PACIFIC GAS AND ELECTRIC COMPANY
QUARTERLY REPORT ON
2020 WILDFIRE MITIGATION PLAN FOR
MAY TO JULY 2020

SEPTEMBER 9, 2020

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CONDITION GUIDANCE-1

LACK OF RISK SPEND EFFICIENCY INFORMATION

Deficiency: 2020 Wildfire Mitigation Plan (WMP) submissions contain sparse and sporadic detail regarding the Risk Spend Efficiency (RSE) of WMP initiatives. RSE calculations are critical for determining whether utilities are effectively allocating resources to initiatives that provide the greatest risk reduction benefits per dollar spent, thus ensuring responsible use of ratepayer funds. Although RSE concepts have been considered for several years through California Public Utilities Commission (CPUC or Commission) General Rate Cases (GRC), utilities still display unrefined and limited abilities to produce such information. Considering that utilities propose to spend billions of dollars on WMP initiatives, not having quantifiable information on how those initiatives reduce utility ignition risk, relative to their cost, severely limits the Wildfire Safety Division's (WSD) ability to evaluate the efficacy of such initiatives and each utility's portfolio of initiatives, as outlined in 2020 WMPs.

Further, RSE is not an appropriate tool for justifying the use of Public Safety Power Shutoff (PSPS). When calculating RSE for PSPS, electrical corporations generally assume 100 percent wildfire risk mitigation and very low implementation costs because societal costs and impact are not included. When calculated this way, PSPS will always rise to the top as a wildfire mitigation tool, but it will always fail to account for its true costs to customers. Therefore, electrical corporations shall not rely on RSE calculations as a tool to justify the use of PSPS.

Condition: In its first quarterly report, each electrical corporation shall provide the following:

i. Its calculated reduction in ignition risk for each initiative in its 2020 WMP;

ii. Its calculated reduction in wildfire consequence risk for each initiative in its 2020 WMP; and

Pacific Gas and Electric Company (PG&E or the Company) has completed the calculated reduction in ignition risk and the calculated reduction in wildfire consequence risk for each initiative in its 2020 WMP. Please see Attachment 2020WMP_ClassB_Guidance-1_Atch01.[1]

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1 2020WMP_ClassB_Guidance-1_Atch01 contains an updated set of 5.3 tables from 2020WMP_ClassA_RCP_PGE-1_Atch01 (submitted with the Class A conditions).

iii. The risk models used to calculate (i) and (ii) above.

PG&E recognizes WSD's desire to have more clarity on the RSE information presented in the 2020 WMP. RSE is a useful tool to inform resource allocation across various initiatives to ensure a good use of dollars spent to achieve greater risk reduction. But there are other factors that go into decisions on how to allocate resources across activities or programs. As RSE methodologies mature, RSE will become a more useful tool for making resource allocation decisions.

As background, the 2020 WMP is the first presentation of PG&E's Wildfire Risk Assessment and Mitigation Phase (RAMP)/Risk model based on the Safety Model Assessment Proceeding (S-MAP) Decision (D.) 18-12-014, which is itself a precursor to the 2020 RAMP Report. Our 2019 risk efforts focused on aligning our wildfire risk assessment with D.18-12-014, and on overhauling program effectiveness to calculate RSEs. Our 2020 WMP calculated RSEs for our largest mitigation programs, specifically, our highest budget programs, such as Enhanced Vegetation Management (EVM) and System Hardening. Unfortunately, we were not able to calculate RSEs at the initiative level as presented in Section 5.3, mainly because programs and costs were not structured in the manner directed in the WSD Guidelines. In order to respond with more transparency, PG&E provided detailed workpapers (data, assumptions, methods and calculations) on program-specific RSE calculations in the 2020 RAMP Report. This is consistent with PG&E's letter on mitigation measures that cannot be disaggregated, submitted on July 13, 2020.[2]

Since Guidance-1 requires calculations of more RSEs at the initiative level, PG&E has re-reviewed each initiative to identify data and methodologies to compute risk reduction for these initiatives. While we believe many of the initiatives do not directly reduce ignition risk or wildfire consequence, many initiatives do. Our new initiative-specific Risk Reduction methodology and calculations are included in the updated Section 5.3 tables and the corresponding workpapers for details (see 2020WMP_ClassB_Guidance-1_Atch01 and 2020WMP_ClassB_Guidance-1_Atch02), accompanied by relevant Subject-Matter Expert (SME) judgment. This is consistent with D.18-12-014 Appendix A #31 ("SME judgment should be used if the methodologies

2 https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/About_Us/Organization/Divisions/WSD/2020%20PGE%20WMP%20Compliance%20Letter%20on%20Wildfire%20Mitigation%20Measures.pdf.

require use of data that is not available. Over time, SME judgment should be increasingly supplemented by data analysis as the methodologies mature.")

This filing attempts to show how risk reduction could be calculated even where there is a lack of data or direct attribution to the initiative. In some cases, we propose the approach we intend to use in our next WMP to: (1) present our overall thinking of the value the initiative provides, and (2) solicit direction about whether this thinking is consistent with WSD's view of the initiative's benefit. We would appreciate WSD's feedback on the Risk Reduction methodology presented versus the RSE value itself.

Below is a high-level overview of the methodologies undertaken for each section. Please note, the details of each methodology and calculation is presented in a series of attachments.

5.3.1 Risk Assessment and Mapping

Overall, the initiatives in this section do not directly reduce wildfire consequence risk. However, the point of these initiatives is to model and understand the variability between the probability of an ignition and the consequence when this occurs. This is extremely important in: (1) understanding the risk in our service territory, and (2) making better prioritization decisions, which are direct benefits of this risk assessment methodology.

In our current Wildfire model, PG&E separates out the 7,100 miles that are in scope to be hardened versus the remaining 18,300 miles in High Fire Threat District (HFTD) areas. Asset failure in these targeted lines is 2.75 times more likely compared to the remaining 18,300 miles, so it is appropriate to focus hardening mitigation efforts on the 7,100 higher risk miles, rather than hardening evenly across HFTD areas. Therefore, PG&E calculates the mitigated risk score of hardening in the higher risk tranche versus the mitigated risk scores where work is proportionally spread across HFTD areas. The difference between the two scores represents the benefits of using a risk assessment and mapping process (assuming that we implement the lower-risk options). Again, while the models themselves do not directly reduce ignition or consequence, having this information helps PG&E make informed choices in WMPs, prioritizing investments to address highest likelihood of failure or highest risk to ultimately reduce ignitions and wildfire consequences.

5.3.2 Situational Awareness and Forecasting

Overall, situational awareness and forecasting initiatives generally provide benefits in managing the likelihood of catastrophic outcomes, and help better predict the need for PSPS while limiting its impact on customers. Because the benefits of managing consequences is much harder to determine, PG&E solicited SME input and proxy data to represent the benefits of these activities. We believe investments in situational awareness provide enormous benefits through: (1) the reduction in the likelihood of an ignition leading to a destructive or catastrophic fire outcome, and (2) the reduction of PSPS impacts due to improved meteorological forecasts. PG&E agrees with WSD's position that RSE cannot be the sole tool to validate the use of PSPS, but this does explain how we plan to minimize PSPS impacts in the future.

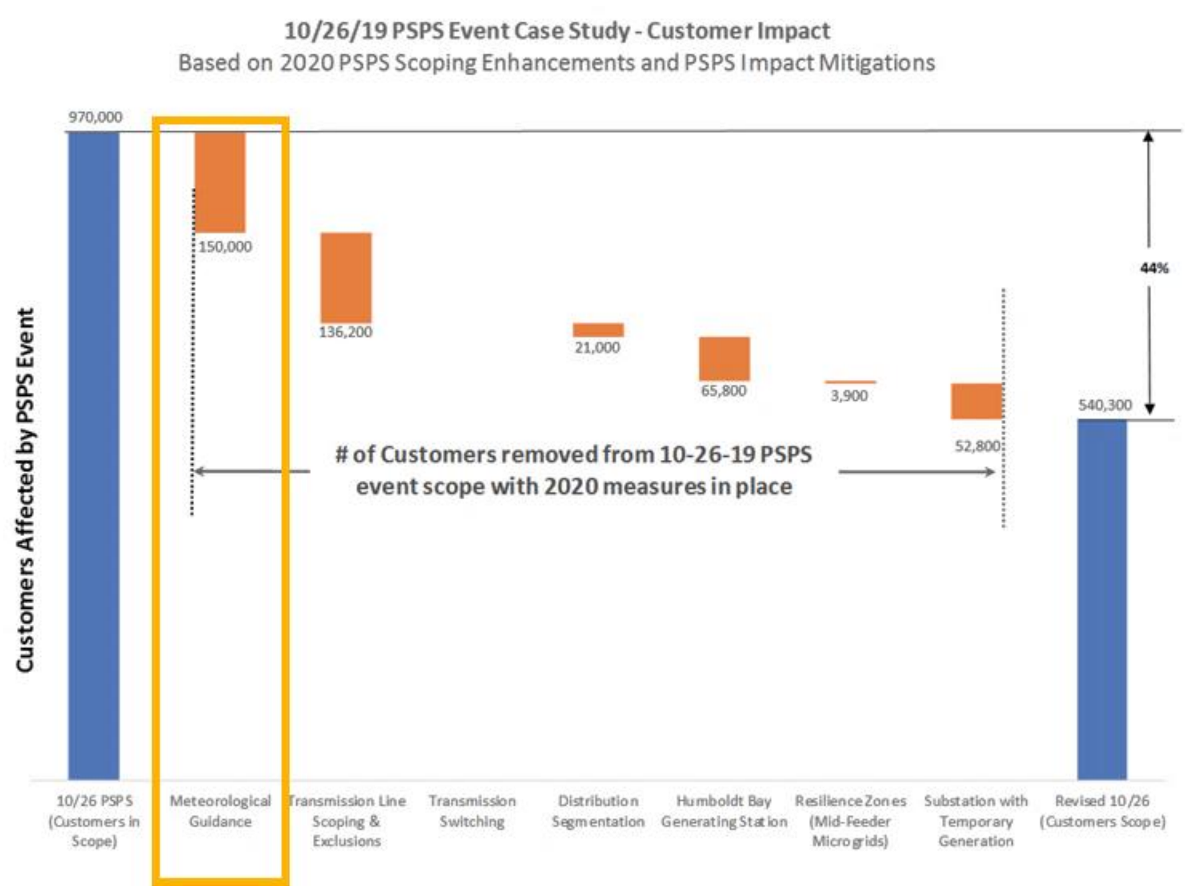
Better weather condition detection allows for better ignition prevention and faster ignition response, reducing the potential spread of a fire. Our weather tools also give local and state authorities access to our satellite detection and high definition (HD) camera tools. We have anecdotal but not quantitative evidence that better detection leads to reduced response time, so we have used SMEs to estimate the reduction in the likelihood of an ignition leading to a catastrophic or destructive fire. This analysis will show significant improvements in risk reduction but still depends on the assumption that various authorities proactively monitor and respond to any ignitions, including having sufficient firefighting resources to do so.

Based on PG&E's current analysis, less than 1 percent of ignitions lead to catastrophic fires. However, the likelihood of a large 300-acre fire of exponentially spreading and becoming catastrophic or destructive is closer to 70 percent, especially during Red Flag Warning (RFW) conditions. Using situational awareness tools to detect and respond to ignitions, the chance of a large fire becoming catastrophic or destructive drops significantly. Therefore, we estimate the likelihood of an ignition growing to a catastrophic or destructive fire as directly, inversely related to the amount of coverage of actively monitored HD cameras in HFTD areas (up to some level after which the incremental benefit of each additional camera falls). We do not anticipate continuing investment in new HD cameras, once our HFTD areas are adequately covered.

PG&E believes that many of our meteorological tool improvements are most effectively used together, and individual meteorology tools are less effective used alone than the synergy that results when they are used collectively. For this reason, we cannot differentiate between individual meteorology initiatives, so we present the benefits in unison and allocate them proportionally between our advanced fire modelling, improvements to Storm Outage Prediction Model, Weather Stations, and other meteorology guidance improvements. To show how meteorological guidance can minimize the scope of PSPS, we show how PSPS customer impact would be reduced based on various initiatives undertaken. The entire PSPS impact reduction is further presented in Workpaper 5.3.6 (see 2020WMP_ClassB_Guidance-1_Atch02).

As shown in the PSPS waterfall analysis below, PG&E attributes ~35 percent of benefit in reduction of customer impact to meteorological guidance improvements as compared to a 2019 PSPS event, or a 15.5 percent in customers impacted overall. Please keep in mind this PSPS waterfall analysis is still a draft and its impacts can vary from event-to-event.

FIGURE 1
PSPS WATERFALL – DRAFT, SUBJECT TO CHANGE



As described in Workpaper 5.3.6 (see 2020WMP_ClassB_Guidance-1_Atch02), PG&E models PSPS in two parts: (1) the benefits of avoided ignitions on the system during RFW conditions, and (2) the detriments of reliability to customers. As this meteorological guidance yields a more refined and granular PSPS scope, the initiatives in this section are focused on Part 2 of the PSPS modelling. Based on 30-year meteorological historical analysis, PG&E estimates approximately 5.4 PSPS events a year. For reliability, PG&E takes the average customer minutes interrupted based on 2019 values times the number of typical PSPS events per year of 5.4 to present the "risk score" of PSPS annually. In this case, meteorological guidance reduces the consequence of negative reliability by 15.5 percent based on the lookback case study of how 2019 would be different with improvements in PG&E's forecasting. With that, PG&E can estimate the effectiveness of these initiatives to calculate the risk reduction of the lessening of customers impacted by PSPS with these meteorological improvements. This, in turn, will provide higher overall effectiveness of the PSPS Program to mitigate wildfire risk, at the cost of investments to improve meteorological tools.

5.3.3 Grid Design and System Hardening

PG&E Control Activities and Risk Reduction

As context, PG&E manages a significant portion of its risk using controls. As defined in the CPUC's S-MAP lexicon, controls are currently established measures that modify risk, including operations, plans and standards, emergency response procedures, and other programs required by law or policy to operate our system. Controls are often associated with compliance requirements, particularly to meet federal rules (e.g., North American Electric Reliability Corporation (NERC) bulk power Vegetation Management (VM) and cyber-security requirements) and satisfy state regulations (e.g., CPUC operational standards such as basic asset management and rules for VM within HFTDs and worker qualifications).

Several control programs are important for wildfire risk reduction, particularly inspections, operations and maintenance (O&M), asset replacement and VM. We perform each of these activities at a standard level every year to assure that our electric system assets remain in suitable condition and perform at a minimally-appropriate level. By performing these programs at a basic level, we reduce reliability and wildfire safety risks by avoiding some basic level of equipment failures and associated outages and ignitions that might occur if we allowed the system to decay.

It is difficult to determine the wildfire risk level associated with these control programs for several reasons:

- We have been performing this work for so long that it is hard to estimate the counter-factual, (i.e., the consequences (number of equipment failures, outages and ignitions) that might occur if we were not performing these routine control activities;
- Since some level of this work is required by regulation and good utility practice, it is difficult to zero-base budget, benchmark against peer utilities, or otherwise determine the appropriate minimum level of effort and investment for these activities;
- As noted in our WMP and these deficiency conditions, we have been tracking program inputs (work hours and resources) and outputs (trees trimmed, inspections performed, circuit-miles replaced) as broad programmatic activities, rather than in more granular terms (although we are changing our budget, activity, and impact tracking going forward).

Over the past 5 years, as wildfire mitigation efforts became more crucial, PG&E began targeting our work through programs such as system hardening, inspections, and EVM to reduce the risk of catastrophic wildfires in HFTDs. These efforts have grown into many of the measures now recognized as elements of the CPUC's Wildfire Maturity Model (WMM), such as Grid design and system hardening and asset management and inspections.

Our control programs for asset repair, asset replacement and system hardening are designed to avoid equipment failures that could create ignitions. They have prevented potential failure and will prevent and mitigate the risk of future ignitions. We recognize WSD's desire to separate out the potential investments in system hardening from other asset replacement programs. However, both asset upgrade and system hardening may require upgrades to multiple assets to ensure the standards and factors of safety are met, with benefits replacing multiple complementary assets at the same time to ensure existing components do not cause a future ignition at a location that has had some elements hardened. Absent these control programs, we would expect to see additional asset failures and potential ignitions on PG&E's system.

To assess how much risk reduction these activities provide, we assume that some proportion of the number of repaired or replaced equipment each year would have failed within a year if the control program work had not been performed. As we presented in the 2020 RAMP Report, PG&E uses SMEs to estimate the chance of a tag/correction action activity causing a failure within 1 year to be 70 percent based on best judgment. We have developed a set of system hardening effectiveness estimates that represent the probability of each defined asset failing had it not been replaced under each initiative (e.g., conductor, pole, transformer failure rates per initiative sub-driver). We estimate initiative costs in a similar fashion. PG&E will continue to look for opportunities to better highlight the RSEs of each of these components as PG&E works with WSD on the appropriate items to track individually.

PG&E used the following logic to test the SME judgment that if an inspection-identified asset is not repaired or replaced, there is a 70 percent probability that the asset will fail within a year. Since Priority A tags are to be fixed immediately or at least within 30 days, and B tags categorization must be fixed within 90 days, we estimate that an asset that is fixed immediately would have otherwise failed between the time differential for correction of an A tag versus a B tag, or approximately 60 days. Assuming that an identified, unrepaired asset could fail within 60 days, we can annualize this to estimate that there is a 1.0 - (60/365) = ~84 percent chance of failure. Based on this assumption, PG&E believes that using a 70 percent chance of failure rate is reasonable (and perhaps somewhat conservative). We estimate the number of avoided ignitions expected per year to equal the number of repaired or replaced assets per year times the 70 percent chance of each asset creating a potential failure. This is compared to the actual number of ignitions related to the specific asset failure per year to estimate the Control Effectiveness of the maintenance program. For example, if PG&E replaces 150 transformers per year, 70 percent of those transformers (105 transformers) could have led to ignitions if they had not been replaced (meaning 105 potential ignitions that were avoided due to the Maintenance Control Program).

If PG&E experiences 10 ignitions due to transformers per year, we estimate the Control Effectiveness of the program as:

Control Effectiveness = (Potential Ignitions)/(Potential Ignitions + Realized Ignitions)

Control Effectiveness = (105) / (105 + 10) = 91.3 percent effective

- Control programs are not expected to reduce ignitions any further, but to set a baseline for effective ignition reductions. In this example, if we replace 150 transformers a year with an effectiveness of 91.3 percent, we may still have 10 additional transformer ignitions per year, despite avoiding potentially 105 ignitions. But it is difficult to estimate the likelihood of an asset failing within one year if it is not replaced, and our objective is to fix an asset problem before it fails and creates a larger problem. We recognize that increased investment in asset management programs may increase the effectiveness and further reduce the number of a set failures, outages and realized ignitions. On the other hand, a decreased investment in the program can potentially increase the number of ignitions seen on the system per year. We welcome conversations with peer utilities, the Commission and other experts on how to estimate the failure probabilities, consequences and risks associated with our control programs and enhanced wildfire initiatives.

5.3.4 Asset Management and Inspections

PG&E appreciates WSD's desire to evaluate the effectiveness of inspection programs overhaul. We summarize inspection program changes in the response to Condition PGE-15. Inspections by themselves do not reduce ignition risk or wildfire consequence; inspection effectiveness lies in the identification of potential asset failures and a better understanding of asset condition for asset maintenance and replacement planning. We estimate the risk reduction from inspection activities assuming that we act on the issues identified during inspection. PG&E welcomes additional feedback on better ways to present the risk reduction of inspection programs in absence of any other actions.

Similar to the methodology described above in Section 5.3.3, PG&E estimates the number of tags identified and corrected as a potential for a failure or outage that can lead to an ignition absent of its identification and correction. The likelihood that an inspection tag leads to an actual asset failure varies by priority type. Based on SMEs, we estimate that Priority A tags have a 70 percent chance of failure within 1 year, Priority B tags have a 50 percent chance of failure, and Priority E and F tags have a 1 percent chance of failure.[3] From this estimation of potential failure depending on tag priority, we estimate the number of avoided outages due to asset failure risk and estimate the probability of an outage leading to an ignition. With these steps, we can estimate the number of potential ignitions avoided through the process of inspection and asset repairs. Given the number of potential avoided ignitions, we can estimate control

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3 PG&E believes E and F tags are likely to fail at a rate higher than 1 percent per tag per year; however, because our Enhanced Inspection Program, in 2019 generated so many additional tags, we do not expect to be able to address all Priority E and F tags within 1 year, so the likelihood of an E tag generating a potentially avoided ignition is reduced significantly to 1 percent.

program effectiveness by comparing the number of ignitions seen due to assets versus potentially avoided ones that were identified through inspections and corrections.

To provide a hypothetical example, if PG&E has 1,000 A tags, 2,000 B tags, and 10,000 E tags, by multiplying these by the likelihood of avoided failure of 70 percent/ 50 percent/1 percent, respectively; we estimate that the inspection program with associated prompt repairs avoided (1,000*70 percent) + (2,000*50 percent) + (10,000*1 percent) = 1,800 potential outages. Assuming 2 percent of those potential outages would have led to ignitions, inspections would have identified 36 potential asset failures causing ignitions, and repaired or replaced the broken assets before the anticipated failure and ignition.[4] That then compares to the number of asset-related failures per year to get control effectiveness as described in Section 5.3.3.

Looking forward, depending on the cadence of the inspection process, we expect to see inspections produce fewer asset tags over time as more asset problems are found and remedied; this is reflected in lower tag rate forecasts for future years. As this is PG&E's first cycle of high asset inspection rates on a fast cycle cadence, we will refine tag "find rates" in the future. An additional benefit of the increased inspection cadence is that it will help us understand the change in asset condition over time, which was not known before 2019.

5.3.5 VM and Inspections

In this response, PG&E presents a methodology for evaluating the benefits of VM activities. This methodology is similar to that of Section 5.3.3. First, PG&E estimates the number of trees with work performed that will minimize the likelihood of a vegetation-caused outage or ignition. Vegetation-caused ignitions are one of the largest drivers of utility-caused wildfires, and the largest driver in HFTD areas. We estimate that 70 percent of the time, if identified vegetation is not worked, it can cause a power-line failure under high fire threat weather conditions.[5] Vegetation that is not actively managed can contact PG&E assets year-round, creating additional ignition

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4 2 percent of avoided potential outages represents outages that may lead to ignitions year round, and by inspecting and fixing this tagged equipment, we are improvement both customer reliability year round and preventing ignitions, highlighting the importance of control programs, which benefits both reliability and catastrophic wildfire prevention.

5 PG&E acknowledges that this number could be refined and welcomes feedback on better ways to estimate the likelihood that an unworked tree could cause a fault.

opportunities. We estimate that the vegetation-caused failure leads to ignitions in about 2 percent of all occurrences.

The same process to estimate a control effectiveness can be determined based on the process described in Section 5.3.3.

5.3.6 Grid Operations and Protocols

Effective grid operations and protocols pre- and post- event are essential for managing wildfire risk and PSPS impacts. This section offers two methodologies to recognize the benefits of ignition prevention from PSPS and the impacts of effective PSPS execution to minimize customer impact.

First, PSPS can lower ignition risk by de-energization during peak fire weather conditions. Before re-energization, patrols on de-energized lines identify damages and hazards caused by equipment failure and vegetation; these damages represent ignitions that could have occurred but for the PSPS de-energization. To estimate the number of potential ignitions avoided, we take the number of damages and hazards identified during pre-energization patrols and multiply this number by the outage-to-ignition rate during RFW conditions. In 2019, PSPS pre-energization patrols identified 727 damages and hazards, and the outage-to-ignition ratio based on historical data during RFW conditions was 7.65 percent. Applying the outage-to-ignition rate to the 727 identified damages yields an estimate of 56 ignitions avoided due to PSPS de-energization. Because there were still power line-caused ignitions that occurred during the same PSPS timeframe, but in other parts of the service territory that were not de-energized, PSPS is not 100 percent effective at preventing ignitions (i.e., a PSPS event only prevents utility-caused catastrophic fires where it de-energizes utility facilities). This portion of the methodology presents the benefits of PSPS in ignition reduction, especially and only during peak fire weather conditions.

Second, PSPS reduces customers' reliability. We can use the Customer Minutes Interrupted in 2019 to estimate PSPS reliability impacts, which offset the benefits from the ignition reduction. PG&E has already modified our PSPS programs extensively in order to reduce customer impacts in 2020 and beyond; we estimate that these improvements will cause 2020 PSPS events to affect about one-third fewer customers relative to equivalent events in 2019. We show this reduction with a PSPS Impact Reduction Waterfall chart, calculating how 2020 PSPS changes would have affected 2019 PSPS weather conditions. (See figure 'PSPS Waterfall.')

PSPS is a highly effective tool to reduce wildfire risk during peak wildfire conditions. However, while power shutoffs protect public safety from wildfires, they cause great inconvenience and cost for our customers and communities. PG&E agrees with WSD that RSE is not an appropriate tool in deciding whether and how to use PSPS. We execute PSPS purely to protect public safety from catastrophic wildfires, and we are working to minimize customer impact by making PSPS events shorter and smaller, as shown in the PSPS waterfall chart. We will continue to look for opportunities to minimize customer impact from PSPS events and invite feedback from WSD.

5.3.7 Data Governance

PG&E recognizes the importance of data governance to effectively manage wildfire risk. However, after thorough review, we have not been able to clearly associate ignition risk reduction or wildfire consequence reduction to data governance. PG&E considers data governance as fundamental to other initiatives. However, the data governance initiatives are very broad and their benefits cannot be directly linked to any specific program or initiative; this may become more clear as our data governance initiatives mature.

PG&E welcomes feedback on how data governance initiatives might be linked to ignition risk reduction and wildfire consequence.

5.3.8 Resource Allocation Methodology

As with data governance initiatives, resource allocation methodology initiatives do not directly reduce ignition risk or wildfire consequence. However, risk modelling and prioritization tools will allow us to make better decisions on where and how to deploy resources to reduce ignitions and wildfire consequences.

PG&E welcomes WSD feedback WSD on ways to identify and quantify the impacts of these initiatives.

