021 WMP Section References	7.3.2.2.3
(i).C: 2020 WMP Section References	5.3.2.2.4
(i).D: Project Objective and Summary	DFA technology captures primary distribution disturbance current and voltage waveforms. It conducts digital signal processing locally, communicates results to a waveform classification engine which then identifies both normal and abnormal events on the distribution system. The DFA technology is installed within the substation and uses existing substation bus Potential Transformers and circuit breaker Current Transformers (CT). When combined with Line Sensor Devices data the technologies of these two projects work in concert to detect where the fault was located (Line Sensor Devices) and provide a precise time of when the fault occurred (DFA).
(i).E: Utility Wildfire Mitigation Maturity Model (UWMMM) Categories & Capabilities Potentially Impacted	F. Grid operations and protocols: 27. Protective equipment and device settings
(ii).A: Project Phase	Design/ Engineering
(ii).B: Project Status	Deployment planning in progress.
(ii).C: Project Location	Feeders with more than 3 line miles within Tier 2 or 3 HFTDs
(iii).A: Results to Date	Q2 2021 No results this quarter as the deployment is currently being planned.
(iii).B: Lessons Learned	None so far.
(iii).C: Quantitative Performance Metrics	Percentage (%) of the events detected by sensors resulting in identification of wildfire risk conditions requiring preventative action. Target: ≥50% Actual Results: To be provided as available from assessment data.

(iii).D: Quantitative Risk Reduction Benefits	Estimated Potential Risk Reduction Score: 2004 NOTE: This Estimated Potential Risk Reduction Score is for the combination of this DFA project and the Line Sensor Devices project also reported on in this section, as the technologies of these two projects work in concert to detect where the fault was located (Line Sensor Devices) and when the fault occurred (DFA). Risk Drivers: Equipment Failure, Vegetation, Consequence of Fire Deployment Scope Assumption: Distribution lines in Tier 2 & 3 HFTDs This initiative, in concert with Line Sensor Devices as previously described, reduces the likelihood of ignition and consequence of fire risk, specifically mitigating the equipment failure, vegetation drivers and financial, safety, and reliability consequences. The risk mitigation potential is driven by an overall ~7% effectiveness estimated by subject matter experts.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	When a suspected high-risk condition is found by project team, the local restoration team is alerted and dispatched to patrol and rectify the situation as needed.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	PG&E is using data provided by continuous monitoring sensor technologies such as DFA to bolster asset health and performance through a three-step process: (i) Collecting sensor data attributes on disturbances to create a database of disturbance signatures for disturbance evaluations; (ii) detecting disturbance information from Tier 2 and Tier 3 HFTDs and matching the captured disturbance data against the signature database to determine if a distribution line risk is likely to materialize as a hazard; (iii) matching sensor data attributes on line risks in a manner in which they can be evaluated in the distribution network model software to estimate the location of the line risk for proactive field patrol, inspection, and repair, if necessary, before failure to reduce risk and improve system safety.
(v).A: ‘End Product’ at ‘Full Deployment’ and Location	This product is one component of a set of grid sensor technologies (as described in 7.3.2.2 Continuous Monitoring Sensors) that, as a set, are optimized to support and complement each other. This product would be deployed to circuits in Tier 2 & 3 HFTDs and would be integrated into DCC, Maintenance, and Field Operations functions to support faster fault identification (including location data) for proactive maintenance prior to high fire risk periods. The intent is to deploy DFA (along with EFD) sensors to monitor a total of 600-800 circuits in Tier 2 and Tier 3 HFTD areas, mitigating 28,000 total line miles (20,200 miles in Tier 2, 7,800 miles in Tier 3).

<u>Program Area</u>: Grid Design and System Hardening – New or Emerging Technologies

PG&E is reducing the risk of fire ignition and potential impacts on public safety through the adoption of system hardening methods enabled through innovative technologies (e.g., new grid topologies or new resilience and PSPS avoidance technologies or techniques). Mitigations leveraging new or emerging technologies include the following:

EPIC 3.15: PROACTIVE WIRES DOWN MITIGATION DEMONSTRATION PROJECT (RAPID EARTH FAULT CURRENT LIMITER)

(i).A: Project Type	Emerging (Pre-commercial) Technology
(i).B: 2021 WMP Section References	7.1.D.3.3 and 7.3.3.17.4
(i).C: 2020 WMP Section References	5.1.D.3.6
(i).D: Project Objective and Summary	The EPIC 3.15 Proactive Wires Down Mitigation demonstration project seeks the ability to automatically and rapidly reduce the flow of current and risk of ignition in single phase to ground faults through the use of Rapid Earth Fault Current Limiter (REFCL). REFCL works by moving the neutral line to the faulted phase during a fault, which significantly reduces the energy available for the fault. This significantly lowers the energy for single line to ground faults by reducing the potential for arcing and fire ignitions, as well as better detection of high impedance faults and wire-on-ground conditions. REFCL technology is applicable to three-wire unit-grounded circuits, which make up the majority of PG&E's distribution circuits within HFTDs.
(i).E: Utility Wildfire Mitigation Maturity Model (UWMMM) Categories & Capabilities Potentially Impacted	C. Grid design and system hardening: 14. Risk-based grid hardening and cost efficiency 15. Grid design and asset innovation
(ii).A: Project Phase	Design/Engineering
(ii).B: Project Status	All of the REFCL system equipment has been installed and initially tested. Further commissioning of the system is ongoing (as of late March) and a comprehensive testing program has started in February and will run through May 2021, with the project completed by July 2021. Based on feedback from Australian utilities who have leveraged this technology, ongoing observation and adjustment of various system parameters may be needed to "fine-tune" the REFCL system going forward. Evaluation of additional substations for suitability of additional REFCL installations has begun but is pending results and learnings of the Calistoga pilot project before design or field work starts on additional sites.
(ii).C: Project Location	Substation in a Tier 3 HFTD in the North Bay.

(iii).A: Results to Date	Q2 2021 Substation and distribution commissioning completed. First staged fault test successfully performed. Q1 2021 Completed Substation Supervisory Control and Data Acquisition (SCADA), and Substation fire alarm system certification. Q4 2020 Completed substation construction and all the distribution field installations in Q4 2020.
(iii).B: Lessons Learned	The original configuration of the Ground Fault Neutralizer (GFN) installation in the substation resulted in ferroresonance issues, which had to be mitigated. Additional preventive measures were needed to avoid ferroresonance and equipment damage resulting from the transient overvoltages. Some of these measures include use of a 3-phase recloser to protect the 12 kilovolt (kV) service going to the GFN equipment, relocation of the substation service transformer, and using Type B voltage regulators or transformer banks with Load Tap Changer capability for voltage regulation. The GFN adds on another layer of system protection with greater sensitivity to ground faults than traditional system protection schemes commonly used in the USA which utilize solid grounding. In digital simulation testing, the GFN showed the capability to detect high impedance ground faults upwards of 16K ohms, which is in the typical range for vegetation contact faults. The GFN also shows promise of detecting reverse earth faults resulting from specific wires-down situations, which are especially challenging to detect and pose a public safety risk. A key lesson learned is the need for balancing the line to ground capacitance of each phase on the distribution circuits where a GFN is deployed. A detailed review was performed in the project and it highlighted the need for capacitive balance units to have precise control over the balancing and achieve the greatest fault sensitivity. Group tapping for line voltage regulators was also determined to be required, so a new multiphase regulator controller was tested and verified for this function.

(iii).C: Quantitative Performance Metrics	Ignition probability reduction with field test results per the Energy Safe Victoria (ESV, Australia) REFCL standard as follows: Faulted conductor voltage < 1,900 V within 85 milliseconds Faulted conductor voltage < 750 V within 500 milliseconds Faulted conductor voltage < 250 V within 2,000 milliseconds Target: ≥ 90% Actual Results: 100% (1 test series). In the first staged fault test series with resistance of 3200 ohms (see the discussion of high impedance faults in the Lessons Learned section above), a momentary high impedance fault was created on the distribution line using a mobile high voltage resistor bank connected to ground. The GFN successfully detected the fault, reduced the voltage on the faulted phase, and correctly identified that the fault was on the specific feeder. Measured voltages of the faulted phase from the test were 1679V at 85 milliseconds, 225V at 500 milliseconds, and 224V at 2000 milliseconds, all of which meet the ESV standard referenced above. False positive rate Target: ≤ 10% Actual Results: 0% (from the limited testing as described above). False negative rate Target: ≤ 5% Actual Results: 0% (from the limited testing as described above). GFN system availability/uptime (excluding external operations constraints) Target: ≥ 95% Actual Results: Not available at this time. Correct identification of faulted circuit and feeder breaker tripping Target: ≥ 95% Actual Results: 100% (from the limited testing as described above).
(iii).D: Quantitative Risk Reduction Benefits	Estimated Potential Risk Reduction Score: 962 Risk Drivers: Equipment Failure Deployment Scope Assumption: ~3,500 miles of 3-wire/12kV distribution lines in Tier 2 & 3 HFTDs. The risk mitigation potential is driven by an estimated overall effectiveness of 58 percent using 2013-2018 distribution ignition data.

(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	The GFN will be operational in the North Bay substation to add another layer of system protection to the two connected distribution circuits. If a ground fault is detected, the GFN will autonomously mitigate the fault current and identify which circuit the fault is on. Pre-defined criteria will determine how the fault is cleared, whether through recloser tripping or cutover to solid grounding depending on ambient conditions. The plan for additional production implementations of the technology is in development.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	A Substation Earth Fault Management relay interface controller is currently in development and is needed to integrate the GFN into operational practices and the SCADA system. Operators will have visibility into the status of the GFN and make control decisions if a fault is detected. Training sessions with operations personnel are being scheduled showing how the REFCL technology works and the associated controls.
(v).A: 'End Product' at 'Full Deployment' and Location	The end product is that the REFCL system would be deployed to substations in Tier 2 and 3 HFTDs, including substation components (arc suppression coil, GFN control cabinet, residual current compensator, and potentially upgraded CTs and relays) and field work (capacitive balancing, upgraded line reclosers, and upgrades to regulators, capacitor banks, and insulation levels as needed). Capacitive planning incorporated into annual distribution planning cycle. Capacitive operational analysis incorporated into planning and analysis of planned and unplanned outages. Annual training for field personnel who would interact with the system, distribution operations, and distribution engineering. Annual testing of circuit and REFCL system to check reliability/sensitivity of REFCL system operations and insulation tests to detect equipment that is overly stressed and likely to fail during REFCL operation.

Distribution, Transmission, and Substation: Fire Action Schemes and Technology (DTS-FAST)

Note: Due to the sensitive nature of the experimental, proprietary technology, PG&E is unable to disclose extensive details about the DTS-FAST project in public filings. Upon request, PG&E can provide further information under confidentiality protections.

(i).A: Project Type	Emerging (Pre-commercial) Technology
(i).B: 2021 WMP Section References	7.1.D.3.4 and 8.1
(i).C: 2020 WMP Section References	5.1.D.3.7
(i).D: Project Objective and Summary	DTS-FAST is an internal PG&E wildfire mitigation development project. This project aims to use real-time technologies to detect objects approaching energized power lines and respond quickly to shut off power before object impact. PG&E is engineering, constructing, installing, and monitoring DTS-FAST technology on PG&E transmission and distribution circuits to assess the technology's efficacy at mitigating PG&E's wildfire and safety risks. Next steps and potential operationalization of this technology is dependent on an assessment of findings.
(i).E: Utility Wildfire Mitigation Maturity Model (UWMMM) Categories & Capabilities Potentially Impacted	C. Grid design and system hardening: 12. Grid design for minimizing ignition risk 15. Grid design and asset innovation
(ii).A: Project Phase	Build/Test (initial installation). Design/Engineer (additional transmission and distribution installation).
(ii).B: Project Status	Construction and testing is complete on the initial 115kV transmission towers.
(ii).C: Project Location	The initial installation is on 115kV transmission towers in Contra Costa County. An additional installation on 115kV transmission towers is planned in Amador County and an installation on distribution poles is planned in Butte County.

(iii).A: Results to Date	Q2 2021 Finalized design of the DTS-FAST system and started manufacturing of the devices for the next planned installations. Q1 2021 Testing of the initial installation on 115kV transmission towers in Contra Costa County is complete. Additional installations on 115kV transmission towers (Amador County) and distribution poles (Butte County) are in a planning and environmental impact analysis phase. Q3 2020/Q4 2020 Engineering and construction details completed for pilot on 115kV transmission circuit.
(iii).B: Lessons Learned	We learned that the system as designed is capable of being installed by crews onto an existing transmission tower, can operate in the high electromagnetic field environment of a transmission tower, and can withstand inclement environmental conditions.
(iii).C: Quantitative Performance Metrics	The detection of objects approaching energized power lines and the corresponding power shut off. Target: Power shut off prior to object impact. Actual Results: Confidential.
(iii).D: Quantitative Risk Reduction Benefits	Estimated Potential Risk Reduction Score: Confidential Risk Drivers: Equipment Failure, Vegetation Deployment Scope Assumption: System-wide The risk mitigation potential is driven by the ability of the new technology to effectively shut off power to distribution and transmission lines as failures are detected by its sensors.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	None to date.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	Leverage project findings for operational implementation. Monitor new installations and assess success criteria to ensure technology is working optimally. Assess impacts on asset inspections enabled through real time sensor data. Assess impacts on ability to reduce PSPS events and expedite restoration times.

(v).A: 'End Product' at 'Full Deployment' and Location	Full deployment plans will be dependent on findings. If successful, PG&E will consider a targeted approach for implementation to help ensure high impact areas are first addressed, taking into account risk-based and feasibility assessments.

REMOTE GRID

(i).A: Project Type	New Technology (Commercially Available Offering)
(i).B: 2021 WMP Section References	7.1.D.3.5 and 7.3.3.17.5
(i).C: 2020 WMP Section References	5.1.D.3.8
(i).D: Project Objective and Summary	A "Remote Grid" is a new concept for utility service using standalone, decentralized energy sources and utility infrastructure for continuous, permanent energy delivery in lieu of traditional wires to small loads in remote locations at the edges of the distribution system. In many circumstances, the feeders serving these remote locations traverse through HFTDs areas. If these long feeders were removed and the customers served from a local and decentralized energy source, the resulting reduction in overhead lines could reduce fire ignition risk as an alternative to or in conjunction with system hardening. In addition to reducing wildfire risk, Remote Grid could be a cost-effective solution against expense and capital costs for the rebuild of fire-damaged infrastructure or for HFTD hardening infrastructure jobs to meet new HFTD build standards. PG&E's Remote Grid Initiative will validate and develop Remote Grid solutions as standard offerings such that they can be considered alongside or as an alternative to other service arrangements and/or wildfire risk mitigation activities such as system hardening. The findings of other pilot or demonstration projects, including EPIC 3.03: Advanced Distribution Energy Resource Management System, which looks to develop increased situational awareness and control capabilities of DERs, will help to support the deployment of remote grid configurations.
(i).E: Utility Wildfire Mitigation Maturity Model (UWMMM) Categories & Capabilities Potentially Impacted	C. Grid design and system hardening: 12. Grid design for minimizing ignition risk 13. Grid design for resiliency and minimizing PSPS 14. Risk-based grid hardening and cost efficiency
(ii).A: Project Phase	Build/Test

(ii).B: Project Status	The projects are advancing through scoping, assessment, contracting, design, and permitting activities, building understanding of the many aspects required for a successful Remote Grid. The three leading projects (some comprising five remote grid sites) are in the permitting and construction stages. Initial projects have been delayed due to unforeseen permitting delays due to presence of threatened species. Additional sites under consideration are undergoing detailed feasibility assessment to address constructability and customer acceptance before down selecting to a complete set of initial projects.
(ii).C: Project Location	Three initial remote grid projects (some comprising five remote grid sites) are in Mariposa and San Luis Obispo counties. Additional projects in HFTDs in El Dorado, Madera, Fresno, Tulare, Santa Barbara, Yuba, and Sierra counties are currently being assessed.

(iii).A: Results to Date	Q2 2021 Completed the Briceburg Remote Grid project, including all construction, commissioning, and performance testing, with customers energized in June. 2021 Request for Proposals (RFP) process completed for six Standalone Power System (SPS) projects (one of the six was subsequently descoped due to changing customer needs), with the remaining five now entering final contract negotiations to complete award for SPS installation and maintenance agreements. Scoped and progressed 11 fire rebuild projects through customer outreach stage in North Complex Fire footprint in Butte County. None of these projects are currently expected to move to deployment stage, due to various factors including particular project economics and lack of customer acceptance at these specific sites. Identified, scoped, and drove 5 new 2021 Remote Grid projects (7 SPS total) through project assessment process including: customer engagement and approval, Wildfire Governance Committee approval, advanced authorization creation, and project design and financial analysis. Released 2021 RFP (5 projects, 7 SPS) bundle to vendor bid. Completed shortlisting of bidders and scheduled interviews with goal of awarding contracts in Q2. Obtained California Public Utilities Commission (CPUC) approval for Supplemental Provisions and other key program regulatory elements via Resolution E-5132 (https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M371/K108/371108623.PDF). Land rights and customer engagement process refinement to support scaling up of 2022 scope. Q4 2020 Negotiated & executed a turnkey Purchase and Sale Agreement and a 10- year full-wrap Maintenance Agreement, forming a reusable template for future SPS procurements. Drafted terms of service into a form of Supplemental Provisions to the Electric Rules, as a tariffed form agreement. The majority of customers engaged to date have voiced positive initial interest in pursuit of service conversion from overhead line to a Remote Grid. Filed the proposed form of Supplemental Provisions Agreement with the CPUC in Advice 6017-E[1] on December 15, 2020. Benchmarking with other utilities shows a point of validation in the advanced program now operational under Horizon Power in Western Australia. In California, Liberty Utilities has procured its first SPS for a similar application.

	Q3 2020 Developed and awarded major update of contract, including updated technical specification. Documented detailed protocol to identify and evaluate potential projects. Q2 2020 Completed field site visits to identify additional projects to pursue for concept validation. Completed first broad RFP solicitation which was received by more than 20 technology integration and construction vendors, delivering initial validation of commercial availability.
(iii).B: Lessons Learned	Failure Modes and Effects Analysis consultant concludes that PG&E has followed industry standards, codes, and best practices in designing SPS. Report includes actionable recommendations for SPS operations and future design refinements, serves as a basis for maintenance and inspection checklists, highlights historically relevant common points of failure, and informs future asset management, risk data analytics, and specification development. In the fire rebuild context, several rebuild-specific conditions can reduce individual project feasibility or delay implementation. Examples include: difficulty in reaching customers who have been impacted by wildfire; varying customer timeline needs across the same line segment, (e.g., immediate power needs for some customers and no near-term power needs for neighbors); and unforeseen changes in post-wildfire customer loads that impact projected Remote Grid project economics vs initial screening. PG&E identified the technology combination of Solar Photovoltaic Generation and Battery Energy Storage with supplemental Propane Generators as the most cost effective, reliable, and cleanest solution for initial Remote Grid sites. PG&E found there was sufficient initial vendor interest and availability to engage in contracting to deploy systems with specifications and terms responsive to PG&E's requirements. A number of site-specific conditions can reduce individual project feasibility or delay implementation. Examples include: customer acceptance, physical space constraints, shading and other constructability related considerations such as grading and geological conditions, permitting challenges such as presence of threatened species, cultural heritage, or adjacency to scenic highway.

1 See Advice 6017-E "Remote Grid Standalone Power System Supplemental Provisions Agreement" https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_6017-E.pdf.

(iii).C: Quantitative Performance Metrics	Safe operating hours (e.g., five SPS units for one year) without a safety or fire incident. Target: ≥ 50,000 hours Actual Results: 662 unit-hours (continuous operation of the Briceburg SPS unit) Portfolio uptime, average Target: ≥ 99% Actual Results: 100% (no SPS outages in the reporting period) Percent (%) Renewable Fraction of portfolio on average, with each SPS meeting applicable California Air Resources Board (CARB) emissions limits. Target: ≥ 60% Actual Results: 100% (solar and batteries supplied the customer load for all operating hours in the reporting period).
(iii).D: Quantitative Risk Reduction Benefits	Estimated Potential Risk Reduction Score: 345 Risk Drivers: Equipment Failure, Vegetation Deployment Scope Assumption: 452 miles of distribution lines in Tier 2 & 3 HFTDs, and 23.8 miles of distribution lines in Non-HFTD areas The risk mitigation potential is driven by an estimated overall effectiveness of 95 percent. This mitigation eliminates overhead feeder lines and therefore should address virtually all risk drivers. However, since remote grids serving multiple customers will likely add or maintain a small amount of overhead conductor to the system, PG&E makes a conservative estimate of 95 percent effectiveness.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	The initial projects are positioned as fully featured, long-term asset deployments with performance and reliability targets that will result in these projects eliminating segments of overhead line exposure. When these projects go online, an immediate ignition risk reduction can be realized upon de-energization of the infrastructure they replace.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	Standardization of to-be-proven Remote Grid site assessment and deployment processes, technical specifications, vendor contract templates, identification of qualified providers, and operational protocols (e.g., outage detection and response coordination) are needed to enable more rapid deployment of potential future Remote Grids. Further validation of the actual costs and lead time to deliver utility-grade performance and reliability will enable understanding of how widespread the benefits of this approach may be, relative to the occurrence of the requisite grid topology existing on the PG&E distribution system today. For instance, it is more likely that a Remote Grid would be appropriate at the end of an overhead distribution feeder with small numbers of customers.

(v).A: 'End Product' at 'Full Deployment' and Location	If this project is determined to be successful, the Remote Grid concept would be developed as a standard service offering and considered alongside other risk mitigations, such as overhead hardening and undergrounding, and deployed wherever it is cost effective and feasible. Possible appropriate deployment locations would be at the ends of overhead distribution feeders that serve small numbers of customers in HFTDs.

EPIC 3.11: MULTI-USE MICROGRID

(i).A: Project Type	Emerging (Pre-commercial) Technology
(i).B: 2021 WMP Section References	7.1.D.3.6
(i).C: 2020 WMP Section References	5.1.D.3.9
(i).D: Project Objective and Summary	The EPIC 3.11: Multi-Use Microgrid demonstration project develops and tests the technology, processes, and business models needed to deploy and operate multi-customer microgrids that are integrating third party-owned renewable energy generation assets to power the microgrid on a section of PG&E's distribution system. This includes the design and development of control specifications and SCADA integrations to maintain visibility and operational control of the microgrid in grid-connected and islanded modes. The findings of this project will help support microgrid growth to further resiliency and enhanced customer choice.
(i).E: Utility Wildfire Mitigation Maturity Model (UWMMM) Categories & Capabilities Potentially Impacted	C. Grid design and system hardening: 13. Grid design for resiliency and minimizing PSPS
(ii).A: Project Phase	Build/Test
(ii).B: Project Status	Functional design specification for the microgrid controller and the end to end integration network architecture and security approach have been finalized. Operational decisions for the microgrid including for communication and hardware fail-safes were evaluated in order to prepare the microgrid for integration at the DCC This specification along with the completed Concept of Operations (CONOP) documentation is now being used to complete PG&E's advanced microgrid testbed. This pilot is progressing towards broader adoption, including creating standards and tariffs that would be needed to enable PG&E to partner with third parties (such as communities) and deploy microgrids.
(ii).C: Project Location	McKinleyville (Humboldt County). The project, the Redwood Coast Airport Microgrid, serves the Arcata-Eureka Airport business community incorporating 18 PG&E and Redwood Coast Energy Authority customers, including critical facilities such as the airport and a U.S. Coast Guard station.

(iii).A: Results to Date	Q2 2021 Completed the Microgrid Description of Operations. Completed Factory Acceptance Testing at microgrid controller manufacturer's site. Developed DCC SCADA screens to enable remote monitoring and control. Developed onsite Human-Machine Interface (HMI) screens to enable local control. Completed the configuration of the Advanced Microgrid Test Bed at a PG&E test facility. Q1 2021 Released initial draft of Microgrid Description of Operations for technical review. Completed control logic configuration of microgrid controllers and onsite HMI. Kicked off Operational Integration activities with PG&E Business Application and field personnel to design devices, interfaces and processes for microgrid telemetry and control. Q4 2020 Configuration of information points list and HMI. Controller Test Plan aligned with third-party manufacturer. Utilized lessons learned from this project to publish a Community Microgrid Technical Best Practices Guide. Q3 2020 Started SCADA design (in progress). Refined Functional Design Specification. Completed communication and hardware fail-safes decisions. Prior Results Provided key feedback to microgrid controller manufacturers to inform the development of the Functional Design Specification document. Developed guideline questions for future microgrid controller testing beyond this project in order to support standardization.

(iii).B: Lessons Learned	In order to ensure reliability and mitigate customer power loss, circuits should be designed to allow microgrid mode transitions to be seamless if possible. Verify prior to system design that preferred resilient communication systems, such as the Field Area Network (FAN), are available. Ensure clear designation and separation of stakeholder responsibilities, particularly between the utility and the microgrid generation owner/operator. Defining if microgrid will be allowed to operate under certain fail-safe conditions requires strong operator buy-in and participatory planning. The process used for this project can serve as a useful guide for future microgrid deployment. Because each microgrid configuration is unique it may not be possible to fully standardize and streamline processes and technology to be applicable for all microgrids. Future frameworks will need to be flexible to accommodate unique project needs. Future project economics will likely differ significantly from the EPIC-funded Redwood Coast Airport Microgrid project and could be a major barrier to future scalability of multi-customer microgrids.
(iii).C: Quantitative Performance Metrics	Ability of the microgrid to safely and seamlessly energize the island and provide electric service throughout the duration of broader multi-hour grid outages. Target: Pass Actual Results: Metric result will be available after the microgrid is commissioned (planned for Q4 2021).
(iii).D: Quantitative Risk Reduction Benefits	Estimated Potential Risk Reduction Score: 13 Risk Drivers: Consequence of Failure – PSPS Deployment Scope Assumption: Tier 2 & 3 HFTDs This project supports PG&E strategy for PSPS activities on mid-feeder microgrids, and reduces the consequence of PSPS, specifically mitigating the impact to customers from PSPS events with an effectiveness of 0.1 percent for all mid-feeder microgrids. This effectiveness/risk reduction score is based on 2020 PSPS impact reduction activities.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	Controller testing in PG&E's Microgrid Test Bed is being designed to be replicable and scalable to a wide range of microgrid controllers. This will facilitate the deployment of control schemes for future microgrid sites.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	This project is designing the microgrid to be visible and controllable from the PG&E control center. Its operational guidebook will be the basis for integrating future microgrids of this kind into the control center operations. A microgrid operating agreement is being developed and will form the basis of similar agreements for future community microgrids.

(v).A: 'End Product' at 'Full Deployment' and Location	Full deployment for this project is a permanent and in-field microgrid at Arcata- Eureka Airport, with visibility and control from PG&E control center. The formalization and documentation of a repeatable process will enable a streamlined approach to deploying additional Multi-Use Microgrids as appropriate in HFTDs.

EPIC 3.11B: CONTROL OF BTM DERS

(i).A: Project Type	Emerging (Pre-commercial) Technology
(i).B: 2021 WMP Section References	N/A
(i).C: 2020 WMP Section References	N/A
(i).D: Project Objective and Summary	This Control of BTM DERs project that is a new addition to EPIC 3.11 will develop the technical capabilities and the production-ready operational processes to utilize BTM DERs for resiliency in microgrids with the following three objectives: Objective #1: Demonstrate that BTM DERs can support microgrid resiliency for cleaner PSPS. Objective #2: Enable higher penetrations of BTM DERs in multi-customer microgrids (e.g., Community Microgrid Enablement Program). Objective #3: Demonstrate the coordination of BTM DERs with Front of the Meter distributed generators coupled with batteries.
(i).E: Utility Wildfire Mitigation Maturity Model (UWMMM) Categories & Capabilities Potentially Impacted	C. Grid design and system hardening: 13. Grid design for resiliency and minimizing PSPS
(ii).A: Project Phase	Design/Engineering
(ii).B: Project Status	Project initiated Planning underway on all three objectives with initial focus on Objective #1
(ii).C: Project Location	TBD
(iii).A: Results to Date	Q2 2021 Kicked off the project. Completed a high-level scoping analysis of control system and protections approach.
(iii).B: Lessons Learned	None so far.
(iii).C: Quantitative Performance Metrics	Reduction in diesel run-time and emissions Target: Greater than 20 percent for sites with DER shutoffs Actual Results: Not available at this time Reduced curtailment hours for DERs Target: Less than 20% Actual Results: Not available at this time Reduction in Number of DER sites shut down for PSPS Target: Less than 20% Actual Results: Not available at this time.

(iii).D: Quantitative Risk Reduction Benefits	Estimated Potential Risk Reduction Score: 13. Risk Drivers: Consequence of Failure – PSPS. Deployment Scope Assumption: Tier 2 & 3 HFTDs. This project supports PG&E strategy for PSPS activities on mid-feeder microgrids, and reduces the consequence of PSPS, specifically mitigating the impact to customers from PSPS events, with an effectiveness of 0.1 percent for all mid-feeder microgrids. This effectiveness/risk reduction score is based on 2020 PSPS impact reduction activities.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	TBD
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	TBD
(v).A: 'End Product' at 'Full Deployment' and Location	Technical capabilities and production-ready processes to utilize BTM DERs for resiliency in microgrids. Documentation of learnings and methods.

CLEAN GENERATION FOR PSPS

(i).A: Project Type	New Technology (Commercially Available Offering)
(i).B: 2021 WMP Section References	5.3.3.11.1 "Generation for PSPS Mitigation"
(i).C: 2020 WMP Section References	7.3 Detailed Wildfire Mitigation Programs
(i).D: Project Objective and Summary	The project objective is to reduce PG&E's reliance on diesel-fired generation for PSPS mitigation. PG&E is committed to moving toward a cleaner portfolio of generation solutions for reducing impacts of PSPS, including: expanding the pool of contractors and technologies, piloting viable non-diesel technologies in 2021, and exploring opportunities to build a portfolio of non-fossil solutions for the longer term. The term "generation" in this case is shorthand for FTM generation, demand response (DR), and BTM generation. PG&E's evaluation of locations in need of PSPS mitigation in 2020 resulted in identification of two types of pilots: Clean Generation Distribution Microgrid Pilots. PG&E is piloting diesel-alternative technologies at two distribution microgrids in 2021 to support the transition toward cleaner generation for PSPS mitigation. The intent is to enable the reduction of the use of diesel in the future by demonstrating non-diesel technologies (a linear generator and battery energy storage, respectively) that can be paired with diesel generators. If successfully deployed, the two pilots will allow PG&E to measure the impact on overall emissions in addition to observing operational effectiveness and to use this data to inform PG&E's PSPS mitigation strategy in 2022 and beyond. Substation DR Pilots. PG&E would like to explore the effectiveness of DR as a tool to reduce run-time of temporary generation for PSPS mitigation, thereby reducing operational costs and emissions (both local criteria pollutants and global greenhouse gases). Two existing DR programs, the Base Interruptible Program and Smart AC, have been identified as a strong starting point. A Tier 3 Advice Letter was filed on June 9, 2021 requesting timely CPUC approval of the use of these two DR programs during PSPS events that lead to the energization of temporary generation at the three substations. If successful, additional substations could be added to the program in 2022. These two pilot types are described and reported on separately below.
(i).E: Utility Wildfire Mitigation Maturity Model (UWMMM) Categories & Capabilities Potentially Impacted	N/A

(ii).A: Project Phase	Clean Generation Distribution Microgrid Pilots: Design/Engineering Substation DR Pilots: Planning
(ii).B: Project Status	Clean Generation Distribution Microgrid Pilots: Negotiating contracts with vendors. Substation DR Pilots: Awaiting CPUC approval of Tier 3 Advice Letter prior to program implementation.
(ii).C: Project Location	Clean Generation Distribution Microgrid Pilots: Napa and Placer counties. Substation DR Pilots (pending CPUC authorization): Nevada, Lake and Yolo counties.
(iii).A: Results to Date	Q2 2021 Clean Generation Distribution Microgrid Pilots: Filed supplemental Advice Letter[2] outlining PG&E’s plans for two clean generation distribution microgrid pilots Substation DR Pilots: Filed Tier 3 Advice Letter[3] on June 9 requesting timely CPUC approval.
(iii).B: Lessons Learned	None as of yet.
(iii).C: Quantitative Performance Metrics	Number of clean gen locations online and operational for PSPS events in 2021. Target: Clean Generation Distribution Microgrid Pilots: 2 Substation DR Pilots (pending CPUC approval): 3 Actual Results: Not available at this time.
(iii).D: Quantitative Risk Reduction Benefits	No incremental wildfire risk reduction benefits beyond existing substation and distribution PSPS initiatives.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	No ignition of fault risk reductions.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	At this early stage of the project, we have not yet developed significant project findings to incorporate into operational practices. The expectation is that findings generated from pursuing clean gen pilot projects in 2021 will generate key lessons learned and findings that will be integrated into clean gen strategy in future years.
(v).A: ‘End Product’ at ‘Full Deployment’ and Location	Full deployment of this project is non-diesel generation used to mitigate the impacts of PSPS in future wildfire seasons. Locations would be in areas affected by PSPS events.

<u>Program Area</u>: Asset Management and Inspections – New or Emerging Technologies

PG&E is developing new inspection tools and methods to quickly identify issues and proactively manage asset and system maintenance. This in turn reduces the risk of asset failure and potential impacts on our customers. PG&E is leveraging existing technologies, including remote sensing technologies such as Light Detection and Ranging (LiDAR) data and drone imagery capture,[4] to accurately identify risks, including encroachment clearance and vegetation health. Combined with machine learning software, remote sensing data are being evaluated to identify dead or dying trees that could pose wildfire hazards or contribute to a wires-down situation. Mitigations leveraging new or untested technologies include the following:

ENHANCED ASSET INSPECTIONS – DRONE/AI (SHERLOCK SUITE)

(i).A: Project Type	New Technology (Not Widely Commercialized)
(i).B: 2021 WMP Section References	7.1.D.3.7
(i).C: 2020 WMP Section References	5.1.D.3.10

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2 See Advice 6204-E-A "Supplemental: Evaluation of Clean Substation Pilot Project Opportunities Pursuant to D.21-01-018" https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_6204-E-A.pdf.

3 See Advice 6204-E "Evaluation of Clean Substation Pilot Project Opportunities Pursuant to D.21-01-018" https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_6204-E.pdf.

4 Future drone technology adoptions are dependent upon Federal Aviation Administration (FAA) regulations for Line of Sight requirements. If exceptions are granted to these requirements, PG&E will have the opportunity to consider new or untested drone technology use cases such as: (i) extended line of sight operations for greater crew efficiency; (ii) autonomous flight paths to expedite drone inspections; (iii) new charging methods that leverage existing asset infrastructure to minimize charging time and increase flight time.; and (iv) new data processing techniques that minimize data hand off processes by capturing and processing data in-air, allowing for greater in-air operation.

(i).D: Project Objective and Summary	In 2019, PG&E collected more than 2.5 million high-resolution images (up to 100 megapixel) of our Electric Transmission assets through drones, helicopters, and other means of data capture as part of our Wildfire Safety Inspection Program, and has collected an additional 2.5 million images in 2020 as a part of the aerial inspection program. This imagery, when labeled appropriately, can be used to train computer vision models to identify specific components, and in some cases, evaluate the condition of those components. To address this, PG&E is developing an application, Sherlock, to bolster its data visualization capabilities. Sherlock is a web application that allows inspectors to view photographs of assets along with associated data. Sherlock allows for remote access to data captured through drone/helicopter images and enables a review of said data to ensure that only corrected data is viewed by inspectors, reducing the time from flight to inspection. In addition, inspectors can markup issues within the inspection profile of the application, which generates the necessary documentation from the application itself, ensuring auditability and data quality. This documentation provides PG&E with increased data management, reporting, and audit capabilities. The markups from Sherlock feed into computer vision models. Computer vision models are being trained to classify photos, identify asset components, and search for potential issues in an automated fashion. Models within the inspection flow are currently being used to flag select images (e.g., overview, right of way, asset tag) for inspectors. Inspectors can label data and provide feedback on the predictions which improves the models over time while reducing the inspection time and increasing inspection quality. Further, building and improving these models provides opportunities to use computer vision to flag images for review before humans see them, for prioritizing assets/lines for inspection, for identifying asset inventory, and as inputs to models that predict future asset failure.
(i).E: Utility Wildfire Mitigation Maturity Model (UWMMM) Categories & Capabilities Potentially Impacted	D. Asset management and inspections: 16. Asset inventory and condition assessments 18. Asset inspection effectiveness 20. Quality Assurance (QA)/ Quality Control (QC) for asset management
(ii).A: Project Phase	Build/Test
(ii).B: Project Status	The Sherlock Suite now includes six different profiles for different types of users across the aerial inspection program, in addition to a number of object detection and image classification models. Four Artificial Intelligence (AI) models are currently in production, classifying images of “standard items” to reduce overall inspection time. Additionally, seven manual processes have been completely automated since the beginning of this project, and the teams are working to further automate manual steps so that inspectors can focus on looking for potential issues on assets.
(ii).C: Project Location	Systemwide Applications

(iii).A: Results to Date	Q2 2021 Inspection forms for all Transmission structure types, multi-pole structures, telecom, and switches are now available within Sherlock, directly connecting to the system of record, and generating a PDF record on write. Woodpecker damage, C-hook wear detection, and bird nest detection models available in Sherlock to flag images where these are potentially occurring. Woodpecker damage and bird nest models now run at scale against historical imagery. Improvements to the Imagery QA profile to improve data quality and ease of use. Started work on improved/re-designed post-inspection QC profile and pre-inspection Imagery QA profile to reduce manual support time and increase effectiveness of reviews. Q1 2021 Inspection forms (checklists) for wood and steel structures available for inspectors within Sherlock, directly connecting to SAP (system of record), and generating PDF record on write. Adjustments to mode of display for predictions (i.e., different visual indicators). Ability to add new AI models to detect potential failures to the pre-inspection QA (Imagery QA) profile in Sherlock. Improved data load processes to bring data into Sherlock, for inspections. Insulator attributes detected at scale against a subset of 2020 aerial images, to assist in risk assessment of Tier 2 & 3 HFTDs. Q4 2020 Ability for post inspection QC with automated tracking within Sherlock Inspection form built within Sherlock, writing to system of record directly Bird nests flagged for inspectors using AI Ability to add new AI models to detect potential failures to the inspector profile Ability to run AI models at scale against millions of images in a cost-effective manner Ability for pre-inspection QA to occur within Sherlock Development of insulator detection, damaged cross-arm detection AI models Q3 2020

	Ability to view completed inspections and potential emergency tags in the post-Inspection quality check profile Line level reporting and prioritization. Standardization of items predictions (level 1 automation). Development of multi component detection capabilities. Development of bird nest detection. Development of C-hook wear classification. Q2 2020 The following items were delivered: Remote image load (cloud to cloud). Image quality assurance capabilities. Near real-time tracking of remote inspections within Sherlock. Created a model to classify images of the top of a structure. Improved data pipeline, and improved application security. C-hook detection capabilities.
(iii).B: Lessons Learned	Research shows that introducing AI can affect behavior. For example, introducing automation, if not done carefully, can lead to human error due to fatigue or complacency. We are consistently measuring behavior to ensure safety of the inspection processes. As a result of this learning, we are starting our AI deployments with standard items, such as images of asset tags, overview image, access path, etc. before deploying failure detection models into production.
(iii).C: Quantitative Performance Metrics	Percentage (%) reduction in time from imagery capture to the inspection queue (as compared with our January 2019 performance) Target: ≥ 50% Actual Results: To be provided as available from assessment data. Percentage (%) reduction in imagery inspection time (as compared with our January 2019 performance) Target: ≥ 25% Actual Results: To be provided as available from assessment data. Rate of upgrades/downgrades of findings between the initial inspector and the quality control reviewer. Target: Non-zero. This metric will set a baseline to be used to measure inspection quality improvements over time. Any improvement in inspection quality is beneficial to wildfire risk reduction. Actual Results: To be provided as available from assessment data.

(iii).D: Quantitative Risk Reduction Benefits	Estimated Potential Risk Reduction Score: 31 Risk Drivers: Equipment Failure Deployment Scope Assumption: PG&E Transmission System-wide This analytics project assumes the ability to assess C-hook condition through AI algorithms and user input. The risk mitigation potential is driven by an estimated overall effectiveness of 10 percent, which is correlated by the ability for PG&E to prioritize the replacement of equipment identified to have a higher probability for failure than the equipment that would have been replaced in the absence of the prioritization provided by this project. This risk reduction score represents an added benefit beyond existing maintenance and replacement programs.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	This technology is already in use by remote inspectors. Models within the inspection flow are currently being used to flag select images (e.g., overview, right of way, asset tag) for inspectors, to help focus inspection efforts on potential ignition risks.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	See reporting input (iv).A.
(v).A: 'End Product' at 'Full Deployment' and Location	Sherlock is in production and being used by different user groups across the transmission aerial inspection process. We continue to release new features on a regular basis. Future state developments include additional remote inspection processes for transmission, distribution, and substation. Potential capabilities to further enable inspectors, supervisors include: (i) data and imagery quality checks and assurance, (ii) data and imagery quality assurance, and (iii) AI enabled search functionalities. Advanced deployments of computer vision models could allow auto-filling inspection forms, automatic flagging of asset issues, and flagging of image quality issues. Additionally, instrumentation to measure inspection quality throughout the process, as well as writing back to source systems (e.g., SAP, Geographic Information System (GIS)), may be considered.

BELOW GROUND INSPECTION OF STEEL STRUCTURES (STEEL TRANSMISSION STRUCTURE CORROSION ASSESSMENT AND MITIGATION PILOT)

(i).A: Project Type	New Technology (Commercially Available Offering)
(i).B: 2021 WMP Section References	7.1.D.3.8 and 7.3.4.10
(i).C: 2020 WMP Section References	5.1.D.3.12
(i).D: Project Objective and Summary	PG&E is implementing a pilot that will inspect steel assets below groundline to detect steel corrosion and concrete degradation that may compromise structural integrity, with the goal of reducing risk of transmission steel structure failure. To inspect below ground, the foundations/footings of steel towers and poles are excavated and evaluated for structural integrity, including measuring steel member material section loss and collecting environmental and soil data (soil resistivity, pH, structure to soil potential/DC voltage, reduction-oxidation reaction). Repairs and mitigations would then be prioritized, based on the field evaluations and soil samples, in combination with other evaluations of tower/structure and overhead assets.
(i).E: Utility Wildfire Mitigation Maturity Model (UWMMM) Categories & Capabilities Potentially Impacted	D. Asset management and inspections: 16. Asset inventory and condition assessments
(ii).A: Project Phase	Build/Test
(ii).B: Project Status	Structure inspections are complete. Analysis of the collected data by data scientists is ongoing; preliminary results are being used to help inform the direction of the next phase of the project.
(ii).C: Project Location	Approximately 1000 locations throughout the PG&E service territory, including in HFTDs.

(iii).A: Results to Date	Q2 2021 Engineering report with the structure inspection data has been received and reviewed with further analysis ongoing by data scientists. Preliminary analysis indicates targeted inspections are advised among direct grillage steel foundations and in regions/locations with evidence of greater corrosion. Q1 2021 Project crews in the field inspected ~1000 structures. Pictures, field measurements, and inspector comments have been gathered and are currently undergoing desktop analysis. Preliminary results and field data are currently being incorporated into other established models that contribute to wildfire safety such as the Operability Assessment. Q4 2020/Q3 2020 Project scope finalized Structures for testing identified Field operations processes and methods for project implementation documented. Prior Results Data analysis and project definition. Structure selection and reaching out to contractors.
(iii).B: Lessons Learned	Verified efficacy of concrete as a subgrade corrosion deterrent of buried steel. Environmental factors of the various PG&E service regions produce varying levels of sub-grade corrosion and should inform inspection priority.
(iii).C: Quantitative Performance Metrics	Ability to apply analytics from data collected for insights on steel section loss based on age, geography, and operational conditions to inform the design of cathodic protection preventative maintenance programs. Target: Pass Actual Results: In progress Ability to validate whether a correlation exists between atmospheric corrosion (as seen on steel members above ground) and subsurface corrosion. Target: Pass Actual Results: We have validated that there is no correlation between atmospheric corrosion and subsurface corrosion.

(iii).D: Quantitative Risk Reduction Benefits	Quantitative Risk Reduction Benefits cannot be calculated for this project due to the lack of historical ignition data for steel structures in PG&E's Enterprise Risk Model wildfire risk assessment and bowtie analysis.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	If the project proves successful, it will provide high quality data inputs that can be used to inform asset maintenance decision-making. PG&E will assess findings and identify next steps based on findings of the project, including an assessment of the accuracy of estimating below ground corrosion based on above ground conditions.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	Data can be integrated into asset management data models to help prioritize asset maintenance practices based on risk assessments. Depending on findings of below ground corrosion conditions, PG&E may consider deploying cathodic protection to better protect from corrosion impacts. The pilot would help dictate where cathodic protection would be most impactful.
(v).A: 'End Product' at 'Full Deployment' and Location	Broader implementation of below ground inspection of steel structures. Data integrated into asset management data models to help prioritize asset maintenance practices based on risk assessments. Depending on findings of below ground corrosion conditions, PG&E may consider deploying cathodic protection to better protect from corrosion impact.

EPIC 3.41 – DRONE ENABLEMENT

(i).A: Project Type	New Technology (Not Widely Commercialized)
(i).B: 2021 WMP Section References	7.1.D.3.9
(i).C: 2020 WMP Section References	This project was mentioned at the end of Section 5.1.D.3 New or Emerging Technologies – Project Summaries as a project that PG&E may pursue within EPIC.
(i).D: Project Objective and Summary	This project proposes to test the following two hypotheses: Transmission Line & Substation Inspections: Automated and Beyond Visual Line of Sight (BVLOS) drone flight operations can offer a more accurate, safe and more efficient alternative to Transmission Line & Substation asset inspection than today's manual drone operations. Distribution Alert Verification: Automated and BVLOS drone operations can provide a fast, safe and effective solution for field-validating the range of alerts that will be produced through the predictive sensors that are planned to be deployed across the distribution system.
(i).E: Utility Wildfire Mitigation Maturity Model (UWMMM) Categories & Capabilities Potentially Impacted	D. Asset management and inspections: 16. Asset Inventory and condition assessments 17. Asset inspection cycle 18. Asset inspection effectiveness 19. Asset maintenance and repair
(ii).A: Project Phase	Design/Engineer
(ii).B: Project Status	The project was officially launched in August 2020. The internal project team has been staffed, and the team has partnered with an external expert of drone technology and the Federal Aviation Authority (FAA) regulatory requirements and process to provide critical support during the Design/Engineering phase of the project. The team has documented the details of each planned use case, developed a preliminary CONOPS document and then translated the CONOPS into technical requirements, and launched an RFP to selecta drone vendor partner. The team has also conducted preliminary coordination with the FAA.
(ii).C: Project Location	Project location is TBD. The team has conducted preliminary assessment of site selection parameters that will both support the project's objectives and meet FAA requirements for BVLOS operations. Sites will be selected in partnership with drone vendor partner.

(iii).A: Results to Date	Q2 2021 Completed development of RFP package for primary drone vendor contract. Launched RFP, completed question & response phase and received bidder proposals. Q1 2021 Conducted preliminary conversations with the FAA to socialize our concept and understand/address any preliminary concerns. Finalized the set of technical requirements for the RFP Developed plan for RFP, began compiling list of invitees, and began developing package RFP documents. Q4 2020 Expert drone consultant onboarded. Project schedule established. Use case questionnaire form completed (transmission, substation & distribution) for CONOPS development. Slide deck for discussion with FAA drafted. Initial RFP invitee list drafted. Q3 2020 Business Plan approved.
(iii).B: Lessons Learned	None to date.

(iii).C: Quantitative Performance Metrics	For transmission & substation inspections: Percentage (%) reduction in time of automated data capture compared to equivalent manual data capture Target: 20% Actual Results: TBD. Results will be available once the field demonstrations have been conducted. Percentage (%) of automated operations without errors or gaps in data capture that would require repeat operations Target: 99% Actual Results: TBD. Results will be available once the field demonstrations have been conducted. For distribution alert verifications: Percentage (%) reduction in duration of patrols executed in response to automated alerts from sensors installed on the distribution system, compared to equivalent patrols performed on foot, by truck or by helicopter, or some combination thereof Target: 20% Actual Results: TBD. Results will be available once the field demonstrations have been conducted.
(iii).D: Quantitative Risk Reduction Benefits	This project has two use-cases where risk reduction scores are not applicable because the risk reduction opportunities are tied to existing processes and new project applications. For transmission and substation inspections, this project will collect images more efficiently and inspectors will continue to use Enhanced Asset Inspections—Drone/AI (Sherlock Suite) to perform virtual inspections. The distribution use-case will leverage drone operations to efficiently field- validate alerts produced by predictive sensors. Risk reduction benefits are tied to and accounted for in specific Asset Health and Performance Center projects and their associated sensors or analytics such as Line Sensors, EPIC 3.13: Transformer Monitoring via FAN, EPIC 3.20: Maintenance Analytics, EPIC 3.43: Momentary Outage Information, EFD and DFA.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	TBD
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	TBD

(v).A: ‘End Product’ at ‘Full Deployment’ and Location	Transmission & Substation Inspections: Scaled up version of the solution at the end of the EPIC project to extend to the broader set of Transmission lines and substations in HFTDs. Ability to collect imagery data utilizing an autonomous Unmanned Aerial Vehicle for detailed inspections on all assets within scope. Distribution Alert Verification: Scaled up version of the solution at the end of the EPIC project to extend to the broader set of distribution assets in HFTDs. Improved integration between sensor alert system and drone system, with automated sharing of geospatially referenced alerts. Command and control application to monitor and track health and status of the fleet of drones and suggest which drone to deploy for inspection or field validation based on location, range, charge level, weather and other relevant factors. Potentially also a consolidated physical mission control center within a DCC for operational management and situational awareness of the fleet of drones. Interfaces between the drone system and additional field sensor alert systems would be created (beyond the specific field sensors being used in this project; for instance, some combination of sensors from the Line Sensor, Enhanced Fault Detection, or DFA projects).