5.3.9 Emergency Planning and Preparedness

PG&E recognizes the importance of emergency planning and preparedness to reduce the consequence of a wildfire event. Because it is difficult to measure quantitatively our improving level of preparedness year over year, we estimated the effectiveness of emergency planning and preparedness using qualitative methods. We believe that emergency planning and preparedness addresses the consequences of an ignition, rather than its probability. Qualitative methods categorize consequence programs into different activities which include replacements, engineered barriers, automated responses, or manual responses. In this case, emergency preparedness programs are considered a manual response activity (i.e., staff-initiated, rather than automated), which sets an effectiveness cap of the program. Because wildfire events can develop rapidly or gradually, each consequence type is categorized as such, rapidly for safety and financial, and gradually for reliability, and we estimate program effectiveness in managing wildfire consequence at 10 percent for rapid consequences, and 25 percent for gradual consequences. As background, our emergency preparedness and response program, together with our public safety partners, is designed to limit and slow the rate of fire spread once a fire begins. Fires once started under RFW conditions tend to grow very rapidly, and then their spread and consequences slow once firefighting and evacuation are underway. Therefore, we estimate program effectiveness is limited in decreasing wildfire consequence by a maximum of 10 percent for rapid fire consequences and a maximum of 25 percent for later gradual fire consequences.

Next, PG&E considers the maturity of the program and discounts its maximum effectiveness cap based on process-related questions such as sufficient staffing, guidance documents, etc. This further reduces the effectiveness of the program itself, reflecting the maturity of the control. In this case for Section 5.3.9, PG&E presents a growth in maturity of the emergency planning and preparedness program from 35 percent in 2019 to 53 percent by 2020. This maturity level is multiplied by the effectiveness cap to represent the control effectiveness. For example, the safety consequence has an effectiveness cap of 10 percent, with a maturity of 53 percent = 5.3 percent effective. Detailed categorizations are detailed in Workpaper 5.3.9 (see Attachment 2020WMP_ClassB_Guidance-1_Atch2).

5.3.10 Stakeholder Cooperation and Community Engagement

PG&E recognizes and values stakeholder cooperation and community engagement. We believe these are complementary activities that are embedded in and essential to all wildfire control and mitigation programs and cannot be separated out or conducted apart from our wildfire control and mitigation efforts. However, stakeholder and community engagement do not directly reduce ignition or wildfire consequence risk, so we consider their value as zero for risk reduction purposes. We welcome new insights about the benefits of these activities for wildfire risk reduction.

CONDITION GUIDANCE-2

LACK OF ALTERNATIVES ANALYSIS FOR CHOSEN INITIATIVES

Deficiency: 2020 WMP submissions contain little to no detail regarding utilities' process for comparing potential WMP initiatives. While most WMP initiatives are generally assumed to reduce utility wildfire risk, there are typically several alternatives that can address specific drivers of utility ignitions and near misses. However, 2020 WMPs generally do not include any discussion of which alternatives were considered, how the utility evaluated the efficacy of each alternative, and how the utility ultimately decided upon the suite of initiatives presented in its 2020 WMP.

Condition: In its first quarterly report, each electrical corporation shall provide the following:

i. All alternatives considered for each grid hardening or VM initiative in its 2020 WMP;

As discussed in PG&E's July 13 report to WSD[6] and other prior filings,[7] PG&E does not manage all of the WSD-listed initiatives as stand-alone programs. Further, while nearly all activities that impact PG&E's electric grid have some relationship to wildfire, a number of the WSD-defined initiatives were not created with a wildfire focus or are longstanding programs that existed for many years before the WMP.

The identification of "standard operations" from "augmented wildfire operations" is provided in the response to Guidance-6 below. PG&E does not have recently analyzed alternatives assessed for wildfire risk mitigation for several of the WSD-defined initiatives within the Grid Hardening (Section 5.3.3) and VM (Section 5.3.5) categories; our risk quantification, risk analysis and related tools continue to mature, as discussed in PG&E's response to condition Guidance-3 submitted on July 27. The following table outlines the general or specific alternatives PG&E considered related to the WSD-defined initiatives within the Grid Hardening (Section 5.3.3) and VM (Section 5.3.5) categories.

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6 "2020 WMP July 13 Submission on Combined Initiatives – PGE" submitted on July 13, 2020; available at: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/About_Us/Organization/Divisions/WSD/2020%20PGE%20WMP%20Compliance%20Letter%20on%20Wildfire%20Mitigation%20Measures.pdff

7 Including in our 2020 WMP at page 5-34 and in "Pacific Gas and Electric Company's Comments on Draft Resolutions WSD-002 and WSD-003 Regarding 2020 WMPs" filed on May 27, 2020.

TABLE 1
ALTERNATIVES IDENTIFIED FOR GRID HARDENING AND VM INITIATIVES

Grid Hardening or VM Initiatives	Alternatives Considered for 2020 WMP
5.3.3.1. Capacitor maintenance and replacement program	A pilot program to assess Capacitor bank failures and adjust replacement decision making or cycles accordingly may create alternatives or changes.
5.3.3.2. Circuit breaker maintenance and installation to de-energize lines upon detecting a fault	Limited alternatives considered for the 2020 WMP, technology evaluations underway related to system protection tools that may impact circuit breaker maintenance, operations and replacement.
5.3.3.3. Covered conductor installation	Alternatives considered as part of system hardening, see subpart iii of this response for discussion.
5.3.3.4. Covered conductor maintenance	Limited alternatives considered to existing maintenance practices as part of the 2020 WMP.
5.3.3.5. Cross-arm maintenance, repair, and replacement	Limited alternatives considered to existing maintenance practices as part of the 2020 WMP.
5.3.3.6. Distribution pole replacement and reinforcement, including with composite poles	Usage of non-wood pole materials has been and continues to be considered as an alternative within this program, non-wood poles may be deployed in appropriate, specific instances.
5.3.3.7. Expulsion fuse replacement	Alternatives considered by SMEs include which equipment to use when replacing existing, non-exempt fuses as well as pace of replacements.
5.3.3.8 Grid topology improvements to mitigate or reduce PSPS events	As a relatively new/revised program from 2019-2020 a number of alternatives or variations within this program were evaluated by SMEs in the development of these PSPS mitigation activities. Alternatives considered included: • Application of fire retardant to reduce risk of ignition during PSPS conditions, as discussed in subpart iii below; • Hardening analysis to exclude distribution segments from PSPS events (as discussed on page 5-124 of the 2020 WMP); • Trade-off between initiatives, for example, if a transmission line can be excluded from PSPS then substation temporary generation is not needed; mid-feeder microgrids may diminish the need for a substation temporary generation solution; and • Operational alternatives, including how to stage generators to support substations and microgrids during a PSPS event, etc. Overall, given the recent changes to this initiative, PG&E has continued to refine our implementation of these programs in 2020 and will continue to learn from the actions implemented in 2020 and adjust/revise going forward.

TABLE 1
ALTERNATIVES IDENTIFIED FOR GRID HARDENING AND VM INITIATIVES
(CONTINUED)

Grid Hardening or VM Initiatives	Alternatives Considered for 2020 WMP
5.3.3.9. Installation of system automation equipment	New technology evaluations considered for the 2020 WMP and remain underway related to system protection tools and coordination.
5.3.3.10. Maintenance, repair, and replacement of connectors, including hotline clamps	Limited alternatives considered to existing maintenance practices as part of the 2020 WMP.
5.3.3.11. Mitigation of impact on customers and other residents affected during PSPS event	N/A – Discussed in Section 5.3.3.8, above.
5.3.3.12-1. Other corrective action	Limited alternatives considered to generally existing programs as part of the 2020 WMP.
5.3.3.13. Pole loading infrastructure hardening and replacement program based on pole loading assessment program	As discussed on page 5-134 of the 2020 WMP, PG&E is updating our pole loading program based off a 2019 proof of concept. A number of considerations and decisions have been and continue to be evaluated and made by SMEs.
5.3.3.14. Transformers maintenance and replacement	Limited alternatives considered to existing maintenance practices as part of the 2020 WMP.
5.3.3.15. Transmission tower maintenance and replacement	2020 WMP approach informed by the 2019 Wildfire Safety Inspection Program (WSIP), which involved a number of alternatives, including: performing climbing inspections or ground-based, leveraging aerial/drone inspections of tower in addition, etc.
5.3.3.16. Undergrounding of electric lines and/or equipment	Decision-making regarding alternatives, namely undergrounding assets or installing covered/hardened overhead, is generally performed at the individual project level.
5.3.3.17-1. Updates to grid topology to minimize risk of ignition in HFTDs - System Hardening, Distribution	As noted immediately above, decision-making regarding alternatives, namely undergrounding assets or installing covered/hardened overhead, is generally performed at the individual project level.
5.3.3.17-2. Updates to grid topology to minimize risk of ignition in HFTDs - Surge Arrestor, Distribution	Alternatives considered by SMEs include which equipment to use when replacing existing, non-exempt surge arrestors, as well as pace of replacements.
5.3.5.1. Additional efforts to manage community and environmental impacts	No material alternatives considered, PG&E pursues continuous improvement and adjustments in community and environmental processes.
5.3.5.2. Detailed inspections of vegetation around distribution electric lines and equipment	Except for continuous improvements, limited alternatives considered as part of the 2020 WMP.
5.3.5.3. Detailed inspections of vegetation around transmission electric lines and equipment	Except for continuous improvements, limited alternatives considered as part of the 2020 WMP.
5.3.5.4. Emergency response VM due to RFW or other urgent conditions	Except for continuous improvements, limited alternatives considered as part of the 2020 WMP.

TABLE 1
ALTERNATIVES IDENTIFIED FOR GRID HARDENING AND VM INITIATIVES
(CONTINUED)

Grid Hardening or VM Initiatives	Alternatives Considered for 2020 WMP
5.3.5.5. Fuel management and reduction of “slash” from VM activities	Alternatives evaluated by SMEs during the development of the EVM Program of the last few years include: performing fuel reduction work at the same time and locations as EVM work, increased or decreased annual volume of work, different scope of fuel management including creating fuel breaks vs. directly under powerlines, etc. Assessment of alternatives has largely been driven by feasibility of implementation.
5.3.5.6. Improvement of inspections	N/A – Improvements relate to other initiatives, no alternatives identified.
5.3.5.7. Light Detection and Ranging (LiDAR) inspections of vegetation around distribution electric lines and equipment	Primary alternative is increased or decreased scope of data gathering; additional consideration is the level and type of analysis performed with the data.
5.3.5.8. LiDAR inspections of vegetation around transmission electric lines and equipment	Primary alternative is increased or decreased scope of data gathering; additional consideration is the level and type of analysis performed with the data.
5.3.5.9. Other discretionary inspection of vegetation around distribution electric lines and equipment, beyond inspections mandated by rules and regulations	Alternatives evaluated by SMEs include continuation of additional inspections as part of Catastrophic Event Memorandum Account (CEMA) Program.
5.3.5.10. Other discretionary inspection of vegetation around transmission electric lines and equipment, beyond inspections mandated by rules and regulations	N/A – No work scope in the initiative.
5.3.5.11. Patrol inspections of vegetation around distribution electric lines and equipment	N/A – No work scope in the initiative.
5.3.5.12. Patrol inspections of vegetation around transmission electric lines and equipment	N/A – No work scope in the initiative.
5.3.5.13. Quality Assurance (QA)/Quality Control (QC) of inspections (Enhanced, Routine, and CEMA)	Primary alternative is increased or decreased scope of quality reviews (increased or decreased sampling), in addition to continuous improvement and adjustments to processes and tools.
5.3.5.14. Recruiting and training of VM personnel	Additional approaches to recruiting and training personnel under development including those discussed in response to Condition PG&E-25 submitted on July 27.

TABLE 1
ALTERNATIVES IDENTIFIED FOR GRID HARDENING AND VM INITIATIVES
(CONTINUED)

Grid Hardening or VM Initiatives	Alternatives Considered for 2020 WMP
5.3.5.15. Remediation of at-risk species – EVM	As a new program started in 2018 a number of alternatives or variations within this program have been evaluated by SMEs. Alternatives considered include: • Analysis of interaction between system hardening (covered conductor) and VM; • Scope of the EVM Program including the width of the overhang clearing zone (currently set at 4 feet); • Population of tree species and/or characteristics to be identified for work (currently defined by the Tree Assessment Tool (TAT) criteria); and • Relationship of this work to fuel reduction activities below the conductor (Section 5.3.5.5). PG&E has continued to refine our processes, tools and implementation of EVM and will continue to learn and adjust/revise going forward.
5.3.5.16. Removal and remediation of trees with strike potential to electric lines and equipment, Transmission	Similar to EVM immediately above, various scope alternatives and considerations with the Transmission Right-of-Way (ROW) Expansion Program have been evaluated by the SMEs.
5.3.5.17. Substation inspections – Enhanced Substation Maintenance Vegetation	Limited alternatives identified related to the maintenance program scope for 2020.
5.3.5.18. Substation VM	N/A – Initiative is captured within 5.3.5.17.
5.3.5.19. Vegetation inventory system	For the 2020 WMP limited alternatives considered, PG&E is pursuing continual improvements, adjustments and enhancements to this software system and related computer systems. Long-term alternatives considered include different software packages and implementation approaches.
5.3.5.20. VM to achieve clearances around electric lines and equipment	Except for continuous improvements, limited alternatives considered as part of the 2020 WMP for maintaining compliance clearances.

ii. All tools, models, and other resources used to compare alternative initiatives;

When PG&E was initially developing the EVM and System Hardening programs in late 2018, we used the risk-spend-efficiency analysis provided in the Attachment 2020WMP_ClassB_Guidance-2_Atch01 (this attachment was also provided in the 2019 WMP process as a response to a data request and numbered "WildfireMitigationPlans_DR_TURN_003-Q13".) As shown primarily on pages 8-11 of that attachment, we reviewed the projected effectiveness of several possible mitigation types and the costs associated with each (in the form of the "frequency reduction value" on page 11). These frequency reduction values were one input into our decision-making for our initial alternatives analysis, along with SME input on implementation capability and efficiency, cost, schedule and other variables.

Since that time, we have further analyzed additional alternatives, including several which are presented in the response to subpart iii below. PG&E's analysis of these alternatives followed the process outlined in PG&E's RAMP Report. In particular, based on PG&E's development of the Wildfire RAMP Risk models, analysis of the largest drivers of ignition were determined to help build out wildfire mitigations to consider. PG&E built its WMPs based on this analysis. In 2019-2020, PG&E further refined its second-generation RAMP Risk model to provide better insight into the sub-drivers, with further tranching based on service territory and various outcomes depending on weather conditions and potential of fire spread. With this model and further alternative analysis, PG&E will consider other, alternative initiatives as we refine our portfolio of WMPs. PG&E provided alternative analyses on the potential benefits of pilot programs like remote grid and fire retardants, as well as alternative scopes and/or levels of system hardening in our 2020 RAMP Report.

For a number of other programs within the grid hardening and VM categories where analysis of alternatives is not captured in the evaluation tools noted above, we used SME judgment to evaluate alternatives and select the appropriate programs to pursue. SME decisions were based on a number of factors, including: their perspective on the greatest risk reduction, their understanding of our system, the tools and processes already in place, and the feasibility of execution and implementation to determine what actions could reduce the most risk as rapidly as possible.

iii. How it quantified and determined the risk reduction benefits of each initiative; and

The attachment titled 2020WMP_ClassB_Guidance-2_Atch01 outlines the analysis performed in 2018 during the initial development of EVM and system hardening programs. Additionally, for the 4 alternatives presented in the 2020 RAMP Report, here is a summary of how risk reduction benefits were determined.

1) Remote Grid: The program focuses on decentralizing energy resources to permanently supply energy to certain remote customers instead of maintaining traditional utility infrastructure. In this case, recognizing the reduction in the number of miles of utility lines (essentially risk on the system), while still meeting the needs

of the customer by providing an alternative source of energy, was considered an additional wildfire mitigation to be included in PG&E's portfolio. The reduction in the number of miles on the system essentially eliminates the risk of wildfire ignitions on those miles for a small capital investment. PG&E believes in limited cases this can provide a very high RSE, while providing minimal impact to the customer. PG&E continues to evaluate and re-assess the effectiveness of such programs.

2) Fire Retardant: PG&E recognizes that fully eliminating ignitions from PG&E territory is not feasible or cost effective. Equipment failures occur during adverse weather conditions, such as storms, wind, and/or heat. In this case, PG&E is exploring the use of long-term commercially-available fire retardants to pre-treat ROWs and around equipment in select locations to limit a spark from causing an ignition that could have a potential of spread during the fire season and potentially minimizing PSPS. As shown in the PG&E's risk assessment of wildfire, the highest risk comes from the low likelihood, high consequence events of an ignition with fire spread, especially during RFW conditions, which have the highest safety risk and can cause the most destruction. This pre-treatment can limit the spread of fires to limit the impact to customers and structures. As the fire retardant would limit any spark, regardless of cause (equipment failure, vegetation, animal, etc.), the cost of applying fire retardant ahead of fire season can potentially be very effective in respect to RSEs. PG&E continues to explore this WMP, but understands there are regulatory and environmental challenges. As this cannot be deployed immediately, PG&E will continue to explore the potential of this "fail safe" alternative.

3) System Hardening Hybrid: PG&E recognizes that there are limitations of the number of miles that can be hardened. Recognizing risk reduction is not only dependent on the effectiveness of a program, but also the scope, PG&E considered alternatives to the System Hardening Program. PG&E continues to believe that full system hardening in the highest risk circuits is effective, but is looking for alternatives to apply other forms of hardening to our system, especially in certain parts of the HFTD areas. In order to develop more risk reduction on the system, PG&E has evaluated a System Hardening Hybrid Program that is less effective in mitigating various sub-drivers of equipment failure, but can be deployed more quickly and at lower cost to provide further risk reduction. These alternatives have favorable RSEs, though they reduce risk less per-mile-implemented, as compared

to the System Hardening Program. This is detailed in the 2020 RAMP Report Workpaper 'EO-WF-26_Alternative Mitigation Effectiveness.'

4) Wildfire Targeted System Upgrades: Similar to the System Hardening Hybrid, this is an even lighter version of hardening or firming to be considered complimentary to the System Hardening Program, as PG&E recognizes that there are limitations to the miles of system hardening that can be executed on an annual basis. This alternative focuses on minimizing potential sparks from equipment on the pole. It does not include covered conductor. There are areas in HFTDs that may not have vegetation near PG&E distribution lines that might strike conductors, so full system hardening may not be effective in that situation.

iv. Why it chose to implement each initiative over alternative options.

PG&E chose to implement specific initiatives over alternatives through a few different processes at various points in time:

1) The initial decisions about the scope for EVM and system hardening were made using the analysis provided in Attachment 2020WMP_ClassB_Guidance-2_Atch01.pdf. In short PG&E selected the scope for those programs based on the activities within that analysis that had the best (lowest) Frequency Reduction Value (a similar calculation to RSE or cost-benefit).

2) As described subpart iii above, additional alternatives to certain programs were assessed as part of the RAMP process, but were ultimately not chosen for implementation, primarily based on SME evaluation that they were not as effective and efficient as the selected program scopes. Additionally, in some cases these alternatives have limitations in applicability that make them potential future compliments to existing programs. For example, Remote Grids are only feasible in some locations and Fire Retardant applications have environmental permitting considerations that may prevent near-term, widespread deployment.

3) For the remaining initiatives beyond the primary system hardening and EVM workstreams, the decisions related to implementing PG&E's chosen actions within the WSD-defined initiatives over the alternatives noted above has been based on SMEs. SME decisions were based on multiple factors, including: the understanding of our staff regarding how our systems work, the tools already in

place, and what can be implemented quickly to reduce the most risk as rapidly as possible.

CONDITION GUIDANCE-4

LACK OF DISCUSSION ON PSPS IMPACTS

Deficiency: Across 2020 WMP submissions, utilities indicate goals of reducing the scope, frequency and duration of PSPS events, but also indicate intentions of continuing to implement PSPS as a wildfire mitigation measure in the immediate future. Considering the rapid expansion of PSPS use as a wildfire mitigation measure, and the numerous hardships, inconveniences, and hazards created by its vast implementation, it is concerning that 2020 WMPs provide no discussion of how the chosen portfolio of initiatives will allow the utility to achieve its goals for reducing PSPS impacts. Specifically, no 2020 WMPs discuss the relationship between various grid hardening, VM, and asset management initiatives and the corresponding impacts on thresholds for initiating PSPS events.

Condition: In its first quarterly report, each electrical corporation shall detail whether and how each initiative in its WMP:

i. ***Affects its threshold values for initiating PSPS events;***

ii. ***Is expected to reduce the frequency (i.e., number of events) of PSPS events;***

iii. ***Is expected to reduce the scope (i.e., number of customers impacted) of PSPS events;***

iv. ***Is expected to reduce the duration of PSPS events; and***

v. ***Supports its directional vision for necessity of PSPS, as outlined in Section 4.4 of its WMP.***

For all of the above subparts, PG&E has provided the requested information in the updated Section 5.3 Tables, please see Attachment 2020WMP_ClassB_Guidance-1_Atch01.[8] The data responsive to these questions provided in the updated Tables is specific to each individual initiative. Where an initiative does not, by itself, contribute to these improvements in PSPS in 2020 they have been noted as "no direct impact", even if the initiative may support or complement another initiative that does, in fact, result in reduced PSPS impacts. Note that some initiatives listed as "no direct impact" for 2020 do have details regarding how they may support the long-term direction for PSPS events in a separate column.

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[8] 2020WMP_ClassB_Guidance-1_Atch01 contains an updated set of 5.3 tables from 2020WMP_ClassA_RCP_PGE-1_Atch01 (submitted with the Class A conditions).

Additionally, note that subparts i (PSPS threshold), ii (frequency of events), and iii (scope of events) are very closely related or even the same concept. For example, if an initiative improves the PSPS threshold for a particular section of line, then it may require fewer PSPS events, which also means fewer customers were impacted by a PSPS event. Therefore, in many cases the same detail is provided for the responses to subparts i, ii, and/or iii within the attachment; however, we attempted to focus, where possible, on the primary benefit of the initiative between those responses.

CONDITION GUIDANCE-5

AGGREGATION OF INITIATIVES INTO PROGRAMS

Deficiency: In their 2020 WMP submissions, electrical corporations often combine various initiatives into broader programs and report cost, risk, and other related data at the program level. This aggregation of initiatives and bundled reporting creates several issues.

First, because cost data is typically reported across programs and not individual initiatives, it is not possible for the WSD to evaluate the efficacy of each initiative.

Second, when initiatives are bundled and reported together as programs, it prevents WSD from being able to assess which initiatives are effectively reducing utility wildfire risk. Consequently, this creates the challenge that ineffective elements of broad programs cannot be determined and future considerations of initiatives within programs can only be done collectively.

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

i. ***Break out its programs outlined in Section 5.3 into individual initiatives;***

ii. ***Report its spend on each individual initiative;***

v. ***Provide the information required for each initiative in Section 5.3 of the Guidelines.***

Attached as "2020WMP_ClassB_Guidance-1_Atch01"[9] are the updated tables from Section 5.3 of the 2020 WMP Templates (Tables 21-30) referenced jointly as "Tables," which includes PG&E's programs broken out into individual initiatives as defined by the WSD, the updated spend information for each individual initiative, and the information required for each initiative in Section 5.3 of the Guidelines.

With regard to the updated spend data for each individual initiative, the original method PG&E used for mapping costs to the initiatives was based upon how PG&E typically tracks costs and files for cost recovery in rate cases at the Maintenance Activity Type (MAT) code level. As PG&E has commented previously (in discussions with the WSD before the 2020 WMP submission date, in our 2020 WMP, in our comments on the Draft Resolutions, and in our July 13 Letter on programs that cannot be disaggregated), PG&E does not have these MAT codes and work activities organized by the WSD-defined initiatives. Given the direction provided in this condition, PG&E has undertaken analyses to estimate the cost, risk reduction benefit, and other details

9 2020WMP_ClassB_Guidance-1_Atch01 contains an updated set of 5.3 tables from 2020WMP_ClassA_RCP_PGE-1_Atch01 (submitted with the Class A conditions).

for each WSD-defined initiative. The methodologies used to estimate these details by WSD-defined initiatives are described below.

In general, due to how granular the list of WSD-defined initiatives is, PG&E leveraged approach #1 below (SMEs) to disaggregate individual initiatives from larger buckets of spend and map costs to the initiative level. Therefore, some of the actual and forecasted amounts in the tables will be different from the Section 5.3 tables provided in the initial filed 2020 WMP. Additionally, some initiatives are related to efforts or work activities that are not tracked in any budget or MAT code. To estimate the costs associated with these WSD-defined initiatives, we leveraged Approach #2 below, looking at employee effort level tracked within a Provider Cost Center (PCC).

- Methodologies described:
  1) PG&E compiled feedback from numerous SMEs and program owners to gather more granular data at detailed levels (including the notification level showing location and asset type) to inform how to disaggregate costs from larger programs and estimate the appropriate costs to assign to each individual WSD-defined initiative as laid out in the WMP templates.
  2) For any employee effort-driven activities or initiatives in which we do not separately track a budget or MAT code, we analyzed personnel costs within PCCs to quantify the effort, and therefore approximate costs associated with that WSD-defined initiative. PG&E again compiled feedback from various SMEs and program owners to vet any assumptions needed to analyze the PCC costs to create these cost estimates by WSD-initiative. Furthermore, the PCC costs captured for this exercise are primarily treated as “overheads” in PG&E’s cost model. These costs differ from costs captured in “programs” in that these types of overhead costs are not explicitly charged to specific orders or programs. Instead, these types of costs flow through our cost model and get captured downstream in our final MAT code recorded costs via overhead allocation mechanisms.

iii. Describe the effectiveness of each initiative at reducing ignition probability or wildfire consequence;

PG&E has described the effectiveness of each initiative at reducing ignition probability or wildfire consequence, please see Attachment 2020WMP_ClassB_Guidance-1_Atch01.

iv. List all data and metrics used to evaluate effectiveness described in (iii), including the threshold values used to differentiate between effective and ineffective initiatives; and

In Attachment 2020WMP_ClassB_Guidance-1_Atch01 and the associated RSE workpapers, where the effectiveness is able to be determined, PG&E has provided a list of data and metrics used to evaluate the effectiveness of the initiative at reducing ignition probability or wildfire consequence. Additionally, the outcomes PG&E is anticipating from each initiative are provided in the "Outlining Outcomes" column of the updated Section 5.3 tables in the Attachment 2020WMP_ClassB_Guidance-1_Atch01. Some of these outcomes can currently be quantified with data, including those that reference outage or ignition data, while others are only qualitative in nature. As PG&E continues to mature our risk modeling and data management processes, we will increase the quantitative nature of this evaluation for those initiatives where a quantitative assessment would be appropriate.

However, as noted previously, many WSD-defined initiatives do not have a unique, direct influence on reducing ignition probability or wildfire consequence. Therefore, PG&E's assessment as to the effectiveness of initiatives is primarily based on SME judgment as quantitative "thresholds" for assessing effectiveness have not been established for initiatives to date. SMEs assess the effectiveness of initiatives in supporting wildfire risk reduction, either individually or in combination with other activities, and determine the need for changes or adjustments to wildfire initiatives, including increases, decreases, or other adjustments to initiative scope.

CONDITION GUIDANCE-6

FAILURE TO DISAGGREGATE WMP INITIATIVES FROM STANDARD OPERATIONS

Deficiency: While WMPs are designed to outline and detail filer's plans and initiatives for mitigating wildfire risk, many existing programs also provide wildfire risk reduction benefits. For example, General Order (GO) 165 requires annual patrol inspections and detailed inspections every five years for electrical infrastructure. These programs and initiatives are often referenced in 2020 WMPs as "supporting," "routine," "enabling," "standard," or "foundational" work. For these types of programs, in most cases, electrical corporations do not report cost or risk reduction data, as the work is considered part of their electric operations and it is indicated that this information is not tracked independently. Several electrical corporations state that their programs for inspecting and maintaining crossarms, poles, transformers, transmission towers and similar infrastructure, which also reduce wildfire risk, are embedded within standard maintenance programs litigated in GRCs.

Consequently, it is difficult to determine whether and how these programs incrementally impact wildfire risk reduction or if related WMP initiatives are redundant and unnecessary. While utilities may not have historically considered the costs and effectiveness of such programs and initiatives, given that numerous WMP initiatives have apparent overlap or potential redundancy, it is imperative that utilities provide such data to validate the need for and effectiveness of additional programs.

It is not clear how electrical corporations are tracking their WMP activities in memorandum accounts if they do not budget for them by type of initiative. The Commission will scrutinize electrical corporations' memorandum accounts for WMP carefully, and if all costs are simply lumped together or included in general O&M accounts, electrical corporations risk failing to provide entitlement to cost recovery.

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

i. ***Clearly identify each initiative in Section 5.3 of its WMP as "Standard Operations" or "Augmented Wildfire Operations;"***

ii. ***Report WMP required data for all Standard Operations and Augmented Wildfire Operations;***

PG&E has identified each initiative in Section 5.3 of its WMP as either "Standard Operations" or "Augmented Wildfire Operations" as instructed and reports WMP required data; please see Attachment 2020WMP_ClassB_Guidance-1_Atch01.[10]

iii. ***Confirm that it is budgeting and accounting for WMP activity of each initiative; and***

As described in PG&E's 2020 WMP and referenced in our July 13 letter to the WSD, many of the initiatives identified by the WSD in the 2020 WMP Guidelines are part of a larger program. Many of PG&E's wildfire-related programs and initiatives have been in place for years and PG&E cannot completely re-classify these programs and initiatives from an accounting perspective; however, as described briefly in the July 13 letter, and then in more depth in the response to Condition Guidance-5, PG&E has undertaken an analysis to isolate the costs associated with each initiative within the updated Tables provided.

iv. Include a "ledger" of all subaccounts that show a breakdown by initiative.

In alignment with consultation with WSD staff on what information would be responsive to this request, PG&E is providing a description of the accounting approach used to breakdown costs for each initiative. That information has been provided in the updated Tables, which now include a column "How are initiative costs tracked?", containing that detail, in Attachment 2020WMP_ClassB_Guidance-1_Atch01. In that column there are several response types:

1) Initiative Specific Order Numbers: For these initiatives, costs are recorded directly into specific order numbers that are associated with only this initiative. Order numbers are the foundational element of PG&E's financial accounting system. Order numbers can be assigned to planning orders, MATs and Major Work Categories (MWC) that then group multiple orders into larger categories. One initiative here could be exclusive to one order number, a planning order, a MAT or a MWC, but the lowest level of PG&E's financial accounting system starts at the order number. For initiatives in this category, there are hundreds or thousands of specific

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[10] 2020WMP_ClassB_Guidance-1_Atch01 contains an updated set of 5.3 tables from 2020WMP_ClassA_RCP_PGE-1_Atch01 (submitted with the Class A conditions).

orders where costs are recorded associated with individual projects or geographic groupings of work.

2) Estimated Portion of Costs Recorded to Orders: Some initiatives are not tracked uniquely and separately, as discussed in PG&E's July 13 letter to the WSD, and are instead tracked in a program that combines multiple WSD-defined initiatives. In these cases, as described in PG&E's response to Condition PGE-1 submitted on July 27, PG&E compiled feedback from numerous SMEs and program owners to gather more granular data at detailed levels (including the notification level showing location and asset type) to inform how to disaggregate costs within a larger program and estimate the appropriate costs to assign to each individual WSD-defined initiative in the WMP templates. For initiatives in this category, there are hundreds or thousands of specific orders that costs are recorded to associated with individual projects or geographic groupings of work.

3) Estimated Portion of a PCC: As described in PG&E's response to Condition PGE-1 submitted on July 27, for any employee effort-driven initiatives that are not separately tracked with specific order numbers (as is the case for Sections 1) and 2) above), those costs are captured in PG&E's PCC cost tracking structure. The PCC costs are primarily treated as "overheads" in PG&E's cost model. These costs differ from costs captured in order numbers in that these types of overhead costs are not explicitly charged to specific orders. Instead, these types of costs flow through our cost model and get captured downstream in order numbers via overhead allocation mechanisms. To estimate the portion of PCC costs assigned to each WSD-defined initiative SMEs and program owners analyzed the PCC costs and determined the estimated volume of time spent within the total PCC time on each WSD-defined initiative.

CONDITION GUIDANCE-7

LACK OF DETAIL ON EFFECTIVENESS OF “ENHANCED” INSPECTION PROGRAMS

Deficiency: Utilities engage in numerous 'enhanced' inspection programs, but it is unclear if such 'enhanced' programs are incrementally effective over routine patrol and detailed inspections, particularly if patrol and detail inspections are scheduled based on risk, rather than GO 95 minimums.

i. ***The incremental quantifiable risk identified by such 'enhanced' inspection programs;***

As provided in response to Condition PGE-15, PG&E performed a RSE analysis to quantify the value of the findings from the 2019 Enhanced Inspections (see Table 2, "Forecast Inspection Reductions Attributed to Enhanced Inspection Corrective Findings"). Some of the key benefits of Enhanced Inspection programs are:

- Results of every inspection are recorded at the asset-level (whether or not there are findings);
- Benefit to risk modeling and asset investment opportunities;
- Enables asset-level planning (capability to plan inspections or not to inspect for specific assets);
- Allows much easier traceability for recent activity of an asset (a repair order or planned replacement can look at the inspection results of a targeted asset to confirm recent photos and asset condition); and
- Allows us to more effectively evaluate appropriate inspection cycles based on year-over-year find rates (i.e., re-inspecting Tier 3 again this year should produce a lower find rate).

Based on the quantification shown in Condition PGE-15, although the RSE is roughly unchanged, we believe that the more comprehensive Enhanced Inspection Program will deliver a significantly larger risk reduction relative to alternatives. The Enhanced Inspection Program has identified a large number of asset issues that we can address through repair or monitoring. This program also enables us to do better asset condition analysis and to design and perform well-targeted preventive maintenance for timely, effective and cost-effective asset management and asset performance.

ii. ***Whether it addresses the findings uncovered by 'enhanced' programs differently than findings discovered through existing inspections; and***

When PG&E's asset inspections identify any asset requiring corrective action, we document appropriate corrective notifications (create a tag) in SAP, regardless of the initiating inspection program type. Any findings that qualify under GO 95, Rule 18 requirements for shorter duration of resolution in HFTD areas trigger a shorter maximum duration for resolution.

We prioritize corrective notification on the basis of the asset issue, irrespective of the inspection program type which identified the concern. As such, corrective findings generated from "enhanced" vs baseline compliance inspections or patrols in same geographies are prioritized according to the assessment of the specific issue's impact and probability "of equipment and/or facilities failure and/or exposure." See attachments 2020WMP_ClassB_Guidance-7_Atch01 and 2020WMP_ClassB_Guidance-7_Atch02.

iii. A detailed cost-benefit analysis of combining elements of such 'enhanced' inspections into existing inspection programs.

PG&E combined "'enhanced' inspections into existing inspection programs" for its 2020 cycle of detailed overhead inspections. Combining the existing routine compliance inspection and WSIP-style inspection programs into a single management and accountability process and structure streamlines planning, reporting and oversight of the field inspection work. We expect that this consolidation will allow us to decrease both the inspector resource demand and the overall cost of program execution without compromising the quality and timeliness of our overall inspection efforts. Analysis for the current year indicates that we have reduced the workforce required to complete the planned Enhanced Inspections by more than two hundred inspectors relative to 2019. As referenced in subpart i, the cost-benefit analysis between routine and Enhanced Inspections are found in the response to Condition PGE-15, Table 2, "Forecast Inspection Reductions Attributed to Enhanced Inspection Corrective Findings."

TABLE 2
RESOURCE COMPARISON OF WSIP 2019 AND 2020 SYSTEM INSPECTIONS OVERHEAD

	Row Labels	Inspection Programs Distribution	Inspection Programs Transmission and Substation	Grand Total
2020 Syst Insp[(a)]	International Brotherhood of Electrical Workers (IBEW) T200	125	95	220
	Non-Employee	379	210	589
	Grand Total	504	305	809
2019 WSIP	IBEW T200	125	–	125
	Non-Employee	318	601	919
	Grand Total	443	601	1044

(a) 2020 counts shown for field overhead Inspector resources through June 27, 2020, and exclude Pole, Test, and Treat; AIR+; Drone; Substation; Centralized Inspection Review Team (CIRT)/Gatekeeper. The latter resources supplemented the field inspectors performing our 2019 inspection programs and remain valuable components for our 2020 inspection process.

These numbers include full-time staff in Electric Distribution Organization Compliance (2019), Electric Transmission Organization Transmission Line (2019 and 2020), System Inspections (2020), and the WSIP Contractor counts previously cited, and 2020 System Inspection resource counts who completed overhead detailed inspections as of June 27, 2020.

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 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.

PG&E continues to actively pursue new and emerging technologies that can mitigate ignition and fire spread risk and their associated potential impact on public safety. PG&E's Condition Guidance-9 first quarterly report provides updates on each project included in Section 5.1.D, New or Emerging Technologies, of PG&E's 2020 WMP. These mitigations that are being pursued using new or emerging technologies are consistent with the following definitions:

- New: Technologies or analytical methods enabled through technology that were new to PG&E after the release of its 2019 WMP (i.e., February 6, 2019), exclusive of 'emerging' technologies.
- Emerging: Pre-commercial technologies, including Technology Demonstration and Deployment (TD&D) projects.[11]

[11] The TD&D project definition was approved by the CPUC in D.12-05-037: "The installation and operation of precommercial technologies at a scale sufficiently large and in conditions sufficiently reflective of anticipated actual operating environments, to enable the financial community to effectively appraise the operational and performance characteristics of a given technology and the financial risks it presents."

PG&E's response to Condition Guidance-9 is included as 2020WMP_ClassB_Guidance-9_Atch01. PG&E has expanded each of the five items requested in Condition Guidance-9 into several targeted, detailed responses using these reporting parameters:

Condition Item (i): "All pilot programs or demonstrations identified in WMP."

- Parameter (i).A: WMP Section – Section where the project was listed in PG&E's 2020 WMP
- Parameter (i).B: Project Title
- Parameter (i).C: Capabilities listed in the Utility Wildfire Mitigation Maturity Model that could be impacted through project implementation
- Parameter (i).D: Project summary

Condition Item (ii): "Status of the pilot, including where pilots have been initiated and whether the pilot is progressing toward broader adoption."

- Parameter (ii).A: Project phase (Initiation, Planning, Design/Engineering, Staging, Build/Test, Closeout, Continuous Improvement)[12]
- Parameter (ii).B: Project location
- Parameter (ii).C: Next steps - Upcoming plans over the next two business quarters following the current reporting quarter
- Parameter (ii).D: Next steps - Upcoming Plans for pilot or demonstration over project lifecycle (cumulative)

Condition Item (iii): "Results of the pilot, including quantitative performance metrics and quantitative risk reduction benefits."

- Parameter (iii).A: Quarterly results/highlights
- Parameter (iii).B: Lessons learned
- Parameter (iii).C: Project performance metrics/success criteria[13]

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12 Definitions of project phase can be found in Tab 2 of Guidance-9 Report (2020WMP_ClassB_Guidance-9_Atch01).

13 Project success criteria are included to address CPUC stated deficiency for Guidance-9: "Electrical corporations do not describe how they will evaluate and expand the use of successfully piloted technology or which piloted technology has proven ineffective."

- Parameter (iii).D: Risk reduction benefits (categorized by capabilities listed in the Utility Wildfire Mitigation Maturity Model[14]

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."

- Parameter (iv).A: Steps that can be taken to promptly implement project findings
- Parameter (iv).B: Methods to incorporate this technology or project findings into operational practices

Condition Item (v): "A proposal for how to expand use of the technology if it reduces ignition risk materially."

- Parameter (v).A: Description of end product at full deployment
- Parameter (v).B: Use cases enabled by project at full deployment
- Parameter (v).C: Path to production

Forward-looking statements detailed through this report, 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.

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14 CPUC's Utility Wildfire Mitigation Maturity Model describes a methodology and provides a framework that can be used to assess utility capabilities in reducing wildfire risk and corresponding maturity levels. The Utility Wildfire Mitigation Maturity Model was corrected for errors following the December 16, 2019 ruling, and is provided in both clean and redline versions. Accessed 14 August, 2020: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2020/2. percent20Utility percent20Wildfire percent20Mitigation percent20Maturity percent20Model percent20- percent20copy percent20correction_clean_final.pdf.

CONDITION GUIDANCE-10

DATA ISSUES – GENERAL

Deficiency: Although the availability of data, including Geographic Information System (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 WMP Guideline data requirements, leading to inconsistency of data submitted.

Condition: Electrical corporations shall ensure that all future data submissions to the 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, 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

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

The data in response to subparts, i, ii, and iv has been provided in file geodatabase (FGDB) files that have been uploaded to the CPUC via Kiteworks, due to the size of these files. "Prior reporting period" data for subpart i covers the months of May, June, and July and "following reporting period data" for subpart iv covers the months of August, September and October. These data submissions followed the Draft WSD GIS Data Reporting Requirements and Schema for California Electrical Corporations, that was provided on August 5, 2020, to the best of PG&E's ability. As was noted in PG&E's Comments on WSD Staff Proposals and Workshops, PG&E is starting from a low level of maturity with regard to data management and technology, related business processes, and subject matter expertise in this space. Those limitations directly impact our ability to compile all data fields in the approximately one month since the draft standard was provided. As a result, PG&E was not able to provide Metadata in the FGDB as the inventory of PG&E's data in relationship to the draft GIS standard was being developed at the same time as the data was being gathered for this submission. An inventory of information regarding all GIS data fields in the draft GIS standard is being provided today, September 9, in response to the WSD's request for additional GIS data. That inventory provides some of the metadata related to the GIS fields submitted in response to this condition, Guidance-10, as well. In subsequent submissions, PG&E will incorporate this data into metadata in the FGDB files themselves.

As it relates to the asset inspection data, please note that PG&E's submission only included inspections that were mapped to 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.

Please see attachment 2020WMP_ClassB_Guidance-10_Atch01.

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

Inspection

PG&E inspects all assets in Tier 3 HFTD areas and approximately one third of the assets in Tier 2 HFTD on an annual work cycle. For Transmission and Distribution (T&D) lines, PG&E leverages a circuit risk ranking model to prioritize enhanced inspection cycles. PG&E's Asset Strategy Department groups assets by circuit and HFTD for both risk ranking and for grouping inspector assignments. Risk ranking uses relative ranking of lines across five equally-weighted categories: PSPS, safety, wildfire, reliability, and commitment/capacity. For substation inspections, SMEs reviewed all substations in HFTD areas to determine the appropriate balancing of the schedule by year (i.e., for the 1/3 in Tier 2 each year) and throughout the calendar year given the operational considerations associated with different substations (winter versus summer peak loads, etc.).

System Hardening

PG&E described the analysis that it uses to target specific areas for system hardening on pages 5-143 through 5-145 of its 2020 WMP. In summary, we identify areas for system hardening through several targeted approaches:

1) Identified Deteriorated Overhead Conductor: Locations identified through a wire-down investigation that have environmental and asset conditions that present a higher risk of line failure in HFTD areas.

2) Fire Risk Ignition Modeling: Creating relative risk rankings based on likelihood of failure, high fire spread and consequence, and egress as modeled inputs at a Circuit Protection Zone (CPZ) level.

3) Electric Correction Tag Optimization Program (ECOP): These projects are sections of overhead primary where numerous Electric Correction tags with high structural impact were found in higher risk CPZs.

4) PSPS Mitigation: These are projects where conductor undergrounding in conjunction with additional segmentation devices could be employed to minimize the impact of PSPS to customers in non-HFTD areas or served from existing underground facilities in HFTD areas.

5) Other Optimization Opportunities: These are projects that are accelerated to be completed in conjunction with other projects, such as transmission line replacement with under-build distribution primary.

These projects are then aligned with the risk model, reviewed with the execution team for project status and dependencies. We try to coordinate hardening measures with other work to assure that we perform all work in geographically and time-coherent ways to maximize efficiency and execution at minimum cost and inconvenience to affected customers. We regularly review and adjust workplans to identify and address field, dependency, clearance, or other conditions that could hamper our ability to execute the plan.

Vegetation Management

In 2019 and 2020, the EVM Program has used a circuit-level risk-ranked approach to prioritize circuits within the HFTD Tier 2 and Tier 3 footprint. VM has used these circuit risk rankings to plan and schedule all EVM work.

In 2019, our EVM Program used a risk-informed approach to plan and schedule work based on relative risk rankings and operational factors. The risk-based prioritization of EVM circuits reflected three components: (1) likelihood of ignition, (2) likelihood of wildfire spread and consequence score, and (3) egress factor.

In 2020, we replaced the 2019 EVM risk-based model with a refined Risk Value Overlay methodology model that incorporates impacts from other wildfire programs, including previous wildfires, capacity, reliability, prior-year PSPS and safety.

CONDITION GUIDANCE-11

LACK OF DETAIL ON PLANS TO ADDRESS PERSONNEL SHORTAGES

Deficiency: Electrical corporations do not explain in detail the range of activities that they are undertaking to recruit and train personnel to grow the overall pool of talent in areas of personnel shortage.

Condition: PG&E shall develop and furnish an RCP that includes:

i. ***A listing and description of its programs for recruitment and training of personnel, including for VM;***

<u>**Inspections**</u>

Recruitment

Recruitment of Qualified Company Representatives (QCR) Inspectors is primarily an internal process targeting our employee pools of Journeyman Lineworker classifications. Through our internal recruitment process, the program typically maintains a baseline of 130 QCRs for distribution operations. For transmission operations, PG&E is developing the appropriate classification to recruit for permanent QCRs. Transmission operations currently uses an internal employee pool of approximately 27 Troublemen and 90 Towermen for overhead asset inspections and patrols.

We also recruit external candidates from other utilities and utility contractors in conjunction with broader Company recruitment efforts. However, we have been unable to hire many external recruits for the QCR Inspector role. Anyone hired into the Compliance Inspector classification receives onboarding training for the inspection task plus on-the-job coaching. We require all externally-contracted QCRs who perform inspections to hold IBEW Journeyman Lineworker credentials that are validated by the supplying vendor company.

As of July 2020, 14 PG&E personnel bid internally for vacated distribution QCR inspector positions. There are another dozen Compliance Inspector positions now open to PG&E personnel. PG&E contracted for 527 field-based QCR Inspectors for both T&D operations, beyond our baseline internal workforce. We have maintained approximately 409 active field-based QCR Inspectors after accounting for personnel attrition (118).

Training

PG&E requires QCRs who conduct patrols and inspections to hold Journeyman Lineworker credentials. QCRs consist primarily of Compliance Inspectors (for distribution lines) and Troublemen (for T&D lines). These personnel have completed Lineworker apprenticeship programs, obtained Journeyman Lineworker IBEW credentials, and are further trained by PG&E to complete patrol and inspection activities.

QCR Inspectors conducting field inspection work in 2020 must either be a qualified IBEW Journeyman Lineworker or working foreman with an active union membership. A Qualified Electrical Worker with prior experience in and knowledge of T&D substation maintenance or construction is qualified to perform inspections of distribution and transmission lines or substations (as outlined in 2020WMP_ClassB_Guidance-11_Atch01).

Construction

Recruitment

PG&E works with IBEW Local 1245 to fill temporary jobs, including utility workers and linemen through Hiring Hall Temporary Opportunities. Temporary hiring hall personnel must have completed the necessary apprenticeships and pre-employment tests.

Training

PG&E's construction personnel must have successfully completed a federal- or state-sanctioned apprenticeship and/or IBEW-sponsored line work apprenticeship, all required pre-employment testing, and be represented by IBEW Local 1245. Any construction work normally performed by IBEW-represented PG&E employees that will be contracted out must only be performed by a contractor who is a signatory to an agreement with IBEW Local 1245. Each contractor must maintain records demonstrating that their personnel have completed training, as well as any associated assessments required by law and/or regulation that certify the organization or PG&E to perform work.

Vegetation Management

Recruitment

PG&E's VM Department works with our internal Human Resources team to recruit appropriate personnel to support VM programs. We develop job descriptions, define responsibilities and qualifications for the appropriate job levels, post positions internally and externally, and ensure a panel review of prospective candidates. The VM Department regularly sources qualified talent for internal positions from current contract staff, who usually have extensive experience working in the industry and working for PG&E. We have also developed Tree Crew and Inspector Training programs to support a steady pipeline of qualified personnel who may later join our contract or internal VM workforce.

In PG&E's 2020 WMP, we explained how we increased our VM pre-inspection workforce to complete the 2019 EVM goal and the subsequent training given to all Pre-Inspectors brought onboard. In 2019, we grew our Pre-Inspector and tree crew workforce from approximately 2,000 to well over 5,000 qualified contractors, in support of exceeding our 2019 EVM work completion goal. We have continued to use these contractors to meet the 2020 EVM goal and we monitor this workforce to identify the most effective contractors to use in future years.

Since 2019, PG&E has created more effective EVM work processes and management to help our current workforce be both safe and more efficient and reduce the need to drastically ramp up future workforce levels. In addition to recruiting and stabilizing our contractor workforce, our VM Department has increased the internal workforce from approximately 75 people in 2018 to over 115 in 2020, with an ongoing focus on how best to size this team to meet all VM goals effectively.

To bolster recruitment and the pipeline of qualified personnel, we have partnered with the IBEW and educational institutions, such as Butte Glenn Community College District, to establish a training program designed to provide the skills and knowledge necessary to perform tree crew work safely and competently. This Tree Crew Training Program will provide both classroom and in-the-field instruction, which will focus on safety, climbing, and line clearance qualifications. The pilot class started on June 22, 2020; subsequent courses are scheduled later in 2020 and 2021. The goal of this initiative is to increase the availability of certified tree crew workers in the industry to support our VM-related wildfire risk mitigation efforts, and to create a curriculum that can be used by any educational institution.

We are also developing a Pre-Inspector Training and Certificate Program in partnership with educational institutions of higher learning and the Utility Arborist Association (UAA). Once established, this training will provide the skills and knowledge necessary to perform Pre-Inspector work safely and competently. The Pre-Inspector Training Program will incorporate both classroom and in-the-field instruction. Curricula are in development now and classes will be ready in early 2021. Those who successfully complete the program will receive a certificate and support for International Society of Arboriculture (ISA) certification. Like the Tree Crew Training Program, this program should increase the availability of certified Pre-Inspectors to help PG&E and industry VM-related wildfire risk mitigation efforts.

Training for Pre-Inspectors

PG&E has implemented a structured, comprehensive nine-course Pre-Inspector training program (see Attachment 2020WMP_ClassA_RCP_PGE-25_Atch01 for the Structured Learning Path summary sheet) for all VM Pre-Inspectors. The program includes web-based training (WBT), scenario-based skills assessments, on-the-job training (OJT), and mentoring from experienced Pre-Inspectors. Pre-Inspectors are required to pass scenario-based skills assessments that test key concepts in the training program. 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.

The training program includes a module devoted entirely to PG&E's EVM Program and is a prerequisite for requirement for contractors performing PG&E EVM inspections.

Training for Tree Workers

Tree work generally involves tree pruning, tree removal, and brush removal. It is very hazardous work that requires extensive training and on-the-job experience to perform properly and safely, even without the threats posed by energized powerlines. To minimize these risks, federal and California law prescribe comprehensive safety, training, and knowledge requirements for tree workers generally. There are additional, specific requirements pertaining to work around energized lines, including requirements to have and know how to use specialized equipment, to adhere to specific safety procedures and to maintain minimum approach distances from energized lines. See 8 California Code of Regulations (CCR) §§ 2940.2, 2950 2951, 3420 3428;

29 Code of Federal Regulations §§ 1910.269(a)(2), (r). Particular kinds of removal and trimming operations that involve climbing trees or the use of cranes may require additional levels of training and experience. See, e.g., 8 CCR 3427(a)(1)(B).

Our contractors expend significant resources to identify, train, manage, equip and deploy appropriately qualified personnel who can perform tree work safely and meet the line clearance needs of PG&E and other electric utilities. Our contracts expressly require that tree workers be appropriately trained and meet all regulations to perform tree work activities in proximity to high voltage conductors (as detailed in Condition PGE-25). We also keep safety personnel in the field to monitor tree crew employees to ensure that all safety measures are followed; our monitors will shut crews down if any safety deficiencies are observed. In such cases, tree crew employees will not be allowed to return to work until the vendor can illustrate the deficiencies have been remedied by training or other means to mitigate the issue.

ii. A description of its strategy for direct recruiting and indirect recruiting via contractors and subcontractors; and

Inspections

PowerPathway (Indirect)

Launched in 2008, PowerPathway is a nationally-recognized workforce development model that helps expand the talent pool of local, qualified, diverse candidates for skilled craft and utility industry jobs through training program partnerships with educational, community-based and government organizations. PowerPathway helps potential workers throughout the PG&E service territory, including women and military veterans, prepare and compete for in-demand jobs in the utility and energy industry. Once enrolled in the program, students receive approximately 8 weeks (320 hours) of industry-relevant education to obtain the academic, job-specific skills and physical training necessary to effectively compete for entry-level employment in the industry. Programs may also include hands-on and OJT.