Program Area: Vegetation Management and Inspections – New or Emerging Technologies

PG&E is using a variety of technologies to improve our vegetation management (VM) practices. For instance, physical ground inspections are being augmented by the capture of LiDAR and related, remote sensing, data that can be thoroughly and consistently analyzed to take measurements, reveal patterns and identify risks. VM has benefited from improved intelligence regarding vegetation density and can leverage this data to strategically deploy resources where vegetation is near electrical assets.

Mitigations leveraging new or emerging technologies include the following:

MOBILE LIDAR FOR VEGETATION MANAGEMENT

(i).A: Project Type	New Technology (Commercially Available Offering)
(i).B: 2021 WMP Section References	7.1.D.3.10 and 7.3.5.7
(i).C: 2020 WMP Section References	5.1.D.3.13 (In the 2020 WMP, titled as "Mobile LiDAR for Distribution Inspections")
(i).D: Project Objective and Summary	This project seeks to validate that high-resolution data captured with vehicle and backpack-mounted LiDAR and imagery units can help reduce fire risk and improve compliance of PG&E's VM process. The 2020 Pilot focused on one 84-mile circuit to evaluate the benefits and risk spend efficiency of LiDAR to the Planning, Pre-Inspection, Work Verification, and Documentation phases of the end-to-end VM radial clearing process. The 2021 Pilot is focused on operationalizing vehicle-based LIDAR data collection and analysis on an individual VM job basis following Work Verification. The 2021 Pilot will inform a determination of whether LIDAR detections can be included in existing operations.
(i).E: Utility Wildfire Mitigation Maturity Model (UWMMM) Categories & Capabilities Potentially Impacted	E. VM and inspections: 22. Vegetation inspection cycle 23. Vegetation inspection effectiveness 24. Vegetation grow-in mitigation 26. QA/QC for VM

(ii).A: Project Phase	2019 Pilot: Closeout 2020 Pilot: Closeout 2021 Pilot: Build/Test
(ii).B: Project Status	The 2021 enhanced Mobile LIDAR collection has started with collection, operationalization and evaluation.
(ii).C: Project Location	2019 Pilot: ~18K miles driven in Tier 2 & 3 HFTDs. 2020 Pilot: 84 driven miles along a circuit in Placer and Nevada counties. 2021 Pilot: Sierra Division.
(iii).A: Results to Date	Q2 2021 The first VM job to be evaluated as part of this Mobile LiDAR project was scanned and data from the vendor was received. Q1 2021 Identified the 856 Circuits that are in HFTDs and are eligible for Mobile LIDAR scanning. Identified the 484 VM Projects that do not map directly to a PG&E circuit and began additional required mapping. Q3 2020 / Q4 2020 Collected and analyzed Pre- and Post-Work measurements. Performed field check of preliminary 2019 radial clearing results, and assigning toward remediation when appropriate. Determined the percent of circuits measurable from a road with sufficient quality in Tier 2 & 3 HFTDs. Prior Results See (iii).B Lessons Learned below.

(iii).B: Lessons Learned	From the 2019 Pilot PG&E learned that Mobile LiDAR is capable of measuring radial clearances and clearances to sky, and: Initiated operationalization of results into VM processes. Derived cost and data analysis cycle time performance measures for both vehicle and backpack-mounted sensors. To reduce false positives, point cloud analysis teams need an accurate inventory of primary conductor assets (e.g., the teams need to be able to exclude secondary conductors and telecommunications cables). Mobile LiDAR can help improve asset locational data accuracy. Field teams could benefit from integrated access to geospatial data in their mobile applications. No public receptivity issues found with the car-based mobile LiDAR inspections. Post-work scan results can support work verification and cycle time planning. From the 2020 Pilot, PG&E learned that the LiDAR data acquisition and processing can occur within 27 days, a period sufficient for VM operational workflow cycle times.
(iii).C: Quantitative Performance Metrics	Scan analysis cycle time Target: 27 days from scan to data delivery. Actual Results: 30 days
(iii).D: Quantitative Risk Reduction Benefits	Quantitative Risk Reduction Benefits are being determined.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	Mobile LIDAR scanning will be performed on road-side miles of distribution line in HFTDs, following the completion of VM work verification on the line. The Mobile LIDAR identification of a radial clearance issue will be delivered to the Work Verification work flow for inspection and mitigation.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	We will evaluate the stepwise integration of the methods described in (iv).A into VM operational workflows for road-side distribution corridors in HFTDs.
(v).A: 'End Product' at 'Full Deployment' and Location	The potential end product is the integration of Mobile LiDAR data outputs into select phases of the VM radial clearing process in HFTD for road-side distribution corridors. Potential VM processes impacted include work verification and documentation.

<u>Program Area</u>: Asset Analytics & Grid Monitoring – New or Emerging Technologies

PG&E is assessing new methods to optimize asset maintenance practices. Unanticipated failure of electric assets due to wear and tear can lead to customer service outages and, in the worst case, fire ignition. Proactive management of asset health can reduce this risk and enhance system resiliency. PG&E is researching new or emerging technologies, such as enhanced sensor technologies that enable real-time system monitoring and situational awareness and developing analytic strategies to coordinate data received from multiple sources (e.g., SCADA, SmartMeter electric meters, primary line sensors, and emerging sensor technologies). Mitigations leveraging new or emerging technologies include the following:

EPIC 3.13: TRANSFORMER MONITORING VIA FIELD AREA NETWORK

(i).A: Project Type	Emerging (Pre-commercial) Technology
(i).B: 2021 WMP Section References	7.1.D.3.11
(i).C: 2020 WMP Section References	5.1.D.3.14
(i).D: Project Objective and Summary	As service transformers reach the end of their usable life or overload, they begin to heat up, leading to potential safety and asset risks. Currently, identification of transformer temperature change and potential associated risks poses challenges and requires regular checks from PG&E field teams. The EPIC 3.13: Transformer Monitoring via FAN demonstration project aims to increase the visibility of transformer health through the design and build of an overhead service transformer temperature sensor, a Temperature Alarm Device (TAD), supplemented by analytical models that analyze temperature data. The project will test the hypothesis that monitoring the external temperature of the tank of an overhead transformer can help in predicting and preventing imminent failure that could pose a wildfire ignition risk as well as impact safety and resiliency.

(i).E: Utility Wildfire Mitigation Maturity Model (UWMMM) Categories & Capabilities Potentially Impacted	C. Grid design and system hardening: 12. Grid design for minimizing ignition risk D. Asset management and inspections: 19. Asset Maintenance and Repair G. Data governance: 33. Data collection and curation
(ii).A: Project Phase	Design/Engineering
(ii).B: Project Status	The team is evaluating TAD samples, TAD costs provided by vendors, obtaining site licenses to access vendors' servers to obtain TAD data, and preparing to compare data from the TAD vendors.
(ii).C: Project Location	Initial planned locations are in the San Jose area.
(iii).A: Results to Date	Q2 2021 Received TADs from four vendors to evaluate safety and installation feasibility. Preparation underway to install a small number of TADs to catch the summer heat wave, and to inform the pending RFP for the larger acquisition of sensors. Q1 2021 Business plan approved for project initiation. TAD vendors interviewed for demonstration project. Installation locations in the San Jose area identified Installation review meetings with the construction contractor. IT cybersecurity coordination initiated. Q4 2020 Prepared business plan approved for project implementation. Identified external TAD vendors for demonstration project.
(iii).B: Lessons Learned	There is a strong preference to install the TADs with the transformer energized so as to not impact customers; however, we have learned that this is not always possible.
(iii).C: Quantitative Performance Metrics	Ability to detect an imminent failure of an overhead transformer and create an alert with an actionable amount of time within current maintenance programs to proactively replace the transformer that is degrading or near the end of its useful life. Target: Pass Actual Results: To be provided as available from assessment data.

(iii).D: Quantitative Risk Reduction Benefits	Estimated Potential Risk Reduction Score: 50 Risk Drivers: Equipment Failure Deployment Scope Assumption: Distribution lines in Tier 2 & 3 HFTDs This analytics project assumes the ability to detect issues with overhead transformers prior to failure. The risk mitigation potential is driven by an estimated overall effectiveness of 10 percent, which is correlated by the ability for PG&E to prioritize the replacement of equipment identified to have a higher probability for failure than the equipment that would have been replaced in the absence of the prioritization provided by this project. This risk reduction score represents an added benefit beyond existing maintenance and replacement programs.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	If the TAD effectively helps in the detection of imminent failure of overhead transformers, PG&E will be able to proactively replace transformers by dispatching field crews, thereby preventing failure, potential ignition risks, and associated outages.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	If the TAD technology is proven to be effective, (i) the communication system used by the TADs would need to be operationalized, (ii) the data would need to be integrated with our production databases, and (iii) the data would need to be combined with other data streams in an enterprise data analytics platform to provide a more holistic understanding of asset health.
(v).A: 'End Product' at 'Full Deployment' and Location	TADs would be installed on existing overhead transformers, prioritized first in Tier 3 HFTDs followed by Tier 2 HFTDs. Deployment in other locations will be based upon a risk analysis and subject to available funding.

EPIC 3.20: MAINTENANCE ANALYTICS

(i).A: Project Type	Emerging (Pre-commercial) Technology
(i).B: 2021 WMP Section References	7.1.D.3.12
(i).C: 2020 WMP Section References	5.1.D.3.15
(i).D: Project Objective and Summary	The EPIC 3.20: Data Analytics for Predictive Maintenance project aims to develop analytical models using machine learning based on existing PG&E data sets (including SmartMeter electric meter connectivity, geolocational assets, and weather data) to predict electric distribution equipment failures so that corrective action can be taken before failure occurs. The project now has 3 phases. Phase 1 aims to predict power quality-related failures of distribution transformers based upon voltage data. Phase 2 focuses on ignition risks and catastrophic failures associated with near-failure distribution transformers. Phase 3 focuses on identifying grid event behavior which may indicate vegetation contact or other intermittent faults on overhead distribution equipment.
(i).E: Utility Wildfire Mitigation Maturity Model (UWMMM) Categories & Capabilities Potentially Impacted	D. Asset management and inspections: 19. Asset maintenance and repair
(ii).A: Project Phase	Build/Test
(ii).B: Project Status	Phase 1 has been completed. Phase 2 is being finalized and Phase 3 is starting.
(ii).C: Project Location	The project's algorithm testing and verification is ongoing across PG&E's entire distribution service territory.

(iii).A: Results to Date	Q2 2021 On multiple occasions assets such as distribution transformers and meters have been proactively replaced based on the model's recommendations (Phase 2), in doing so reducing wildfire risk and improving reliability for customers. Given the successful results of the model in Phase 2, as described in (iii).C, this phase of the project is intended to grow from an early stage demonstration project to an operational data product. Deep dive conducted with CPUC's EPIC Program staff in June during a quarterly CPUC/PG&E check-in meeting. In addition, the project was presented to Filsinger Energy (the Governor-appointed Operational Observer). Q1 2021 Additional use cases for incipient transformer failures (Phase 2) and intermittent faults with overhead equipment (Phase 3) have been approved. Developed Minimum Viable Product (MVP) of Phase 2 model for predicting distribution transformer failures. The model learns from past failures that resulted in catastrophic and ignition events. Q4 2020 Failure model MVP is in progress Developed scope of the Phase 2 and Phase 3 use cases. Q3 2020 Field validation of predicted failing transformers due to power quality (in progress) Through iterative development, the best model has improved and now has 98 percent precision for predicted failures. Q2 2020 Added heuristic to identify fuse failures. The best prediction model had 87 percent precision when making predictions on a set of 300 failures.

(iii).B: Lessons Learned	Occurrences of poor data quality must be addressed to ensure prediction accuracy. Resolving data quality as close to the source as possible helps to ensure that data cleansing activities are not being duplicated by independent downstream processes. Similar to how risk calculations include both the expected consequence of the event, as well as the probability of the event occurring, benefits calculations should include both the expected business value as well as the probability of that value being realized. Critical elements of this probability include data fidelity, the existence of an established business process, and the availability of change management support. While the model development is still in progress, it has been demonstrated that using aggregated SmartMeter data allows for the identification of transformers that are performing outside of normal operating parameters. Working on a centralized data platform (i.e. Foundry) now allows for productivity acceleration in terms of access to data, scaling, and a path to production.
(iii).C: Quantitative Performance Metrics	Percentage (%) of predictions that upon review warrant field investigation. Target: ≥50% Actual Results: To date, over 125 reviews of Phase 2 predications have been conducted by engineering, from which ~72 percent were confirmed to be relevant transformer anomalies and were flagged for field investigation. Additional anomalies, that do not represent an imminent wildfire risk have also been identified accounting for an additional ~5 percent.
(iii).D: Quantitative Risk Reduction Benefits	Estimated Potential Risk Reduction Score: 195 (across all phases) Risk Drivers: Equipment Failure, Vegetation Deployment Scope Assumption: Distribution lines in Tier 2 & 3 HFTDs This analytics project assumes the ability to detect issues with distribution transformers prior to failure. The risk mitigation potential is driven by an estimated overall effectiveness of 10 percent, which is correlated by the ability for PG&E to prioritize the replacement of equipment identified to have a higher probability for failure than the equipment that would have been replaced in the absence of the prioritization provided by this project. This risk reduction score represents an added benefit beyond existing maintenance and replacement programs.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	If the model predicts a failing asset, a Troubleman could be alerted based on model findings and dispatched to inspect the asset and perform maintenance or replace the asset as needed.

(iv).B: Methods to Incorporate Project Findings Into Operational Practices	The EPIC 3.20 analytics model will be integrated into the Asset Health and Performance Center asset monitoring workflow by using machine learning and automating the troubleshooting process of signal anomalies. When a failure is predicted, the asset will be flagged for review. Depending on findings of the review, PG&E may dispatch crews to inspect and then perform maintenance on, or replace, the asset as needed.
(v).A: ‘End Product’ at ‘Full Deployment’ and Location	The end product will be an analytical model fully integrated into the Asset Health and Performance Center’s distribution grid monitoring and analytics platform. This would include integration of workflows to proactively address and track outcomes from issues identified by the analytic model. The model will enable better-informed decisions made by the Power Quality and Asset Health & Performance Center teams throughout the entire service territory.

EPIC 3.32: SYSTEM HARMONICS FOR POWER QUALITY INVESTIGATION

(i).A: Project Type	Emerging (Pre-commercial) Technology
(i).B: 2021 WMP Section References	7.1.D.3.13
(i).C: 2020 WMP Section References	5.1.D.3.16
(i).D: Project Objective and Summary	The EPIC 3.32: System Harmonics for Power Quality Investigation demonstration project explores the use of next generation metering technology harmonics data to help automate the detection, investigation, and resolution of harmonics issues. Excessive harmonics have been shown to reduce utility equipment life, can cause premature equipment failure due to the potential to overheat, and can interfere with the operation of protection devices. Harmonics data from next generation metering technology can enable power quality engineers to monitor harmonics levels on the circuits and proactively address harmonics issues before they create a negative impact on PG&E and customers' equipment, mitigating the chances of equipment failure to have adverse effects or safety impacts.
(i).E: Utility Wildfire Mitigation Maturity Model (UWMMM) Categories & Capabilities Potentially Impacted	C. Grid design and system hardening: 12. Grid design for minimizing ignition risk 14. Risk-based grid hardening and cost efficiency
(ii).A: Project Phase	Design/Build
(ii).B: Project Status	The project team is currently working with Information Technology (IT) to build the data collection and analytics server for the meter data and working on data analysis, algorithm development, and display of results.
(ii).C: Project Location	Three phase commercial/industrial customer locations with a high number of DER/Solar PV systemwide and agriculture customers in the Central Valley region.

(iii).A: Results to Date	Q2 2021 Completed installation of 180 next generation meters. Completed IT infrastructure required to communicate with the meters and acquire the harmonics data from the meters. Q1 2021 Identified 180 meter install locations. Completed inspection and wiring of 88 meter locations. Q4 2020 Issued PO to meter hardware vendor. Kick-off project with IT. Q3 2020 Finalized field installation plan including meter installation locations. Completed RFP and selected meter hardware that met the requirements to provide the necessary harmonics data.
(iii).B: Lessons Learned	Meter procurement took longer than expected due to contractual issues between the vendor and PG&E legal teams. We should connect the vendor legal team and PG&E teams together sooner next time. PG&E awarded the contract to the vendor's distributor instead. Some of the predetermined meter locations were inspected and found infeasible by Field Metering. So, we had to revise the list of meter locations based from Field Metering feedback, we could benefit engaging Field Metering earlier during the process of identifying meter locations for the project.
(iii).C: Quantitative Performance Metrics	Percentage (%) availability of harmonics data from installed meters. Target: ≥ 90% Actual Results: To be provided as available from assessment data. Number (#) of hours to notification after harmonics levels meet analytical criteria. Target: ≤48 hours Actual Results: To be provided as available from assessment data.

(iii).D: Quantitative Risk Reduction Benefits	Estimated Potential Risk Reduction Score: 198 Risk Drivers: Equipment Failure Deployment Scope Assumption: 12,728 miles of distribution lines in Tier 2 & 3 HFTDs, and 32,423 miles of distribution lines in Non-HFTDs This analytics project assumes the ability to detect harmonics that lead to failure of capacitor banks, fuses, and transformers. The risk mitigation potential is driven by an estimated overall effectiveness of 10 percent, which is correlated by the ability for PG&E to prioritize the replacement of equipment identified to have a higher probability for failure than the equipment that would have been replaced in the absence of the prioritization provided by this project. This risk reduction score represents an added benefit beyond existing maintenance and replacement programs.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	The plan is to validate locations with high levels of harmonics and determine if there is a harmonics-associated ignition risk to the transformers, cap banks, and fuses in the location. If a suspected ignition risk is found, the plan is to take action using existing operational processes.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	The plan is to use next generation metering technology to monitor and collect harmonics data on our electric distribution system for operationalizing harmonics-associated risk reductions.
(v).A: ‘End Product’ at ‘Full Deployment’ and Location	The end product is an analytics tool with the ability to monitor for, and enable proactive mitigation of, harmonics-related issues at approximately 3,000 large commercial customers throughout the service territory.

SENSOR IQ

(i).A: Project Type	New Technology (Commercially Available Offering)
(i).B: 2021 WMP Section References	7.1.D.3.14 and 7.3.2.2.4
(i).C: 2020 WMP Section References	5.1.D.3.17
(i).D: Project Objective and Summary	Sensor IQ is a SmartMeter software application that enables SmartMeter electric meters to collect data at a higher frequency and deliver alarms such as high/low voltage outside configurable thresholds without disruption to normal billing data collection. This pilot enables and collects high frequency SmartMeter data; analytics using this data will only be performed through other projects. PG&E has a license to pilot Sensor IQ through October 2021 and will collect voltage, current, and power factor data every five minutes from meters included in this pilot. The purpose of this Sensor IQ project is to collect the needed data to be analyzed through other exploratory use cases to evaluate if the high frequency data supports 1) improved meter phase identification, as this information is needed by the EPIC 3.15: Proactive Wires Down Mitigation Demonstration Project (REFCL), which requires feeder phasing to determine the line-earth capacitive imbalance; and 2) EPIC 3.43: Momentary Outage Information, which seeks to use near real time meter data, including the data provided through Sensor IQ, to develop algorithms that can potentially identify the sources of momentary outages or other anomalies to create predictive maintenance strategies and processes; 3) other predictive grid monitoring and maintenance approaches for potential wildfire risk reduction methods through incipient fault detection as well as improvement of the ability to find faults in wires-down analytics.
(i).E: Utility Wildfire Mitigation Maturity Model (UWMMM) Categories & Capabilities Potentially Impacted	C. Grid design and system hardening: 12. Grid design for minimizing ignition risk 14. Risk-based grid hardening and cost efficiency
(ii).A: Project Phase	Build/Test
(ii).B: Project Status	Project is in a validation phase scheduled to complete by the end of Q1 2022.
(ii).C: Project Location	~500K SmartMeter electric meters located in Tier 2 & Tier 3 HFTDs.

(iii).A: Results to Date	Q2 2021 Meter profile deployment completed to 500K meters with data collection ongoing. Q1 2021 Meter profile deployment completed to 500 additional meters, bringing total of Sensor IQ-enabled meters to 1,500. Network impact monitoring tools now used to assess network impact during rollout. Q3 2020/Q4 2020 Data collection profiles, alarm thresholds and configurations have been developed for various meter types. Sensor IQ has been deployed in the meter test environment to validate developed Data Collection Profiles. Production meter deployment started
(iii).B: Lessons Learned	High frequency SmartMeter data alone was not enough to detect issues accurately. Analytics support is necessary to make the data provided by this project useful. Therefore, PG&E plans to direct this project's data, when available, into the EPIC 3.20: Maintenance Analytics, and EPIC 3.43: Momentary Outage Information projects to use their analytical components for meters in Tier 2 & 3 HFTDs. See the EPIC 3.20 and 3.43 project descriptions in this report for more information.
(iii).C: Quantitative Performance Metrics	Percentage (%) of high frequency interval data and events from the meters collected and made available for use within two hours under non-event conditions (e.g. no outage). Target: ≥95% Actual Results: To be provided as available from assessment data.
(iii).D: Quantitative Risk Reduction Benefits	Sensor IQ is a foundational data collection project without its own Quantitative Risk Reduction Benefits. The EPIC 3.15 Proactive Wires Down Mitigation Demonstration Project (REFCL), EPIC 3.20 Maintenance Analytics, and EPIC 3.43 Momentary Outage Information projects rely on data from this Sensor IQ project, and each have their own Quantitative Risk Reduction Benefits as provided herein.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	If this project is found to benefit early identification of wildfire risks, the analytics developed in companion projects can be automated and integrated into existing preventative monitoring schemes.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	Automate the ingestion of Sensor IQ data into a data platform and apply analytical methods to assess events for indications of incipient conditions. Integrate data and analytics into existing or newly developed workflows for detection and resolution of incipient grid conditions that could create wildfire risk. Move the project to a production IT environment. The software contract for this pilot would be extended for deployment and converted to a full license.

(v).A: 'End Product' at 'Full Deployment' and Location	If effective, this product would be deployed in all circuits in Tier 2 & 3 HFTDs and integrated into standard distribution operation functions. It could also be extended to systemwide deployment to all compatible SmartMeter electric meters with an additional per-meter software license.