PG&E Apprenticeship Programs (Indirect)

PG&E operates apprenticeship programs (PG&E/IBEW Apprenticeship Program and PG&E Substation Electrician Apprenticeship Program) which are administered by IBEW under the oversight of the California Department of Apprenticeship Standards. The Joint Apprenticeship and Training Committee (JATC) sets the guidelines for our apprenticeship programs' eligibility and achievement standards. The JATC establishes criteria for successful apprenticeship program completion, including: program duration, formal classroom instruction requirements, OJT, work task repetition, oversight, and mentoring, among others.

Internal Recruitment (Direct)

Internal Journeymen Lineworkers in appropriate lines of progression may "bid" into vacant or open System Inspections Program QCR positions in alignment with PG&E's collective bargaining agreement with IBEW, provided they hold the Journeyman Lineman credential and can pass a required internal training course.

Contractor Recruitment (Direct)

PG&E has established relationships with multiple vendors (five vendors specifically for 2020 overhead equipment inspections) to ensure a sufficient number of externally-recruited QCRs. Our partner vendors provide qualified personnel who possess required credential qualifications, as stated in the contract with PG&E:

> Contractor shall provide only Qualified Electrical Workers ("QEW") (per Title 29, Code of Federal Regulations (CFR), Part 1910, Subpart S, along with Journeyman Lineman (hereinafter, "Inspector") who are well-qualified, having the qualities and capabilities required by law and training to efficiently and effectively perform this Work. … Only qualified IBEW journeymen linemen and foreman with active union memberships will perform inspections. MEO, groundmen, towermen, construction managers are not acceptable substitutes, but may be used to support safety of climbing inspection activities.

Both PG&E and contracted QCR Inspectors are required to complete PG&E's System Inspections Program orientation. Additionally, contracted QCRs must complete a 3-day, pre-work PG&E orientation for all personnel who conduct detailed inspections. The 3-day contractor orientation does not provide basic industry training regarding the Journeyman Lineman skillset, tools or methods, but does address enhanced inspections criteria, documentation, and processes.

<u>Construction</u>

PG&E's construction personnel recruitment methods include those outlined above, including PowerPathway and PG&E Apprenticeship Programs. We use additional methods to recruit and retain external contactors.

Contractor Recruitment

PG&E's Construction Management Program recruits contractors using Contract Opportunity Announcements (COA) and Requests for Proposal (RFP). We routinely post COAs on our website and we release project RFPs through all available recruitment channels that invite contractors to opportunities in system hardening, pole replacement and routine maintenance and repairs.

We also use direct outreach to reach potential VM contractors. For instance, our Supply Chain Responsibility team also conducts direct outreach to diverse and small businesses, hosting and attending outreach events and engaging contractors via phone, e-mail and in-person meetings to inform them of upcoming opportunities. We occasionally invite potential local, regional, national and Canadian partners to complete surveys regarding their safety, capability, capacity, and experience standards. For instance, PG&E engaged over 150 contractors from across the nation and Canada through the T&D Electric Construction Services Request for Information in August 2020. We also work with the IBEW recruit contractors from across the nation.

Contractor Retention

PG&E's retains contracted partners by awarding successful bidders a three-year or longer Master Service Agreement (MSA). These MSAs enable us to keep good contractors over a longer period and enhance our ability to recruit past partners for new projects. We use regular Requests for Information to stay in contact with contractors who may be interested in PG&E projects. Our partnership with the IBEW and our Supply Chain Responsibility team's partnerships with diverse and small businesses help us retain and grow contractor relationships from reliable source points.

Vegetation Management

For VM services, PG&E works with the contractors to ensure their performance enables the compliance of GO 95, California Public Resource Code (PRC) Sections 4292 and 4293, Electric Safety and Reliability Branch-4 (ESRB-4), and Facility Agency Code 003-4. PG&E also directly recruits vendors that have significant industry experience and good standing with both state and federal environmental laws. PG&E also reviews and approves any subcontractors, that a prime vendor would like to hire, in order to give authority for that subcontractor to work on any of PG&E's VM programs.

With the passage of Senate Bill (SB) 247 and the continued steady workload in 2020, we are using an appropriate number of qualified tree crew personnel with no current staffing challenges. This includes a large number of contract Pre-Inspectors and tree crew personnel. We expect to be able to manage our staff to meet all demands of VM's existing programs for the remainder of 2020 and subsequent years.

PG&E is now changing the contracting model we use for the VM Program. The new model will be a "Defined Scope" model where a single VM company will be responsible for all Routine patrols and tree work along a specific circuit or grouping of circuits, and a separate VM company will be responsible for CEMA work across PG&E's whole distribution system. This new contractor strategy should better align our contractor capabilities with the VM Program's strategies and needs.

Under the Defined Scope model, both pre-inspection and tree work will be completed by a single vendor that will apply its expertise to determine the most efficient and effective way to complete the work along its assigned circuit(s). This will allow the responsible vendor the flexibility to determine the level of resources needed to complete the work, as well as the best method to complete the work, instead of PG&E requiring the assumed resource levels. We will be monitoring vendor work closely to ensure that they are performing all pre-inspection, VM and QC work in a safe and effective fashion that complies with all PG&E, state and federal performance requirements.

PG&E's VM team routinely attends industry conferences and participates with industry leaders to not only share ideas about what PG&E is doing, but to hear what others are doing and how we might leverage their lessons learned to enhance our own practices. We leverage networking opportunities to meet qualified vendors and assess potential partnerships. Our VM team works closely with counterparts at the other California utilities and shares best practices for recruitment and management of contractors.

iii. Its metrics to track the effectiveness of its recruiting programs, including metrics to track the percentage of recruits that are newly trained, percentage from out-of-state, and the percentage that were working for another California utility immediately prior to being hired.

<u>Inspections</u>

As of July 2020, PG&E has contracted a total of approximately 527 Inspectors. This includes 275 returning contractors from the 2019 WSIP and 252 new contractors; 118 contract personnel left our service over the past year. The size of our active cohort of inspectors varies depending upon workload and attrition.

As previously mentioned, PG&E has an established relationship with multiple vendors to ensure a sufficient number of externally-recruited QCRs. These vendors recruit and provide the trained and qualified personnel needed. As such, we do not have access to data about which states or prior utilities contractors came from.

As of July 2020, the System Inspections Program has hired 14 new full-time PG&E employees as QCRs for distribution operations to offset internal movement and attrition. This maintains our baseline internal inspections workforce at 130 QCRs for distribution operations.

<u>Construction</u>

As mentioned, Construction Management requires contractors to be a signatory to IBEW Local 1245 to help recruit and ensure contractors are vetted for the job. Personnel must have previous qualifications and training prior to working on PG&E construction projects. Additionally, with our partnership with the IBEW, we rely on the IBEW to track out-of-state hires and necessary qualifications.

However, our Construction Management team uses scorecards to track contractor performance on safety, quality, cost, and productivity. We take immediate action with contractors if their performance begins to drop below our high standards, and we base contract decisions on scorecard results.

<u>Vegetation Management</u>

In 2019, PG&E increased both VM pre-inspection and tree crew contract staff from approximately 2,000 to over 5,000 personnel, which illustrates our recruiting effectiveness. All Pre-Inspector contractors must complete the Structured Learning Path Program starting in March of 2020. All tree crew vendor personnel are trained on PG&E SAFE-0101 (Contractor Safety Program Requirements) before starting work for PG&E. Starting in August 2020, PG&E will track all Occupational Safety and Health Administration requirements in a third-party tracking program known as ISNetWorld.

As of June 2020, approximately 8 percent of Pre-Inspector and tree crew contract employees are from out-of-state and approximately 24 percent of contract employees were working for another California utility prior to being hired by PG&E.

CONDITION GUIDANCE-12

LACK OF DETAIL ON LONG-TERM PLANNING

Deficiency: Electrical corporations do not provide sufficient detail regarding long-term WMPs and how the initiatives in their WMPs align with and support those long-term plans.

Condition: In their first quarterly report, each electrical corporation shall detail:

i. ***Its expected state of wildfire mitigation in 10 years, including 1) a description of wildfire mitigation capabilities in 10 years, 2) a description of its grid architecture, lines, and equipment;***

ii. ***A year-by-year timeline for reaching these goals;***

iii. ***A list of activities that will be required to achieve this end goal; and***

iv. ***A description of how the electrical corporation's 3-year WMP is a step on the way to this 10-year goal.***

The CPUC WSD found that PG&E's WMP dated February 28, 2020 did not provide enough detail on the state of PG&E's expected wildfire mitigation capabilities and accomplishments in 10 years, and directed that PG&E provide that information with a list of activities and timeline to achieve those capabilities. PG&E's long-term plan for wildfire mitigation improvement is summarized here and detailed below.

PG&E's wildfire mitigation strategy is structured around three strategic imperatives: reducing wildfire ignition potential, reducing wildfire spread, and reducing the impact of PSPS events. The first and most critical of those imperatives, reducing ignition potential, is implemented at a tactical level primarily by four major initiative groups: EVM, inspections, and repairs of electric distribution and transmission facilities, system hardening, and an improving PSPS Program supported by situational awareness capabilities and PSPS mitigation activities.

Much of our work will leverage the CPUC's WMM's 52 capabilities. To this end, we will be focusing particularly on improving efforts that underlie and support many of the 52 WMM capabilities, including:

- Risk assessment, quantification, predictive analytics, and modeling;
- Degree of collaboration with other agencies;
- Data granularity;
- Data accuracy;
- Data validation;
- Geographic or topological granularity (circuit level to asset level);

- Degree of process automation;
- Maturity of analytics;
- Learning agility;
- Update frequency/information latency (ranging from annual to real time); and
- Procedural standardization.

Improvement on these dimensions will improve our ability to refine and improve key fire mitigation activities such as: VM, asset inspection, system hardening, and PSPS targeting and implementation. All of these topics are addressed in the ten-year roadmaps and discussion in the section below.

Given the many changes in electricity, energy technologies, economics, customer, and societal preferences, climate change, and institutional and political direction in California, it is difficult to commit to a specific set of plan elements beyond a horizon of three to five years. Our plans and capabilities may need to change significantly, with a challenging balance between longer-term plans and short-term requirements and actions. It is essential to recognize that since the nature of wildfires and wildfire risk is dynamic and we continue to learn more every year, plans are very likely to change and evolve as the utilities and the Commission develop a greater understanding of wildfire risks and effective mitigations.

The above changes will not have a major effect on how we move forward on many of the data and analytical objectives above, but they will have significant impacts on how we approach infrastructure standards updates, system hardening investments, remote grid investments, grid architecture, and the adoption of innovative technologies over the long term. While we are deeply committed to the goal of reducing the risk of catastrophic wildfires, that cannot be our only goal. As a broader context, our customers and our state need us to reimagine and build the electric grid of the future as a secure, resilient, reliable, affordable, and integrated platform that enables continued gains for clean-energy technologies and California's economy. Such a grid re-design can leverage low-carbon resources, high levels of energy efficiency and demand flexibility, smart grid, electrification, and advanced energy storage. These changes, integrated and implemented in a thoughtful fashion, can give our customers maximum flexibility, more choices in how they use energy, and ultimately increased value from their utility grid in a dynamic energy future with less wildfire risk.

In principle, PG&E anticipates the overarching strategic imperatives and tactical initiatives that outline our wildfire safety plan to remain similar over the requested

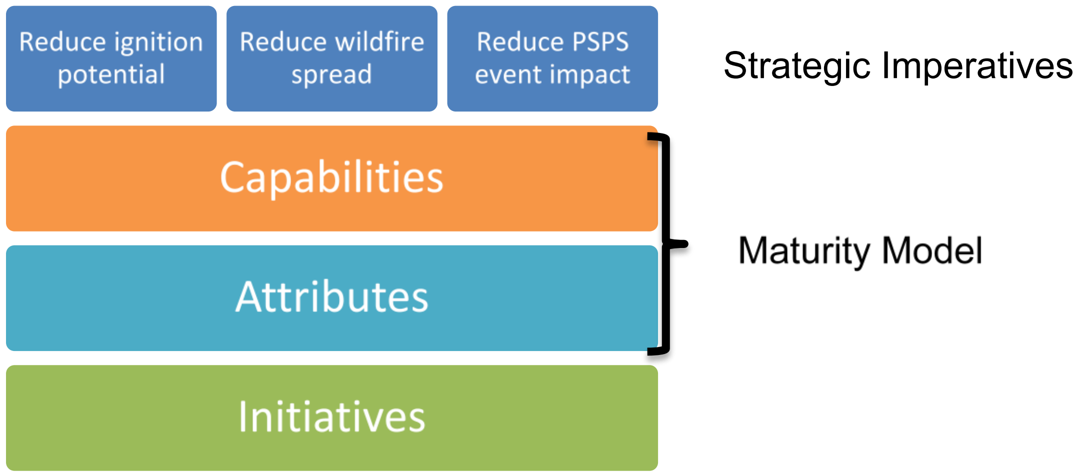
10-year horizon. As we progress through that time period, our long-term planning method incorporates these steps:

- Identify High-Priority Actions to Initiate and Sustain Improvements in Maturity Levels: Based on our current assessment (quantitative and qualitative) of the wildfire mitigation maturity model categories, our initial focus is on the categories of perceived highest, immediate impact, setting near-term goals, while applying the "Plan, Do, Check, Act" management cycle framework to continuously improve. Accordingly, some categories have been built out more expansively, and are therefore described in more detail, than others;
- Develop a Framework to Further Guide Alignment Between Initiatives and Results: We are developing a long-term planning framework that incorporates and further validates the relationships between the maturity model capabilities, attributes that support those capabilities, and PG&E's initiatives and programs. The objective of this framework is to improve the overall maturity of our Community Wildfire Safety Program (CWSP), as measured by the maturity model capabilities and metrics while supporting the ultimate goals of optimally reducing ignition risk and PSPS impact; and
- Incremental Steps: Our recent WMP represents a first step in this effort and is discussed later in this response. We know that we will continue to learn from experience, partners, researchers and others along this journey which will inform future actions and steps to continuously improve our WMPs, efforts, and outcomes.

PG&E is actively developing a long-term plan to guide our wildfire mitigation efforts and will report on the progress of this plan in the fourth quarter of 2020. This section provides an overview of this planning effort.

As noted above, PG&E's wildfire mitigation strategy is structured around three key strategic imperatives: reducing wildfire ignition potential, reducing wildfire spread and reducing the impact of PSPS. Those imperatives follow the WSD's WMM, which defines 52 capabilities across 10 categories. The capabilities are themselves enabled by essential functional attributes that are common across multiple capabilities. PG&E's WMP programs support these underlying attributes, as shown in the figure below.

FIGURE 2
PG&E WILDFIRE MITIGATION PLAN STRATEGY AND RELATION TO MATURITY MODEL



Our long-term plan will identify and distinguish the underlying attributes that enable the 52 capabilities, prioritize those attributes with respect to their impact on the WMP capabilities, prioritize our portfolio of initiatives and programs relative to their ability to support the attributes, identify the actions to improve performance of the initiatives, and develop a portfolio of initiatives and 10-year roadmap. This process is described in detail below.

1) Identify and Distinguish the Underlying Attributes That Enable the 52 Capabilities: The maturity model articulates five maturity levels for each of the 52 capabilities amounting to 260 distinct states of maturity. During this phase we will review, identify and articulate all the individual attributes across the maturity model space. Since many attributes are common across multiple capabilities, this task will compile a distinct set of attributes to focus on.

2) Prioritize the Attributes With Respect to Their Ability to Support the Capabilities: The specific attributes will be prioritized based on two primary factors. One is the relative importance of an attribute or the extent to which an attribute supports the 52 capabilities, with the number of capabilities a given attribute supports and the current maturity level of those capabilities being considerations. The second factor is the relative maturity of the attribute which indicates the potential upside for improvement. Relative importance and potential for improvement will be considered in combination to prioritize which key elements to focus on. For example, a

relatively immature attribute that has high relative importance would be given a higher priority based on its ability to impact aggregate maturity of the 52 capabilities.

3) Prioritize the Portfolio of Initiatives With Respect to Their Ability to Support the Attributes: Initiatives will be prioritized based on their strategic value through several considerations. The first is a scoring of the relative importance of a given initiative in supporting attributes across the capabilities within the maturity model with the number of attributes a given initiative supports and the relative priorities of those attributes being important considerations. The second factor is the relative maturity of an initiative or the potential for that initiative's performance to be improved.

4) Identify the Actions to Improve Performance of the Initiatives: For each initiative, we will evaluate and identify ways to improve its effectiveness in supporting the attributes. While some initiatives have existing metrics that may be useful for this activity, others do not, and gauging effectiveness will involve a combination of inputs including subject matter expertise. Some example of actions to improve effectiveness include increasing numbers of units planned for installation, deploying technology, improving data, improving processes, and deepening institutional knowledge.

5) Evaluate the Need for New Initiatives: Improvement in some attributes may require initiatives that are under development to be accelerated or new initiatives to be developed. We will evaluate and identify such initiatives as well as prioritize them and identify actions needed to accelerate their development.

6) Develop Portfolio of Initiatives and 10-Year Roadmap: We will develop a roadmap which contains an optimized combination of initiatives, actions to improve how the initiatives support the overall maturity model and a timeline for executing those actions. The long-term planning process will consider the interdependence among programs and identify activities that are complementary and or resource constrained and reflect those relationship accordingly. The plan will also account for the Company's investment plans related to Distributed Energy Resource (DER) adoption and integration, grid modernization, decarbonization, and infrastructure replacement. In developing the program portfolio, the long-term planning process will also consider the operating environment including load forecasts, population

changes, adoption of DERs, community microgrids and community profiles (i.e., critical facilities, Limited English Proficiency (LEP), Access and Functional Needs (AFN) populations, etc.)

The following section discusses the wildfire capabilities, at the category level, in 10 years, along with associated timelines. Timelines are color coded to express three phases of maturity. The first phase is one of developing foundational capabilities that are core to furthering maturity. The second phase is the period during which capabilities and their implementation is refined and advanced. By the third phase, significant maturity in capabilities has been achieved and small refinements continue to be made as appropriate. The third phase largely represents the "vision" of PG&E's wildfire mitigation capabilities and, in some categories, the characteristic of PG&E's grid, in 10 years. The durations for the various phases across the categories differ based on the current state of maturity, and the interdependencies between the categories. The timelines illustrate our current thinking as to the specific timing and sequence of the development of capabilities, but are subject to revision, particularly in the outer years, as we learn and incorporate new information.

TABLE 3
MATURITY MODEL TIMELINE PHASES

First Phase of Maturity Advancement	
Second Phase of Maturity Advancement	
Third Phase of Maturity Advancement	

Risk Assessment and Mapping

TABLE 4
RISK ASSESSMENT AND MAPPING MATURITY TIMELINE

2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030

- Incorporate future climate change into risk models.
- Independent expert assessment of risk reduction impact.
- Increase granularity of ignition risk reduction to below the circuit level.
- Explore climate factors that affect risk over time into risk models (i.e., sea-level rise, extreme heat conditions, erratic wind patterns).
- Partial automation of risk assessment processes (i.e., automation of data refreshes for risk monitoring).
- Increase granularity of ignition risk reduction to below the circuit level, including integration of fire spread consequences.
- Incorporate near-miss data (e.g., non-reportable ignitions, unplanned outages, electric faults), and pilot technologies to support utilizing this information.

- Full automation of current risk assessment processes and tools, including risk performance (i.e., projected risk vs realized risk)
- Continue partial automation of risk reduction and RSE tools.
- Risk reduction impacts measured by models, with confidence intervals, and reviewed by independent experts.
- Increase granularity of ignition risk reduction models including integration of a full-cycle of inspection data for some assets.
- Incorporate long-term climate factors (dependent on climate modeling maturity) into risk models.
- Facilitate information sharing for intra- and inter-industry risk assessment/reduction methodology developments.
- Enable forward predictive ignition risk models, including integration of more robust consequence modeling (i.e., fire spread at varying hours).
- Incorporate pilot technologies' effectiveness for impacting near miss and ignition incidents.

- Incorporate industry and research advances in risk modeling, wildfire science and geographic risk mapping as learnings are identified.
- Leverage real time data and specific asset failure modes as modeling inputs.
- Expand consequence modeling to include factors such as population, buildings, and environmental considerations.
- Incorporate independent third-party assessment of risk modeling methods and scenarios.
- Improve asset data collection practices (e.g., asset condition, failure modes) and consider granular wind patterns and temperature effects.
- Automate the flow of data inputs and information between analytical tools and platforms.
- Full automation of current risk level, reduction, and RSE tools.
- Climate integration fully developed into real-time and long-term asset planning and design standards.
- Real time reporting of risk performance.
- Develop "real-time" risk models that incorporate condition of asset, environmental factors, weather conditions, and potential fire spread.
- Integration of tools for risk models and levels of risk actively allow for real-time situational awareness shared with stakeholder agencies and communities.

We will continue to advance our longer-term risk assessment and mapping capabilities through advancements in:

- Modeling and predictive analytic capabilities;
- Independent expert review and model validation;
- Data quality and granularity; and
- System integration and automation.

In particular, we continue to make significant progress on our Large Fire Probability Model which analyzes weather, winds, and fuel to identify the conditions which have driven the development of large fires in the past and thus predict the potential for large fires to occur. The model considers the potential for winds to produce outages and the condition of individual assets that may fail and ignite fires. It also considers the characteristics of vegetation and incorporates machine learning to improve its accuracy based on experience.

Modeling and Predictive Analytics Capabilities

Over the 10-year period, we will develop RSE scores for nearly all of our programs. We are working to create an integrated and unified risk tool that allows us to understand risk with granularity down to the asset level. The tool's Multi-Attribute Value Framework (MAVF) will combine probabilistic outputs for ignition, outages, and wire-down scenarios, with consequence data sets, to develop MAVF risk scores. This risk score will not be a relative ranking, like prior models, but instead will represent a quantitative risk score that ties to the enterprise risk scoring communicated in our 2020 RAMP Report filing. By combining safety, reliability, and financial consequences, our future risk scores will enable prioritization across multiple risk vectors. In addition, we will have the capability to decompose each risk reduction measure to better evaluate the cross-cutting impacts across various risk reduction targets.

Other features of our future modeling capabilities include:

- Modifying ignition risk estimation methods to use real-time data model inputs, rather than the historical data currently in use;
- Expanding consideration of wildfire consequences on communities to include consequences such as: potential buildings and populations impacted and environmental considerations;

- Including additional quantitative features such as: specific asset failure modes for ignition risk estimation and introducing characteristics such as: fuels and moisture for estimating wildfire consequences; and
- Enhancing other tools (e.g., Technosylva) to allow for quantitative and accurate assessment of the risk of ignition and fire spread across the service territory based on characteristics and condition of power lines, equipment, surrounding vegetation, and localized weather patterns.

These future modeling capabilities will allow stakeholders to understand our modeling and probability of events when targeting specific levels of risk.

Independent Expert Review and Model Validation

We will increasingly use independent expert review for validating our modeling tools and results, which will lead to continuous improvement of the tools and processes. For climate scenarios, we have hired a third party to conduct an independent expert assessment of those scenarios. We will incorporate independent assessment of ignition risks using either an external-third-party or an internal assessment team that is independent of the team conducting the risk impact analysis. PG&E will validate its risk reduction estimation process through actual circuit performance. With these future advancements, we will incorporate learnings from past risk assessments and independent expert analysis at a faster pace.

Data Quality and Granularity

Over the 10-year time horizon, we will be capturing ignition risks, wildfire consequences, and estimation of wildfire and PSPS risk reduction initiatives at the asset level rather than the circuit or system level. We will have the ability to incorporate unique weather conditions at the equipment level for estimating ignition risks. This increasingly granular view of risks and mitigation initiatives will better match the granularity of the vegetation probability model.

To support these future capabilities, we are revising and improving field data collection practices to use these data in modeling and predictive analytics. We are also reviewing, assessing, and cleaning our historic data files on electric asset performance and failures, because predictive models are only as good as the data they use. Better asset failure and outage data collection will make asset and failure modeling more accurate, which will enable better identification of asset failure causes and better-targeted and risk-appropriate mitigation efforts. We will also improve design and construction standards using the best available climate data and predictions. Ultimately, PG&E plans to have its risk modeling and the overall asset strategy consider factors such as granular wind patterns and temperature of individual transformers. To support these future capabilities, PG&E will seek to leverage relevant data from other utilities and other sources through data-sharing practices.

Wildfire Risk and Information Modeling, Integration, and Automation

Part of our wildfire capabilities maturity effort entails the integration of multiple wildfire risk assessment tools and capabilities; and improving and automating the flow of data inputs and of information between analytical tools and platforms. For example, we plan to integrate equipment failure modes information into asset management, spread analysis in Technosylva, and weather scenarios into a single model to estimate risk. We plan to develop an interface that integrates and updates critical data sets (e.g., outage history, asset characteristics and conditions) to automate and streamline the risk calculation process. Our long-term goal is to fully automate the development of integrated estimates for ignition risk, wildfire consequences on communities, and estimation of wildfire and PSPS risk reduction initiatives. This will enable us to use risk analysis and RSE evaluations more effectively from the asset level upward to the system level.

Situational Awareness and Forecasting

TABLE 5
SITUATIONAL AWARENESS AND FORECASTING MATURITY TIMELINE

2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030

- Deploy cameras to cover approximately 90 percent of the high fire-risk areas.
- Continue deploying weather stations and expand the number of weather variables being measured that impact ignition probability.
- Complete the evaluation of the usefulness of satellite data in situational awareness.
- Finalize validation of the operational application of the PG&E Operational Mesoscale Modeling System (POMMS) high-resolution weather model.
- Continue to increase the geographic granularity of weather prediction.
- Partially automate the forecasting processes.
- Deploy Smart Meter™ devices for enhanced wire down detection in HFTD.

- Continue deployment of cameras to cover remaining high-risk areas and evaluate further deployment based on current HFTD maps.
- Evaluate weather station needs to support desired forecasting granularity and deploy additional stations as needed.
- Evaluate results of automation of forecasting process and expand as appropriate.
- Continue to validate POMMS against historical weather data to refine prediction accuracy.
- Complete evaluation of enhanced wire down detection to guide additional Smart Meter™ deployment.

- Fully automate forecasting process, subject to favorable results in Phase II, supported by an extensive camera and weather station network.
- Achieve state of the art level in geographic granularity of weather prediction.
- Incorporate external sources and partner with academic institutions to support achieving the desired level of automation, forecasting granularity and forecasting accuracy.
- Further automate fire detection via intelligence from our extensive network of cameras and weather stations.
- Complete deployment of Smart Meter™ devices for enhanced wire down detection.

We will continue to advance our situational awareness and forecasting processes by:

- Improving the resolution of weather data across the service territory;
- Improving the accuracy of our forecasting;
- Using external sources for validation of our forecasting models;
- Partnering with academic institutions to help advance fire science in California; and

- Continuing to incorporate intelligence and automation in fire detection.

We will continue increase the resolution of weather data, supported by additional installations of cameras and weather stations across the service territory.

Grid Design and System Hardening

TABLE 6
GRID DESIGN AND SYSTEM HARDENING MATURITY TIMELINE

2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030

Remote Grid

- Pilot remote grids to develop a standardized product for installation, operations, and maintenance.
- Formalize remote grid site selection framework for future opportunities.

Temporary Microgrid – Substation

- Continue to design energization plans and install make-ready infrastructure at relevant substations.
- Continue to convert temporary generation configurations to permanent.

Permanent Microgrids – Substation

- Advance framework for determining which substations are best suited to leverage permanent generation in support of cost-effective PSPS mitigation.
- Test clean permanent generation technologies in controlled and field environment and work with vendors to address any operational concerns and ensure scalability of technology and any fueling/refueling logistics.
- Develop best practices for designing multi-faceted solutions that pair permanent in front of the meter generation with other resources (e.g., demand response (DR), behind-the-meter (BTM) resources, etc.).
- Partner with relevant external stakeholders to ensure envisioned solutions meet local communities' needs.

Community Microgrid Enablement Program (CMEP)

- Develop and implement program framework based on Microgrid Order Instituting Rulemaking (OIR) Phase 2 decision.

Grid Hardening

- Continue to harden at-risk infrastructure consistent with evolving risk prioritization and strategies.
- Further development of hardening strategies to support PSPS, Fire Rebuild, deteriorated conductor, and other work optimization opportunities.
- Monitor and assess system performance once hardened to help inform future scoping decisions.
- Identify opportunities to pilot new products or construction methods to reduce cost or increase fire resiliency.

TABLE 6
GRID DESIGN AND SYSTEM HARDENING MATURITY TIMELINE
(CONTINUED)

2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030

Remote Grid

- Full-scale implementation and operations of remote grids based upon site selection framework.

Permanent Microgrids – Substation

- Complete construction of multiple permanent generation solutions at relevant substations.
- Continue to partner with vendors and local communities in solution design.
- Scale penetration of clean technologies in permanent generation portfolio.

Community Microgrid Enablement Program

- Continue to enhance the CMEP based upon lessons learned from Phase 1.

Grid Hardening

- Continue to harden at-risk infrastructure consistent with evolving risk prioritization and strategies.
- Optimize opportunities with other programs to align system hardening with programs such as reliability and capacity.
- Incorporate hardened system performance with weather data to inform design decisions and standard design requirements.
- Develop criteria for alternate hardening levels to become more targeted in wildfire risk reduction measures.
- Increase the application of higher risk reduction measures such as remote grid and undergrounding.

Remote Grid

- Enhance remote grid capabilities based upon technology innovations and cost reductions.
- Community Microgrid Enablement Program
- Continue to enhance the CMEP based upon lessons learned from Phase 2.
- Deploy microgrids and back-up power solutions where appropriate.
- Leverage resilience planning criterion to optimize mitigation measures (e.g., grid hardening, non-wires alternatives).
- Deploy innovations in engineering and protection for overhead electrical infrastructure.

Grid Hardening

- Capture, analyze, and use data on asset condition and the interactions between assets and vegetation to inform long-term asset management approaches.
- Complete hardening of highest risk distribution circuits and eliminate all non-exempt equipment.
- Continue to Harden next highest risk infrastructure consistent with evolving risk prioritization and strategies.
- Improve material and design standards based on risk modeling.
- Operationalize asset condition information by improving field tools and resources.
- Test and deploy innovative technologies to reduce ignition risk
- Develop a robust field scoping process for all work done in HFTD areas, not just system hardening, to maximize fire resiliency effectiveness of all maintenance and asset work in HFTDs.

We will advance our grid design and hardening capabilities by improving:

- Our understanding and modeling the fire risk of our infrastructure;
- Capturing, analyzing and using data on asset condition and the interaction between assets and vegetation;
- Our ability to plan and execute the right type and extent of hardening in the right places to reduce risk to the desired level;
- Incorporating state-of-the-art engineering design practices, tools, and materials;
- Updating our standards to reflect the implications of climate change for future asset design, materials, placement and use; and
- Considering how to use energy efficiency, energy storage, DR, community and customers' BTM generation to reduce the need for or change the character of PG&E assets.

Within 10 years, our system hardening program plans to harden our highest risk distribution circuits (approximately 30 percent of total distribution miles) in HFTD areas and will have eliminated all non-exempt equipment in HFTD areas.

Grid design and hardening standards support execution activities that ultimately reduce risk. The standards are informed by and dependent on inputs from risk modeling that identifies and quantifies risk across the asset portfolio. PG&E will make substantial improvements in risk modeling over the 10-year timeframe; those improvements are discussed in the risk assessment and mapping section above.

Because asset condition influences fire risk, we will improve our ability to capture, analyze and operationalize information on asset condition by improving the tools and resources that crews use to capture asset information in the field. We will be consolidating the disparate information systems where asset data currently resides and improving the way asset information is used in our models and grid design and hardening standards.

Our design and execution of hardening will become more surgical and thus more efficient, supporting improvements in the RSE of our programs. Between 2014 and 2019, 70 percent of PG&E's distribution-triggered fire ignitions were caused by connectors, conductors, and certain pole-top equipment. With better asset data and failure models, we will gain more granular insight about components, to identify and address the components that most contribute to risk. These improvements will allow more assets to be targeted at more granular levels rather than at the "asset class" level.

We anticipate continued industry innovations in this field of wildfire risk reduction and grid hardening. We stay connected to industry innovations through our membership in: the Electric Power Research Institute (EPRI), the National Electric Energy Testing and Research Applications Center, the Association of Edison Illuminating Companies, and other peer groups. These relationships will support our ability to identify and incorporate promising innovations into our grid hardening programs to improve risk reduction and reduce execution costs. For example, we continue to explore new system protection technologies (e.g., rapid earth fault current limiter) and, subject to evaluation, will progressively deploy them on our system, to learn about how they can complement existing tools and technologies to reduce the risk of ignitions. We will continue testing the latest and best technologies to evaluate their potential to further reduce risk. We continue to advance our engineering standards to incorporate new technologies and have implemented such innovations, with composite wood poles and the use of low flammability transformer oil as existing examples.

It is neither appropriate nor sufficient to just rebuild the current electric system, with the current capabilities, using hardened materials and equipment. As noted previously, PG&E's goals reach beyond wildfire mitigation. We believe our customers and our state need us to reimagine and build the electric grid of the future as a secure, resilient, reliable, affordable, and integrated platform that enables continued gains for clean-energy technologies and California's economy.

Asset Management and Inspections

TABLE 7
ASSET MANAGEMENT AND INSPECTIONS MATURITY TIMELINE

2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030

- Move all patrol and inspection activities to digital data platforms.
- Evaluate consolidation of distribution and transmission inspection tools, methods, and personnel.
- Move towards risk informed inspection protocols.
- Increase granularity of asset inventory data to include inspection and repair history.
- Increase frequency of condition assessment updates to quarterly.

- Continue refining risk informed inspection protocols.
- Mine inspection data to better target at-risk assets.
- Develop a more comprehensive list of asset failure modes.
- Research methods for detecting and preventing asset failures.

- Increase ability to identify asset problems before they result in failure.
- Complete the transition to and widespread integration of a risk-informed and data-driven inspection process.
- Refine risk data for more targeted inspections.
- Gain deeper insight into asset condition through advanced technologies, data management, and analytical capabilities.

Our asset management and inspection programs include maintaining the inventory of T&D asset information, inspections and condition assessments, repair and maintenance of conditions in need of repair and the associated quality assurance processes.

We will continue to advance our asset management and inspection processes by:

- Moving all patrol, inspection, and construction activities away from paper records towards digital data collection platforms;
- Fully transitioning to a risk-informed and data-driven inspection process;
- Identifying and implementing process efficiencies;
- Establishing improved governance, change management, and communications to enable stability through this intense maturation process;
- Employing new technologies to gain deeper insight into asset conditions; and
- Using advanced data management and analytical capabilities to use asset condition and inspection data more effectively.

The objective of our inspection programs is to identify asset problems before they result in a system failure. We are implementing technology solutions to improve the effectiveness of our asset management and inspection process. We are adopting mobile inspection applications to improve accuracy, thoroughness and timeliness of our inspection data. We are piloting measures that aim to detect failures, or imminent failures, that are undetectable through visual assessment alone, including below-grade foundation assessments and infrared inspections. We are also exploring the effectiveness of machine learning to identify potential component failures from high-resolution, targeted images.

A risk-informed and data-driven inspection process that includes a broad range of considerations including asset performance trending, asset condition, environment, consequence and other factors will improve the overall RSE of our inspection program. For example, we are already conducting detailed inspections (ground and aerial) of a subset of structures in non-HFTD areas because of higher potential consequences or threats (e.g., highway crossings, high population density regions, higher areas of corrosion, etc.). As we improve our ability to model and quantify risk, our inspection processes will similarly advance to incorporate more refined risk data allowing us to target inspections in location and timing to most impact risk.

We are continuously seeking to improve our inspection process efficiencies. For example, we are fine- tuning our coordination between our asset management and inspection process and our VM process to leverage synergies between the two programs. We have also improved the quality and consistency of asset inspections by using sophisticated data management tools to aggregate field-collected data and photographic documentation on each structure and use Expert Inspectors to review the collected data rather than have assessments conducted in real-time during a field visit.

Vegetation Management and Inspections

TABLE 8
VEGETATION MANAGEMENT AND INSPECTIONS MATURITY TIMELINE

2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030

Vegetation Inventory and Inspection Planning

- Incorporate risk considerations into inspection frequency.
- Expand software tools to manage inspection process.
- Evaluate EVM scope to focus on higher risk trees with the goals of improving overall RSE and achieving a greater overall risk reduction in the short term.
- Incorporate the EVM radial clearance and overhang removal scope into our routine work procedure.
- Increase fuel reduction programs and assess the benefits of these efforts.
- Establish an integrated work management system and database for all of PG&E's VM programs.

Program Execution

- Establish a California-based training program to increase population of trained Pre-Inspectors.
- Establish a California-based training program to increase population of trained tree crew personnel.
- Improve routine program administration structure to increase resource efficiency and customer satisfaction.
- Standup inspection team to oversee PI and tree crew work as it is being implemented.

Vegetation Inventory and Inspection Planning

- Perform a systemwide species inventory of all trees with strike potential of PG&E Distribution Assets.
- Continue to expand the ROWs of higher risk transmission lines with the goal of increasing separation between vegetation and transmission assets.
- Improve RSE outlook for the program overall and incorporate into decision making.

Program Execution

- Continue outreach with communities to educate about the VM Program, with the goal of reducing overall refusals and creating increased partnership on powerline safety and wildfire risk reduction.
- Continue to evaluate new technologies for ways to improve efficiency and effectiveness.
- Enhance work management systems with automation to improve reporting capabilities and timeliness to internal and external parties.

Vegetation Inventory and Inspection Planning

- Extend EVM to most distribution line miles in Tier 2 and Tier 3 HFTDs.
- Leverage risk modeling advancements to inform inspection processes, vegetation clearances, and trim cycles.
- Explore Targeted tree species removal of trees with high fail rates in high risk areas.

Over the 10-year timeframe, we will advance our VM Program in several ways. We will continue to improve our vegetation inventory and condition database beyond the current 365,000 trees in HFTD Tier 2 and Tier 3 areas capable of striking transmission infrastructure. Within 10 years, most of our highest risk distribution line miles in Tier 2 and Tier 3 HFTDs will have had EVM completed to reduce the risk of vegetation-caused wildfire ignitions. We will continue to improve our vegetation inventory, expanding it to our distribution program for all areas within HFTD. We will continue to incorporate the advances in risk modeling (see Risk Assessment and Mapping) to better use ignition risk modeling to identify ways of reducing vegetation ignition Risk. VM will incorporate lessons learned, will assess the risk reduction and effectiveness of our VM programs and adjust as needed.

Grid Operations Protocols

TABLE 9
GRID OPERATIONS PROTOCOLS MATURITY TIMELINE

2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030

Load Management and BTM for Microgrids

- Partner with key external stakeholders for DR and BTM Program design (e.g., California Energy Commission (CEC)).
- Identify candidate substations for piloting DR and BTM programs to support load management during PSPS events.
- Pilot DR and BTM program(s) and document lessons learned, including which generation technologies can best pair with DR.
- Propose DR and BTM program(s) for full-scale rollout.

Clean Temporary Generation

- Test and pilot clean temporary generation technologies in controlled and field environment.
- Partner with vendors to address any operational concerns and ensure scalability of technology and any fueling/refueling logistics.
- Embed clean temporary generation in procurement framework for PSPS mitigation.

PSPS Event Execution

- Reduce average grid re-energization time to 12 hours after all clear from a PSPS event.
- Track and validate restoration timeliness performance, identify constraints, and develop continuous improvement solutions.
- Partially automate the re-inspection process prior to re-energization following a PSPS event.
- Increase and maintain fleet of 65 exclusive-use helicopters for patrol.
- Acquire two fixed wing aircraft with MX15 camera systems to enable night patrol of transmission circuits.
- Develop, test, and operationalize drone use for patrol.
- Conduct pre-flights of all potential PSPS circuits to identify patrol method and incorporate into mapping.
- Identify PSPS enhancements based on after-action reviews from exercises and events.
- Develop updated training materials and refine cadence based on after-action reviews, process updates, and PSPS exercises and events.
- Redevelop circuit segmentation guides and restoration maps by circuit, incorporating and prioritizing critical and essential customer restoration.
- Automate PSPS map creation in GIS.
- Incorporate Estimated Time of Restoration (ETOR) management at the Operations Emergency Center-level post-weather event for more granular and accurate ETOR management.
- Increase PSPS notifications to greater than 95 percent of customers and virtually 100 percent of known medical baseline customers.
- Expand the fidelity of modeling for PSPS decision support to include historical data and expert evaluation.

TABLE 9
GRID OPERATIONS PROTOCOLS MATURITY TIMELINE
(CONTINUED)

2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030

Load Management and BTM for Microgrids

- Deploy DR and BTM programs at multiple substations in combination with temporary and/or permanent generation technologies.

Clean Temporary Generation

- Continue supporting market development and partnering with clean temporary generation technology vendors.
- Scale penetration of clean technologies in temporary generation portfolio.

PSPS Event Execution

- Evaluate exclusive use helicopter quantities based on risk and historical use.
- Continue refining use of drones.
- Continue Identifying program enhancements based on after-action reviews from exercises and events.
- Continue refining PSPS restoration collateral (segment guides, maps).
- Identify opportunities to partially automate PSPS patrols (e.g., LiDAR, satellite).
- Continue tracking and validating restoration timeliness performance, identify constraints, and develop solutions.
- Continue ETOR refinement processes.
- Continue updating training collateral based on after-action reviews from exercises and events.

PSPS Event Execution

- Target smaller and less frequent PSPS events through better system and weather modeling.
- Continue refining use of drones.
- Continue identifying program enhancements based on after-action reviews from exercises and events.
- Continue refining PSPS restoration collateral (e.g., segment guides, maps).
- Identify program enhancements based on after-action reviews from exercises and events.
- Track and validate restoration timeliness performance, identify constraints, and develop solutions.
- Continue ETOR refinement processes.
- Continue updating training collateral based on after-action reviews from exercises and events.

PG&E’s continuous learning, as well as benchmarking of the best practices around PSPS reduction, indicates that improving weather forecasting, enhancing VM, hardening the grid, and the use of microgrids and other backup power solutions, where appropriate, can substantially reduce PSPS events and their impact.

PG&E’s current grid architecture has a high proportion of overhead distribution and transmission infrastructure within high fire threat districts. With an ever-increasing wildfire risk from climate change coupled with periodic Diablo wind conditions, it is likely that we will still need to use PSPS events to manage catastrophic wind-related fire risk over the next ten years, barring any significant innovations in engineering and/or system protection. However, we expect to be able to significantly reduce their scale, and duration through measures including better risk management, grid re-design and hardening, and distributed resources.

PG&E's approach to reducing the impact of PSPS events is to:

- Improve our meteorology modeling so that PSPS events potentially become less frequent or smaller, without increasing risk of a catastrophic wildfire;
- Improve our distribution and transmission modeling so that de-energization scope for a given PSPS event increasingly becomes more targeted and smaller, without increasing risk of a catastrophic wildfire;
- Improve operational protocols so PSPS events become less frequent, impacting fewer customers and shorter in duration;
- Harden the grid in combination with some grid re-design efforts to reduce ignition risk during high wind conditions posed by overhead infrastructure in high fire threat environments, to drive down ignition risk and spread;
- Align on a target PSPS resilience planning criterion and refine our ability to compare options like transmission hardening to other options like the use of non-wires energy supply solutions;
- Work with customers and other partners to innovate in areas where stand-alone power systems can cost-effectively eliminate the need for overhead infrastructure without jeopardizing customer reliability or safety;
- Develop a portfolio of non-wires energy supply solutions that can effectively provide power to safe-to-energize customers impacted by an upstream outage during a PSPS event. Explore the suitability, reliability, and cost-benefit of various non-wires solutions including temporary and permanent generation at our substations for microgrids, temporary and permanent mid-feeder generation on the distribution system, providing backup power support to individual customers where needed, identifying and deploying clean temporary generation technologies, facilitating community microgrids, supporting deployment of BTM resources, and the use of energy efficiency and DR. These solution options vary by reliability, PSPS scoping and wildfire risk, land availability, the suitability and scalability of various generation technologies, local distribution grid characteristics, customer acceptance, cost,

operational profile, and the profile of the customers served by the substation such as critical customers like medical facilities, pharmacies, police and fire stations;

- Partner with industry experts to identify new innovations in engineering and system protection that can significantly reduce or eliminate the risk of overhead electrical infrastructure in high fire threat areas;
- Continue the evolution and deployment of our sectionalizing program which can reduce PSPS scope by allowing more surgical application of PSPS when required, limiting the number of customers affected when a PSPS event is necessary; and
- Work to quantify the value of hardening by developing RSEs for more programs, improving data accuracy and granularity.

Ignition risk is also affected by climate change. Our current modeling processes are primarily backward-looking, using historical weather data as a stressor against planned hardening to determine the future likelihood of shutting down a power line and thus requiring a PSPS. Moving forward, we plan to: increasingly incorporate the impact of climate change on weather, improve the predictive capability of our modeling, and seek new mitigation insights.

Data Governance

TABLE 10
DATA GOVERNANCE MATURITY TIMELINE

2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030

- Develop an Enterprise Data Management Program, enterprise strategy, enterprise governance and operating model, Electric Operations' implementation plan, and key performance indicators to track progress against said plan.
- Develop a catalog/inventory of data sources including profiling of databases for duplicity and utilization.
- Develop a catalog/inventory of critical business terms and other relevant metadata.
- Continue execution of improvements to data quality and related business processes, including: corrections to customer contact information, grid topology, and asset information.
- Create data literacy educational materials/curriculum customized to key personnel to improve data collection, quality, and utilization processes,

- Scaled execution against Electric Operations' implementation plan, resulting in the improvement or creation of data products that enable business processes focused on risk reduction and operational excellence.
- Continue to grow and enable a Data Stewards community, including establishing a board of Data Owners and outlining the board's role in data governance and retention decisions.
- Development and initial execution of a cloud migration approach, including data selection criteria, prioritization of databases to be migrated and a roadmap of required activities, including change management plan.
- Execute data architecture activities, including the rationalization and retirement of databases to increase database integration.
- Continue to improve and document business processes that generate data.

- Rationalize and align business intelligence dashboards and reports, including profiling for duplicity and utilization.
- Develop data access Application Programming Interfaces to enable increased partnerships and transparency with researchers, regulators, and state and local governments.
- Establish and enforce comprehensive governance patterns for the collection and storage of new data.
- Refine analytics operating model and organization structure to further develop high-quality predictive and prescriptive analytics for risk informed decision making.
- Continuously evaluate tools, technology, and performance against industry best practices to adjust the plan as appropriate.

PG&E has already begun to improve our data governance capabilities. We have created a new Enterprise Data Management Program with a Chief of Data Governance accountable for improving the utility's data management maturity and capabilities within each line of business including Electric Operations. The Data Management Program will strengthen the:

- Ability of data to support coherence across the business strategy, objectives, and plan;
- Way in which our data systems and embedded information facilitate risk-based decision-making processes; and
- Accuracy of the data in our systems.

This program establishes an enterprise data governance policy and objectives aligned to PG&E's priorities, plans, and processes for maturing data governance functions across the enterprise. The plan embeds data governance competencies in staff involved in key processes and establishes data governance metrics and corrective actions to address data nonconformities.

We have a number of initiatives to improve the accuracy of the data in our systems. These include improving the basic accuracy of customer contact information, including that of PG&E's most vulnerable medical baseline customers; using advanced technology to correct the system of record locations and accurately reflect real-world conditions for assets; and mapping customer locations to county parcels to improve outage reporting accuracy.

The data management plan adopts a data stewardship approach that treats data as an asset, investing in it to maximize long-term value. The plan is flexible and structured to evaluate the impact of problems and achieve quick wins while maximizing realized value to the business over the long term. We will "tune" our efforts across the enterprise by identifying appropriate levels of investment in data, considering the downstream uses of data and asking whether the effort can make the data "fit for purpose." Our plans to measure data baselines, implement improvements, track our progress, and identify the impact of each investment in data quality will be iterative and flexible, minimizing lost productivity when business conditions and priorities change.

Resource Allocation Methodology

TABLE 11
RESOURCE ALLOCATION METHODOLOGY MATURITY TIMELINE

2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030

- Move to a circuit-based approach to planning to achieve higher risk reduction through coordination, such as planning system hardening and VM work to be executed concurrently.
- Incorporate scenarios and associated risk reduction potential into plans for initiatives.
- Increase granularity of scenario projections and RSE down to the circuit level.
- Develop RSEs across a broad range of initiatives.
- Increase the detail and geographic granularity of RSE down to the circuit level.
- Incorporate RSE into capital allocation process.
- Risk effectiveness by mitigation is deeply embedded into the resource allocation process guiding the prioritization and tradeoff analysis.
- Refine use of investment decision optimization tools.
- Leverage a more comprehensive analysis framework.
- Continue improving end-to-end work management processes.
- Improve staff competencies with risk and investment modeling tools.

The resource allocation methodology fully incorporates the concept of RSE and prioritizes across a wide variety of mitigations. PG&E continues to develop capabilities for optimizing resource allocation across a broad portfolio of initiatives, targeting risk at the protection zone and asset levels. We are in the process of piloting an investment planning tool (Copperleaf C55), based on industry asset management best practices, to identify the optimal timing and combination of investments balancing risk reduction effectiveness, execution capabilities and affordability (impact on rates). This tool will allow PG&E to build upon our current optimization scenario analysis and workplan selection process for grid hardening and VM, recognizing portfolio-wide RSEs across a multi-year planning time horizon. We are structuring data at the more granular protection zone and asset levels to build the foundation for the more comprehensive analysis framework we are developing over the coming years.

Key components of advancing PG&E's resource allocation capabilities over the 10-year timeframe include:

- Enhancing asset management and inspection practices;

- Advancing investment planning tools for optimizing portfolio-wide RSE;
- Continuing to improve end-to-end work management; and
- Increasing personnel competencies with risk and investment modeling tools and strategies.

Emergency Planning and Preparedness

TABLE 12
EMERGENCY PLANNING AND PREPAREDNESS MATURITY TIMELINE

2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030

- Incorporation of drills to audit viability and execution of wildfire plans.
- Evolution of wildfire plan to incorporate confounding and simultaneous disasters.
- Taking a leading role in the integration of PG&E’s wildfire plan with the plans of other stakeholders.
- Refine inventory of resources available for repairs to those with high RSEs.
- >99 percent of PSPS-affected customers and virtually 100 percent of PSPS-affected Medical Baseline customers receiving complete information.
- Develop an After-Action Review Standard and After-Action Procedures that outline the execution steps of the After-Action Review process.
- Develop After-Action Procedures that outline the execution steps of the After-Action Review process.
- Develop Wildfire Annex and enhancements based on after-action reviews from exercises and events.
- Conduct enhanced wildfire exercise in 2021 and begin developing progressively complex exercises including the use of drills, seminar, table-tops, and functional exercises.
- Include public sector agencies as planners and players.

- Evaluate After-action Standard and Procedures for continuous improvement.
- Continue incorporating enhancements based on after-action review, exercises, and event response.
- Include Wildfire exercises in PG&E's Multi-Year Training and Exercise plan, and begin to incorporate concurrent hazard response from the additional Hazard Specific Annexes to the Company Emergency Response Plan.
- Expand the inclusion of public sector agencies as both exercise planners and participants in a PG&E exercise.

- Continue to integrate the WMP with disaster and emergency plans.
- Update service restoration workforce training from after-action reviews.
- Continue incorporating enhancements based on after-action review, exercises, and event response.
- Identify program enhancements based on after-action reviews from exercises and events.
- Expand inclusion to the public sector agencies in a collaboratively led full-scale wildfire exercise.

Within 10 years we expect to be using robust emergency management plans and strategies that meet and exceed established best practices in the industry. We will continue to integrate our wildfire plan with our overall disaster and emergency management plans. We will continue to improve our community and public safety agency outreach and education efforts through open houses and webinars for customers and improving the interactivity and robustness of our website. Our training for our service restoration workforce will be updated as we learn from past experiences and after-action reviews.

Stakeholder Cooperation and Community Engagement

TABLE 13
STAKEHOLDER COOPERATION AND COMMUNITY ENGAGEMENT MATURITY TIMELINE

2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030

- Incorporate benchmarking and best practices from other utilities.
- Formalize processes to incorporate lessons learned from other utilities.
- Improve cooperative relationships with communities in HFTD.
- Implement annually-updated plans to further reduce wildfire and PSPS risk to LEP and AFN communities, among other critical constituencies.
- Increase coordination with fire suppression crews including fire detection and fire propagation.
- Further gather, evaluate, and incorporate feedback from community partners and first responders to improve collaboration and processes.

- Continue to gather and incorporate feedback from community partners and first responders.
- Incorporate technology such as integrated communications and data sharing platforms to support better partnership with fire suppression and first responder agencies.
- Deepen community outreach programs and relationships with property owners.
- Develop new partnerships within and outside California to identify and incorporate risk-reduction best practices.