EPIC 3.43: MOMENTARY OUTAGE INFORMATION

(i).A: Project Type	Emerging (Pre-commercial) Technology
(i).B: 2021 WMP Section References	7.1.D.3.15 and 7.3.2.2.4
(i).C: 2020 WMP Section References	N/A
(i).D: Project Objective and Summary	PG&E has deployed over 5 million SmartMeters that provide alarm traps related to the meter's health and status during abnormal system conditions, such as outages, broad detection of sag and swell events, voltage deviations, intermittent power "blinks", or other anomalies as reported by the SmartMeter technology. This project proposes to leverage SmartMeter data through Sensor IQ as described in Section 7.1.D.15 above on about 500K meters for more granular and real-time data streams that include high frequency voltage, current, power factor, and temperature, and real time notifications voltage variations or temperature alarms that can be used to develop algorithms that can potentially identify the sources of momentary outages/voltage excursions to create predictive maintenance strategies and processes. An objective is to determine if momentary electrical events (sometimes referred to as "blinks" akin to a light flickering) and other electrical event trap alarms available from PG&E's fleet of over 5 million SmartMeters correlate and can be used to identify specific equipment shortcomings such as transformer failure, cracked insulator, loose neutrals, and/or vegetation contact, thereby leading to preventative maintenance practices that could also help reduce wildfire ignition risk. A second part of the project is underway that adds field insight from two additional sources of information: a new generation smart meter/grid edge sensor, and a BTM electrical condition detection sensor. The use of a new generation of meter potentially offers measurement and analysis of various primary and secondary issues including but not necessarily limited to loose neutrals, failing service transformers, failing splices, and vegetation contact, while the BTM electrical condition detection sensor provides an independent view of similar potential issues, but from the customer side of the meter. These BTM electrical condition detection sensors are owned by a third-party though PG&E will receive access to the data as part of this project.
(i).E: Utility Wildfire Mitigation Maturity Model (UWMMM) Categories & Capabilities Potentially Impacted	D. Asset management and inspections 16. Asset inventory and condition assessments
(ii).A: Project Phase	Design/Engineer

(ii).B: Project Status	The first part of the project has initiated analytics development using the now-available Sensor IQ data from ~500K meters in Tier 2 & Tier 3 HFTDs. The second part of the project, related to the new generation meter and BTM electrical condition detection sensor, is being initiated. Vendors have been selected; one of the two contracts has been executed and the other is expected to be executed in Q3 2021.
(ii).C: Project Location	The Sensor IQ-based analysis is applicable to the entire PG&E electric distribution service territory served by SmartMeters but is now focused on meters in Tier 2 & Tier 3 HFTDs. The new generation meters are being installed on a feeder in Napa County. The BTM electrical condition detection sensors have third-party ownership and PG&E does not control where they are installed. They are actually installed throughout PG&E's service territory through PG&E is focusing analysis efforts on Tier 2 & Tier 3 HFTDs .
(iii).A: Results to Date	Q2 2021 The internal change request formalizing the addition of the two additional sensor technologies to the scope of the demonstration has been approved. Connection established from Sensor IQ data source into Foundry. Q1 2021 Developed a project change request formalizing the addition of the two additional sensor technologies to the scope of the demonstration. Q4 2020 For the first part of the project: Defined data points and data frequency requirements to perform analytics work to potentially identify equipment failures for enhanced preventative maintenance practices that focus on replacement before failure. Developed IT framework (solutions blueprint) to ingest and provide data for analytics work. For the second part of the project: Vendors and installation locations have been selected. Two additional potentially useful data sources have been identified: new generation SmartMeter technology, and in-home electrical fire sensing. Analysis of project scope and cost changes to accommodate these data sources has been initiated.
(iii).B: Lessons Learned	None to date

(iii).C: Quantitative Performance Metrics	Percentage (%) of predictions that upon review warrant field investigation. Target: ≥50% Actual Results: To be provided as available from assessment data.
(iii).D: Quantitative Risk Reduction Benefits	Estimated Potential Risk Reduction Score: 365 Risk Drivers: Equipment Failure, Vegetation Deployment Scope Assumption: Distribution lines in Tier 2 & 3 HFTDs This analytics project assumes the ability to detect issues with conductors, insulators, splice/clamp/connectors, transformers, and vegetation failures prior to failure. The risk mitigation potential is driven by an estimated overall effectiveness of 10 percent, which is correlated by the ability for PG&E to prioritize the replacement of equipment identified to have a higher probability for failure than the equipment that would have been replaced in the absence of the prioritization provided by this project. This risk reduction score represents an added benefit beyond existing maintenance and replacement programs.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	None to date.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	For the first part of the project: If the predictive models using Sensor IQ data are found to be successful, the next phase of development would be to move the analytical model to full production. Operational actions potentially include more precisely targeted PSPS events, more precisely targeted VM, optimized truck rolls, or temporarily reconfiguring distribution system topology. Additionally, improved maintenance planning and optimized capital allocations are likely benefits of more precisely understanding equipment condition. For the second part of the project: If the technologies (the new generation meter and the BTM electrical condition detection sensor) are found to be successful in identifying incipient issues the more effective version will be assessed for larger deployment.

(v).A: 'End Product' at 'Full Deployment' and Location	If the first part of the project is more successful in its predictions, full deployment would include Sensor IQ aggregation/analysis on SmartMeters in Tier 2 & Tier 3 HFTDs and/or on select SmartMeters throughout the system, to be determined. If the second part of the project is more successful in its predictions, select or all SmartMeters would need to be upgraded to the new generation, or the BTM electrical condition detection sensor would need to be installed in select or all customer premises. Regardless of which part of the project is deployed, it would also include: Verified predictive analytics developed through application of data analytics platform toolsets and methods Multiple algorithms for determining equipment failure or underperformance risk in key categories (transformers, cabling, insulators, etc.) Integration of data streams and alerts into operational tools Ongoing tuning of algorithms and analytics using data analytics platform capabilities

WIND LOADING ASSESSMENTS

(i).A: Project Type	Emerging (Pre-commercial) Technology
(i).B: 2021 WMP Section References	7.1.D.3.16 and 7.3.3.13
(i).C: 2020 WMP Section References	5.1.D.3.18
(i).D: Project Objective and Summary	Excessive wind loads on PG&E's distribution poles may cause asset failure that in turn increases wildfire ignition risk. This project will reduce risk by providing asset intelligence to identify locations that require corrective actions driven by pole safety factors or limitations for wind speeds, for both individual poles and lines of up to 300 poles. The project will leverage existing LiDAR data from VM efforts to geo-correct pole locations. Objectives of this project include a greater understanding of failure modes, establishment of a common repository of data gathered, and effectively updating workflows of key asset systems to align with new data strategies. Wind loading segmentation will be performed to identify the wind loading of each asset on a support structure with the objective of integrating findings into risk models.
(i).E: Utility Wildfire Mitigation Maturity Model (UWMMM) Categories & Capabilities Potentially Impacted	A. Risk assessment and mapping 2. Ignition risk estimation D. Asset management and inspections 16. Asset inventory and condition assessments
(ii).A: Project Phase	Deploy
(ii).B: Project Status	The project is in its deployment phase, deploying the Wind Loading Assessment application to estimators as well as to external vendors doing desktop reviews of PG&E Distribution poles.
(ii).C: Project Location	PG&E service territory (PG&E owned distribution poles)

	Q2 2021 Completed the deployment to an additional 221 Distribution estimators, bringing the total to 373 (of 800) estimators using the new application. Deployed to the Desk Top Reviewer contract staff (66 staff), who review existing Distribution poles for safety. Further upgrades to improve synchronization of pole location corrections identified between the new software and PG&E's GIS application. Initiated the second phase of the Wind Loading Assessment initiative, focused on better pole modeling to speed up Desk Top Reviews, inclusion of details of third party attachments in modeling, standardizing and simplifying the pole assembly process by designers to reduce error risk and cost, and provide high availability for the application during periods of peak activity like fires and major storms.
(iii).A: Results to Date	Q1 2021 Additional upgrades to the modeling software to improve estimator productivity. Improved the process for determining conformance to FAA pole height/flight path obstruction clearance requirements. Completed the deployment to 152 (of 800) Distribution estimators using the new application. Q4 2020 Upgraded the foundational modeling software to handle "tree poles" and crossarm framing automation. Implemented a Citrix version of Wind Loading that allowed PG&E to switch to a less expensive third party Desk Top Review (pole loading review) vendor. Consolidated all Distribution wind loading data onto a PG&E platform. Completed the initial deployment stage of the project, with 62 (of 800) Distribution estimators using the new application.
(iii).B: Lessons Learned	Data integration into external cloud environment has the potential to provide significant benefit by enabling greater data access and data sharing capabilities with external partners. Data sharing through the external environment requires new methods for cybersecurity when sharing data externally. LiDAR holds potential in enabling PG&E to geo-correct pole configurations and arrangements in an automated fashion, which will be further explored through the next phase of this project.

(iii).C: Quantitative Performance Metrics	Accurate data for pole loading calculations. Target: Pass Actual Results: Pass Integration of data into an external cloud environment for greater accessibility. Target: Pass Actual Results: Pass Ability of a separate downstream project to perform pole geo-correction based on this project's LiDAR data. Target: Pass Actual Results: Pass
(iii).D: Quantitative Risk Reduction Benefits	This project is foundational and therefore Quantitative Risk Reduction Benefits are not applicable. This project's technology will supplement existing technology as an input to better assess and predict pole loading. Its output does not solely provide information to identify corrective actions, but enhances existing operations to identify pole overload conditions.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	Integrate data provided through wind loading assessment for failure mode insights to inform manual inspection cycles (integration would occur through a separate project). Pole geo-corrections will assist field crews in identifying correct pole locations in the field.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	Data provided through this project can provide insights for proactive asset management practices (e.g., integrate results into distribution risk model).
(v).A: 'End Product' at 'Full Deployment' and Location	Wind loading segmentation analysis will be performed to identify the wind loading of each asset, e.g., a conductor, on a support structure and integrate findings into appropriate systems. This will provide asset intelligence to identify locations that require corrective actions driven by pole safety factors or limitations for wind speeds, or to assess the safety factor of distribution poles as part of the preparation to exit a PSPS event. In addition, geo-corrections to pole locations can be determined based on LiDAR data.

Program Area: Foundational – New or Emerging Technologies

Foundational new or emerging technologies, including grid communication tools and control networks, can enable greater exchange of information required to provide real or near-real time operational visibility across the grid for enhanced decision-making including for PSPS events. These foundational items can also increase the flexibility of the grid, providing fundamental capabilities to advance system resiliency.

EPIC 3.03: ADVANCED DISTRIBUTION ENERGY RESOURCE MANAGEMENT SYSTEM

(i).A: Project Type	Emerging (Pre-commercial) Technology
(i).B: 2021 WMP Section References	7.1.D.3.17
(i).C: 2020 WMP Section References	5.1.D.3.20

(i).D: Project Objective and Summary	The EPIC 3.03: Advanced Distributed Energy Resource Management System (DERMS) demonstration project seeks to design, procure, and deploy a prototype enterprise DERMS providing foundational operational capabilities which will support situational intelligence and broader wildfire mitigation efforts including remote grids, microgrids, and other Distribution Investment Deferral Framework opportunities (i.e., Non Wires Alternatives). This project includes the development of a cost-effective solution for providing advanced situational awareness and control capabilities for operators to manage DERs, dispatch DER registration data requests and monitor smart inverter-based DERs. As part of the effort to lower the cost of telemetry for interconnected DER assets, PG&E is engaging with vendors that would eventually produce PG&E-certified site gateways. Additionally, the project is engaging with potential DER aggregator partners to evaluate feasibility of integrating with the PG&E DER Headend Server as an alternative to the site gateway approach. Anticipated benefits of this project once deployed at scale include: (1) increased situational awareness of DER grid impacts which could allow for greater operational flexibility to safely reconfigure the grid during PSPS; (2) decreased time to de-energize remote grid locations by utilizing the remote disconnect feature of DERMS for remote grids during PSPS events; and (3) potential reduction in the number of customers impacted from PSPS events through microgrid technologies. We note that this project's technology is foundational; actual reduction is dependent on broader microgrid implementations.
(i).E: Utility Wildfire Mitigation Maturity Model (UWMMM) Categories & Capabilities Potentially Impacted	C. Grid Design and System Hardening: 12: Grid design for minimizing ignition risk 13. Grid design for resiliency and minimizing PSPS
(ii).A: Project Phase	Build/Test
(ii).B: Project Status	Factory acceptance testing for the gateway device to be installed at the first pilot site at Blue Lake Rancheria (BLR) has been completed. Installation of DER Headend Server at PG&E has been completed. Installation of the gateway device at the pilot site has been completed. Third-party site gateway vendors have begun interoperability testing with the DER Headend Server.
(ii).C: Project Location	BLR, Blue Lake, CA (Humboldt County). The BLR is a 100-acre tribal reservation and State-designated Disadvantaged Community.

(iii).A: Results to Date	Q2 2021 Selected a third gateway device manufacturer vendor to build an interoperable remote site gateway device. Q1 2021 Common Smart Inverter Profile (CSIP) certification of the Institute of Electrical and Electronics Engineers (IEEE) 2030.5 standard compliant DER Headend Server achieved. This certification increases the likelihood of interoperability between the PG&E-approved gateway devices and PG&E's DER Headend server. Installation of the pilot gateway device at the BLR pilot site is complete. This installation allows the project team to test the system in the real-world environment. Q4 2020 Completed design and installation of IEEE 2030.5 DER Headend Server (CSIP certification pending) Gateway device installed at the BLR site to test telemetry and control (testing in progress). To build a market for remote site gateway devices for DER developers, PG&E selected two vendors for development of additional third-party remote site gateways meeting PG&E standards and requirements. This also set up a pathway for future vendors to develop their own remote site gateways.
(iii).B: Lessons Learned	Technology ecosystem for DER integration utilizing the IEEE 2030.5 protocol is still rapidly evolving and is not yet "plug and play." Further interoperability testing and industry collaboration is required. Technology architectures for integrating critical operational systems with 3rd party owned devices needs multiple levels of cybersecurity.
(iii).C: Quantitative Performance Metrics	Ability to meet CPUC telemetry maximum cost and minimum functionality requirements for each DER site or DER aggregator. Target: Pass Actual Results: Not available at this time.
(iii).D: Quantitative Risk Reduction Benefits	This project is foundational and therefore Quantitative Risk Reduction Benefits are not applicable. See the Remote Grids and EPIC 3.11 Multi-Use Microgrid projects as they partially depend upon this foundational project for their Quantitative Risk Reduction Benefits.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	This project will demonstrate capabilities to: Enhance situational awareness and DER control capabilities for distribution operators to support grid needs as part of wildfire mitigation related initiatives. Enable PG&E to dispatch registration data requests to verify compliance of Smart Inverters with Rule 21 curve settings and monitor Smart Inverter- based DERs to maintain safe and reliable grid operations during PSPS and normal grid conditions.

(iv).B: Methods to Incorporate Project Findings Into Operational Practices	The DERMS would be integrated into the distribution system operators' systems and processes as described in (iv).A. The project team is also coordinating with the Advanced Distribution Management System (ADMS) team (see the ADMS report below) for future integration to optimize DER utilization and system-wide grid services.
(v).A: 'End Product' at 'Full Deployment' and Location	The end product is a fully integrated enterprise DER Headend that can scale to accommodate the growth of managed DERs over time. The headend server will be located at PG&E and the remote site gateways will be located at customer DER sites.

ADVANCED DISTRIBUTION MANAGEMENT SYSTEM

(i).A: Project Type	New Technology (Commercially Available Offering)
(i).B: 2021 WMP Section References	7.1.D.3.18 and 8.1
(i).C: 2020 WMP Section References	5.1.D.3.21
(i).D: Project Objective and Summary	PG&E is undertaking the first component of a multi-year effort to implement an ADMS which will, when fully deployed, integrate into a single platform several of the current mission critical DCC applications (Distribution Supervisory, Control and Data Acquisition (D-SCADA) software, Demand Management System, and Outage Management System (OMS)) that are currently spread across multiple platforms. The ADMS will become part of the core distribution operations technology tools that enable the visibility, control, forecasting, and analysis of a more dynamic grid. ADMS impacts grid resiliency through: (i) facilitation of DER integration; (ii) switching operation enablement during PSPS events by providing more timely and accurate data to operators; (iii) identification of devices within fire areas to allow operators to disable reclosing relays when weather and conditions pose significant risk to the system.
(i).E: Utility Wildfire Mitigation Maturity Model (UWMMM) Categories & Capabilities Potentially Impacted	F. Grid operations and protocols 27. Protective equipment and device settings 28. Incorporating ignition risk factors in grid control
(ii).A: Project Phase	Multiple (phase varies with functionality considered)
(ii).B: Project Status	The software has been released as expected and testing has begun.
(ii).C: Project Location	Applicable to the entire PG&E electric distribution service territory.

(iii).A: Results to Date	Q2 2021 Initial functional testing for wildfire mitigation functionality has begun. Testing will continue through to Q2 2022 at which time the User Acceptance Testing is planned to complete. Q1 2021 Software Build for wildfire mitigation functionality is 85 percent complete. Testing of beta version of completed functionality occurred in Q1 2021. Q3 2020/Q4 2020 Performing software build for wildfire mitigation functionality.
(iii).B: Lessons Learned	None to date
(iii).C: Quantitative Performance Metrics	Identification of automatic reclosing devices (e.g., Line Reclosers, Trip Savers, Fuse Savers) within fire areas and presentation of the potentially impacted areas to operators for verification (to inform reclosing relay disablement). Target: Pass Actual Results: To be provided as available from assessment data.
(iii).D: Quantitative Risk Reduction Benefits	This project is foundational and therefore Quantitative Risk Reduction Benefits are not applicable. Quantitative Risk Reduction Benefits may be potentially derived through the multiple systems built upon this foundation.
(iv).A: Ignition or Fault Risk Reduction Project Findings That Inform Current Operational Practices	PG&E is taking a phased approach to ADMS implementation to ensure that foundational capabilities are first established. Operator training simulator is planned for SCADA system and reclosing relay capabilities will help train operators on ADMS functionality to ensure timely adoption of ADMS platform.
(iv).B: Methods to Incorporate Project Findings Into Operational Practices	ADMS is a platform used for distribution operations. Operators will require training on the system and former systems will need to be sunset in a methodical manner that minimizes disruption to ongoing operations. Change management practices focused on people, process, and technology will be employed to ensure value streams from ADMS implementation are captured.
(v).A: 'End Product' at 'Full Deployment' and Location	Multi-year ADMS deployment will integrate several mission critical DCC applications that are currently spread across multiple platforms. This technology will enable the visibility, control, forecasting, and analysis required from a more dynamic grid. When fully deployed, the ADMS platform will bring the capabilities of today's D-SCADA software, DMS, and OMS into a single platform. Integrating these systems into a single, more efficient platform will reduce the potential for operator error, improve cybersecurity risk controls, and enable PG&E to run a new suite of advanced applications that enhance current capabilities associated with safety and resiliency, while responding to future needs associated with the growth of DERs and complexities from wildfire risk.

CONDITION GUIDANCE-10

DATA ISSUES – GENERAL

Deficiency: Although the availability of data, including GIS data, provides unprecedented insight into utility infrastructure and operations, inconsistencies and gaps in the data present a number of challenges and hurdles. As it relates to GIS data, electrical corporation submissions often had inconsistent file formats and naming conventions, contained little to no metadata, were incomplete or missing many data attributes and utilized varying schema.

These deficiencies rendered cross utility comparisons impossible without substantive, resource, and time-consuming manipulation of the data. Additional data challenges included varying interpretations of Wildfire Mitigation Plan (WMP) Guideline data requirements, leading to inconsistency of data submitted.

Condition: Electrical corporations shall ensure that all future data submissions to the* Wildfire Safety Division (*WSD) adhere to the forthcoming data taxonomy and schema currently being developed by the WSD. Additionally, each electrical corporation shall file a quarterly report detailing:

I. Locations where grid hardening, Vegetation Management (VM), and asset inspections were completed over the prior reporting period, clearly identifying each initiative and supported with GIS data;

ii. The type of hardening, VM and asset inspection work done, and the number of circuit miles covered, supported with GIS data;

iii. The analysis that led it to target that specific area and hardening, VM or asset inspection initiative; and

iv. Hardening, VM, and asset inspection work scheduled for the following reporting period, with the detail in (i) – (iii).

Introduction

In their 2019 and 2020 WMPs, electrical corporations were requested to provide various GIS data with limited guidance or standardization, which required significant interpretation and effort to address. Pacific Gas and Electric Company (PG&E) appreciates the Office of Energy Infrastructure Safety's (OEIS) effort to refine its guidance and provide standardization through the Draft GIS (Geographic Information

System) Data Reporting Requirements and Schema (GIS Data Standard) released on August 5, 2020 and updated on February 4, 2021 (V2). Condition Guidance-10 addresses one feature dataset (3.5: Initiatives) of the six total feature datasets included in OEIS' GIS Data Standard.

Consistent with prior quarterly reports, and as directed through the WMP August workshops, PG&E is simultaneously submitting a Status Report (.xls) and additional Data Submission alongside the initiatives data required by Condition Guidance-10. PG&E's submissions of the requested Status Report and Data Submission (collectively referred to as "GIS Data Standard Submission") are not fully complete as we do not have all the requested data or have all the data in the format requested. That this process would take time to accomplish and that all data would not be immediately available was anticipated by OEIS, who noted on page 5, Section 2.8 of the Draft GIS Data Standard that:

> Realistically, the WSD understands that electrical corporations are at different stages of their data journeys and employ differing business practices, which may impact certain electrical corporations' abilities to fully comply with the requirements in this document. The WSD looks forward to working collaboratively with electrical corporations and other stakeholders to determine appropriate and feasible submission schedules for regular reporting of GIS data.

Furthermore, a full quality validation of all data being provided in the submission was not possible in the time period given and it is possible there may be some incorrect data in the datasets. Additionally, some of the inputs in the submission report necessarily reflect preliminary estimates, and not final results. For example, Planned Initiative data reflects forecasts that are subject to change based on operational developments. In addition, for data not provided in the current submission, the Status Report inputs for "Estimated Delivery Timeframe" represent conceptual approximations that have significant dependencies, including but not limited to procedural and technological developments, which could impact timeframes for delivery.

PG&E's existing data and system architecture were developed over decades to address specific operational uses and lack integration capability and a cohesive data schema. This presents significant challenges to accessing and aligning data to meet OEIS' GIS Data Standard. The various data requested exist across disparate systems and in the current state require significant time and resources to manually align data sets to the data schemas provided by OEIS and then to extract the data. Many of these same resources are currently involved in core operations work, including emergency response and Public Safety Power Shutoff (PSPS) readiness. Provided the compressed timelines for this submission, there was insufficient time and resource availability to perform a comprehensive quality check of data and the associated Status Report included in this submission. For reference, select data in this submission was requested through June 30, 2021, and due by August 1, 2021, providing only approximately 4 weeks to collect, curate, transform, perform antivirus scanning, and submit the data in a file-geodatabase (FGDB) format.

PG&E submitted its Q2 2020 submission on September 9, 2020. This submission included data in the FGDB format for 15 of 38 feature classes and 4 of 15 related tables. Data for another 4 feature classes and 2 related tables was submitted in tabular format as an appendix file.

In our Q3 2020 submission, submitted on December 9, 2020, PG&E instituted multiple measures to improve the quantity and quality of its submission. Improvements included an increase in the number of Feature Classes and data attributes submitted while providing a more comprehensive Status Report to describe the FGDB data. To meet the first objective, PG&E implemented data collection processes for this new reporting requirement to enable more efficient data collection, curation, and organization and invested significant time in mapping the OEIS GIS Schema to PG&E's internal GIS schema for 3.1 (Asset Point) and 3.2 (Asset Line).

On January 8, 2021, OEIS provided its *Evaluation of Pacific Gas and Electric Company's First Quarterly Report* (WSD Evaluation)[5] detailing findings on completeness and quality of GIS data submitted by PG&E on September 9, 2020. Prior to receiving the OEIS Evaluation, PG&E had already delivered its Q3 2020 submission, which addressed various issues raised in the OEIS Evaluation. PG&E appreciates the thoroughness of the OEIS Evaluation and is taking actions to address the findings on a prioritized basis, as detailed in the Guidance-10 table below.

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5 WSD Quality Control (QC) Report on GIS Data Submitted by PG&E on September 9, 2020.

In our Q4 2020 submission, submitted on February 5, 2021, PG&E expanded the mapping of the OEIS GIS Schema to PG&E's internal SAP schema for feature dataset 3.1 (Asset Point) and 3.2 (Asset Line). This mapping was performed on an expedited basis. Provided the time constraints for this submission (detailed earlier in this section), it was not feasible to integrate this data, which requires manual consolidation and curation across the SAP and GIS systems. However, the data mapping provides a foundation for incremental data inputs into future quarterly submissions. It also provides a baseline to assess the level of effort required to automate portions of the quarterly and annual GIS Data Schema submissions. Automation will require significant inputs and resources to address, including but not limited to: (i) coordination across Asset Owners, Subject Matter Experts (SME), and technical resources; (ii) architectural changes; and (iii) technology implementation. In addition, PG&E enhanced the quality for this Q4 2020 submission relative to former submissions by addressing prioritized findings from the OEIS Evaluation. For example, we increased the specificity of the Status Report and enhanced its accuracy relative to the FGDB data submitted. Additionally, a baseline Metadata entry was delivered. A series of workshops were performed to add detail to both the Data Inventory and Metadata.

On February 4, OEIS released an updated GIS Data Standard (V2) that incorporated new feature classes and data fields as well as changes to the structure of the data schema. PG&E appreciates OEIS' incorporation of feedback from the electrical corporations into the updated GIS Data Standard (V2) and we will continue to provide feedback through our Status Report. Adopting the data structures provided through the updated schema introduced significant complexity in that it required re-development of existing queries, re-training of Data Owners (SMEs), and changes in overall data collection, curation, and transformation requirements.

In our Q1 2021 submission, submitted on May 3, 2021, PG&E adopted the updated GIS Data Standard (V2). In addition to the incorporation of new requirements, we spent considerable manual effort assessing the revisions to the data structure (schema) and implications to its existing reporting automations and underlying data architecture. PG&E incorporated additional fields (e.g., PSPSDays and PSPSDaysDateBasis in the Critical Facilities feature class) and feature classes such as 3.6.5 Major Woody Stem. We developed a minimum viable product for our new data management platform used for this effort, to help manage data pipelines across source systems and automate reporting for select feature classes. This platform will continue to develop in future quarters, dependent on technical resource availability given other operational and emergency needs. PG&E continued to address issues raised in the OEIS Evaluation, including additional build out of information provided through the Status Report, incorporation of new metadata, and the addition of select photos.