- Continue to improve stakeholders' outreach and education efforts.
- Lead collaborative partnerships to identify and incorporate best practices to reduce risk.
- Complete buildout of integrated operations and communications structures to support true collaboration with communities and customer groups.
- Final maturation of processes to seamlessly share information with industry peers, researchers, scientists, and other inside and outside California.

We will continue to deepen our community outreach programs and relationships with the communities and property owners where PG&E assets are located. We will work with partners inside and outside California to identify and incorporate best practices that can reduce wildfire risk. We have made significant progress working with fire suppression agencies across a range of activities including: VM, training, deployment of cameras and weather stations, and system hardening; these efforts will continue to strengthen and evolve. The absolute essence of Stakeholder Cooperation and Community Engagement is about learning from our partners and paving the path forward together. PG&E is committed to that journey and increased, improved partnership over the next 10 years.

Overall

In summary, PG&E's grid architecture, lines and equipment will need to change over the next 10 years to support our objectives. PG&E's long-term WMP effort seeks to optimally-reduce wildfire risk and the impact of PSPS events, while supporting other objectives, including maintaining overall reliability, improving resiliency, and advancing grid capabilities to integrate DERs and support decarbonization goals. The regulatory, technological, and customer dimensions around these other objectives are unclear, and the appropriate, precise architecture of the grid in 10 years is uncertain. As discussed above, we expect our grid to be smarter, safer, more flexible, cleaner, more distributed, and more resilient with significantly fewer PSPS events affecting fewer customers. But more analysis is needed to identify how we can achieve these attributes, given the need to address evolving technology and engineering capabilities and societal goals.

Over the next 10 years our grid will be significantly more hardened, which should substantially reduce the risk of wildfire ignition. Our hardening will include 7,100 miles of distribution infrastructure and targeted re-location of some overhead distribution lines to underground. The grid will incorporate microgrids and other local, flexible generation in some areas where hardening utility infrastructure was not the optimal choice.

Most of our distribution line miles in Tier 2 and Tier 3 HFTDs will have had EVM activities completed to reduce the risk of vegetation-caused wildfire ignitions.

Much of the T&D grid will have been sectionalized and automated to enable more surgical operation and segmentation, and to make PSPS de-energizations and restorations smaller, faster, and less impactful. We will also have installed more monitoring and sensors across the grid, with sophisticated analytics tools to improve situational awareness and operational capability.

Our WMP positions us for long-term improvements in wildfire risk. PG&E's approach to wildfire risk reduction has evolved and improved over the past several years. The Company's three strategic imperatives, outlined in the 2020 WMP—reducing wildfire ignition potential, reducing wildfire spread, and reducing the impact of PSPS—provide a solid foundation to support long-term wildfire safety goals.

PG&E's WMP is structured to support long-term wildfire safety goals. The plan tracks and assesses the performance of wildfire risk mitigation activities over time to validate their effectiveness and support prioritizing of those activities. The plan incorporates improving research, information, data, technologies, and other tools into wildfire risk reduction efforts, including PSPS targeting and minimization activities. Based on observed performance, we will continue using, modifying, and improving elements of WMPs for as long as these measures are cost-effective in reducing the risk (frequency, scope, and consequences) of wildfires—given the evolving threat of climate change in California.

We have found, and will find, many solutions to the wildfire risks from collaborations; our WMP is informed by regular benchmarking with other utilities within California and Australia, as well as engagement with academia, government agencies, technology providers, and others.

At a tactical level, PG&E's WMP identifies near- and mid-term actions to advance our programs. We understand that more analysis is needed to calibrate and appropriately extend these actions, and we have built such analyses into our current long-term plan development process. As we build that plan and execute it, we will continue to learn and harvest the best ideas from many sources to continue striving toward our ultimate goal of avoiding catastrophic wildfires associated with utility equipment for the benefit of all Californians.

CONDITION PG&E-1

PG&E GROUPS INITIATIVES INTO PROGRAMS AND DOES NOT PROVIDE GRANULAR INITIATIVE DETAIL

Deficiency: PG&E groups initiatives into "programs," making it difficult to assess the effectiveness as well as the cost of individual initiatives within these programs. For example, PG&E does not separately report undergrounding from its overall $5.1 billion system hardening planned spend, making it impossible to determine how much PG&E spends on undergrounding and difficult to assess the various initiatives within this program. Furthermore, PG&E does not break down the outcomes or results of individual initiatives as required by the guidelines. For example, in Table 1, PG&E was required to break down results from inspections over the past 5 years into each of the following inspection types: Patrol inspections, Detailed inspections, and Other inspections. PG&E reported all inspection types together, providing no basis for comparison of PG&E to its peers by inspection type and making it difficult to determine the effectiveness of PG&E's various inspection types.

Condition: In addition to the requirements of the relevant Condition in the Guidance Resolution, PG&E shall develop and furnish an RCP that includes:

i. A detailed break-down of its programs outlined in Section 5.3 into individual initiatives, reporting planned spend on each individual initiative, describing the effectiveness of each initiative at reducing ignition risk, outlining outcomes (including providing results of detailed, patrol, and other inspections individually in Table 1, as required in the WMP Guidelines), and providing the information required for each initiative as required in Section 5.3 of the Guidelines; and

In our July 27, 2020 response to Condition PGE-1, we committed to following up in this filing with three remaining pieces of information: (1) completing the remaining columns (highlighted in gray below) in the Section 5.3 of the 2020 WMP Templates, (2) outlining outcomes of all WSD-defined initiatives, and (3) providing a further breakdown of previous inspection findings.

FIGURE 3
SECTION 5.3 COLUMNS OF THE 2020 WMP TEMPLATES

Table																
Initiative activity	Year	Total per-initiative spend	Subtotal A: Capital expenditure ($1000's)	Subtotal B: Operating expenses ($1000's)	Line miles to be treated	Spend ($1000's)/ treated line mile	Ignition probability drivers targeted	Risk reduction	Risk-spend efficiency	Other risk drivers addressed	Existing/ new	Existing: What proceeding has reviewed program	If new: Memorandum account	In / exceeding compliance with regulations	Cite associated rule	Comments

For the first PGE-1 follow-up, please refer to Attachment 2020WMP_ClassB_Guidance-1_Atch01,[15] which consists of the updated tables from the set of tables (2020WMP_ClassA_RCP_PGE-1_Atch01) submitted on July 27, 2020. These are referenced jointly as "Tables." The Tables submitted include updated information for each initiative and all of the columns as required in the WMP Guidelines. As we have broken down our programs into individual initiatives, the updated information in the tables may not link precisely to the 2020 WMP submitted in February.

For the second PGE-1 follow-up, we have added a column to the updated Section 5.3 Tables (see Attachment 2020WMP_ClassB_Guidance-1_Atch01). This new column describes the anticipated near-term outcomes from each WSD-defined initiative. Given the diverse nature of the initiatives many of these outcomes are qualitative descriptions of expected outcomes, and others reflect quantifiable anticipated improvements. The added outcomes focus on near-term measures because the long-term outcomes of most initiatives converge on very similar, ultimate outcomes like fewer outages, ignitions, and wildfires or limited wildfire spread.

The third PGE-1 follow-up asks for a further breakdown of previous inspection findings. As we explained in the July 27 response and in subpart ii below, our systems only allow for further breakdown of findings for the Transmission inspection program in 2019. This has been broken down in the updated Table 1-2 below by enhanced ground inspection, enhanced aerial (drone or helicopter), and all other findings.

15 2020WMP_ClassB_Guidance-1_Atch01 contains an updated set of 5.3 tables from 2020WMP_ClassA_RCP_PGE-1_Atch01 (submitted with the Class A conditions).

TABLE 14
TABLE 1-1 FROM THE 2020 WMP

Progress Metric Name	Annual Performance					Unit(s)
	2015	2016	2017	2018	2019	
Grid Condition Findings From Inspection – Distribution	0.434553	0.580677	0.591185	0.577253	6.910547	Number of Level 1, 2, and 3 findings per mile of circuit in HFTD, and per total miles of circuit for each of the following inspection types:
	0.000118	0.000236	0.041991	0.009524	0.014522	Number of Level 1 findings (A tags) per mile of circuit in HFTD (Zone 1, Tier 2 and Tier 3 combined)
	0.013066	0.009327	0.013656	0.022117	0.175954	Number of Level 2 findings (B tags) per mile of circuit in HFTD (Zone 1, Tier 2 and Tier 3 combined)
	0.421370	0.571114	0.535537	0.545612	6.720071	Number of Level 3 findings (E+F tags) per mile of circuit in HFTD (Zone 1, Tier 2 and Tier 3 combined)
	0.000984	0.001535	0.058284	0.234986	0.035931	Number of Level 1 findings (A tags) per mile of total circuit
	0.062810	0.053483	0.070327	0.085006	0.314207	Number of Level 2 findings (B tags) per mile of total circuit
	1.395317	1.704329	1.451082	1.383038	7.976348	Number of Level 3 findings (E+F tags) per mile of total circuit

TABLE 15
UPDATED TABLE 1-2 FROM THE 2020 WMP

Progress Metric Name	Annual Performance					Unit(s)
	2015	2016	2017	2018	2019	
Grid Condition Findings From Inspection – Transmission	0.523258	0.687421	0.419910	0.926878	10.956742	Number of Level 1, 2, and 3 findings per mile of circuit in HFTD, and per total miles of circuit for each of the following inspection types:
	0.018100	0.005792	0.009774	0.003620	0.007240	Number of Level 1 findings (A tags) per mile of circuit in HFTD (Zone 1, Tier 2 and Tier 3 combined) Ground (EI)
	0.037828	0.021357	0.027873	0.030226	0.463529	Number of Level 2 findings (B tags) per mile of circuit in HFTD (Zone 1, Tier 2 and Tier 3 combined) Ground (EI)
	0.467330	0.660271	0.382262	0.893032	5.301719	Number of Level 3 findings (E+F tags) per mile of circuit in HFTD (Zone 1, Tier 2 and Tier 3 combined) Ground (EI)
	0.000000	0.000000	0.000000	0.000000	0.006878	Number of Level 1 findings (A tags) per mile of circuit in HFTD (Zone 1, Tier 2 and Tier 3 combined) Drone (DI)
	0.000000	0.000000	0.000000	0.000000	0.434751	Number of Level 2 findings (B tags) per mile of circuit in HFTD (Zone 1, Tier 2 and Tier 3 combined) Drone (DI)
	0.000000	0.000000	0.000000	0.000000	4.742624	Number of Level 3 findings (E+F tags) per mile of circuit in HFTD (Zone 1, Tier 2 and Tier 3 combined) Drone (DI)
	0.038069	0.011862	0.014014	0.006179	0.026428	Number of Level 1 findings (A tags) per mile of total circuit (Other)
	0.059697	0.057710	0.061683	0.061021	0.142566	Number of Level 2 findings (B tags) per mile of total circuit (Other)
	0.565352	0.543614	0.436138	0.711062	0.967007	Number of Level 3 findings (E+F tags) per mile of total circuit (Other)

ii. If PG&E does not have the relevant data in its possession at the initiative level, it shall:

1) Explain the difference between what it reports and what the WMP Guidelines require;

2) ***Explain why it cannot meet the WMP Guidelines; and***

3) ***Develop a plan including a detailed timeline to obtain and share the required information at the initiative level, rather than the program level.***

Table 1 (Results of detailed, patrol, and other inspections): As Condition PGE-1 stated, the 2020 WMP Guidelines required that we provide results of detailed patrol, and other inspections individually by year initiated and by HFTD location in Table 1. In our 2020 WMP at Tables 1-1 and 1-2, PG&E provided a list of corrective notifications (Line Corrective for Transmission or Electric Corrective (EC) for Distribution) by year initiated and by HFTD location. However, we cannot produce a split of those historic corrective notifications by source, e.g., patrol or inspection activity type (initiative level), to fully align with the WMP Guidelines. We do not have meaningful historic data that specifies the initiating patrol or inspection activity (initiative) for each tag in our system of record—before we instituted the WSIP in 2019, PG&E records did not uniformly identify specific distinctions for routine patrol, routine inspection, non-routine patrol or inspection, IR inspection, or other patrol or inspection types when creating a Corrective Notification. Our system of record has no way to trace back to the source activity (initiative) for corrective notifications predating 2019 (although the date, initiator name, and other details are available).

During the 2019 WSIP, PG&E began manually assigning keywords to transmission corrective notifications to designate them as WSIP-related, making manual record adjustments to attach a prefix of EI (enhanced ground inspection) or DI (drone/aerial inspection) to flag the initiating inspection activity type. For the 2019 Transmission WSIP, PG&E can therefore split the EI (ground) and DI (aerial) corrective findings for transmission inspections, as reflected in the updated Table 1. For distribution WSIP inspections, only ground inspections were performed so no further split of corrective findings is possible.

PG&E adopted a new mobile application (the “Inspect App”) in 2020 for detailed overhead inspections. This app follows the enhanced inspection process developed in 2019 as part of WSIP, and enables our inspectors to automatically assign a descriptor for the detail inspection records and associated corrective notifications for both T&D (see Inspect App screenshot below).

FIGURE 4
INSPECT APP – "IDENTIFIED DURING" FIELD

From now on, corrective notifications records generated from Detailed Overhead Inspections, Climbing Inspections, Aerial Inspections, and PSPS Patrols will have an indicator facilitating the required initiative-level reporting. The following patrol and inspection programs will begin using the mobile, digital platform (Inspect App) during 2021 and 2022: Routine Overhead Patrols (2021), Nonroutine (Emergency) Patrols (2021), Pole Test & Treat, Substation Enhanced Ground Inspections, Underground Patrols and Underground Inspections. While Pole Test & Treat and Substation Enhanced Inspections currently use existing mobile/electronic software solutions, they will be converted to the unified mobile inspection software (the Inspect App) during 2022. Electronic solutions for other programs (such as Underground Patrol and Inspection) will depend on the successful release of mobile technology for the above-mentioned overhead inspection programs, which have priority due to their greater alignment with wildfire risk. Once a program has been integrated into the mobile digital platform, and the process has stabilized, we will be able to report the corrective actions identified from that inspection type from that point forward.

CONDITION PG&E-2

EQUIPMENT FAILURE

Deficiency: Of all PG&E ignitions on its distribution system, 37 percent were caused by equipment failures over the last five years with the largest driver being conductor failures at 19 percent of total PG&E ignitions (or 53 percent of all equipment failure driven ignitions). Based on normalized data, this rate is almost 50 percent higher than other large electrical corporations and has a significant impact since PG&E has by far the most overhead conductor miles.

Condition: In its first quarterly report, PG&E shall:

i. ***Explain why its equipment failure rate is so high compared to other large electrical corporations;***

PG&E acknowledges that its high rate of equipment failure pose a serious risk to the safety and reliability of our system. One reason why we have higher than expected equipment failures is the current protocol for categorizing "initiating events." At this time, when a PG&E first responder is unable to identify the cause for ignition in a timely manner, our reporting standards and requirements direct that the ignition cause is defaulted to equipment failure. In many instances, this designation may not properly categorize the true cause for ignition, but it remains documented as such.

Our current wildfire data analysis shows that out of the approximately 38 percent equipment failure rate reported, 13.6 percent is attributed to unknown/other causes. Even if we are able to determine a specific ignition cause after the initial investigation (e.g., tree limb contact or other third-party contact with a line, rather than equipment failure), staffing limitations often preclude correction of the historical investigation records. We have committed to overhaul our ignitions tracking process to better understand and accurately assess ignition cause, and this will lead to better ignition data records and better ignition cause analysis. Until these improvements have been completed, the 38 percent of ignitions reported as caused by equipment failure probably overstates actual failure rates and consequences.

A second leading factor is the large percentage of small copper conductor found across PG&E's rural service territory. PG&E provides electric service to 16 million customers across a 70,000 square-mile service area encompassing six times more rural land relative to other large electric utility providers. In rural areas that are not at an elevated (Tier 2) or extreme (Tier 3) risk of wildfire, according to the CPUC HFTD Map, the most prevalent type of conductor found are small copper conductor (#6 and #4), which have elevated equipment failure rates relative to other types of conductor (see

PG&E's response to Condition PGE-3 for additional insight into the small conductor failure rates). There are approximately 19,300 circuit miles of small copper conductor (#6 and #4) in the PG&E service territory that were installed before 2015, when PG&E stopped using this conductor; this represents 24 percent of the system total.

As noted in PG&E's response to Condition PGE-3, given the risk associated with small copper conductor, we are considering committing additional funding to increase our rate of conductor replacement. Besides routine conductor replacement, we are also replacing a substantial amount of conductor in HFTD areas through our system hardening program.

PG&E acknowledges the need for and commits to develop an equipment failure definition consistent with the other large electrical corporations. This will facilitate more accurate reporting of equipment failures going forward, with more direct data comparisons with other large electrical corporations' equipment failure rates.

ii. Explain how it expects grid hardening, asset management and other initiatives affect the probability of 1) near misses and 2) ignitions; and

PG&E analyzed over 4,000 outage data points from 2015 through 2019 to assess the effectiveness of grid hardening, asset management and other initiatives on reducing the probability of near misses (defined by PG&E as unplanned outages) and ignitions and the potential impact of new wildfire mitigation efforts.

In general, and as detailed in PG&E's "Wildfire 2020 RAMP Post-Filing Workshop," we use an internal System Hardening Mitigation Effectiveness model to guide implementation decisions for select system hardening and targeted VM projects. System hardening and VM show various levels of effectiveness depending on the drivers and sub-drivers that mitigate near misses and ignitions.

In this analysis, PG&E assigned quantitative effectiveness values to determine whether near misses and ignitions would be potentially mitigated as part of its program efforts. The assessment involved over 4,000 combinations of data, including near miss/ignition cause, supplemental cause, equipment involved and equipment condition. These combinations were aggregated to the driver and sub-driver level to determine the overall benefit the wildfire risk reduction mitigation work has on various equipment (effectiveness percentage), summarized in table below. For instance, in line number six noted in the chart below, the broader categorization is a "third-party" driver and the precise sub-driver is a vehicle. Should a circuit and/or pole be considered eligible for system hardening, the effectiveness rate for reduction in a potential ignition is calculated at ~47 percent. For a more detailed assessment, please refer to the 2020 RAMP Report (see Attachment 2020WMP_ClassB_PGE-2_Atch01, "Section EO-WF-25_Mitigation Effectiveness WP").

TABLE 16
SYSTEM HARDENING DRIVER EFFECTIVENESS – IGNITION

Line No.	Driver	Sub-Driver	Effectiveness
1	Third Party	Third Party – Other	48 percent
2	Third Party	Third Party – Unknown	40 percent
3	Third Party	Balloons	80 percent
4	Third Party	Vehicle	47 percent
5	Animal	Animal	69 percent
6	Equip Failure	Capacitor Bank	7 percent
7	Equip Failure	Conductor	50 percent
8	Equip Failure	Crossarm	75 percent
9	Equip Failure	Equip Failure – Other	43 percent
10	Equip Failure	Equip Failure – Unknown	71 percent
11	Equip Failure	Fuse	69 percent
12	Equip Failure	Guy/Span Wire	73 percent
13	Equip Failure	Insulator	68 percent
14	Equip Failure	Lightning Arrestor	90 percent
15	Equip Failure	Pole	55 percent
16	Equip Failure	Recloser	61 percent
17	Equip Failure	Sectionalizer	40 percent
18	Equip Failure	Splice/Clamp/Connector	70 percent
19	Equip Failure	Switch	77 percent
20	Equip Failure	Transformer	74 percent
21	Equip Failure	Voltage Regulator	34 percent
22	Unk or Other	Unk or Other – Other	59 percent
23	Unk or Other	Unk or Other – Unknown	60 percent
24	Vegetation	Branch (Not overhanging, > 12ft)	54 percent
25	Vegetation	Branch (Overhanging)	47 percent
26	Vegetation	Dead	53 percent
27	Vegetation	Fell into (Moderate-Severe defect)	46 percent
28	Vegetation	Fell into (No defect)	50 percent
29	Vegetation	Fell into (slight defect)	45 percent
30	Vegetation	Grow Into	50 percent
31	Vegetation	Other/Unknown	17 percent
32	Vegetation	Branch (Not overhanging, Distance Unknown)	51 percent
33	Vegetation	Branch (Not overhanging, 4-12ft)	65 percent
34	Vegetation	Branch (Not overhanging, within 4ft)*	57 percent

TABLE 17
SYSTEM HARDENING DRIVER EFFECTIVENESS – OUTAGE

Line No.	Driver	Sub-Driver	Effectiveness
1	Third Party	Third Party – Other	48 percent
2	Third Party	Third Party – Unknown	40 percent
3	Third Party	Balloons	80 percent
4	Third Party	Vehicle	47 percent
5	Animal	Animal contact	77 percent
6	Animal	Bird Contact	74 percent
7	D-Line Equipment Failure	Capacitor/Booster/Regulator	44 percent
8	D-Line Equipment Failure	Conductor	54 percent
9	D-Line Equipment Failure	Connector/Splice/Jumper/Kearney	70 percent
10	D-Line Equipment Failure	Cross-arm	86 percent
11	D-Line Equipment Failure	Cutout/Fuse	78 percent
12	D-Line Equipment Failure	Insulator/Woodpin	85 percent
13	D-Line Equipment Failure	Other	77 percent
14	D-Line Equipment Failure	Pole	63 percent
15	D-Line Equipment Failure	Recloser/Sectionalizer	40 percent
16	D-Line Equipment Failure	Secondary/Service	22 percent
17	D-Line Equipment Failure	Support Structure	81 percent
18	D-Line Equipment Failure	Surge Arrestor	90 percent
19	D-Line Equipment Failure	Switch	71 percent
20	D-Line Equipment Failure	Transformer	70 percent
21	Human Performance	Construction Activity	0 percent
22	Human Performance	Contact with High Voltage – Company	0 percent
23	Human Performance	Coordination failure	0 percent
24	Human Performance	Improper Construction	0 percent
25	Human Performance	Operating error	0 percent
26	Human Performance	Personnel- company	0 percent
27	Natural Hazard	Fire – Forest/Grass	27 percent
28	Natural Hazard	Flood/Erosion	42 percent
29	Natural Hazard	Heat Wave	71 percent
30	Natural Hazard	Ice or snow	90 percent
31	Natural Hazard	Lightning	68 percent
32	Natural Hazard	Seismic/Earth Movement/Landslide (Seismic Related)/Liquefaction	70 percent

TABLE 17
SYSTEM HARDENING DRIVER EFFECTIVENESS – OUTAGE
(CONTINUED)

Line No.	Driver	Sub-Driver	Effectiveness
33	Natural Hazard	Water	56 percent
34	Other	Patrol – found nothing	90 percent
35	Other	Patrol – not conducted	90 percent
36	Other PG&E Assets or Processes	Generator	20 percent
37	Other PG&E Assets or Processes	Metering Equipment	0 percent
38	Other PG&E Assets or Processes	Other Circuits	0 percent
39	Other PG&E Assets or Processes	Return Circuit Normal	0 percent
40	Physical Threat	Vandalism	68 percent
41	RIM	RIM – Mapping Errors	0 percent
42	RIM	RIM – Other	0 percent
43	Third Party	Aircraft	53 percent
44	Third Party	Car pole	63 percent
45	Third Party	Contact with intact	75 percent
46	Third Party	Customer equipment	38 percent
47	Third Party	Dig in – Third Party	48 percent
48	Third Party	Fire- house or bldg.	40 percent
49	Third Party	Gun Shot	42 percent
50	Third Party	Kite	90 percent
51	Third Party	Metallic Balloon	89 percent
52	Third Party	Other	76 percent
53	Third Party	Thrown Object	85 percent
54	Third Party	Tree-cutting – Third Party	67 percent
55	Vegetation	Branch (Overhanging)	71 percent
56	Vegetation	Branch (Not overhanging, > 12 ft)	73 percent
57	Vegetation	Other/Unknown	68 percent
58	Vegetation	Fell into (No defect)	56 percent
59	Vegetation	Grow Into	73 percent
60	Vegetation	Fell into (slight defect)	55 percent
61	Vegetation	Fell into (Moderate-Severe defect)	57 percent
62	Vegetation	Dead	67 percent
63	Vegetation	Branch (Not overhanging, Distance Unknown)	69 percent
64	Vegetation	Branch (Not overhanging, 4-12 ft)	70 percent
65	Vegetation	Branch (Not overhanging, within 4 ft)	59 percent

iii. Address whether its prior maintenance history is causing higher rates of equipment failure now and, PG&E shall include in this report all instances where a court or other decision making body found fault with PG&E's historical equipment maintenance, either with regard to individual assets or its maintenance policies as a whole.

PG&E's Prior Maintenance History and Equipment Failure Rates

PG&E's system maintenance practices have been and continue to be in line with industry practices and standards. Historically, our maintenance activities were performed in accordance with California regulatory requirements such as GO 95, GO 128, and GO 165. However, recent incidents and lessons learned confirm that more can be done beyond the existing regulatory requirements to maintain and/or strengthen our electric infrastructure and reduce wildfire risk. PG&E has recently made a number of improvements to inspection practices, construction standards, system automation, and VM that will increase safety and reduce fire ignitions and wildfire risk since they have been implemented.

Much of the utility industry still primarily assesses system health and performance based on reliability performance, where fewer and shorter unplanned customer outages indicate a "healthy" system. PG&E's historical practices similarly focused on reliability as a primary measure of system health and the improvements in system reliability supported a continuation of existing maintenance practices. Industry reliability data from the time before our recent changes in practices and standards demonstrate that our system reliability performance was generally around the industry median. However, we did not have a thorough understanding that the environment surrounding our assets was changing and the electric system risk profile was shifting. Industry standards and the regulatory compliance framework were also not changing to take into account the changing environment and the increasing risk around our assets. As climate change accelerates and California's population in the urban-wildlands interface grows, the consequences of an outage or failure may no longer be just a customer outage, but a potentially catastrophic wildfire.

With the benefit of hindsight, PG&E acknowledges that our prior maintenance practices could have been improved sooner to shift from the utility industry standard and the regulatory compliance framework that had a reliability focus to a focus on wildfire risk. However, it is impossible to state whether our prior maintenance practices have caused "higher-than-expected" equipment failures rates, as we were following the universally accepted standards and regulations that are largely similar to the practices being followed by other large utilities inside and outside of California. As indicated in the tables below, PG&E's reliability performance, in terms of both number of outages per customer (System Average Interruption Frequency Index (SAIFI)) and total outage duration per customer (System Average Interruption Duration Index (SAIDI)), were better than the nationwide utility median every year from 2014-2017 (before the onset of catastrophic fires in our service territory).