On June 23, 2021, OEIS held a joint meeting with the electrical corporations to communicate expectations around 2021 WMP data reporting, including desired alignments across spatial and non-spatial reports. Subsequently, PG&E sent a list of questions to OEIS to better align on reporting requirements and provide feedback. PG&E welcomes further collaboration between OEIS and the electrical corporations to advance the GIS Data Standard schema and submissions. In preparation for the Q2 2021 data reporting submissions, PG&E performed an initial assessment of overlaps in data reported between the Quarterly Data Report (QDR, non-spatial) and OEIS GIS Data Standard (spatial) submissions. During this assessment, differentials in substation facility data were found, driven by variation in definitions applied to identify substation facilities.[6] To address this, SMEs across various lines of business were consulted to derive a common definition to identify substation facilities for inclusion, incorporating information in PG&E's internal Standards and Procedures. Technical experts then identified the source systems for data that aligned with this definition and curated, transformed, and performed QC on a final data set representing substation facilities for use across the 2021 Q2 QDR and WSD GIS Data Standard submissions.

In this Q2 2021 submission, PG&E is providing data in accordance with the GIS Data Standard (V2). PG&E progressed its Q2 2021 submission through SME workshops and developments in its data management platform. PG&E hosted workshops between SMEs and technical resources to drive new data inputs, including added transmission splice data in Feature Class 3.1.2 – Connection Device and other

6 OEIS did not define "substation facility" in its GIS Data Standard. PG&E referenced the equipment types that comprise a substation facility in its Procedure TD-3305P, which may include transformers, voltage regulators, circuit breakers, switches, and bus work. The function of a substation facility is subject to vary between distribution, transmission, and power generation - depending on voltage levels and/or power transformation requirements.

utility-owned power line data in Feature Class 3.6.1 – Other Power Line Connection Location.

PG&E's data management platform enabled data quality improvements and helped to drive connectivity between select data sets for the Q2 2021 submission. Utilizing this platform, PG&E consolidated Distribution Outage data across multiple source systems and trackers. The traceable code used for this and other consolidations can be leveraged in future submissions or adapted to meet changes in either OEIS' schema or PG&E's internal data architecture. Quality check processes were used to validate the platform's Distribution Outage data outputs which identify potential data quality issues that were corrected in the Q2 2021 submission.

PG&E also leveraged its data management platform to create connectivity across source systems that contain data inputs for Feature Class 3.4.3 – Ignitions. This feature class contains data that associates nearest weather station to an ignition event. Associating these data requires consolidation and curation of data across multiple source systems. Weather station connectivity status (in service/out of service) is refreshed at the source level on a continual basis – thus, if the weather station data were not collected from its source system at the exact time other ignition event related data were collected from its source system, potential discrepancies in connectivity status could occur. In recognition of this, PG&E leveraged its data management platform to connect weather station and ignition data, reducing data siloes and helping to ensure reporting accuracy.

While we are working to integrate the OEIS Evaluation findings into future submissions, it was infeasible to address some findings at this time. We plan to further assess methods to address these findings in the period between the upcoming submissions. Below is a table summarizing the progress PG&E has made in addressing the OEIS Evaluation:

GUIDANCE-10-TABLE 1: WSD EVALUATION FINDINGS

WSD Evaluation Findings				
Line No.	Finding	Description	Status	Q2 2021 Submission Notes
1	2.2.1 Reporting Accuracy (Appendix files)	Data Inventory inconsistent with FGDB content “There were inaccurate status statements in the Excel tracking document that indicated data were provided when they were not.”	Addressed	This finding was addressed in the Q3 2020 submission, for which PG&E submitted ‘appendix’ file attachments for several Feature Classes and indicated that such Feature Classes were included in the submission. In subsequent submissions, PG&E only labeled data fields ‘Complete’ if they were included in the FGDB with 100 percent data attributes.
2	2.2.1 Reporting Accuracy (Modified Inventory Reporting)	Data inventories were duplicated to provide additional reporting information “PG&E modified the conventions of the provided data tracking spreadsheet tables by sometimes breaking down reporting into multiple responses for the same tables. This involved creating more than one set of the provided tracking columns.”	Addressed	This finding was addressed in the Q4 2020 and subsequent submissions through the consolidation of Status Report templates that were broken out. Status Report templates were not broken out for the Q2 2021 submission.
3	2.2.1 Reporting Accuracy (Partial Completion)	Data attributes not 100 percent complete should be marked ‘Partial’ “Reporting did not adhere to the guidance provided by the WSD on how to complete the spreadsheets”	Addressed	PG&E has updated internal processes to label any data attributes <100% complete as ‘Partial’. PG&E addressed this finding in the Q4 2020 and has applied this change to subsequent submissions.

GUIDANCE-10-TABLE 1: WSD EVALUATION FINDINGS (CONTINUED)

WSD Evaluation Findings				
Line No.	Finding	Description	Status	Q2 2021 Submission Notes
4	2.2.2 Data Absence and Timeframe Explanations	Generic explanations for data absence repeatedly used “Responses that are vague are not acceptable. Highly detailed field-specific responses are not expected for all fields, but general repeated responses that are more specific than “Further assessment required” would be an improvement.”	Improvements in progress	PG&E continued to utilize working sessions with SMEs in preparation for the Q2 2021 submission to add detail and specificity to Availability Explanation, Data Procurement Action, and Timeframe entries where feasible. These sessions focused on automation development and collecting previously omitted fields yielded new learnings that informed the entries. For example, PG&E included partial Switchgear Exemption status data for the first time in its Q2 2021 submission. While this field is still partial in the Switchgear dataset, SME working sessions allowed PG&E to communicate more details around Data Procurement Actions and Timeframe for this field. Developing more detailed entries requires assessment of potential people, process, and technology solutions, the change management associated with altering data and system architecture originally built with an operational focus, and cross-team dependencies. While progress continues to occur on a quarterly basis, we recognize that there is still room to address this finding.

GUIDANCE-10-TABLE 1: WSD EVALUATION FINDINGS (CONTINUED)

WSD Evaluation Findings				
Line No.	Finding	Description	Status	Q2 2021 Submission Notes
5	2.2.3 Confidentiality Assessments	Confidentiality explanations were generic "[Confidentiality] explanations were sometimes vague, but their inclusion was appreciated." The confidentiality declaration document ("DRU-2914B_Confidentiality Declaration.pdf") covers some general categories of data... but does not specifically address the submitted GIS data."	Improvements in progress	Consistent with the feedback expressed during the June meeting between OEIS and the California electrical corporations, PG&E would appreciate collaboration with OEIS and the other electrical corporations to develop a more standardized method for the identification and treatment of confidential information. The geospatial nature of the GIS Data Standard deliverables and breadth of datasets included warrant a deliverable-specific approach to protecting sensitive data.
6	2.3 Overall Schema and Requirement Adherence	Values were input in an incorrect format A. "Values were input that were in a completely incorrect format B. Values were sometimes all capitalized or had inconsistent capitalization when they were required to all have sentence style capitalization. C. Domain values provided by the WSD were not always used."	Improvements in progress	PG&E will continue to refine the format used as feasible. Please note that OEIS schema changes require updates to scripts used to collect and organize the FGDB input data (e.g., changes to field domain values and capitalization require parallel updates in any coding used to collect and organize that data). PG&E remains committed to matching data formats but acknowledges that pending Data Standard updates make doing so more challenging.

GUIDANCE-10-TABLE 1: WSD EVALUATION FINDINGS (CONTINUED)

WSD Evaluation Findings				
Line No.	Finding	Description	Status	Q2 2021 Submission Notes
7	2.3 Overall Schema and Requirement Adherence	All data not submitted as one geodatabase "Contrary to WSD guidance, PG&E did not submit all data in one geodatabase. ...All future quarterly GIS data submission from PG&E must be in a single geodatabase per WSD directions, and there must not be multiple versions of the same data in a single submission."	Addressed	This finding was first addressed in the Q4 2020 submission and continues to be addressed in subsequent submissions through the provision of a single, consolidated FGDB.
8	2.4 Related Table Issues	Initiative Asset Log table missing from submission "A major related table problem is the absence of the required 'Initiative Asset Log' table. Without 'Initiative Asset Log' data, the value of all initiative data provided is significantly diminished and is unacceptable... The 'Initiative Asset Log' table must be provided in future submissions."	Closed	This finding is no longer applicable given the update to the GIS Data Standard (i.e., V2). While the Initiative Asset Log table was removed from the GIS Data Standard, PG&E will continue to explore sustainable technology solutions to relate Initiative Feature Classes and Tables to assets and circuits as specified in the revised Data Standard.

GUIDANCE-10-TABLE 1: WSD EVALUATION FINDINGS (CONTINUED)

WSD Evaluation Findings				
Line No.	Finding	Description	Status	Q2 2021 Submission Notes
9	2.4.2 VM Inspection	Data not in one-to-many relationship "For Vegetation Management (VM) inspection data, the "VM Inspection Log" related table was supposed to have a one-to-many relationship with the "VM Inspection Point" and "VM Inspection Line" feature classes."	Open	PG&E's existing data and system architecture were built with an operational focus and differs from the data schemas provided through the Draft GIS Data Standard. The various data requested exist across disparate systems and in the current state require significant time and resources to manually pull and align data sets to data schemas provide by OEIS. We are continuing to explore the ability to create a 'one to many relationship' to address this finding through its data management platform.
10	2.4.3 VM Project	Data not in one-to-many relationship "VM project data was meant to have a one-to-many relationship."	Open	
11	2.4.4 Asset Inspection	Data not in one-to-many relationship "Asset Inspection data was meant to have a one-to-many relationship."	Open	
12	2.5 Submission Procedure Adherence	Empty Feature Classes were not removed prior to submission "Feature classes or tables that are completely empty, need to be deleted. Only submit feature classes and tables that have data."	Addressed	This finding was addressed in the 2020 Q4 submission and empty Feature Classes were removed from the 2021 Q2 submission. Note: there were no PSPS events or Transmission VM Outages to report on in 2021 Q2 – these Feature Classes were removed prior to submission of the 2021 Q2 FGDB.
13	2.5 Submission Procedure Adherence	Data were not initially submitted to the correct location "The data were not initially submitted to the correct location"	Addressed	This finding was addressed in the 2020 Q4 submission and data were submitted to the correct location starting with the Q1 2021 submission.

GUIDANCE-10-TABLE 1: WSD EVALUATION FINDINGS (CONTINUED)

WSD Evaluation Findings				
Line No.	Finding	Description	Status	Q2 2021 Submission Notes
14	2.6 Metadata	Metadata not included in submission A. “Field definitions are among the higher priority metadata that were absent.” B. “Describe the methodology for how the data were developed.”	Improvements in progress	For the Q2 2021 submission, PG&E continued to build off the Metadata included in former submissions. For example, PG&E integrated metadata to define customer meter manufacturer abbreviations and enhanced the Initiative Vegetation Inspections and VM feature classes. Additionally, PG&E provided key Use Limitations for Grid Hardening datasets in an effort to clarify a distinction between the dataset in the GIS Data Standard relative to targets or progress metrics communicated in other forums (e.g., the Quarterly Initiative Update). Finally, because there were no PSPS events to include in the Q2 2021 submission, the SMEs responsible for these datasets used their increased bandwidth to refine metadata entries for upcoming submissions.

GUIDANCE-10-TABLE 1: WSD EVALUATION FINDINGS (CONTINUED)

WSD Evaluation Findings				
Line No.	Finding	Description	Status	Q2 2021 Submission Notes
15	2.7 Data Absent in 9/9/20 Submission but Present in Previous Submissions	Data omitted, but provided in other data requests “WSD provided a table showing data that was previously provided, but absent in this submission.”	Improvements in progress	Though data may have been provided in other data requests, it may not have been required in a similarly prescriptive manner which introduces significant complexity necessitating procedural and/or technology solutions. We will continue to look for opportunities to incorporate new data where feasible. In the Q2 2021 submission, PG&E incorporated new transmission data to the 3.1.2 Connection Device Feature Class and integrated data on Connections to Other Utilities into the 3.6.1 Other Line Connection Feature Class. Additionally, PG&E is in the process of incorporating Switchgear Exemption Status data into the submission and included partial data for this field for the first time in its Q2 2021 submission.

GUIDANCE-10-TABLE 1: WSD EVALUATION FINDINGS (CONTINUED)

WSD Evaluation Findings				
Line No.	Finding	Description	Status	Q2 2021 Submission Notes
16	2.8 Photos	Photos and photo-related data not included in submission "PG&E did not submit any photo log data or photos, but photos are a requirement and expected in future submissions."	Improvements in progress	This finding is being reviewed by SME and Information Technology (IT) teams. The IT architecture for photos was built for operational purposes and is not aligned with WSD's GIS Data Schema. In the Q1 2021 submission, PG&E manually uploaded photos for PSPS Damages and Ignitions, which took considerable time for SME teams to convert. Going forward, especially during the PSPS and wildfire season, this manual extraction method will not be sustainable. For select photo types, PG&E is working towards the development of an IT solution to make sharing photos a less manual and time-consuming process. However, the current solutions in development are exhibiting technical limitations that would require costly IT solutions or operational changes. For example, a new IT solution allows mass downloading and renaming of Asset Inspections photos to match the naming convention required by the Data Standard. However, identifying photos of inspections that reveal issues, as specified in section 2.5.2.8 of the GIS Data Standard, is not feasible given existing

				technology solutions and operational processes. Given this limitation, PG&E would like to know if OEIS would prefer to receive all Asset Inspections photos, regardless of whether they reveal an issue, or if OEIS would prefer not to receive the broader set of photos. This question also applies to PG&E's VM Inspections photos. PG&E did include photos for Risk Events during the Q2 2021 submission.

In the Q4 2020 submission, submitted on February 5, 2021, we included Electric Incident Report (EIR) ignitions that were still under investigation in the inventory for the Risk Event Ignitions Feature Class (3.4.3). In this Q2 2021 submission, PG&E continues to include these EIR ignitions still under investigation and ignitions where it is unknown whether the reportability threshold was met, but have been confirmed to be attributable to PG&E. The cadence of quarterly submissions makes it difficult to gather all the relevant data and form a timely conclusion on the reportability threshold. As an example, PG&E relies on external agency fire reports to make determinations for some ignition events and, depending on the agency and event, these fire reports could take several months for PG&E to receive. Additionally, PG&E may also exclude ignition events in these quarterly reports that were originally determined to be not PG&E attributable or meeting reporting criteria but are later determined to have met reporting criteria.

For data not currently collected or not architected per OEIS' required schema, PG&E is currently exploring the feasibility and resource requirements to collect, transform, and ultimately submit these data. These assessments are accomplished through workshops with cross-functional teams (Asset Owners, SMEs, GIS Analysts) and will assess the feasibility and prioritization of future potential improvements. Updates to individual data field availability can be found through PG&E's Status Report. PG&E would appreciate the opportunity to share these findings with OEIS to assist with potential refinements to the Draft GIS Data Standards going forward.

PG&E has continued to quantitatively and qualitatively improve our quarterly submissions and will continue to seek ways to enhance future submissions. Enhancement opportunities will largely require more involved operational and technological changes, including a significant level of resources required to collect, curate, and organize the Data Standard submissions on a recurring basis, while simultaneously advancing our data maturity. PG&E looks forward to continued conversation and collaboration with the OEIS and other stakeholders on the GIS Data Standard.

Response to Subpart i, ii, iv

The data in response to Subparts, i, ii, and iv has been provided in GDB files and an accompanying Status Report. A stand-alone FGDB file and Status Report were not uploaded separately for Guidance-10, as the data and information in these files would overlap with what is being submitted for the GIS Data Standard submission. "Prior reporting period" data for Subpart i covers the first quarter of 2021 (the months of January, February, and March) and "following reporting period data" for Subpart iv covers the first quarter of 2021 (the months of April, May, and June). These data submissions followed the Draft OEIS GIS Data Standard to the best of PG&E's ability. As noted in our Comments on OEIS' Staff Proposals and Workshops, PG&E's data management and technology, related business processes, and subject matter expertise in this space continues to mature and allow PG&E to improve its reporting capability. However, PG&E's data systems have evolved organically over many decades, which has created challenges in accessing and mapping mass data to the WSD data schema or accessing some data for reporting purposes. Those limitations directly impact our ability to incorporate all identified data fields.

As it relates to the asset inspection data, please note that PG&E's submission only included inspections that were associated with valid equipment records. Because PG&E's electric infrastructure is a dynamic collection of assets, equipment is regularly replaced and deactivated, at which time the GIS feature for that asset is removed. Some population of inspections are associated with equipment that has subsequently been removed from the GIS system. Those inspection records have, therefore, been removed from this data submission as well.

Response to Subpart (iii)

Asset Inspections

PG&E described the Asset Management and Inspections programs in Section 7.3.4 of our 2021 WMP.

Preventive maintenance tasks such as enhanced inspections of overhead assets are a key means for PG&E to proactively identify potential failure modes that could lead to ignition if not resolved timely. Through a combination of ground inspection, intrusive wood pole testing, aerial inspections, infrared (IR) assessments, and patrols, PG&E seeks to identify conditions that require repair or replacement of assets prior to failing. Previously, PG&E utilized a time-driven cycle to prescribe patrol and inspection activities to transmission circuits or distribution plat maps. Since 2019, PG&E has undertaken efforts to develop risk-informed models that prioritize preventive asset patrol and inspection activity cycles aligned with the risk of wildfire ignition, including increasing the frequency of such preventive tasks in High Fire Threat District (HFTD) Tiers 2 and 3. Similarly, the evaluation and finalization of corrective findings for distribution, transmission, and substation assets was brought together in 2019 under the Centralized Inspection Review Team and continues as a core component of the patrol and inspection program.

For 2020 through 2022, PG&E's detailed inspections of overhead assets exceed the minimum frequency requirements of General Order (GO) 165 in HFTDs and include the following enhanced protocols:

- Distribution: digitized capture of detailed visual inspection via checklists and photographic documentation from a ground vantage point.
- Transmission: digitized capture of detailed visual inspection via checklists and photographic documentation, both from ground position and by aerial vantage, are coupled to complete an enhanced inspection cycle.
- Transmission (500 kilovolt (kV)): this examination also includes structural integrity assessment of tower structures via climbing inspection.

The supplemental (enhanced) substation inspections carried on in addition to the baseline GO 174 inspections include digitized capture of detailed visual inspection via checklists and photographic documentation, both from ground vantage and by aerial means, coupled to complete an enhanced inspection. Supplemental enhanced substation inspections also include an IR assessment of the station equipment in addition to the visual inspection.

Enhanced inspections also include use of digital checklists, documentation of asset features, capture of standard imagery, and centralized inspection review of findings as well as work quality monitoring, these have been applied systemwide for overhead transmission and distribution (T&D) assets as of the 2020 detailed inspection cycles. This applies to ground, climbing, and aerial inspection collection methods in T&D whether in HFTD or otherwise. Corrective findings from patrol inspections, equipment testing, and IR inspections are also subject to centralized inspection review, but those patrol and inspection methods have not yet shifted to use the electronic documentation approach and remain largely paper-based in their documentation.

Although the approach to digital data capture for enhanced overhead inspections in HFTD and non-HFTD areas is the same, the frequency of inspections and specific checklist content may be different. In 2021, PG&E intends to complete enhanced detailed inspections of overhead electric assets in HFTD areas at the following recurrence interval:

- HFTD Tier 3 and Zone 1 annually; and
- HFTD Tier 2 every three years.

Aerial inspections of overhead transmission assets in the following recurrence interval:

- HFTD Tier 3 annually and Zone 1; and
- HFTD Tier 2 every three years.

Climbing inspections of 500kV transmission tower structures in the following recurrence interval:

- HFTD Tier 3 annually and Zone 1; and
- HFTD Tier 2 every three years.

Patrol inspections (patrols) of overhead assets of T&D in the following recurrence interval:

- HFTD Tier 2 on years when enhanced detailed inspections are not scheduled (e.g., two of every three years).

IR inspections of overhead assets of transmission, and substation in the following recurrence interval:

- HFTD Tier 3 and Zone 1 annually; and
- HFTD Tier 2 every three years.

IR inspections of overhead assets of distribution in the following recurrence interval:

- HFTD Tier 3 and Zone 1 1/3 annually for three years; and
- HFTD Tier 2 1/3 annually for three years.

Supplemental Ground and Aerial Inspections of Substation assets in the following recurrence interval:

- HFTD Tier 3 and Zone 1 annually; and
- HFTD Tier 2 every three years.

Intrusive wood pole inspections of overhead wood poles in the following recurrence interval:

- Within 15 years of wood pole installation date, and every ten years thereafter.

Aside from locations with access constraints, PG&E plans to complete these enhanced inspections in HFTD Tiers 2 and 3 locations before July 31, 2021. Per PG&E's Q2 2021 Quarterly Initiative Update (QIU) update, a total of 354,131 of 394,936 HFTD electric distribution poles had been inspected, and 20,159 of 24,290 electric transmission inspections (includes ground, climb, and air inspections) have been inspected.

Grid Hardening

System Hardening – Distribution

PG&E described the System Hardening Program in Section 7.3.3.17 of our 2021 WMP. System hardening work is performed in alignment with TD-9001B-009 Rev 2.

For 2021, PG&E has switched over from REAX to Technosylva, which has been adopted as our Wildfire Consequence Model. The Wildfire Consequence Model was incorporated into PG&E's 2021 Wildfire Distribution Risk Model (see further explanation in Section 4.5.1 of the 2021 WMP). This change and other associated improvements in our modeling, data, and understanding of fire risk, has led to a shift in thinking about where to target system hardening resources. PG&E's 2021 Wildfire Distribution Risk Model resulted in a significant pivot for PG&E in the targeting work to continue to harden the highest wildfire risk miles. For the 2021 work plan, the System Hardening Program has added projects, and has paused or deferred other projects, based on the new risk model.

As noted in Section 7.3.3.17 of the 2021 WMP, the highest wildfire risk miles are separated into three categories:

1. The top 20 percent of circuit segments as defined by PG&E's 2021 Wildfire Distribution Risk Model for System Hardening
2. Fire rebuild miles
3. PSPS mitigation miles

PG&E also considers secondary risks as part of the System Hardening efforts such as PSPS impacts, egress/ingress routes to support fire department response times and public safety, past fire history and effects on available fuels, current system condition, environmental risks to reconstruction activities, and general accessibility considerations to enhance employee safety.

PG&E is targeting 180 miles for system hardening in 2021. Over a three-year period from 2021-2023, PG&E has established that 80 percent of the miles hardened be highest risk miles and 10 percent must be undergrounded. While this target of 180 miles does represent a drop from the 2020 mileage target, this is a result of the previously referenced improvement in risk modeling and the associated pivot in targeting. This target for 2021 is still aggressive because the cycle time for a system hardening project generally exceeds 12 months. Per PG&E's Q2 2021 QIU update, approximately 67 miles of hardening have been completed. As of beginning of June 2021, there are 98 miles are in construction or are ready for construction. Another 100 miles of hardening projects are currently in a dependency phase (e.g., permitting).

Emergency Strategic Fire Rebuild – Covered Conductor Installation

If a distribution line requires a fire rebuild in response to a fire event; and Remote Grid/Customer Buy Out, line removal, or undergrounding strategies are not feasible; overhead hardening is utilized. Once the overhead hardening alternative is identified as the appropriate solution, we look to relocate the circuit if possible. This is typically the case for distribution primary conductor that runs through rural, heavily wooded, or inaccessible terrain that could be relocated to a road or more accessible location. For primary distribution overhead conductor in Tier 2/3 HFTD areas where >4 spans require full reconstruction or large sections of intermittent damage are present, overhead hardening is done in place in compliance with TD-9001B-009. In 2020, approximately

194 miles of overhead hardening were completed as part of the Emergency Strategic Fire Rebuild.

Capacitor Inspections and Replacement

PG&E described its Capacitor Inspections and Replacement Program in Section 7.3.3.1 of our 2021 WMP. Capacitors are placed on the distribution system based on engineering capacity studies that target low voltage areas where installing capacitors can improve low voltage conditions. Once installed, PG&E's capacitor inspections and replacements are governed by Utility Procedure: TD-2302P-05. This utility procedure classifies maintenance tasks for electric overhead and underground equipment, including capacitor banks, fault indicators, interrupters, reclosers, voltage regulators, Supervisory Control and Data Acquisition (SCADA) and Primary Distribution Alarm and Control controls, sectionalizers, streetlights, and sump pumps. Individually, capacitor banks in the distribution system, both overhead and pad-mounted, are tested and inspected annually. The visual part of the inspection includes verifying conditions on the bushings, switches, capacitor tanks, cut-outs, fuses, control cabinets. Within the control cabinet, PG&E further visually inspects the controller, controller box socket and rack to make sure it is properly grounded, as well as inspecting the potential and Current Transformers.