TABLE 18
INDUSTRY QUARTILE PERFORMANCE ON RELIABILITY INDICES

Year	SAIFI	SAIDI
2008	2	3
2009	3	3
2010	3	3
2011	2	2
2012	3	3
2013	2	3
2014	2	2
2015	2	2
2016	2	2
2017	2	2
2018	3	3

Note: Based on the IEEE Benchmark 2019 Results that included reliability data through 2018.

PG&E and utilities across the country are adapting to a changing environment. In 2012, only 15 percent of PG&E's service area was designated by California regulators as having an elevated fire risk. Today, the CPUC recognizes 50 percent of our service area as having an elevated fire risk—tripling in under a decade—and that proportion appears to be growing. For this reason, we began developing a new risk-based approach that goes beyond the standard, historical, reliability-based operating practices and incorporates a risk-informed, resilience-based framework. PG&E programs are now designed to reduce the wildfire threat (i.e., EVM, System Hardening, System Inspections, and PSPS) and are going beyond existing regulatory requirements to address the environmental realities and risks that our customers, communities and assets face. PG&E is performing this work on a scale and pace that the industry has never seen before.

Finding Fault With PG&E's Historical Equipment Maintenance – Courts

With regard to Court decisions, PG&E has searched for decisions in which a court "found fault with PG&E's historical equipment maintenance, either with regard to individual assets or its maintenance policies as a whole" for the period 2010-2020. PG&E also understood that Condition PGE-2 was focused on electrical equipment based on the deficiency, and so limited its search to court decisions addressing electrical equipment maintenance.

There were a number of orders in PG&E's probation proceeding (*United States v. PG&E*, Case No. C 14-00174 WHA, United States District Court for the Northern District of California) related to electrical equipment and maintenance. Because it was not entirely clear what constituted a court decision finding fault, we included probation proceeding orders that reference electrical issues. These orders are included as Attachments (2020WMP_ClassB_PGE-2_Atch02).

In addition, while not a court decision, we include the People's Statement of Factual Basis in Support of the Pleas and Sentencing Statement prepared by the Butte County District Attorney (Factual Statement) (the file named 1220-1 within 2020WMP_ClassB_PGE-2_Atch02) and the Plea Agreement and Settlement with the Butte County District (within 2020WMP_ClassB_PGE-2_Atch02). The Factual Statement addresses in part maintenance issues related to PG&E electric equipment.

Finding Fault with PG&E's Historical Equipment Maintenance – Other Decision-Making Bodies

With regard to decisions by other decision-making bodies, PG&E conducted a search for decisions in which the CPUC and/or the Federal Energy Regulatory Commission (FERC) "found fault with PG&E's historical equipment maintenance, either with regard to individual assets or its maintenance policies as a whole" for the period 2010-2020. PG&E interprets Condition PGE-2 as focused on electrical equipment based on the deficiency, and so limited the search to court decisions addressing electrical equipment maintenance. No formal CPUC or FERC decisions were found.

However, PG&E has received Notices of Violation (NOV) from the CPUC about equipment failures which may result from past maintenance practices. PG&E has categorized NOVs for the cause of the incident as either Third Party, Work Procedure Error, Animal, Equipment Failure, Vegetation, or Other. The 37 NOV letters received from the CPUC from January 1, 2013 to June 4, 2020 categorized as Equipment Failure are summarized in Attachment 2020WMP_ClassB_PGE-2_Atch03. NOVs for equipment failure may include maintenance-related issues and thus this information is being provided in response to Condition PGE-2. PG&E will provide additional information about the NOVs to the WSD upon request, if the WSD would like additional background regarding the issues addressed in any NOV.

CONDITION PG&E-5

PG&E PROVIDES LITTLE DISCUSSION OF HOW IT USES THE RESULTS OF RELATIVE RISK SCORING METHOD

Deficiency: On p. 5-274 of its WMP, PG&E provides Figure PG&E 5-26, which depicts relative risk scores as a function of system hardening in HFTD. The figure and supporting narrative indicate that 95 percent of PG&E's wildfire risk pertains to approximately 5,500 circuit miles in HFTD areas. PG&E's WMP lacks detail and discussion regarding: (1) how this information was used to prioritize WMP initiatives, (2) how this information was used to target where to implement WMP initiatives, and (3) which and what portion/percentage of its 2020 WMP initiatives are targeted toward these identified 5,500 circuit miles.

Condition:

i. Where each of these 5,500 miles are located within its grid, including supporting GIS files;

The underlying data used to create Figure PG&E 5-26 was collected in the later part of 2018 and the 5,500 miles related to circuit segments as PG&E's system was configured at the time. 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. Therefore, PG&E's response to this condition uses current protection zone information to create the supporting GIS files. As such, there are differences caused by the changes to the distribution system, since the original data set was created approximately 2 years ago. See the attached GIS files (2020WMP_ClassB_PGE-5_Atch01) for the locations of just over 4,900 miles of the highest priority circuit segments (based on the 2018 analysis). The remaining approximately 600 miles of the 5,500 highest priority segment miles originally identified can no longer be accurately mapped because of changes to equipment on PG&E's distribution circuits (namely, that the original start or end point of those high priority circuit segments no longer exists in PG&E's GIS system).

ii. How this information was used to prioritize WMP initiatives;

PG&E 2020 WMP p. 5-274 used Figure PG&E 5-26 to depict relative wildfire risk prioritization scores as a function of system hardening in HFTD areas, not to represent PG&E's overall wildfire risk. Figure PG&E 5-26 is a representation of the System Hardening remaining relative score. The figure and the observation that approximately 95 percent of the wildfire risk prioritization of system hardening is in 22 percent of the distribution line miles (5,500 miles) are a representation of the relative risk of the system hardening initiative, that is, an individual analysis to determine a wildfire risk prioritization score for each CPZ based upon components of risk specific to the system hardening program. The information that makes up Figure PG&E 5-26 is taken from the system hardening risk model which is used as one of the tools to prioritize system hardening projects.

iii. How this information was used to target where to implement WMP initiatives;

PG&E identifies areas for system hardening through several targeted approaches:

1) <u>Identified Deteriorated Overhead Conductor</u>: Locations that have been identified through a wire down investigation that have conditions, both environmental and asset, that present a higher risk of line failure in HFTD areas.

2) <u>Fire Risk Ignition Modeling</u>: Utilizing relative risk rankings based on likelihood of failure, high fire spread and consequence, and egress as modeled inputs at a CPZ level.

3) <u>ECOP</u>: These projects are sections of overhead primary where numerous EC tags with high structural impact were found in higher risk CPZs.

4) <u>PSPS Mitigation</u>: These are projects where targeted undergrounding in conjunction with additional segmentation devices could minimize the impact of PSPS to customers in non-HFTD areas or served from existing underground facilities in HFTD areas.

5) <u>Other field Identified Optimization Opportunities</u>: These are projects that are accelerated to be completed in conjunction with other projects such as transmission line replacement with under-build distribution primary.

These projects are then aligned with the risk model, reviewed with the execution team for project status and dependencies, and then targeted geographically to ensure the best possible execution of the work. Throughout the year, the workplan is reviewed and adjusted based on field, dependency, clearance, or other conditions that may slow PG&E’s ability to execute the plan.

iv. ***What percentage of its total planned spend for each of the years 2020-2022 are targeted toward these identified 5,500 circuit miles comprising 95 percent of PG&E's wildfire risk;***

As explained above in PG&E's response to Condition PG&E-5 subpart ii, the 5,500 circuit miles are only relevant to the relative risk score of system hardening. That being said, PG&E's system hardening program is currently targeting around 90 percent of its spend toward these specific 5,500 circuit miles for 2020-2022.

v. ***What percentage of total VM personnel hours are targeted toward these identified 5,500 circuit miles comprising 95 percent of PG&E's wildfire risk; and***

70 percent of total EVM personnel hours, per the WMP initiatives, are for targeted circuit miles within the 5,500 circuit miles of the system hardening risk model. VM and other WMP initiatives (e.g., inspections) address different risks and have different relative risk profiles than system hardening. In this way the different WMP initiatives coordinate to target circuit miles for which the initiative is most effective. The 5,500 circuit-miles specific to the Distribution System Hardening are not the same miles and circuits identified as high risk under the Distribution EVM model because each wildfire risk management initiative uses different methodologies to identify its priority target line-miles.

vi. ***Its rationale for this level of spend and resource allocation to these 5,500 circuit miles and whether PG&E expects to change its allocation of spend and resources from these 5,500 circuit miles.***

The primary benefit of system hardening is to reduce wildfire risk. However, system hardening mitigates other risks such as Failure of Distribution Overhead Assets and Third-Party Safety Incidents because it will reduce equipment failure and reduce the potential for third-party contact with energized conductors.

System Hardening has one of the highest RSE scores in PG&E's 2020 RAMP Report. The 2023-2026 RSE of 7.3 that PG&E has calculated for System Hardening in its RAMP Report is higher than the 2020-2022 RSE of 4.12 calculated in PG&E's 2020 WMP Report. In the 2020 RAMP process, PG&E SMEs reviewed assumptions about how effective System Hardening will be at mitigating certain equipment failure-related ignitions. This review led to an upward revision of PG&E's estimate of the overall mitigation effectiveness of System Hardening.

PG&E is completing our system hardening commitment in 2020 and aims to harden approximately 1,060 circuit miles in 2020-22. PG&E will continue to evaluate the effectiveness of the System Hardening Program and may further adjust its scope to better mitigate risk. System hardening presently accounts for 44 percent of PG&E’s planned spending on wildfire mitigations from 2023-2026, with an RSE of 7.3. The total benefits of System Hardening will grow over time as PG&E upgrades a larger portion of the distribution system in HFTD areas.

CONDITION PG&E-6

DISCREPANCY BETWEEN IGNITION REDUCTION PROJECTIONS

Deficiency: In its WMP, PG&E estimates a 10 percent reduction in vegetation-caused equipment failure and animal caused ignitions from 2019 levels due to its planned system hardening, EVM, and "Tag Repair" work (repair of asset problems discovered during inspections) for 2020 and beyond. It anticipates the same 10 percent trend in 2021 and 2022. PG&E anticipates approximately an 8 percent reduction for all HFTD ignitions, year over year, for 2020, 2021 and 2022. However, on p. 5-274 of its WMP, PG&E indicates expectations that its overhead system hardening efforts will reduce ignitions by 56 percent. Additionally, Table 31 of PG&E's WMP, which reports projected ignitions over the plan period, only reflects a projected 2 percent annual reduction in ignitions over the plan term assuming 5-year historical average weather. PG&E must explain these discrepancies.

Condition: In its first quarterly report, PG&E shall detail:

i. How it arrived at each of these estimates; and

ii. How these estimates can be reconciled.

Development of the 10 percent, 8 percent and 2 percent Ignition Reduction Estimates

The varying ignition reduction figures cited above are not discrepancies because they reflect ignition impacts estimated for different programs, geographies, and denominators, rather than erroneous uses of different figures for the same program and applicability.

PG&E's 2020 WMP estimate of a 10 percent reduction in vegetation-caused equipment failure and animal-caused ignitions is based on an analysis of past performance. PG&E determined that in 2019, EVM, system hardening, and tag prioritization work resulted in a 10 percent reduction in vegetation-, equipment failure-, and animal-caused ignitions (see 2020 WMP, p. 4-22) where these programs were applied within HFTDs (HFTDs).

Taking into account that vegetation-, equipment failure-, and animal-caused ignitions are responsible for approximately 85 percent of all ignitions in HFTDs, multiplying 85 percent of all HFTD ignitions by the 10 percent reduction estimate calculated above, PG&E calculated an estimated 8 percent reduction for *all* ignitions within HFTDs.

PG&E further calculated that only 25 percent of all ignitions in PG&E's system territory occurred in HFTDs. Multiplying this variable by the 8 percent reduction in ignitions in HFTD, PG&E estimated that our EVM, system hardening, and tag prioritization work would cause a 8 percent times 25 percent = 2 percent reduction in all ignitions overall, across PG&E's entire service territory.

PG&E's fundamental forecast of an overall 10 percent reduction for vegetation-, equipment failure-, and animal-caused ignitions in HFTDs, and subsequently 8 percent reduction in HFTD area overall ignitions, was based on the qualitative judgment of PG&E SMEs using the results of 2019 ignitions. At the time, this was viewed as appropriately reflecting the impacts of our EVM, system hardening, and tag prioritization work, which reduced ignitions in 2019 compared to historical averages. PG&E applied that estimate to 2021 and 2022 as well. We also calculated the effectiveness of mitigation programs using RSE, which also estimated an 8 percent HFTD ignition reduction. Thus, we determined that the 8 percent ignition reduction within HFTDs was a reasonable method of calculating ignition reduction estimates. For further details regarding actual and forecast ignition data, please see Table 31-1 and 31-2 in the 2020 WMP.

PG&E has continued to refine the mitigation effectiveness assessments described above in preparation for the RAMP Report filed on June 30, 2020. One key variable that has been newly factored into the assessment is the impact of PSPS compared to our other mitigation programs.

The PSPS variable reflects two additional factors that have been found to influence PG&E's previous assumptions. First, the execution of PSPS during severe fire weather condition reduces the number of ignitions in our system territory by eliminating the possibility of utility equipment-caused ignitions in the areas that have been de-energized. PG&E's nine PSPS events in 2019 further reduced the number of ignitions that would have otherwise occurred in our service area.

Second, as a result of the 2019 PSPS events, PG&E was able to mitigate conditions that may have led to potential ignitions. However, we did not fully reflect these ignition reductions in the original assessments we conducted. By factoring in the PSPS variable, we now believe that ignitions in 2020 and future years may not be reduced by as much as initially forecasted in the 2020 WMP solely as a result of only EVM, system hardening and tag prioritization work. While PG&E believes that a continued decrease in ignitions can be expected in HFTD areas with the efforts of risk-ranked circuit prioritization of continued system hardening, EVM, and tag prioritization work, the percentage reduction may not be the forecasted 10 percent included in the 2020 WMP.

Development of the 56 percent Outage Reduction Estimate

On p. 5-274 of the 2020 WMP, PG&E stated:

> Although overhead system hardening efforts (e.g., covered conductor installation, pole replacement, exempt equipment replacement, etc.) typically will not change the geographic location of those facilities, it is projected to result in a relative risk mitigation effectiveness of 56 percent of reducing ignitions attributed to PG&E's electric assets.

This 56 percent reduction is based on a historical analysis and represents the percentage of past outages that would not have occurred due to system hardening. This portion of the 2020 WMP should have referred to <u>outages</u>, rather than ignitions; PG&E apologizes for this error.

To calculate the 56 percent reduction in past outages due to system hardening, PG&E analyzed five top-level risk drivers for fire ignitions caused by PG&E assets (e.g., vegetation-caused equipment failure, animal-caused ignitions, third-party contact) in HFTDs. This analysis found that system hardening (e.g., covered conductor upgrades, pole replacement, equipment replacement) would have mitigated 56 percent of historical outages with the potential to cause ignitions. The analysis also examined outages where SMEs concluded that system hardening would eliminate the risk of an outage leading to an ignition. Incorporating these outages into this new methodology and applying it back to historical outage data in HFTD areas, we estimate that 374 actual historical outages would not have occurred (out of 664 total outages), or 56 percent, if the above mitigations had been performed to each specific circuit and equipment before the event that caused those specific past outages. This reduction in outages is different than a reduction in the number of ignitions; because most outages do not cause fire ignitions, the percent reduction of ignitions will likely be lower than 56 percent.

Reconciliation

As explained above, the 10 percent, 8 percent, and 2 percent ignition reduction forecasts differ because the 10 percent reduction relates to certain types of ignitions, the 8 percent reduction relates to all ignitions in HFTDs, and the 2 percent reduction relates to ignitions in PG&E's entire service territory. The 56 percent addresses a reduction in outages, not ignitions, and thus is different from the 10 percent, 8 percent and 2 percent ignition reduction estimates.

CONDITION PG&E-7

IT IS NOT CLEAR IF PG&E'S LINE RISK SCORING SUFFICIENTLY INCORPORATES ALL RISKS THAT CAUSE IGNITION AND PUBLIC SAFETY POWER SHUTOFF

Deficiency: PG&E appears to primarily rely on outage data and asset condition to conduct line risk scoring. It is therefore not clear whether PG&E's line risk scoring sufficiently incorporates all factors that cause ignition and impact the consequences of a given ignition.

Condition: PG&E shall in a first quarterly report:

i. List and describe the inputs to its line risk scoring and summary risk map;

At a high level, PG&E's line risk scoring model includes three major sub-models. Below we provide the various inputs that inform the various sub-models:

1) Sub-Model #1: Likelihood of Failure model predicts the occurrence(s) of an ignition on each circuit or protection zone. This sub-model consists of the following 20 inputs:

   a) Tier 3 miles divided by HFTD miles;

   b) HFTD miles divided by total OH miles;

   c) Health Score – Conductor age (15 percent) + Size & wire type (20 percent) + Number of splices (20 percent) + High probability of corrosion and Copper wire (15 percent) + Potential for snowpack (10 percent) + Conductor damage curve (I^2T[16]) issues exist (15 percent) + percent loading of conductor (5 percent);

   d) Environmental Score – Wildfire probability score based on various environmental factors;

   e) Age Score – Score based on conductor installation year;

   f) Size Score – Score based on wire type, size, description, category, and miles of line;

   g) Splice Score – Score based on the number of splices on a particular phase;

   h) Corrosion Score – Score based on the probability of corrosion + percent of conductor being copper wire;

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16 I^2t is a calculated value based on available fault current on the distribution system. When this value exceeds the conductor I^2t rating and the conductor experiences a fault condition, damaged or failure will occur. The units for I^2t are expressed in ampere-squared-seconds.

i) Conductor damage curve (I^2T) Score – Score based on whether I^2T issues exist;

j) Loading Score – Score based on the percent of loading on a conductor;

k) Percent Aluminum reinforced material – Percent of the HFTD miles that utilize aluminum reinforced materials;

l) Percent Aluminum material – Percent of the HFTD miles that utilize aluminum materials;

m) Percent Copper material – Percent of the HFTD miles that utilize Copper materials;

n) Conductor size – Average size of the conductor (1-9);

o) Wind Score – Based on GIS climate layer added (PG&E climate hazards);

p) Company-related and equipment failure outages - Company related and equipment failure sustained outages between 2015 and 2017;

q) Vegetation related outages – Vegetation related sustained outages between 2015 and 2017;

r) Number of trees per mile – Tagged trees per mile;

s) Number of total tagged trees – Tagged trees; and

t) Number of high-risk tree species per mile – Tagged high-risk trees per mile.

2) Sub-Model #2: Likelihood of Wildfire Spread and Consequences model, this model (developed by Reax Engineering) was developed following a similar fire modeling methodology to one that influenced the development of the HFTDs included in CPUC's Fire Map 2, Data Source 4.

Reax Engineering developed a wildfire spread score using factors such as:

a) Fuel type and density (grass vs. brush);

b) Topography (slope and natural fire breaks);

c) Weather/Wind; and

d) Distance from fire station/air suppression bases (speed to suppression).

Reax Engineering developed a consequence score by using factors such as:

a) Density of population;

b) Density of structures; and

c) Potential negative impact to natural resources.

3) Sub-Model #3: Egress Score model, this model focuses on the potential ease of accessing or exiting a community in case of a mass evacuation during a wildfire. The model uses the below inputs specific to each community around transportation infrastructure and census population data to produce an egress score:

a) Population of towns and unincorporated communities

b) The road density for each community by road type

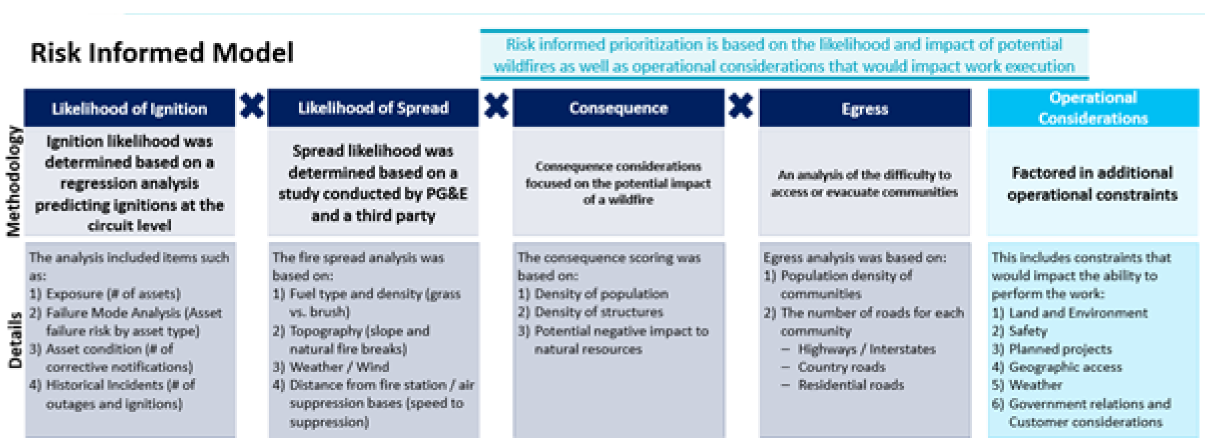
c) Highways/Interstates

d) Country roads

e) Residential roads

The graph below summarizes the model and other operational considerations factored in:

FIGURE 5
RISK-INFORMED MODEL



ii. ***If PG&E primarily relies on outage data and asset condition, PG&E shall outline other risks that it does not include; and***

iii. ***PG&E shall further explain why those risks are currently excluded, and outline a plan including a detailed timeline to include those risks, if applicable.***

PG&E interprets the term "risks" in this requirement to mean factors with the potential to cause an ignition. As described in subpart i, we rely on more than just outage data and asset condition to conduct line risk scoring. Our current models incorporate all known factors relevant to utility-caused ignitions creating a catastrophic wildfire.

PG&E is working to incorporate LiDAR surveys, inspection results, maintenance tags, and meteorology data sets as inputs to risk modeling, to increase accuracy of predictions. We will assess the impacts of these measures in 2020 and incorporate them in the 2021 WMP if they are shown to improve current capabilities.

CONDITION PG&E-9

HOW PG&E WEIGHS EGRESS AS A RISK FACTOR

Deficiency: While it is good PG&E includes egress, the ability of community members and first responders to leave a community during a wildfire, as one of the factors indicative of risk, it is not clear how PG&E weighs this factor against other factors in its risk modeling and deployment of initiatives.

Condition: In its first quarterly report, PG&E shall detail:

i. How egress factors into its risk assessment, including how egress is weighted against other factors; and

PG&E incorporates an egress score as a sub-model in its electric line risk scoring methodology. Our line risk scoring model can be conceptually divided in three areas: (1) a triggering event; (2) the consequence of that event escalating; and (3) the emergency response to mitigate the consequence, which is affected by the egress score. The egress score has a variable range that relates to the specific circuit, so we do not apply a uniform weighting for the egress score. The egress score is a dynamic measure that attempts to capture the complexity of PG&E's geographical territory, California's road infrastructure, and how these affect communities' fire risk.

ii. How egress impacts the prioritization and deployment of initiatives.

The egress score is a factor affecting a sub-model within PG&E's electric line risk scoring model, which is used to prioritize many of the WMP initiatives. The egress score affects the emergency response to mitigate consequences, but has a relatively low impact on the overall line risk score and a small impact on mitigation prioritization and initiative deployment.

PG&E is currently re-evaluating how we apply the egress score to our models and improving the egress model to increase its accuracy. This will have a small effect on the prioritization and deployment of wildfire mitigation initiatives.

CONDITION PG&E-10

PG&E LACKS SUFFICIENT WEATHER STATION COVERAGE

Deficiency: PG&E lacks sufficient weather station coverage on U.S. Forest Service (USFS) National Forest lands relative to other locations. Since a large portion of Tier 2 and Tier 3 HFTD areas are in National Forests, it is important to understand PG&E's methodology for choosing where to put weather stations and its justification of why they are not in National Forests. While PG&E understandably has fewer electric assets in these areas, weather stations in these areas could paint a picture of how weather systems are moving across PG&E's whole territory.

Condition: In its first quarterly report, PG&E shall:

i. ***Explain in detail how it chooses to locate its weather stations and explain gaps or areas of lower weather station density, including in the National Forest Areas; and***

Station siting is performed by the Meteorology Department using Google Earth, and on rare occasions, in person. We first sited stations to be mounted on PG&E's distribution assets, then moved to leverage transmission asset infrastructure. This year we plan to install additional cameras on third-party lands where there are no assets, mounting a stand-alone pole to house each weather station. Our weather stations are sited in mostly Tier 2 and Tier 3 HFTDs, as identified by the CPUC. Locations must be bucket truck accessible for installation and on-going maintenance and calibration of the station units. The locations are chosen based on accessibility and location from a meteorological standpoint, to gain observability to sites with the greatest exposure to the offshore Diablo wind events that prompt catastrophic wildfire risk and possible PSPS events. We use a 3 kilometer (km) by 3 km high-resolution 30-year climatology study to develop a detailed historical view of the highest-risk fire weather areas across our territory; we use this analysis as a guide to align weather station placement with highest meteorological risk on and off of the PG&E grid. By the project's end, we expect to have placed a PG&E weather station roughly every 20 circuit miles in Tier 2 and Tier 3 HFTDs, with up to 1,300 weather stations total.

PG&E currently has 111 stations awaiting installation in federal forest lands, many far from PG&E electrical assets. These station locations have been determined and we are now working through the environmental review and permit/easement access agreements with the federal agency. Many of these areas are highly wooded with limited vehicular access, but these locations are critical for collecting critical fire weather and wind observations.   Once these stations are installed on stand-alone towers, they will provide data critical to wildfire safety that can be used by PG&E, the federal landowners, and stakeholders like California Department of Forestry and Fire Protection (CAL FIRE), local fire agencies, and the National Weather Service (NWS). The land permitting and environmental process on federal lands can be slow, but we are working with the USFS to reduce the time needed to get access rights and permission to install the weather stations. We are prepared to install these weather stations as soon as we have secured all necessary permissions.

ii. Provide a cost/benefit analysis of the impact of having a higher density of weather stations across its territory, including on USFS National Forest lands.

When we first established the weather station program in 2018, PG&E did not conduct a formal cost/benefit analysis for the 1,300 weather station target density. However, we benchmarked the project against Southern California Edison Company's (SCE) and San Diego Gas & Electric Company's (SDG&E) weather observation programs and scaled-up our plan to account for our larger service territory. We also recognized that we could change the number of weather stations over time as we assessed the operational use and value of the stations installed.