Annual testing entails recording a clamp-on ammeter reading on the primary jumper on each phase of the bank while the capacitor bank is energized. These values are compared to standard expected ranges based on the tank size and circuit voltage. If recorded values exceed the normal ranges, further inspection is required to determine the possibility of a failed capacitor unit or a bad connection. This comprehensive annual testing validates the proper operation and wildfire safety of capacitors deployed in PG&E's system.

As noted above, the actual location of capacitors is determined based on system conditions. Planning engineers perform capacity reviews generally targeting capacitor for areas with known low voltage conditions such as long rural circuits or areas with high inductive loads due to large air conditioning or industrial power usage.

In 2021, PG&E plans to inspect approximately 11,400 capacitors, approximately 10 percent of which historically require corrective action based on inspection results. By the end of Q2 2021, we completed inspections/testing on 10,188 capacitors out of a total population of 11,166. This leaves 1 remaining required capacitor inspection that has not been completed due to access issues from a homeless encampment in Oakland. We are currently working with the City of Oakland to resolve this access issue. The other 276 capacitors are not in scope for inspection as they are already planned for replacement or repairs. As capacitors are replaced/repaired, they no longer show as not in scope for inspection and are inspected the following calendar year. If more information is needed on a capacitor inspection, a request may be reissued to send out an employee for the information requested.

All repairs or replacements are required to be completed by June 1, before peak summer conditions increase electric load. By the end of Q2 2021, of the total 1,893 identified tags/correctives identified through inspections, 1,100 were closed out and 793 tags/correctives are open. Of the 793 tags still open, 630 are high priority tags that involve repairs or replacements. The remaining 163 are lower priority tags that involve relocations or removals that may be closed beyond June 1. Because of the number of repair tags, we were not able to complete all high priority capacitor repairs and replacements by June 1, but are currently developing workplans to address the remaining tags by end of year. Please note that the June 1 requirement described in the WMP was driven by work scheduling needs (i.e., to complete tags before peak summer conditions increase electric load or before clearance constraints become a barrier).

PG&E plans to continue this annual inspection and testing approach going forward.

Distribution Sectionalizing

PG&E described its distribution line sectionalizing program in Section 7.3.3.8.1 of our 2021 WMP. PG&E's plan is to enhance its distribution segmentation strategies including: (a) adding automated sectionalizing devices; (b) circuit reconfiguration/pre-PSPS Event switching; and (c) additional system hardening to support PSPS switching. Distribution sectionalization work is performed in compliance with Utility Standard PSPS-1000S.

Distribution sectionalizing device installations have been focused on circuits that traverse into HFTD areas. PG&E plans to incorporate learnings from past events and focus efforts primarily on counties and specific areas that are repeatedly impacted by PSPS. This includes (but is not limited to) Butte, Yuba, Sonoma, Napa, Nevada, and

El Dorado counties. In 2020, PG&E installed 603 SCADA commissioned distribution sectionalizing devices. In 2021, PG&E plans to install at least 250 more distribution sectionalizing devices integrating learnings from 2020 PSPS events, 10 year historical look-back of previous severe weather events, and feedback from county leaders and critical customers. As of the end of June 2021, 157 devices had been commissioned.

As each yearly wildfire PSPS season concludes, PG&E will integrate learnings from actual PSPS events and feedback from county leaders and critical customers to become even more precise on what areas of circuits to target for shutoff to minimize customer impact and outage duration. With this data and feedback PG&E can continue to install new SCADA automated sectionalizing devices closer to the refined meteorological shutoff boundaries and learn what areas of the community to analyze for even further granular sectionalizing.

Vegetation Management and Inspection Programs

PG&E describes the VM and Inspection (VM) programs in Section 7.3.5 of the 2021 WMP. PG&E's Distribution VM program has been designed and implemented to ensure safe and reliable operation of distribution facilities and to prevent foreseeable vegetation outages. In addition, the Distribution VM program is designed to monitor compliance with state and federal laws and regulations including GO 95, Rule 35, California Public Resources Code (PRC) Sections 4292 and 4293, and PG&E's 2021 WMP. PG&E accomplishes these goals through the following programs.

***Routine* Vegetation Management**

The Routine VM program performs scheduled inspections on all overhead primary and secondary distribution facilities to maintain radial clearance between vegetation and conductors by identifying trees that will encroach within the minimum distance requirements required by law or PG&E procedures, dead, dying, and declining trees.

The VM Mid-Cycle Patrol (previously known as the Second Patrol program and also known as a Catastrophic Event Memorandum Account Patrol), performs scheduled mid-cycle patrols approximately six months before or after the routine patrol on all overhead primary and secondary distribution facilities to maintain radial clearance between vegetation and conductors by identifying trees that will encroach within the minimum distance requirements required by law or PG&E procedures and by identifying dead, dying, and declining trees that have the potential to strike the conductors. Second patrols occur primarily within HFTDs.

In 2021, the plan for Routine VM includes approximately 1.3 million trees and the Mid-Cycle Patrol plan includes approximately 25,000 trees. In the first quarter of 2021, 457,045 trees were worked in Routine VM, including 2020 carry over, and 17,623 Mid-Cycle trees were worked. These numbers are higher than previously reported due to latency with reporting in the system. In the second quarter of 2021, 361,212 trees were worked in Routine VM and 19,295 Mid-Cycle trees were worked.

Vegetation Control (Pole Clearing)

PG&E performs removal of vegetation around T&D poles and towers, in accordance with PRC Section 4292, to maintain a firebreak of at least 10 feet in radius (out from the pole) up to 8 feet up from the ground. These requirements apply in the State Responsibility Areas (SRA) during designated fire season and such designation is a priority in performing this defensible space activity. PRC 4292, which applies to SRA and United States Forest Service lands, determines the geospatial application pole clearing requirements. The 2021 plan includes approximately 101,000 poles. During the second quarter of 2021, 63,063 poles were cleared.

Enhanced Vegetation Management (EVM)

EVM program exceeds compliance requirements and, starting in 2021, is prioritized according to outputs from the Vegetation Risk Model (See Section 4.5.1 of the 2021 WMP), which is a risk-informed model that allows us to prioritize our work at the Circuit Protection Zone (CPZ). CPZs are the smallest non-overlapping sections of the distribution grid that can be de-energized.

The EVM Program is a multi-year program that performs risk-based, scheduled patrols on overhead primary distribution facilities. EVM patrols occur on specific line sections, based on risk, within Tier 2 and Tier 3 of the California Public Utility Commission (CPUC)-designated HFTDs. In HFTD areas, PG&E's Routine VM meets regulations requiring 4 feet radial clearance around overhead distribution lines. The EVM program is much more expansive and aggressive and includes the following:

- Radial Clearances: Exceeding the 4-foot minimum clearance requirement by ensuring vegetation requiring work is trimmed to the CPUC recommended 12-foot clearance at time of trim and in some cases, trimming beyond 12 feet depending on tree growth rates, among other factors. Trimming to the CPUC recommended 12-foot clearance ensures compliance with GO 95, Rule 35.
- Overhang Trimming: Removing overhanging branches and limbs four feet out from the lines and up to the sky around electric power lines to further reduce the possibility of wildfire ignitions and/or downed wires and outages due to vegetation-conductor contact.
- Assessing Trees with the Potential to Strike: Evaluating all trees in HFTDs tall enough to strike electrical lines or equipment and, based on that assessment, trimming, or removing trees that pose a potential safety risk, including dead and dying trees.

At this time, PG&E is forecasting to work on approximately 1,800 circuit miles for the EVM program. As of the second quarter of 2021, approximately 595 miles were work verified in EVM. However, this number is being reviewed and validated by our VM and Internal Audit departments and may be subject to change.

Data Management

PG&E is reviewing work management platforms and is planning to perform proof-of-concepts with one or more vendors in 2021 to begin to test how platforms may perform with current data collected in VM programs as well as to collect additional data required by the WSD GIS Data Standard and Condition Guidance-10. VM is also engaging with PG&E's internal Information Technology department to define and plan database support.

As of the second quarter of 2021, the results of the Proofs of Concept have been delivered to our management team. The management team is reviewing the top two vendor selections, and a final vendor selection has not yet been made. Vendors are reviewing requirements for release schedule. Year 2 scope has been defined.

CONDITION PG&E-11

INCLUDING ADDITIONAL RELEVANT REPORTS

Deficiency: In Section 5.2.A of its Wildfire Mitigation Plan (WMP), Pacific Gas and Electric Company (PG&E) identifies several internal reports it generates for its leadership and Board of Directors (BOD) (a weekly dashboard, status and tracking reports that provide leadership and the Board visibility into the different elements of the WMP). PG&E also makes reports to the federal monitor in its federal criminal probation case before District Judge William Alsup.

Condition: In its quarterly reports, PG&E shall append the following:

i. ***All internal reports provided to its Executive Officers and/or BOD, as described in Section 5.2A of its 2020 WMP, during the previous quarter. In its first quarterly report, PG&E shall also produce all internal reports or other documents provided to its Executive Officers and/or BOD related to its electric grid from January 1, 2018 to the present; and***

Per Resolution WSD-011, Attachment 3, page 6, for the purposes of this response, the "previous quarter" is defined as April 1, 2021 to June 30, 2021. PG&E is submitting all internal reports provided to its Executive Officers and/or BOD, as described in Section 5.2A of our 2020 WMP, in the previous quarter. Please note that the responsive documentation excludes:

1. Documents provided to the Executive Officers and/or BOD under attorney client or attorney work product privileges; and,
2. Documents not related to WMP progress tracking as described in Section 5.2A of our 2020 WMP.

Please see attachment 2020WMP_ClassB_PGE-11_Atch01 for those documents.

ii. ***All reports or other documents related to its electric grid provided to the federal monitor in the previous quarter. In its first quarterly report, PG&E shall also produce all reports or other documents related to its electric grid provided to the federal monitor from January 1, 2018 to the present.***

PG&E is enclosing all reports or other documents related to our electric grid provided to the Federal Monitor from the previous quarter—please see attachment: 2020WMP_ClassB_PGE-11_Atch01 for those documents.

The materials provided in the previous quarter to our Federal Monitor include the listed dashboards below. These reports allow the Monitor team to assess progress on an ongoing basis to ensure PG&E complies with probation requirements and metrics set forth in the WMP. Any Excel documents provided include only the visible tabs provided to the Federal Monitor. The origination dates of reports to the Monitor vary due to these items being discussed at different stages of the Monitor's assessment of PG&E.

Federal Monitor Dashboards

- Weather Station and Camera Progress;
- Enhanced Vegetation Management (EVM) Progress Dashboard;
- Expense and Capital Spending Report;
- Ignition Tracker;
- System inspections progress;
- Aerial inspection progress;
- System Hardening progress;
- Electric Operations Expense Capital Spending Forecast Report;
- Report 33: Gatekeeper Report;
- Quarterly Hazard Notification (HN) Dashboard;
- Safety and Enforcement Division Audit Findings;
- Weekly Vegetation Management (VM) Ops Dashboard;
- Key Performance Indicator A Tag Remediation Dashboard;
- VM Inspection Tracker;
- Work, Resource, and Financial Review Meeting Minutes and Slide Decks;
- Year-to-date VM Reg Compliance;
- Updated Field Automated System (FAS) Missed Ignition Audit Dashboard; and
- Maintenance & Repair Tag Dashboards.

The Federal Monitor team also receives additional reports and dashboards related to other areas of electric operations which include but are not limited to safety, compliance and ethics, and contractor trainings. These materials are not provided in this response as they do not directly impact the electric grid.

CONDITION PG&E-22

SOME OF PG&E'S VM INSPECTORS MAY LACK PROPER CERTIFICATION

Deficiency: PG&E's VM inspectors may lack proper certification; they may not be certified by the International Society of Arboriculture (ISA). Since the scope of its program is so large, PG&E developed a specific evaluation tool called the "Tree Assessment Tool (TAT)" to be used by inspectors; however, PG&E is not requiring inspectors to be ISA certified.

Condition: In PG&E's quarterly reports, PG&E shall detail:

i. The portion of its inspectors who are ISA certified;

The ISA offers many different levels of certification. PG&E assumes that the statement above is referring to ISA Certified Arborists. Approximately 25 percent of PG&E's Pre-Inspectors are ISA Certified Arborists. Additionally, approximately 4 percent of Pre-Inspectors are Registered Professional Foresters in the State of California. However, it is important to note that while being an ISA Certified Arborist may be helpful, this credential alone does not sufficiently qualify or determine whether an individual will be a good Pre-Inspector. For instance, VM has experienced an influx of out-of-state ISA Certified Arborists in the past who could not properly identify California trees and did not understand local vegetation growth rates. Also, VM has experienced ISA Certified Arborists who have been active in the industry for a long time and still misidentify trees or miscalculate growth rates. Additionally, to become an ISA Certified Arborist, you must be trained and knowledgeable in all aspects of arboriculture and meet a minimum qualification of having three or more years of on the job experience. That is why PG&E's pre-inspection program focuses on: (1) a Structured Learning Path to train Pre-Inspectors, (2) verification of 100 percent of EVM Pre-Inspector work, and (3) use of PG&E's TAT. Each of these elements is described below.

The Structured Learning Path

The Structured Learning Path for Pre-Inspectors includes the completion of a nine-course comprehensive training program that includes web-based training (WBT), scenario-based skills assessments, on-the-job training (OJT), and mentoring relationships with experienced Pre-Inspectors. Pre-Inspectors are required to pass scenario-based skills assessments that test key concepts covered in the training program, and experienced Pre-Inspectors will be paired with new Pre-Inspectors to provide OJT and serve as mentors and resources during the Pre-Inspector's first year of training. We also require that contracted Pre-Inspectors pass an assessment in order to work as a PG&E Pre-Inspector contractor for VM.

Work Verification (WV)

100 percent of EVM pre-inspection work is reviewed by the WV team, approximately 46 percent of whom are ISA Certified Arborists. Please note, the percent of ISA Certified Arborist resources changed due to a shift in resources. The WV team reviews all completed pre-inspection work to provide opportunities for correction, learning, and insight. We believe that teaming up the Pre-Inspector with the WV individual during the review provides the best opportunity for Pre-Inspector learning and corrective action, if needed. Additionally, WV has begun the process of hiring additional work verifiers both internal and external to support the continued effort of the WV process. PG&E has begun WV for both routine and Catastrophic Event Memorandum Account work.

Tree Assessment Tool

Finally, Pre-Inspectors using the TAT are less likely to need to make subjective decisions when identifying hazard trees. The PG&E TAT incorporates historical data on tree failures, regional species risk, and local wind gust data, to supplement the Pre-Inspector's knowledge and judgment with solid data and analytical insight. We have found that most, if not all, other risk assessment tools in the industry today still rely on subjective judgment by inspectors in the field who may lack access to the types of data and historical analysis available to PG&E Pre-Inspectors using the TAT. External SMEs from California Polytechnic State University and University of California, Berkeley have contributed to the TAT.

In summary, PG&E's approach to pre-inspection does not solely rely on the individual certifications of each inspector. Rather, our pre-inspection program provides and improves the overall training for everyone, verifies all work prescribed by EVM inspectors, and leverages a new tool to improve assessments.

ii. The portion of its inspectors who plan to be ISA certified by the time of its 2021 WMP supplement filing; and

Our vendors continue to actively support all Pre-Inspector employees in becoming ISA Certified Arborists. Currently 25 percent of our Pre-inspectors are ISA Certified

Arborist and our plan is to continue to support certification efforts as described in our 2021 WMP.

iii. How it will ensure effective inspection QC protocols if some inspectors are not ISA certified.

As we have described above, PG&E uses training, procedural guidance, and WV to ensure pre-inspection QC.

As discussed above in Subpart i, PG&E has implemented the Structured Learning Path, a 9 course, comprehensive Pre-Inspector training program for all Pre-Inspectors that includes WBT, scenario-based skills assessments, OJT, and mentoring relationships with experienced Pre-Inspectors. Pre-Inspectors are required to pass scenario-based skills assessments that test key concepts covered in the training program, and experienced Pre-Inspectors will be paired with new Pre-Inspectors to provide OJT and serve as mentors and resources during the Pre-Inspector's first year of training. This training includes a module devoted entirely to PG&E's EVM Program and is thus also a requirement for contractors performing EVM inspections. Contract Pre-Inspectors must also pass an assessment in order to work as a Pre-Inspector contractor for VM within PG&E.

PG&E's VM Department uses an Expert Technical Writer with a small contract staff team. These writers are currently reviewing all procedural documents related to VM and ensuring consistent, easily understood guidance for staff to use. They develop Bulletins where needed for additional clarity, and Job Aids as step-by-step guides. They may re-write entire procedural documents to ensure that these documents offer clear work and compliance guidance.

PG&E believes that through a combination of training, procedural guidance improvements, WV, and use of the TAT, we can ensure that VM inspection quality is effective and appropriate for providing safe and reliable electric service, while mitigating wildfire risks.

CONDITION PG&E-28

LACK OF JUSTIFICATION AND DETAIL FOR PG&E'S SELF-ASSESSED STAKEHOLDER ENGAGEMENT CAPABILITIES

Deficiency: In response to the utility survey for the maturity model, PG&E answered many questions regarding its stakeholder and community engagement capabilities in ways that do not align with PG&E's documented poor coordination and engagement efforts. For example, PG&E's responses indicate that it has a clear and actionable plan to develop and maintain collaborative relationships with local communities; however, continued fallout and harsh criticism for poor coordination and collaboration with local communities during its October 2019 Public Safety Power Shutoff (PSPS) events, as well as, in preparation for the 2020 wildfire season suggests their "actionable plan" is not sufficient nor effective.

Condition: In a quarterly report, PG&E shall:

i. List and describe all actions it is taking to coordinate and collaborate with local communities regarding its wildfire mitigation activities and PSPS;

For ease of reference in this response, the following table contains the relevant filings, reports and documents that are referenced throughout this update:

TABLE 1
STAKEHOLDER ENGAGEMENT-RELATED REPORTS ATTACHED

Line No.	Document Name	Proceeding	Date	File Name
1	PG&E's 2021 PSPS Access and Functional Needs (AFN) Plan	Decision (D.) 20-05-051	February 1, 2021	Attachment 2020WMP_ClassB_PGE-28_Atch01
2	PG&E's Q2 2021 Regional Working Group Summary Report	D.20-05-051; D.20-06-017	June 28, 2021	Attachment 2020WMP_ClassB_PGE-28_Atch02
3	PG&E's PSPS AFN July 2021 Quarterly Progress Report	D.20-05-051	July 30, 2021	Attachment 2020WMP_ClassB_PGE-28_Atch03

PG&E acknowledges that there were significant issues with communications and coordination with local communities during PSPS events in 2019. As stated in previous reporting, since 2019 we have changed the way we engage with local communities, and the resources we provide, to give better information before wildfire season, as well as to improve coordination for PSPS events in 2020. This began in late 2019 when we conducted Listening Sessions to gather direct feedback from customers, agencies, and stakeholders on the ways that we could improve and to create outreach plans that were responsive to the concerns we heard. Since that time, we have been focused on improving local outreach, resources, and coordination to avoid the issues experienced during 2019 PSPS events. This has included significantly increasing transparency around how PG&E's system is designed and operated and the processes involved in PSPS events.

The response to the increased and improved engagement efforts in 2020 was positive compared to comments made following the 2019 PSPS events. We have continued those efforts in the second quarter of 2021 and will continue to do so throughout the year.

We are including below a description of the steps that we have taken to improve local coordination since our last reporting.

Listening Sessions

As stated in previous reporting, listening sessions allow PG&E to meet with county and tribal emergency managers and local governments, listen to concerns, gather feedback, and identify ways we can improve our coordination going forward. In November 2020, PG&E began reaching out to counties and tribes impacted by 2020 PSPS events to schedule listening sessions. The sessions were held virtually throughout December 2020 and January 2021.

We completed 20 sessions in December 2020 and 15 in January 2021, for a total of 35 sessions.[7]

We have documented the feedback and action items received during these sessions and shared the report with participants, as well as the California Public Utilities Commission (CPUC), on February 26, 2021. PG&E is taking feedback and action items from the Listening Sessions for consideration into our 2021 wildfire related work plans, and we will be closing feedback loops with communities in upcoming 2021 engagements, including the Wildfire Safety Working Sessions.

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7 Ten county Office of Emergency Services (OES) and county administrator departments declined a meeting and nine were not impacted by a PSPS event in 2020 (Kings, Merced, Sacramento, San Benito, San Francisco, San Luis Obispo, Santa Barbara, Sutter and Tulare)

PG&E also conducted unofficial listening sessions as part of collaboration meetings with large commercial customers and critical facilities in Q2 2021, in addition to regularly engaging both sets of customers directly and in group settings. PG&E will continue engagement efforts following each PSPS season.

Wildfire Safety Working Sessions

Wildfire Safety Working Sessions are one component of our efforts to partner with local and tribal officials to prepare for PSPS events.

In late March 2021, PG&E local agency representatives began outreach to local and tribal agency partners, along with key stakeholders to schedule virtual Wildfire Safety Working Sessions. The objective for the Working Sessions was to follow-up on feedback received during the Listening Sessions, discuss the steps PG&E is taking to address the feedback received during the Listening Sessions, share updates regarding county-specific plans for wildfire mitigation, system resiliency, and find additional ways to partner ahead of wildfire season.

All counties and tribal governments in the PG&E service area were invited to co-host a session regardless of whether they have been impacted by a PSPS event in the past. In total, we completed 26 Wildfire Safety Working Sessions with counties, cities and tribal governments (noted below); 23 counties invited declined to participate (Alameda, Butte, Colusa, Glenn, Kern, Lassen, Merced, Monterey, Nevada, Placer, Plumas, Sacramento, San Joaquin, Shasta, Siskiyou, Sierra, Sutter, Tehama Trinity, Tulare and Yuba). Each counties' reasoning for opting out of a Wildfire Safety Working Session is noted in Appendix B.

The Working Sessions were conducted at the county level and averaged 60 minutes in length. All Working Sessions were led by PG&E's local Public Safety Specialist, or Tribal Liaison for tribal-specific sessions, with support from the Local Public Affairs and Customer Experience and Division Lead representatives.

During the Wildfire Safety Working Sessions, PG&E gathered all actions requiring follow up and have since responded to the appropriate external participants to discuss and collaborate on solutions. Meeting participants were also provided emails and phone numbers for local representatives should they need to reach out following the working session.

TABLE 2
2021 COMPLETED WILDFIRE SAFETY WORKING SESSIONS

Line No.	County/Tribe	Date	Number of External Participants
1	Santa Clara County	4/27	50
2	Lake County	4/27	30
3	Yolo County	4/29	15
4	Tuolumne County	4/29	20
5	Napa County	4/29	8
6	El Dorado County	5/4	26
7	Sonoma County	5/5	82
8	Mendocino County	5/6	21
9	Pit River Tribe	5/7	3
10	Amador County	5/12	11
11	Madera County	5/14	16
12	Alpine County	5/17	19
13	Calaveras County	5/17	19
14	San Luis Obispo County	5/18	10
15	Fresno County	5/19	13
16	Solano County	5/19	6
17	Marin County	5/21	20
18	City of San Jose	5/21	9
19	Stanislaus County	5/24	23
20	San Mateo	5/25	29
21	Kings County	5/26	11
22	Mariposa County	5/27	8
23	Contra Costa County	6/10	68
24	San Benito County	6/23	5
25	San Francisco County	6/23	9
26	Humboldt County	6/28	21

Standardized Emergency Management System (SEMS) Training

A key finding from 2019 PSPS events was the need for PG&E teams who are working in the Emergency Operations Center (EOC) to receive more structured and consistent emergency management training. As a result, everyone who supports PSPS events in PG&E's EOC is being trained on SEMS, National Incident Management System (NIMS) and Incident Command System (ICS). Since the state and local governments use SEMS to manage emergencies, this new training requirement will ensure PG&E's procedures are aligned with these agencies.

The specific training requirements included:

- IS-100.C – Introduction to Incident Command;
- IS-200.C – Basic ICS for Initial Response;
- IS-700.B – An Introduction to the National Incident Management System;
- IS-800.C – National Response Framework, an Introduction; and

- SEMS G606 – Standardized Emergency Management Introduction.

In Initiative 7.3.9.1 of our 2021 WMP, we explained a four-phased approach that we were undertaking to train our EOC staff, with a targeted completion date of all four phases by 2022. We are continuing to make progress with training for all emergency response roles in each phase. This will ensure all required personnel are prepared to support our improved PSPS execution.

Phase 1 consists of the foundational trainings to understand the basic structure and functional process associated with SEMS/ICS command. We targeted completion of the five web-based courses including in Phase 1 training within 60 days of assignment to the emergency response team. Due to the volume of EOC staffing attrition and the transition from a four-team structure to an eight-team structure to decrease fatigue and improve work-life balance associated with the increased frequency of activations, we have adjusted this timeline to December 31, 2021 for all current team members.

Phase 2 is designed to ensure all Command and General staff (i.e., Officers and primary Assistants, Section Chiefs and Deputies) complete Integrating AFN training such as G197 or equivalent courses. G197 AFN is instructor led by Cal OES. The calendar is developed by Cal OES for the entire year and PG&E was able to secure three courses in 2021. PG&E successfully executed all three courses. Approximately 32 percent of the 173 rostered Command & General Staff have completed the available G197 training. Going forward and with concurrence from CSTI, we will allow members to enroll in the web-based equivalent course, IS 368 in lieu of G197 until a utility specific G197 course is available. We are also monitoring progress on a weekly basis to ensure the September 1, 2021 targeted completion is attained.

Phase 3 training is targeted towards all Command & select roles in the General staff. It requires key EOC team members to complete the ICS 300 and 400 courses. To date, we have 54 percent of the 173 targeted population have completed this training. We inadvertently were tracking this completion towards a December 31, 2021 due date instead of the June 30, 2021 due date. This error resulted in us not completing this item within the desired timeline. Training sessions for ICS 300 and ICS 400 have been scheduled on alternating weeks moving forward through the remainder of 2021. All remaining Command & General Staff team members who were not previously trained are currently enrolled in the classes to complete Phase 3 by December 31, 2021. We are monitoring progress on a weekly basis for validation of completion and adjustments to class scheduling.

Phase 4 training courses are in development through collaboration with CSTI. We have completed the curriculum and gained approval from CSTI for one position specific course for staff in the Safety Officer role. This course was delivered as a pilot and will be placed in the training schedule. We will continue to partner with CSTI on the development of the remaining thirteen position specific courses.

PSPS Advisory Boards

PG&E's advisory boards provide hands-on, direct advisory functions related to PSPS. This includes helping develop best practices for PSPS protocols, community preparedness, customer support resources and program offerings, regional coordination, and the optimal use of existing and emerging technologies. We currently engage in five PSPS-focused advisory boards: PSPS Advisory Committee, People With Disabilities and Aging Advisory Council (PWDAAC), Statewide Investor-Owned Utility (IOU) AFN Advisory Board, the PG&E Telecommunications Resiliency Collaborative and, PG&E's partnership with the Hospital Council of Northern and Central California.

1) PSPS Advisory Committee: PG&E established a PSPS Advisory Committee (also known as the PSPS Advisory Board) in February 2020, which includes representatives from the seven rural and urban cities or counties, two tribal agencies, the League of Cities, and California State Association of Counties. The meetings provide a forum for participants to weigh in on a variety of PSPS Program updates such as customer notification scripts, The PSPS Policies and Procedures, Wildfire Safety Working Session content and meeting outlines, and PSPS full-scale exercises, among other topics.

   In Q2 2021, PG&E hosted two meetings: on April 8 and 11, 2021 and June 10, 2021. Meeting topics for the April meeting included grid resiliency efforts, microgrids, customer preparedness and resources, PSPS full-scale exercises, and updates to the PSPS Policies and Procedures document. The June PSPS Advisory Committee meeting included a recap of the May PSPS full-scale exercise and areas for improvement identified, potential enhancements to PSPS decision-making and an overview of the updated 7-day PSPS potential forecast tool.

Throughout 2021, PSPS Advisory Committee meetings will take place on the second Thursday of every other month from 2 p.m. – 3 p.m. The meeting schedule will be as follows:

- August 12, 2021;
- October 14, 2021; and
- December 9, 2021.

2) People With Disabilities and Aging Advisory Council: PG&E launched an AFN-focused advisory council called the PWDAAC in 2020. The PWDAAC is a diverse group of recognized community based organization (CBO) leaders supporting people with developmental or intellectual disabilities, physical disabilities, chronic conditions, injuries, and older adult communities, as well as members and advocates from within these communities.

In Q2 2021, the PWDAAC held the Second Quarter Meeting on June 11, 2021. Topics discussed during the Q2 meeting included:

- Updates to PSPS scoping;
- Portable Battery Program (PBP) planning; and
- New CBO partnerships

PG&E received the following feedback during the meetings:

- Participants appreciated the level of scientific research and weather forecasting that goes into every potential PSPS event;
- Members were encouraged by the microgrid systems both operational and in planning phases in High Fire Threat Districts; and
- Participants were supportive of the continued expansion of the PBP and CBO partnerships.

PG&E plans to convene the PWDAAC for at least four meetings per year (quarterly) and on an ad hoc basis, although the frequency or timing may be modified near the PSPS season. The next two PWDAAC meetings are scheduled to take place September 17 and December 17, 2021.

We will continue to solicit feedback from the Council regarding PSPS, Medical Baseline, and other programs that support the AFN community. Due to the coronavirus (COVID-19) pandemic conditions, PG&E will host virtual meetings until it is safe to hold in-person meetings.

3) Statewide IOU AFN Advisory Council: PG&E also worked in partnership with Southern California Edison Company and San Diego Gas & Electric Company to establish the Statewide IOU AFN Advisory Council. The council is composed of a diverse group of recognized CBO, association and foundation leaders supporting the AFN population and leaders from various state agencies. The AFN Advisory Council provides insight into the unique needs of the IOUs' most vulnerable customers and stakeholders, offers feedback, makes recommendations, and identifies partnership opportunities to serve the broader AFN population before, during and after a PSPS event.

   Since last reporting, the Statewide IOU AFN Advisory Council held three meetings on April 30, May 21, and June 25, 2021. The primary objectives of the meetings were to:

   - Hold a discussion regarding 2-1-1 partnerships with IOUs;
   - Solicit feedback from the Advisory Council on the 2-1-1 AFN identification and intake questions;
   - Provide progress updates on subcommittee efforts and solicit participation in upcoming working sessions; and
   - Review IOU matrix and zip code data aggregation and subcommittee accomplishments and updates.

   PG&E will work with the other IOUs to continue to engage with members, advocates, and leaders across all populations identified as vulnerable, to inform a more holistic and strategic view on how to help the many constituencies served by the utilities. The joint IOUs aim to convene the Council for no less than four meetings per year. The meetings will be held virtually given the current COVID-19 pandemic conditions and will move to in-person meetings when it is safe to do so.

   The next Statewide IOU AFN Advisory Council meeting is scheduled to take place on July 30, 2021.

Key Customer Association Collaboration

1) PG&E and Telecommunications Resiliency Collaborative: PG&E initiated this coordination group in early 2020 to create a forum for communications providers to provide feedback on PG&E's current PSPS implementation protocols and to coordinate engagement before and during PSPS events, as well as to enhance collaboration and coordination during emergency response generally. In Q2 2021, PG&E held its second session of the year with this group on April 20, 2021. Representatives from American Telephone and Telegraph, Inc. (AT&T), Comcast, Consolidated Communications, Crown Castle, Cellular Telecommunications Industry Association (CTIA), Frontier Communications, Mediacom, T-Mobile, US Cellular and Verizon attended the meeting. Topics included a meteorology update, 2021 preparations, outreach and engagement (full-scale and tabletop exercises, county working sessions), notifications and portal updates, and federal and state updates.

   Outside of the Collaborative group, PG&E held a Public Safety Partner Webinar for Telecommunication Providers on May 26 with attendees from Charter Communications, T-Mobile, Verizon, AT&T, Sierra Telephone, Comcast, American Tower, Altice/Suddenlink, Consolidated Communications, and Mediacom. Topics of discussion included progress on wildfire prevention efforts, resources to help our customers and communities before, during and after PSPS events and improved wildfire safety technology and tools.

   The next Collaborative meeting will be scheduled for early August 2021.

2) Partnership with the Hospital Council of Northern and Central California: In March 2020, the Hospital Council of Northern and Central California, California Hospital Association, and PG&E representatives kicked off an energy resiliency project to reduce impacts of PSPS events. The Council is a member organization comprised of approximately 150 hospitals in Northern and Central California.

   Given the vital role hospitals serve in the community, and especially in light of the COVID-19 pandemic, PG&E made a commitment to identify the PSPS risk for each hospital and support the development of customized solutions for those most likely to experience a PSPS event.

The energy resiliency project that was formulated in 2020 is being further refined in 2021 to both support 2021 fire season readiness and more fully explore longer term grid-based, single site, and microgrid resiliency solutions. Weekly meetings between PG&E and the Hospital Council continued in Q2 2021, are a forum for information sharing and collaboration, and have been supporting exploration of available grant funding, innovative technology solutions, and improved communication with hospitals. We anticipate continuing this meeting cadence in Q3.

3) Collaborating with Association of California Water Agencies (ACWA) and individual water agencies: Building on the successful engagement in 2020 where PG&E supported EPA Region 9's development of PSPS Standard Operating Procedures with a particular focus on small and tribal water systems, we engaged with multiple individual water agencies, with a particular focus in Q1 on eight water agencies who had requested back up generation in multiple PSPS events to provide resources, and encourage resiliency planning. We continued collaboration with ACWA's Energy Committee and individual water agency engagement in Q2.

   In addition to our engagement described above, PG&E invited public safety partners, telecommunication providers, and water agencies to participate in our May PSPS Tabletop Exercise and PSPS full-scale Exercise. PG&E will continue to meet with the stakeholders and advisory groups listed above and will periodically bring them together, along with other stakeholder groups outlined in D.20-05-051, to solicit feedback on the PSPS Program.

PSPS Portal Improvements

As mentioned in our last report, PG&E established the PSPS Portal Working Group with external users and hosted three working group meetings on March 16, March 23, and April 6. PG&E gathered feedback during those meetings regarding updates to the proposed 2021 Situation Report template, data provided during an event, and a proposed page layout changes for a more optimal user experience.

As a result of the PSPS Portal Working Group and feedback received, the following improvements have been made to the PSPS Portal:

- Completed end-to-end automation and cloud migration of data processing for faster PSPS Portal updates following changes to geographic scope or customer impacts;
- Deployed user interface updates to more clearly indicate when data was last validated as current on the main PSPS event page; and
- Added PDF maps for tribal organizations to visualize tribal lands affected by PSPS events.

County Report

PG&E representatives will be providing counties and tribes with a quarterly report that contains the following information:

- **County Engagement Update:** A summary of quarterly outreach efforts that PG&E has conducted with each county, tribe, and community and when these efforts were conducted or are scheduled. These efforts include PSPS Listening Sessions, Safety Town Hall, PSPS Advisory Committee meetings, PSPS Portal training, quarterly Regional Working Group meetings and ongoing engagements with key stakeholders from within the respective jurisdiction. This document also includes status updates regarding specific follow up items that have been identified during recent engagements to ensure that we are honoring requests made by partners and helping with PSPS and wildfire preparation efforts as much as possible.

- **County Progress Report:** A summary of county-specific status updates regarding the various wildfire mitigation efforts we are conducting, which include weather station and high-definition camera installation, CRCs, sectionalizing device and transmission line switch installation, system hardening, EVM work and temporary generation at substation (as applicable) locations.

The Q2 quarterly County Reports were disseminated to counties and tribes throughout the week of May 3, 2021. PG&E plans to distribute County Reports for Q3 in July 2021. These reports will then be made available online on PG&E's CWSP page (www.pge.com/cwsp).

Customer Outreach

PG&E expanded outreach efforts in 2020 to include additional informational resources, including videos, brochures, events, and online tools to help customers and communities prepare. We reached out to customers through multiple touchpoints to provide communities with CWSP/PSPS-related information via:

- **Wildfire Safety Webinars:** PG&E is conducting 10 Safety Town Halls and approximately 18 Wildfire Safety Webinars in 2021 targeted to various regions within the service territory. Due to the COVID-19 pandemic, PG&E will continue to host events as virtual webinars with continued best practices established in 2020 and in support of customers that may have AFN.

  These customer-focused CWSP webinars are being held in advance of 2021 wildfire season. As of June 30, 2021, we had completed 31 webinars, with seven more webinars scheduled between July and August. A total of approximately 4,070 people have attended the webinars we have held so far. Details regarding these webinars are provided below in Table 3.

  PG&E posts the full schedule of webinars, along with presentation documents and recorded videos of presentations, at www.pge.com/firesafetywebinars. We will continue to update this webpage as we schedule additional 2021 webinars.

TABLE 3
Q2 2021 WILDFIRE SAFETY WEBINARS AND VIRTUAL TOWN HALLS

Line No.	County/Audience	Date
1	Wildfire Safety Webinar – Fresno, Kern and Tulare Counties	April 1, 2021
2	Virtual Safety Town Hall – Mendocino, Humboldt, Trinity and Siskiyou Counties	April 7, 2021
3	Wildfire Safety Webinar – Madera, Mariposa and Tuolumne Counties	April 8, 2021
4	Wildfire Safety Webinar – Alpine, Amador and Calaveras Counties	April 15, 2021
5	Virtual Safety Town Hall – Sacramento, Solano and Yolo Counties	April 21, 2021
6	Wildfire Safety Webinar – El Dorado County	April 22, 2021
7	Wildfire Safety Webinar – Solano and Yolo Counties	April 29, 2021
8	Virtual Safety Town Hall – Alpine, Amador, Calaveras, Mariposa and Tuolumne Counties	May 5, 2021
9	Wildfire Safety Webinar – Nevada County	May 6, 2021
10	Wildfire Safety Webinar – Lassen, Plumas, Sierra and Tehama Counties	May 13, 2021
11	Virtual Safety Town Hall – El Dorado and Placer Counties	May 19, 2021
12	Wildfire Safety Webinar – Shasta County	May 20, 2021
13	Wildfire Safety Webinar – In-Language (Spanish)	May 25, 2021
14	Wildfire Safety Webinar – In Language (Chinese)	May 26, 2021
15	Wildfire Safety Webinar – Humboldt, Mendocino, Siskiyou and Trinity Counties	May 26, 2021
16	Wildfire Safety Webinar – In-Language (Spanish)	May 27, 2021
17	Wildfire Safety Webinar – All PG&E Customers	June 2, 2021
18	Wildfire Safety Webinar – In-Language (Spanish)	June 3, 2021
19	Wildfire Safety Webinar – Butte County	June 3, 2021
20	Wildfire Safety Webinar – Colusa, Glenn, Placer and Yuba Counties	June 10, 2021
21	Wildfire Safety Webinar – Lake County	June 17, 2021
22	Wildfire Safety Webinar – CBOs Supporting Customers with Disabilities and AFN	June 22, 2021
23	Wildfire Safety Webinar – CBOs Supporting Customers with Disabilities and AFN	June 23, 2021
24	Wildfire Safety Webinar – Napa County	June 24, 2021
25	Wildfire Safety Webinar – K-12 Schools	June 29, 2021
26	Wildfire Safety Webinar – Marin and Sonoma Counties	June 30, 2021
27	Wildfire Safety Webinar – In-Language (Hmong)	July 6, 2021
28	Wildfire Safety Webinar – Alameda, Contra Costa and San Mateo Counties	July 8, 2021
29	Wildfire Safety Webinar – Santa Clara and Santa Cruz Counties	July 15, 2021[(a)]
30	Wildfire Safety Webinar – Merced, San Joaquin and Stanislaus Counties	July 22, 2021[(a)]
31	Wildfire Safety Webinar – Customers with Disabilities and AFN	July 27, 2021
32	Wildfire Safety Webinar – Monterey, San Luis Obispo and Santa Barbara Counties	July 29, 2021[(a)]
33	Wildfire Safety Webinar – All CBOs	TBD

(a) Dates subject to change.

- **Intensive Large and Critical Customer Outreach**: As part of PG&E's efforts to provide additional support to customers more likely to be impacted by a PSPS event, PG&E identified approximately 2,300 critical customers and large commercial customer accounts that will receive more intensive outreach and engagement starting in Q2 2021. These customers were identified based on current PSPS criteria, modeling, grid configuration, and high fire-threat areas as defined by the CPUC High Fire-Threat District Map.

  In addition to the general customer outreach and engagement described in this section, the following includes various proactive outreach initiatives:

  – **Customer Information Validation**: Between June 16 and July 15, 2021, PG&E reached out to critical customers to confirm their contact information is up to date for PSPS notifications, validate support for regular and safe operation of critical facilities and service points, and confirm their backup power capabilities.

  – **Proactive PSPS Communication**: Before and during a PSPS event, critical customers will be proactively contacted if they do not confirm receipt of at least one PSPS notification and assigned a 24-hour contact that will be accessible and responsive throughout the duration of the event.

  – **Resiliency Planning Assistance**: PG&E will conduct intensive outreach customers to customers providing support in creating an emergency plan for PSPS events, including information to be shared with employees to prepare at home, and provide PSPS planning data at each of their locations (i.e., historical PSPS data, simulated 10-year PSPS distribution and transmission event lookback, and mitigation data).

  – **In-event CBO Support Survey:** Water agencies and telecommunications Public Safety Partners were sent a survey on how they engage CBO partners for in-language emergency communications and provided information how we plan to coordinate and share information during a PSPS event. Public Safety Partners were also informed on the process for requesting a seat in our EOC.

– **Annual Primary Voltage Customer Letter:** On June 16, 2021, PG&E sent a letter to Primary Voltage Customers of their maintenance and repair responsibilities. The letter included the following topics:

  - Annual inspection reminder;
  - Preforming necessary VM work;
  - Fault Duty awareness;
  - Responsibilities following a PSPS shutoff; and
  - Encourage customers to have liability insurance.

On April 15 and April 20, PG&E hosted internal outreach and engagement trainings for the Local Customer Experience representatives and Business Energy Solutions assigned account managers who will be a part of this effort. Outreach for the program started on April 16 and was completed May 7.

- **Direct-to-Customer Mailings/E-Mails:** As we did in 2020, to help customers prepare for emergencies and a potential PSPS event in 2021, PG&E is conducting a multi-channel outreach and awareness campaign that includes letters, e-mails, tenant education kits, postcards and more. See Table 4 below for details regarding our mailings in Q2 2021.

TABLE 4
Q2 2021 CWSP/PSPS DIRECT-TO-CUSTOMER EMAIL/MAILING CAMPAIGNS

Line No.	County/Audience	Date
1	4/15 Wildfire Safety Webinar Email Invite – Alpine, Amador and Calaveras Counties	April 1, 2021
2	4/21 Virtual Safety Town Hall Email Invite – Sacramento, Solano and Yolo Counties	April 8, 2021
3	4/22 Wildfire Safety Webinar Email Invite – El Dorado County	April 9, 2021
4	April Internet Protocol (IP) Warming Email: Gas Safety (commercial)	April 10, 2021
5	4/29 Wildfire Safety Webinar Email Invite – Solano and Yolo Counties	April 15, 2021
6	April IP Warming Email: Gas Safety (residential)	April 17, 2021
7	5/5 Virtual Safety Town Hall – Alpine, Amador, Mariposa, Tuolumne and Calaveras Counties	April 21, 2021
8	5/6 Wildfire Safety Webinar Email Invite – Nevada County	April 22, 2021
9	5/13 Wildfire Safety Webinar Email Invite – Lassen, Plumas, Sierra and Tehama Counties	April 29, 2021
10	Medical Baseline Healthcare Sector Emails (healthcare providers, hospitals and device manufactures)	April 29, 2021
11	Address Alert Campaign: Emails, Postcards, Interactive Voice Response	April 29, 2021
12	May Bill Insert: PSPS Alert/Notification Preferences	May 1, 2021
13	5/19 Virtual Safety Town Hall Email Invite – Placer and El Dorado Counties	May 5, 2021
14	5/20 Wildfire Safety Webinar Email Invite – Shasta County	May 6, 2021
15	5/26 Wildfire Safety Webinar Email Invite – Humboldt, Mendocino, Siskiyou and Trinity Counties	May 12, 2021
16	May IP Warming Email: Address Alerts & Language Preference (residential)	May 15, 2021
17	6/2 Virtual Safety Town Hall Email Invite – All Customers	May 19, 2021
18	6/3 Wildfire Safety Webinar Email Invite – Butte County	May 20, 2021
19	May IP Warming Email: Address Alerts & Language Preference (commercial)	May 22, 2021
20	6/10 Wildfire Safety Webinar Email Invite – Colusa, Glenn, Placer and Yuba Counties	May 27, 2021
21	June Bill Insert: PSPS Awareness	June 1, 2021
22	6/17 Wildfire Safety Webinar Email Invite – Lake County	June 3, 2021
23	6/24 Wildfire Safety Webinar Email Invite – Napa County	June 10, 2021
24	**Address Alerts Direct Mail (DM) (non-account and commercial)**	**June 14, 2021**
25	**6/29 Wildfire Safety Regional Webinar Email Invite – Educational Stakeholders**	**June 15, 2021**
26	**Address Alerts DM (residential and small and medium business)**	**June 17, 2021**
27	6/30 Wildfire Safety Webinar Email Invite – Marin and Sonoma Counties	June 17, 2021
28	**Master Meter Tenant Kit Email**	**June 18, 2021**
29	**6/22 and 6/23 Wildfire Safety Webinar Email Invite – Organizations Supporting Customers with AFN**	**June 18, 2021**
30	June IP Warming Email: Consumer Protections (residential)	June 19, 2021
31	7/8 Wildfire Safety Webinar Email Invite – Alameda, Contra Costa and San Mateo Counties	June 24, 2021
32	June IP Warming Email: Consumer Protections (commercial)	June 26, 2021
33	7/15 Wildfire Safety Webinar Email Invite – Santa Clara and Santa Cruz Counties	June 30, 2021

Note: **Bold** denotes items actualized since last reporting (Q1 2021).

- **Informational Videos:** In 2020, PG&E developed a series of short (3-5 minute) and long-form videos (30 minutes) about the CWSP and PSPS programs that can be found at www.pge.com/pspsvideos and on PG&E's YouTube Channel at www.youtube.com/user/pgevideo. In 2021, PG&E is working to update these with the latest operational efforts.
  In Q1 2021, PG&E also began planning to create another 30-minute television program called "Responding to California's Changing Environment" which will highlight the shared challenges we all face along the Pacific Coast with climate change and what PG&E is doing to address these changes. In Q2 2021, PG&E continued to develop the program.

- **Social Media:** PG&E regularly provides customer preparedness resources through its official social media channels, including Twitter, Facebook, YouTube, Instagram and Nextdoor. Table 5 below summarizes posts, views, shares, and reach (impressions) recorded for wildfire preparedness social media.

TABLE 5
Q2 2021 SOCIAL MEDIA USAGE SUMMARY
(APR. 1 – JUNE 31, 2021)

Line No.	Social Media Platform	Posts	Shares or engagements	Reach (impressions)
1	Facebook	65	165	1,514,900
2	Instagram	26	2,153	76,352
3	NextDoor	46	3,516	4,666,191
4	Twitter	182	413	636,651

Some social media posts related to PSPS are translated into up to 15 languages. We continue to work with 38 multicultural media organizations and five CBOs to assist with in-language communications and share our social media posts before and during PSPS events.

Website Improvements

PG&E remains committed to the continuous improvement of its websites to better meet the diverse needs of its customers. As we launch new features and functionality to pge.com and pgealerts.alerts.pge.com, we ensure compliance with Web Content Accessibility Guidelines 2.0 AA standards. We also seek to improve the customer experience with user testing for key components.

In Q2 2021, improvements made to the PG&E website include:

- Enhanced the 7 Day PSPS Potential Forecast to improve customer awareness and understanding of upcoming events. Improvements include a more granular, county-based forecast which can be found at pge.com/pspsweather.
- Updated our PSPS preparation page with additional resources such as locating electrical vehicle charging stations at pge.com/pspsprep.
- Updated the in-language instructions on how to sign up for PSPS event information and notifications at pge.com/pspslanguagehelp.
- Improved access to AFN information and notifications enrollment on the Emergency Website PSPS Event homepage. Made the content part of large design pods to help it stand out further.
- Launched the Language Preference Campaign, enabling customers to select language preference for receiving PSPS and wildfire event notifications in 16 languages.
- Launched customer testing of the outage map on the Emergency Website to make the outage map more user-friendly, particularly in mobile view. Removed icons that were getting in the way of using the map on smaller phone screens. Tested microgrid language for the Emergency Website Address Lookup Tool to help improve comprehension.

Meetings with Key Stakeholders

PG&E regularly meets with key stakeholders including city/county/tribal officials, community groups and business associations. In 2021, meeting topics include additional information about PSPS mitigation efforts, local progress on wildfire safety measures and expanded resources available to prepare for PSPS events. So far, PG&E conducted meetings with approximately 68 individual stakeholders (including some meetings referenced throughout this report). A list of stakeholder meetings held since last reporting has been provided in Table 6 below.

TABLE 6
Q2 2021 STAKEHOLDER MEETINGS

Line No.	Event/Audience	Date
1	Wildfire Safety Webinar – Fresno, Kern and Tulare Counties	April 1, 2021
2	PG&E Annex Emergency Disaster and Preparedness Plan Discussion – North Area	April 5, 2021
3	U.S. Congressional Districts Webinar	April 6, 2021
4	Tehama County Coordination Committee	April 7, 2021
5	Virtual Safety Town Hall – Mendocino, Humboldt and Trinity Counties	April 7, 2021
6	PG&E Annex Emergency Disaster and Preparedness Plan Discussion – Central Area	April 7, 2021
7	Wildfire Safety Webinar – Madera, Mariposa and Tuolumne Counties	April 8, 2021
8	San Francisco Federal Executive Board Meeting	April 8, 2021
9	PSPS Advisory Committee	April 8, 2021
10	PG&E Annex Emergency Disaster and Preparedness Plan Discussion – South Area	April 9, 2021
11	PG&E Annex Emergency Disaster and Preparedness Plan Discussion – North Area	April 12, 2021
12	PG&E Annex Emergency Disaster and Preparedness Plan Discussion – Central Area	April 13, 2021
13	Plumas County Board of Supervisors	April 13, 2021
14	Lake County Board of Supervisors	April 13, 2021
15	City of Placerville	April 13, 2021
16	Oakmont Community	April 14, 2021
17	Wildfire Safety Webinar – Alpine, Amador and Calaveras Counties	April 15, 2021
18	PG&E Annex Emergency Disaster and Preparedness Plan Discussion – South Area	April 15, 2021
19	Rossmoor Community Meeting	April 15, 2021
20	Cobb Area Council	April 15, 2021
21	Disadvantaged Communities (DAC) Advisory Group	April 16, 2021
22	CPUC PSPS Workshop	April 20, 2021
23	Virtual Safety Town Hall – Solano, Yolo and Sacramento Counties	April 21, 2021
24	Cal OES Joint IOU Workshop	April 21, 2021
25	CARE Contractor Training	April 21, 2021
26	Wildfire Safety Webinar – El Dorado County	April 22, 2021
27	Disasters Don’t Wait	April 25, 2021
28	Forest Advisory Committee	April 26, 2021
29	Brentwood Senior Health and Safety Circus Resource Drive-Through	April 26, 2021
30	Corning City Council	April 27, 2021
31	Butte County Board of Supervisors	April 27, 2021
32	Wildfire Safety Working Session – Santa Clara County	April 27, 2021
33	Wildfire Safety Working Session – Lake County	April 27, 2021
34	Kern County	April 28, 2021
35	Cloverdale City Council	April 28, 2021
36	West Valley Mayors and City Managers	April 28, 2021
37	County General Services Administration (Day 1)	April 28, 2021
38	Fresno Area Agency Executives	April 28, 2021
39	Wildfire Safety Working Session – Yolo County	April 29, 2021
40	Wildfire Safety Working Session – Napa County	April 29, 2021
41	Wildfire Safety Working Session – Tuolumne County	April 29, 2021
42	Wildfire Safety Webinar – Solano and Yolo Counties	April 29, 2021
43	County General Services Administrators (Day 2)	April 28, 2021
44	Carmel Valley Homeowners Association	April 29, 2021

TABLE 6
Q2 2021 STAKEHOLDER MEETINGS
(CONTINUED)

Line No.	Event/Audience	Date
45	CPUC AFN Panel	April 30, 2021
46	Vallejo Senior Roundtable	May 3, 2021
47	King’s County Board of Supervisors	May 4, 2021
48	Wildfire Safety Working Session – El Dorado County	May 4, 2021
49	Anderson City Council	May 4, 2021
50	Yuba City Council	May 4, 2021
51	Lakeport City Council	May 4, 2021
52	Shasta County Board of Supervisors	May 4, 2021
53	Windsor Town Council	May 5, 2021
54	San Mateo County Emergency Managers Association	May 5, 2021
55	CWSP Deep Dive Series – Electric Grid, Part 1	May 5, 2021
56	Wildfire Safety Working Session – Sonoma County	May 5, 2021
57	San Luis Obispo County	May 5, 2021
58	Virtual Safety Town Hall – Mariposa, Tuolumne and Calaveras Counties	May 5, 2021
59	Marin Health	May 6, 2021
60	Mid County Democratic Club	May 6, 2021
61	Knights Ferry Pre-Fire Season Town Hall	May 6, 2021
62	Arroyo Grande Major Caren Ray Russom	May 6, 2021
63	Wildfire Safety Working Session – Mendocino County	May 6, 2021
64	Wildfire Safety Webinar – Nevada County	May 6, 2021
65	Stanford Healthcare	May 7, 2021
66	Wildfire Safety Working Session – Pit River Tribe	May 7, 2021
67	Jackson City Council	May 10, 2021
68	Ripon City Council	May 11, 2021
69	Mendocino County Board of Supervisors	May 11, 2021
70	Placerville City Council	May 11, 2021
71	CWSP Deep Dive Series – Electric Grid, Part 2	May 11, 2021
72	Cotati City Council	May 11, 2021
73	Yuba Fire Safe Council	May 12, 2021
74	Wildfire Safety Working Session – Amador County	May 12, 2021
75	PSPS Tabletop Workshop – South/Central Area	May 12, 2021
76	Wildfire Safety Webinar – Lassen, Plumas, Sierra and Tehama Counties	May 13, 2021
77	Santa Clara County Emergency Manager’s Association	May 13, 2021
78	Wildfire Safety Working Session – Madera County	May 14, 2021
79	Lafayette City Council	May 17, 2021
80	El Dorado County (Districts 1-5)	May 17, 2021
81	Wildfire Safety Working Session – Alpine and Calaveras Counties	May 17, 2021
82	Half Moon Bay City Council	May 18, 2021
83	Pismo Beach – 5 Cities Rotary Club	May 18, 2021
84	Sebastopol City Council	May 18, 2021
85	Red Bluff City Council	May 18, 2021
86	Glenn County Board of Supervisors	May 18, 2021
87	Wildfire Safety Working Session – San Luis Obispo	May 18, 2021
88	Sunol Citizens Advisory Council	May 19, 2021

TABLE 6
Q2 2021 STAKEHOLDER MEETINGS
(CONTINUED)

Line No.	Event/Audience	Date
89	Wildfire Safety Working session – Fresno County	May 19, 2021
90	Wildfire Safety Working Session – Solano County	May 19, 2021
91	Virtual Safety Town Hall – Placer, El Dorado and Alpine Counties	May 19, 2021
92	Silicon Valley Leadership Group Energy Committee	May 20, 2021
93	Atascadero Democrat Club	May 20, 2021
94	Wildfire Safety Webinar – Shasta County	May 20, 2021
95	Clearlake City Council	May 20, 2021
96	Wildfire Safety Working Session – Marin County	May 21, 2021
97	Wildfire Safety Working Session – City of San Jose	May 21, 2021
98	City of Berkeley	May 24, 2021
99	Wildfire Safety Working session – Stanislaus County	May 24, 2021
100	PSPS Full-Scale Exercise – South/Central Area	May 24, 2021
101	Solano County Board of Supervisors	May 25, 2021
102	Lassen County Board of Supervisors	May 25, 2021
103	Tehama County Board of Supervisors	May 25, 2021
104	All Customer Webinar – Spanish	May 25, 2021
105	Wildfire Safety Working Session – San Mateo County	May 25, 2021
106	Wildfire Safety Webinar – Humboldt, Mendocino, Siskiyou and Trinity Counties	May 26, 2021
107	All Customer Webinar – Chinese	May 26, 2021
108	Wildfire Safety Working Session – Kings County	May 26, 2021
109	California Cattlemen’s Association Wildfire Risk Workshop	May 26, 2021
110	Public Safety Partner PSPS Readiness Webinar – Telecommunications Providers	May 26, 2021
111	All Customer – Spanish (Fusion Latina Network)	May 27, 2021
112	Sonoma County Community Organizations Active in Disaster	May 27, 2021
113	Public Safety Partner PSPS Readiness Webinar – Community Choice Aggregators	May 27, 2021
114	San Joaquin County Pre-Season Heat Planning Meeting	May 27, 2021
115	Wildfire Safety Working session – Mariposa County	May 27, 2021
116	County of Santa Clara, Emergency Operational Area Council	May 27, 2021
117	WSPE Learning Series – Electric Grid Overview	May 28, 2021
118	Santa Barbara County Emergency Operational Area Council	June 2, 2021
119	City of Santa Maria	June 2, 2021
120	Virtual Safety Town Hall – All Customer	June 2, 2021
121	All Customer Webinar – Spanish	June 3, 2021
122	El Sobrante/Richmond Neighborhood Group	June 3, 2021
123	Atascadero Kiwanis Club	June 3, 2021
124	Wildfire Safety Webinar – Butte County	June 3, 2021
125	Town Talks with the Mayor of Danville	June 4, 2021
126	WSPE Learning Series – Remote Grids	June 4, 2021
127	City of San Ramon	June 4, 2021
128	Healdsburg City Council	June 7, 2021
129	San Francisco Airport Emergency Management Team and Airlines	June 8, 2021
130	San Mateo County Emergency Managers Association	June 8, 2021
131	Yuba County Board of Supervisors	June 8, 2021
132	Mariposa Board of Supervisors	June 8, 2021

TABLE 6
Q2 2021 STAKEHOLDER MEETINGS
(CONTINUED)

Line No.	Event/Audience	Date
133	Santa Rosa City Council	June 8, 2021
134	Chartwell’s Outage Conference	June 8, 2021
135	CPUC PSPS Preparedness Staff Briefing	June 9, 2021
136	City of Willits	June 9, 2021
137	Santa Barbara County Administrative Staff	June 9, 2021
138	Alameda County Office of Education	June 9, 2021
139	Regional Working Group – Central Valley	June 9, 2021
140	Regional Working Group – North Valley/Sierra	June 9, 2021
141	Mountain View Chamber of Commerce	June 9, 2021
142	Placer County Office of Education Safety Committee	June 9, 2021
143	Oakdale City Council	June 9, 2021
144	People with Disabilities and Aging Advisory Council	June 10, 2021
145	Wildfire Safety Webinar – Colusa, Glenn, Placer, and Yuba Counties	June 10, 2021
146	Middletown Area Town Hall	June 10, 2021
147	Wildfire Safety Working Session – Contra Costa County	June 10, 2021
148	Regional Working Group – North Coast	June 10, 2021
149	Regional Working Group – South Bay/Central Coast	June 10, 2021
150	Shasta County Office of Education – Safety Coalition	June 10, 2021
151	PSPS Advisory Committee	June 10, 2021
152	Regional Working Group – Bay Area	June 11, 2021
153	WSPE Learning Series – WMP	June 11, 2021
154	Wildcat Canyon Fire Group	June 14, 2021
155	City of Rio Dell	June 15, 2021
156	Angels Camp City Council	June 15, 2021
157	Calistoga City Council	June 15, 2021
158	Madera County Board of Supervisors	June 15, 2021
159	Western Region Town Hall	June 16, 2021
160	El Dorado County Meteorology Briefing	June 17, 2021
161	Southern Marin Area Disaster Council Summit	June 17, 2021
162	Senior Safety: It Takes a Community Symposium	June 17, 2021
163	Wildfire Safety Webinar – Lake County	June 17, 2021
164	WSPE Learning Series – Safety and Infrastructure Protections Teams	June 18, 2021
165	Lucerne Region Town Hall	June 18, 2021
166	Sonoma City Council	June 21, 2021
166	PSPS County and Tribal PIO Webinar	June 22, 2021
167	CWSP CBO Webinar	June 22, 2021
168	CWSP CBO Webinar	June 23, 2021
169	Colfax City Council	June 23, 2021
170	CPUC Enhanced Enforcement Public Workshop	June 23, 2021
171	Marin County Council of Mayors and Managers	June 23, 2021
172	Wildfire Safety Working Session – San Benito County	June 23, 2021
173	Wildfire Safety Working Session – San Francisco County	June 23, 2021
174	Santa Rosa Fire Department Meeting	June 24, 2021
175	Wildfire Safety Webinar – Napa County	June 24, 2021
176	Silicon Valley Council of Nonprofits and CADRE	June 25, 2021
177	WSPE Learning Series – CWSP Messaging Refresh	June 25, 2021
178	Wildfire Safety Working Session – Humboldt County	June 28, 2021
179	Public Safety Partner PSPS Readiness Webinar – Water Agencies	June 30, 2021
180	Wildfire Safety Webinar – Marin and Sonoma Counties	June 30, 2021

Note: Additional stakeholder meetings will be added as requests are received from cities, counties, tribal governments, critical customers and other key stakeholders.

Regional Working Groups

In Q3 2020, PG&E began hosting Regional Working Group meetings. Regional Working Groups provide an additional forum for communities impacted by PSPS events and PG&E to share lessons learned and discuss wildfire mitigation progress. These meetings address CPUC requirements from the PSPS Order Instituting Rulemaking (OIR) Phase 2 Decision, the Wildfire OII Settlement/Decision, and the Microgrid OIR Decision.

From June 9-11, PG&E hosted the second quarterly Regional Working Group meetings of 2021 with key stakeholders from communities impacted by PSPS events in each of the five regions of PG&E's service area: Central Valley, North Valley/Sierra, North Coast, South Bay/Central Coast and Bay Area (note that these regions were slightly adjusted from previous Regional Working Group meetings). These meetings provided participants and PG&E a forum to provide an update regarding regionalization efforts, share 2021 PSPS event improvements, discuss rotating outages and collaborate on best practices for local wildfire safety.

Please see Table 6 below for the Q2 2021 Regional Working Group schedule. Planning for the Q3 2021 Regional Working Group meeting is in progress.

TABLE 7
Q2 2021 REGIONAL WORKING GROUP MEETINGS

Line No.	Region	Counties	Date
1	Central Valley	Calaveras, Fresno, Kern, Kings, Madera, Mariposa, Merced, San Joaquin, Stanislaus, Tulare, Tuolumne	June 9, 2021
2	Sierra	Alpine, Amador, Butte, El Dorado, Lassen, Nevada, Placer, Plumas, Shasta, Sierra, Sutter, Tehama, Yuba	June 9, 2021
3	North Coast	Colusa, Glenn, Humboldt, Lake, Mendocino, Napa, Sacramento, Siskiyou, Solano, Sonoma, Trinity, Yolo	June 10, 2021
4	South Bay/ Central Coast	Monterey, San Benito, San Luis Obispo, Santa Barbara, Santa Clara, Santa Cruz	June 10, 2021
5	Bay Area	Alameda, Contra Costa, Marin, San Francisco, San Mateo	June 11, 2021

In addition to counties, the following stakeholder groups also attended these meetings: tribes, CCAs, critical facility representatives, representatives of AFN people/communities, the CPUC and others.

The Q2 2021 Regional Working Group meetings addressed the topics required under the CPUC's PSPS Phase II Decision,[8] specifically: lessons learned and feedback from prior PSPS events, communication strategies, information sharing and strategies for supporting customers and communities with AFN. The Q2 2021 Regional Working Groups also integrated topics from the Wildfire OII Settlement/Decision[9] directing utilities to conduct workshops to gather feedback on wildfire safety activities including issues raised by the local governments, action items to address identified issues and a progress report for previously identified action items. PG&E representatives participated in the meetings to answer questions and engage with meeting participants. Working group participants included representatives from tribal and local government entities, small multi-jurisdictional electric utilities, publicly owned electric utilities, communications and water service providers, public safety partners, the disabled, aging and AFN communities (e.g., directors of local Independent Living Centers) and CPUC staff. Meetings were structured to provide attendees with key information and metrics on the above topics and participants were encouraged to provide feedback, engage and collaborate with each other.

The feedback gathered during each Regional Working Group and subsequent participant survey helps to further inform our 2021 plans and local solutions to reduce PSPS impacts and wildfire risks. Additionally, we are continuing to engage with key stakeholders from each region through ongoing outreach efforts and upcoming Regional Working Groups. The third quarter Regional Working Group meetings of 2021 will be focused on PSPS weather and climatology analysis, local reliability statistics, microgrids and temporary generation and PSPS outage scenarios.

AFN Community Outreach

On February 1, 2021, PG&E filed its 2021 PSPS AFN Plan, which includes a summary of the research, feedback and external input that has shaped the AFN population support strategy before and during PSPS events, the programs that serve these customers, the preparedness outreach approaches that are focused on

8 D.20-05-051.

9 D.19-06-015, Exhibit C, p. 7.

vulnerable populations and the in-event customer communications that serve AFN populations.

PG&E continues to actively support and collaborate with the AFN community in multiple ways, including but not limited to:

Conducting External Feedback and Research: Through consultation with PG&E PWDAAC, Statewide IOU AFN Council, DAC Advisory Group, Low Income Oversight Board (LIOB), local government advisory councils and working groups, Communities of Color Advisory Group, as well as research directly with its customers.

Continuing Outreach for and Management of Ongoing Customer Support Programs: Such as the Disability Disaster Access Resources Program, PBP, Medical Baseline Program, Energy Savings Assistance Program, California Alternate Rates for Energy Program, Family Electric Rate Assistance Program, Tribal Engagement, Food Bank and Meals on Wheels Programs, Well Pump Generator Rebate Program, Self-Generation Incentive Program, CRC Program and 211 referral service.

Conducting Direct-to-Customer and Community Preparedness Outreach: Through written communications to customers (e.g., e-mails, fact sheets, flyers, brochures, signage), Medical Baseline program acquisition targeting using its newly developed propensity model to target Medical-Baseline eligible customers, providing master meter tenant education with both owners and tenants, engaging with the healthcare industry, conducting Wildfire Safety Open House webinars, broadcasting and posting educational videos, engaging with over 300 CBOs and multicultural media organizations, and making communications translated and accessible for people with disabilities.

Bolstering PSPS In-Event Customer Communications: PG&E continues improving customer notifications content, optimizing Medical Baseline customer contacts (including hourly retry process and door knocks), improving the quality and content of PGE.com, improving the dedicated CBO Liaison process, providing prompt customer contact center support, increasing media engagement, offering address-level alerts.

Working with CBOs and multicultural media organizations: PG&E engages with these partners to provide resources in a PSPS event, such as backup power solutions and communication for those with AFN. To date, PG&E has engaged with over 250 CBOs for information sharing and has secured contracts with 97 CBOs to provide additional resources to customers during PSPS events (e.g., portable battery provision, food replacement and translation services/event communications in indigenous languages).

PG&E filed its second quarterly 2021 PSPS AFN Progress update in July 2021. The progress report includes further information about the activities and progress of these various efforts. In addition, the 2021 WMP includes details on PG&E's AFN outreach strategies and tactics – see Sections 7.3.10.1, 8.2.4, and 8.4.

ii. The timeline for completion of the actions identified in (i);

Timing for each of these items is described above in Section i.

iii. Actions it completed in the previous quarter;

Details for each of these items are described in Section i.

iv. Actions planned for completion in the following quarter (Q3 2021), all dates provided are as of July 30, 2021, and subject to change.

TABLE 8
Q3 2021 STAKEHOLDER MEETINGS

Line No.	Event/Audience	Date
1	Supervisor Tom Wheeler Town Hall (Madera County)	July 1, 2021
2	El Dorado County Chamber of Commerce	July 1, 2021
3	Lawrence Berkeley National Labs	July 1, 2021
4	CPUC Staff PSPS Preparedness Briefing	July 2, 2021
5	Placer County Board of Supervisors	July 6, 2021
6	Winters City Council	July 6, 2021
7	Tri-Agency Fire Season Monthly Meeting	July 6, 2021
8	Angels Camp City Council	July 6, 2021
9	East Area Town Hall (Lake County)	July 7, 2021
10	Mendocino County Tribes Solar Suitcase and PSPS Resiliency Workshop	July 8, 2021
11	Regional Webinar – Alameda, Contra Costa and San Mateo Counties	July 8, 2021
12	El Dorado Hills Community Services District	July 8, 2021
13	Redwood Community Health Coalition Podcast (Lake County)	July 9, 2021
14	City of San Ramon	July 13, 2021
15	PSPS Tabletop Workshop – North Area	July 14, 2021
16	CA Rural Indian Health Board	July 14, 2021
17	Regional Webinar – Santa Clara and Santa Cruz Counties	July 15, 2021
18	WSPE Learning Series – Meteorology and Fire Science	July 16, 2021
19	City of Pleasanton	July 16, 2021
20	Amador County Chamber of Commerce	July 16, 2021
21	Sonoma County Board of Supervisors	July 20, 2021
22	El Cerrito City Council	July 20, 2021
23	El Dorado County Board of Supervisors	July 20, 2021
24	City of Dublin	July 20, 2021
25	Wildfire Safety Webinar – Merced, San Joaquin and Stanislaus Counties	July 22, 2021
26	City of Oakland	July 22, 2021
27	WSPE Learning Series – Wildfire System Hardening	July 23, 2021
28	PSPS Full-Scale Exercise – North Area (July 26 to July 30)	July 26, 2021
29	South Hills Community Group (Oakland)	July 27, 2021
30	CWSP CBO Webinar	July 27, 2021
31	Wildfire Safety Webinar – Monterey, San Luis Obispo and Santa Barbara Counties	July 29, 2021
32	City of San Rafael	August 2, 2021
33	Ione City Council	August 3, 2021
34	WSPE Learning Series – Sectionalizing	August 6, 2021
35	San Mateo County HealthCare Coalition	August 6, 2021
36	Cameron Park Community Services District	August 10, 2021
37	PSPS Advisory Committee	August 12, 2021
38	WSPE Learning Series – Substation and Distribution Microgrids	August 16, 2021
39	City of Fairfield	August 17, 2021
40	Morgan Hill City Council Briefing	August 18, 2021
41	Shasta County Commission on Aging	August 20, 2021
42	PSPS Advisory Committee	October 14, 2021
43	PSPS Advisory Committee	December 9, 2021

Note: Additional stakeholder meetings will be added as requests are received from cities, counties, tribal governments, critical customers and other key stakeholders.

TABLE 9
Q3 2021 CWSP/PSPS DIRECT-TO-CUSTOMER EMAIL/MAILING CAMPAIGNS

Line No.	Name of Direct-to-Customer Email or Mailing Campaign	Date
1	July Bill Insert – PSPS Resources	July 1, 2021
2	Master Meter Tenant MBL Awareness Letter (first deployment)	July 6, 2021
3	CBO Toolkit Email	July 6, 2021
4	Doctor's Portal Email	July 6, 2021
5	7/22 Wildfire Safety Webinar Email Invite – Merced, San Joaquin and Stanislaus	July 8, 2021
6	Master Meter Tenant Kit DM	July 8, 2021
7	Master Meter Tenant MBL Awareness Letter (second deployment)	July 9, 2021
8	7/27 Wildfire Safety Webinar Email Invite – Customers with Disabilities and AFN	July 13, 2021
9	7/29 Wildfire Safety Webinar Email Invite – Monterey, San Luis Obispo and Santa Barbara	July 15, 2021
10	MBL Acquisition Email	July 15, 2021
11	MBL Acquisition DM Part 1	July 16, 2021
12	July IP Warming Email – PSPS Resources & Tools (residential)	July 24, 2021
13	MBL Acquisition DM Part 2	July 30, 2021
14	July IP Warming Email – PSPS Resources & Tools (commercial)	July 31, 2021
15	PSPS Impact/Tree Overstrike Customer Email	July 31, 2021
16	PG&E Report It App Email	July/August TBD
17	PSPS Preparedness Brochures (General, AFN, Master Meter, Frequently Impacted, and Commercial)	August 1, 2021
18	August Bill Insert – Contact Info	August 1, 2021
19	CWSP Quarterly Progress Customer Email	August 16, 2021
20	August IP Warming Email – PSPS Safety (residential)	August 28, 2021
21	PSPS Frequently Impacted Customer Letter	August 31, 2021
22	September Bill Insert – Resources and PG&E Report It App	September 1, 2021
23	August IP Warming – PSPS Safety (commercial)	September 4, 2021

TABLE 10
Q3 2021 WILDFIRE SAFETY WEBINARS AND VIRTUAL SAFETY TOWN HALLS

Line No.	County/Audience	Date
1	Wildfire Safety Webinar – In-Language (Hmong)	July 6, 2021
2	Wildfire Safety Webinar – Alameda, Contra Costa and San Mateo Counties	July 8, 2021
3	Wildfire Safety Webinar – Santa Clara and Santa Cruz Counties	July 15, 2021[(a)]
4	Wildfire Safety Webinar – Merced, San Joaquin and Stanislaus Counties	July 22, 2021[(a)]
5	Wildfire Safety Webinar – Customers with Disabilities and AFN	July 27, 2021
6	Wildfire Safety Webinar – Monterey, San Luis Obispo and Santa Barbara Counties	July 29, 2021[(a)]
7	Wildfire Safety Webinar – All CBOs	TBD

(a) Dates subject to change.