We are beginning to study the overall weather station density and station density per Tier 2 and Tier 3 circuit mile. We have met with a vendor from the National Center for Atmospheric Research to learn more about a program they are developing to analyze utility station density and associated risk analysis; however, this program will not be in operation until the first or second quarter of 2021. In the interim, we will continue internal analysis of the costs and benefits of weather station density options and consider feedback from external partners such as CAL FIRE and the NWS.

CONDITION PG&E-11

INCLUDING ADDITIONAL RELEVANT REPORTS

Deficiency: In Section 5.2.A of its WMP, PG&E identifies several internal reports it generates for its leadership and Board of Directors (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 Board of Directors, 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 Board of Directors related to its electric grid from January 1, 2018 to the present; and***

Subject to the clarifications and exclusions described below, PG&E is submitting internal reports provided to its Executive Officers and/or Board of Directors, as described in Section 5.2A of our 2020 WMP, in the previous quarter. Please see attachments: 2020WMP_ClassB_PGE-11_Atch01.

PG&E is also submitting internal reports or other documents provided to its Board of Directors related to its electric grid from January 1, 2018 to the present. Please see attachments: 2020WMP_ClassB_PGE-11_Atch01. For purposes of this response, PG&E interpreted the request to be reports or documents directly related to the electric grid, including its operation, maintenance, and other issues directly related to the electric grid. Financial, regulatory, and legal materials that mention or refer to the electric grid were not included as these materials were addressing financial, regulatory and/or legal issues, but the primary purpose of the document was not to discuss issues such as electric grid O&M. PG&E is continuing to review the Board of Directors materials for confidentiality. PG&E is submitting all of these materials initially to WSD as un-redacted documents. We are working through the redaction process and will provide redacted copies that can be made public as soon as they are available.

PG&E is also submitting internal reports or other documents provided to its Executive Officers related to its electric grid from January 1, 2018 to the present. Please see attachments: 2020WMP_ClassB_PGE-11_Atch01. Similar to the documents provided to our Board of Directors, PG&E is continuing to review the Executive Officer materials for confidentiality. PG&E is submitting all of these materials initially to WSD as un-redacted documents. We are working through the redaction process and will provide redacted copies that can be made public as soon as they are available.

Finally, please note, based on the comments that PG&E submitted, and the final language proposed by the WSD and adopted by the Commission for Condition PGE-11, PG&E interpreted “electric grid” to include documentation and internal reports relating to wildfire and/or electric operations.

Clarifications

For clarification, “Executive Officer” is defined in Rule 16a-1(f) and Rule 3b-7 under the Securities Exchange Act of 1934; PG&E currently has five such Executive Officers. PG&E was not sure if the WSD intended to use the defined term “Executive Officer” and so is also including in its response Senior Vice Presidents (SVP) when it uses the term “Executive Officers.” For a comprehensive list of “Executive Officers” responsive to PGE-11, please see the table below.

TABLE 19
EXECUTIVE OFFICERS IN SCOPE FOR DOCUMENT GATHERING

Executive Officer	Title
Michael Lewis	Interim Chief Executive Officer (CEO) and President
Pat Hogan	Former SVP Electric Operations
Andy Vesey	Former President
Bill Johnson	Former CEO
Bill Smith	Interim, CEO and President
Geisha Williams	Former CEO and President
Julie Kane	SVP Chief Ethics and Compliance Officer
John Simon	Executive Vice President (EVP) Law, Strategy and Policy
Jason Wells	EVP and Chief Financial Officer

Exclusions for Board Materials

Please note that the following documents or internal reports were excluded from PG&E’s response to part (i) of Condition PGE-11:

- Draft Materials: Materials marked as DRAFT.
- Privileged Materials: Materials that are marked Privileged and Confidential. This includes legal updates provided by the Law Department and legal analysis from various outside counsel.

- Financial and Business Highlights (FBH) Reports to the Board of Directors. PG&E provides on a monthly basis an FBH Report to the Board. The FBH Report includes a wide variety of information including financial performance, operational performance, highlights regarding specific projects, regulatory developments, and other business information. Some of the information included in the FBH Report is related to PG&E's electric grid, but the report is not primarily focused on electric grid issues. Providing the FBH Report in this proceeding would require substantial redactions of non-electric grid information. Given the substantial volume of other Board materials being provided and that the focus of the FBH Report is not specifically on the electric grid, we did not believe that these reports were required by this request. However, we wanted to identify these reports and if WSD believes that these reports are responsive or otherwise would like these materials, PG&E can provide redacted versions. The redaction process will take some time to complete.
- Materials Mentioning Electric Operations: There are materials provided to the Board that address other areas of PG&E's business but include references or discussions of electric facilities or operations. However, these materials are prepared for other purposes and thus have been excluded. These materials include: regulatory/legislative updates or information provided on regulatory proceedings or legislative actions; Financial Performance Plans, Plan Updates and Budgets; Internal Audit materials; environmental materials; risk management materials; cybersecurity materials; and physical security materials.
- Specific Committee Materials: Materials provided to the Audit Committee, Compensation Committee, or Nomination and Governance Committee, Technology Committee (as it is newly-formed and only had one meeting since January 1, 2018; none of the information provided related to Electric Operations or the electric grid).

Exclusions and Timing for Executive Officer Materials

To locate internal reports and documents provided to Executive Officers from January 1, 2018 to the present related to the electric grid and wildfire-related issues, PG&E used the following approach as a part of a reasonable search for responsive materials.

PG&E searched e-mails and calendar items for its Executive Officers (as described above) for final reports/presentations (pdf, word, pptx) related to “electric”, “wildfire”, “wild fire”, “WMP”, “grid” or “PSPS” received January 1, 2018 to the present.

After these materials were gathered, we separated attachments (i.e., reports and documents) from the e-mails because Condition PGE-11 requested reports and documents. We eliminated all duplicates if a report and/or document was sent to multiple Officers and all documents marked as “privileged.” We also eliminated materials provided to the Board of Directors that were separately gathered for the response to Condition Guidance-11.

This initial review resulted in approximately 130,626 documents.

To further refine the search for responsive documents, we removed:

- Any family groups where FileName contains “legal” as potentially privileged;
- Any family groups where FileName contains: “Bankruptcy”, “Board Deck”, “Pay”, “NDA” or “Agenda & Template” as non-responsive;
- Any e-mail from Janet Loduca as “potentially privileged”; and
- Duplicate attachments based on FileName and LastModified Date.

To further refine the search for responsive documents, within this population of 130,626 we marked any attachments where file name contains any of the following terms as “Potentially Responsive”: Weekly, Dashboard, Report, Committee, Steering, Update, PSPS, “System Hardening” or “Vegetation Clearing.” This yielded 10, 377 reports and/or documents.

As a result of this refined search, PG&E identified the potentially responsive documents in the following categories:

TABLE 20
VOLUME OF DOCUMENTS AFTER REFINED SEARCH

Name	Documents With Hits	Documents With Hits, Including Group
Weekly	982	3,644
Dashboard	426	1,206
Report	4,134	9,927
Committee	1,553	4,644
Steering	285	668
Update	2,666	8,960
PSPS	2,105	4,035
“System Hardening”	28	173
“Vegetation Clearing”	–	–

After further de-duplication, we were able to narrow the number of unique documents to approximately 6,000. These documents were further reviewed to remove documents with the specific words in the file name indicating that the documents were unlikely to be final reports or documents that include specific information regarding wildfire activities or electric grid operations such as Diablo Canyon Power Plant, Tort and/or Tort Committee, COVID, real estate, etc.

PG&E then identified as potentially privileged any documents using terms in file names such as Motion, Demurrer, Law, etc.

These additional refinements resulted in 4,471 documents. PG&E then conducted a manual review of the file names for these documents and was able to further eliminate 1,959 documents that were not responsive for a remaining document population of 2,512. PG&E did a further privilege review of these documents and was able to eliminate 166 privileged documents that had not been identified in earlier screens. The remaining document population consisted of 2,346 documents.

At this point in the process PG&E incorporated feedback from the WSD that they are most interested in materials that relate to wildfire risk reduction activities. Therefore, the file names of the remaining 2,346 documents were manually reviewed by SMEs from PG&E’s Program Management Office for the CWSP to determine which documents likely included information that was relevant and responsive to PG&E’s wildfire programs. Documents that were assessed to primarily include information on non-wildfire aspects of PG&E’s electric operations were set aside, this included documents primary focused on safety, finances, resources, and employee management. Additionally, specific populations of documents were also eliminated to reduce duplication and the overwhelming population of documents, these included removing from the population:

- Publicly-available documents like those filed with the CPUC and press releases;
- Intelligence summaries, situational reports and weather reports related to individual PSPS events as the final details and data from these events have been provided in the publicly available post-PSPS event reports;
- Frequent (i.e., daily) intelligence summary reports from specific programs like the VM Accelerated Wildfire Risk Reduction Program in 2018; summary information from these programs is already captured in recurring reports already captured in this population; and
- Documents for the Board of Directors which were also provided to or circulated to PG&E Officers, to avoid duplication since those documents have already been identified through collection documents provided to the Board of Directors

After filtering for wildfire-related documents, and excluding the items listed immediately above, the remaining population of nearly 300 documents was finalized, and is being provided to the WSD.

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 January 1, 2018 to the present—please see attachments: 2020WMP_ClassB_PGE-11_Atch01.

The materials provided to our Federal Monitor include the listed dashboards below. These reports allow the Monitor team to assess Company progress on an ongoing basis to ensure we comply with probation requirements and metrics set forth in the WMP. The origination dates of reports to the Monitor vary due to these items being discussed at different stages of the Monitor's assessment of the Company. The Federal Monitor also receives dashboards related to other areas of electric operations which include but are not limited to safety, compliance and ethics, and contractor trainings. These materials were not provided in the response due to not directly impacting the electric grid.

Federal Monitor Dashboards

- CWSP Weekly Dashboard
- Weather Station and Camera Progress
- VM Weekly Dashboard
- EVM Progress Dashboard
- Monitor Report Tracker
- Weekly Electric Distribution Director deck
- Expense and Capital Spending Report
- Ignition Tracker
- System inspections progress
- Aerial inspection progress
- System Hardening progress

CONDITION PG&E-12

PG&E'S FUSE REPLACEMENT PROGRAM PLANNED TO TAKE 7 YEARS.

Deficiency: PG&E estimates it has more than 15,000 "non-exempt" fuse devices located in Tier 2 or 3 of its HFTD. These devices operate on average 2,920 times per year. Operation of these non-exempt devices creates an ignition sources; however, PG&E states it will replace 625 fuse cutouts per year (starting in 2019) for 7 years. It is unclear why the program is so drawn out.

Condition:

i. ***Its plans for replacing non-exempt fuses, including the pace of fuse replacements; and***

In its 2020 WMP, PG&E indicated that:

> [S]tarting in 2019, PG&E forecasts replacing approximately 625 fuses/cutouts, and other non-exempt equipment identified on the pole each year for seven years in Tier 2 and Tier 3 HFTD areas.[17]

Since that time, we have continued to evaluate our non-exempt fuse replacement program, including the effectiveness and rate of replacements in 2019 (for details on the RSE analysis for fuse replacements, please refer to Attachment 2020WMP_ClassB_Guidance-1_Atch02).

In 2019, we completed 708 fuse replacements. Our team recommends that we increase this replacement rate to 1,200 fuse replacements per year through 2026. This recommendation has been approved as part of the 2021-2026 investment plan; we believe, based on our experience with fuse replacements in 2019, that we have the resources and capability to replace this many non-exempt fuses each year through 2026.

ii. ***How this pace is supported by wildfire risk analysis, including providing the cost and benefit estimates.***

Replacing non-exempt fuses with exempt fuses reduces wildfire risk. If a non-exempt fuse fails it has the potential to spread hot molten metal which could cause one or more ignitions, while exempt fuses are designed to internalize any molten material when they blow. Because exempt fuses are safer and less externally destructive, CAL FIRE has deemed these fuses "exempt" from needing vegetation clearing around the base of their respective poles. By using exempt fuses, we can

17 See 2020 WMP, p. 5-121.

greatly reduce the potential for vegetation ignitions due to molten metal, removing 1,200 potential sources of ignition from our system each year.

PG&E proposes to replace 1,200 non-exempt fuses per year based on analysis of the value of this program in terms of costs and risk reduction. From a cost avoidance perspective, non-exempt fuses require annual vegetation clearance of 10 feet in diameter at the base of the pole. This vegetation clearing requires annual, ongoing expenses that can be eliminated or substantially reduced by the one-time installation of exempt fuses.

In addition to financial benefits and risk reduction, replacing non-exempt equipment is also beneficial for PG&E customers. Many customers have aggressively opposed PG&E clearing vegetation at the base of utility poles, including refusing to allow PG&E to clear vegetation or brush on their property—each year, we receive 300-500 customer refusals per year for vegetation clearance at the base of these poles at these sites. Replacing non-exempt fuses with exempt fuses reduces the need to clear vegetation at these locations and will therefore reduce customer complaints about VM.

CONDITION PG&E-13

PG&E DOES NOT EXPLAIN HOW THE FACTORS LIMITING MICROGRID DEPLOYMENT WILL IMPACT ITS MICROGRID PLANS

Deficiency: PG&E has committed to installing microgrids and switches to sectionalize the grid to mitigate PSPS events. However, PG&E explains that construction resource, land access, permitting, substation upgrades and the presence of interconnection points are limiting factors in microgrid deployment. Further, PG&E does not state how each of these factors will limit microgrid deployment or identify limitations to microgrid deployment posed by its network system design. PG&E also does not explain if it considered microgrid proposals as alternate solutions to traditional grid design.

Condition: In its first quarterly report, PG&E shall:

i. ***State all factors that will limit microgrid deployment or identify limitations to microgrid deployment posed by its network system design;***

Background

SB 1339,[18] a bill enacted in 2018, directs the CPUC, in consultation with the California Energy Commission and California Independent System Operator (CAISO), to undertake a number of activities to further develop policies related to microgrids. The CPUC voted to initiate a new rulemaking to consider how to implement the requirements of SB 1339 at its September 12, 2019 public meeting. The OIR that formally launched the new proceeding was issued on September 19, 2019.[19] On June 11, 2020, the CPUC approved PG&E's microgrid proposals designed to harden the electric system, reduce the number of customers affected by future PSPS events and mitigate the impacts to those who are affected. These include a temporary generation program, as well as PG&E's new CMEP.

For 2020, PG&E's microgrid solutions focus primarily on building grid resilience and keeping the power on for customers in communities that historically have experienced a higher frequency of PSPS events. To that end, PG&E has reserved more than 450 megawatts (MW) of temporary mobile generation to be deployed in four ways detailed below, each with a unique objective:

- Substation Microgrids: High fire risk weather conditions can force PG&E to de-energize some transmission lines for safety; this may cause entire substations, and all distribution load and customers served by those lines and substations to be

18 https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180SB1339.

19 http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M314/K274/314274617.PDF.

de-energized. In certain instances, some or all of the customers served by the de-energized substations could have remained safely energized if not for the loss of source power delivered by the de-energized transmission line. PG&E will be deploying temporary generation at many of these safe-to-energize substations to support safe-to-energize residential customers who would otherwise be impacted by upstream transmission line outages during PSPS events. PG&E has prepared 60 prioritized substations to be ready to connect temporary generators as need arises during PSPS events, depending upon operational logistics and available fuel supplies.

- Temporary Microgrids: There are some designated areas, such as "main street" corridors, where PG&E can safely provide electricity to central community resources (such as medical facilities and pharmacies, police and fire stations, gas stations, banks, and markets) by isolating them from the wider grid and re-energizing them using temporary generation during an outage. One microgrid backup generation site, in Angwin (Napa County), was completed in late 2019 and is currently operational. Several other microgrid backup generation sites are under development to be available to support customers during PSPS events in 2020. The temporary microgrid generation sites were identified and selected through an extensive process including analysis of prior and expected PSPS events, along with overall feasibility and ways to minimize fire ignition risk in PSPS weather conditions[20] for these selected "main street" corridors to allow them to remain safely energized.
- Backup Power Support: Deployment of temporary generation on an as-needed basis to critical customers for whom the failure of existing backup power would either directly or indirectly harm public health, safety and welfare. PG&E is working closely with the California Hospital Association and Hospital Council of Northern and Central California to identify those hospitals currently supporting the COVID-19 response efforts that have a higher likelihood of experiencing a PSPS event. We are developing grid-based solutions where possible and supporting hospital readiness and resiliency planning to ensure that those hospitals remain energized in the event of a broader grid outage.

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20 These provisions include system hardening, EVM, and the installation of additional sectionalizing devices capable of re-directing power to reduce the number of customers impacted PSPS events.

- Community Resource Centers (CRC): These are pre-existing public and private facilities powered by temporary generation to give customers affected by PSPS events a climate-controlled location where they can charge devices and receive refreshments.

As part of the CMEP, PG&E will partner with local communities to identify and build multi-customer microgrids serving local critical facilities and/or vulnerable customers not already served by other microgrid solutions offered by PG&E. The CMEP will support communities in designing microgrids by providing enhanced technical support, improved access to relevant utility information, financial support for qualifying projects, and tariffs to support the accounting for the flows of services, energy, and costs between the parties. PG&E will refine the eligibility criteria and other program requirements through consultation with local governments and communities, with a goal of full program implementation and projects in development by November.

Finally, PG&E's Remote Grid Initiative is a new utility service concept using decentralized stand-alone power energy systems for permanent energy supply to remote customers as an alternative to energy supply through traditional utility infrastructure. Throughout PG&E's service area, there are pockets of isolated small customer loads (single, residential customers) that are currently served via long overhead electric distribution lines. In many circumstances, these lines traverse through HFTD areas. If these long distribution lines 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.

PG&E is conducting two remote grid demonstration projects starting in 2020 to develop the policies, rate structures, and operating procedures necessary to integrate remote grids as a feasible product for wires elimination. These projects will allow PG&E to potentially develop a scalable product that can be utilized for both existing distribution lines and new business customer requests, serving customers effectively while eliminating long, higher-risk exposure distribution infrastructure to centralized power.

Limitations of Microgrid Deployment

At the time of the 2020 WMP filing, PG&E's plans to use microgrids for PSPS mitigation were still in the early development phase. Since then we have gained additional understanding and experience with developing microgrids for PSPS mitigation. PG&E decided not to develop any permanent microgrids in 2020 and instead use temporary generation to address PSPS challenges. This decision to leverage temporary generation in the short term allowed us to rapidly deploy microgrid-like capabilities in a scaled fashion in time for the 2020 PSPS season, avoiding many of the time-intensive challenges that permanent microgrids face (including permitting, permanent land acquisition, permanent fueling infrastructure, significant substation upgrades, and CAISO interconnection). We are currently on track to achieve our 2020 goals for microgrid PSPS mitigation.

Several factors limit microgrid deployment. First, PG&E can only energize a microgrid (whether permanent or temporary) when it is safe to do so in the context of high wind conditions that trigger a PSPS de-energization (aka the "wind polygon"). Therefore it may not be feasible to energize multi-customer microgrids that use overhead distribution lines in HFTD areas with high wildfire risk; overhead distribution lines and the generator and substation feeding those lines must be entirely outside of the wind polygon to be safe to energize. However, it is possible to use microgrid configurations to supply power to customers in non-HFTD areas even while some Tier 2 and Tier 3 HFTD areas are de-energized due to fire risk. These microgrid configurations fall into three categories: substation microgrids, temporary microgrids, and single customer microgrids. Each category has associated limitations detailed below.

Second, a microgrid must have sectionalizing devices to ensure that the microgrid service area can be safely islanded from the rest of the surrounding grid, particularly if the surrounding grid will be deenergized. This is true for any microgrid, whether permanent or a temporary microgrid intended to support customers or a community that would otherwise be de-energized.

Third, many of the substations identified as candidates for substation microgrids have high peak MW requirements and large megawatt-hour (MWh) requirements over a 24 hour+ period. The larger the MWh requirement, the more generation needed for the microgrid. More generation will require more space, especially for photovoltaic solar and energy storage; but many PG&E substations have limited land availability and thus are site-constrained. In some instances this year, we are working with local governments to request permits to place temporary generation outside of the substation footprint. Over the longer term, any permanent generation placed outside the substation footprint will require land acquisition and California Environmental Quality Act (CEQA) review, possibly adding years of lead time to the project.

Fourth, temporary microgrids aim to maintain service to commercial corridors in HFTD areas. This cannot be done safely unless the area to be energized is safe-to-energize. Generally speaking, this requires that the area is relatively vegetation-free, distribution lines are underground or over hard-scape, the topology does not facilitate fire spread, and/or any overhead line systems have been hardened and reviewed to ensure they would not create wildfire risk if an ignition occurred during PSPS conditions.

Finally, microgrids involving permanent generation face some unique limitations that do not apply to temporary microgrids:

- Limited Flexibility: Permanent microgrid assets cannot be moved, but as weather changes, temporary generation assets can be moved to different locations to address varying PSPS weather and scope patterns.
- Land Constraints: As previously mentioned, permanent generation assets may require significant land acquisition and CEQA review that can be a high cost and long lead time process. This applies for both compact thermal generation units as well as land-intensive solar storage solutions.
- Cost Offset and Valuation Outside of PSPS Resilience: Permanent generation assets typically have a minimum asset life of 10 years and require some form of financial offset, usually gained through wholesale market and Resource Adequacy (RA) participation. The current CAISO RA deliverability studies in PG&E's service territory[21] indicate minimal to no available deliverability into the CAISO market in locations where generation solutions would mitigate PSPS impacts without the potential need for potentially expensive transmission upgrades.
- Interconnection and Upgrades: Permanent generation solutions require lengthy distribution and transmission interconnection studies. Microgrids sized to serve larger community loads may require significant, expensive, and time-intensive distribution and transmission asset upgrades, especially if those microgrids intend to participate in the wholesale market.

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21 http://www.caiso.com/Documents/2020PotentialDeliverabilityforDistributedGenerationWorksheet-PGE.pdf.

ii. Explain if it considered microgrid proposals as alternate solutions to other grid solutions; and

PG&E's approach to wildfire mitigation activities has been to first identify grid solutions and then to explore microgrids in locations where grid solutions are infeasible, extremely cost-prohibitive, or need a "bridge" solution until other solutions can be completed. Grid solutions do not require generation and thus do not have many of the limitations described in subpart (i) above. In circumstances where a grid solution is feasible, but requires a long lead time, microgrids using temporary generation can serve as a "bridge" while the long-lead time grid solution is implemented.

While not fitting the strict definition of SB 1339 of a microgrid due to its permanent islanding design, as noted previously, the Remote Grid Initiative is an innovative grid architecture that identifies locations where stand-alone power systems may be a more cost-effective piloting implementation of this architecture in 2020 and 2021 to determine the feasibility and scalability of this alternative to grid hardening or undergrounding design requirements, and therefore could eliminate the need for overhead distribution infrastructure that eliminates or significantly minimizes wildfire risk to provide power to those customers.

iii. Address whether options the other large electrical corporations are exploring might be feasible in its territory.

PG&E meets regularly with the other California utilities to discuss what each utility is considering as a means to mitigate wildfire safety risks. PG&E is unaware of other California microgrid-related efforts to mitigate wildfire risk that differ much from our current activities.

CONDITION PG&E-14

LEVEL 3 FINDINGS

Deficiency: In accordance with GO 95, Rule 18, to determine the priority level classification of an inspection finding, a utility must differentiate the potential severity of the risk to safety or reliability, classified as high (i.e., Level 1), moderate (i.e., Level 2) or low (i.e., Level 3). As shown in Appendix B, Figure 2.1a, PG&E's increased inspection efforts in 2019 generated a huge spike in Level 3 findings which it has 60 months or longer to address. Considering that this determination of risk level is made at the discretion of utilities and directly corresponds to the amount of time allowed to address the risk, the lack of parity with SCE and SDG&E in the number of Level 3 findings gives the WSD concern that PG&E may be using the Level 3 category to avoid fixing problems quickly. In notes to Table 7 of its WMP, PG&E indicates it currently utilizes two models to calculate ignition risk, with a third developed in 2019, all of which produce outputs in potential structures damaged or acreage burned should an ignition occur. However, it seems as though PG&E is currently prioritizing utilizing these models to enhance and support its PSPS implementation over grid hardening, asset inspections and VM decision-making. While it is encouraging that PG&E is utilizing its meteorology resources to develop models and analyses to support short-term initiatives such as PSPS, these resources must be equally-leveraged for long-term planning and management of its grid.

Condition: In its first quarterly report, PG&E shall detail:

PG&E's response to Condition PGE-15 outlines the guidelines used to classify types of corrective notifications and assign priorities to those corrective notifications.

Currently, PG&E classifies corrective notifications (tags) as Priority "A", "B", "E", and "F" based upon assessment of potential Impact and Probability of occurrence. In 2020, PG&E adopted internal guidance to begin transitioning tag classification to align with GO 95 Rule 18 Levels 1, 2, 3 (in TD-8123S: Electric System (T/S/D) Patrol, Inspection, and Maintenance Program**,** see Attachment 2020WMP_ClassB_PGE-14_Atch01 – TD-8123S).

In PG&E's usage, "Priority" is defined as the urgency to perform the repairs or replacements identified in a notification (inspection tag). This priority is assigned to a problematic condition on a facility to indicate a degree of importance, aligned with the assessment of impact and probability "of equipment and/or facilities failure and/or exposure" (e.g., see the Electric Distribution Preventive Maintenance Manual (EDPM) TD-2305M Chart: Impact/Probability Matrix on page 188 in Attachment

2020WMP_ClassB_PGE-14_Atch02). Unfortunately, inspection of a single facility may yield multiple tags.

When corrective tags are created, each tag is assigned an expected/intended corrective action completion date. The date is based on the urgency and risk perspective, which would align with priority level. This process will allow PG&E to develop all the necessary steps (tool, resources, and training) to make the transition and eliminate alphabetical tags and move to the three levels.

- Priority "A" is defined as "emergency." "A priority" inspection findings requiring corrective action are considered equivalent to "high…risk to safety and reliability" under GO 95, Rule 18.
- Priority "B" is defined as "urgent" with a short duration of 0-3 months for corrective action, reflecting High impact and Moderate to High probability of occurrence (e.g., probability of failure). Inspection findings resulting in "B" priority tags are considered equivalent to "moderate…risk to safety and reliability" as per GO 95, Rule 18.
- Priority "E" is applied to situations with Moderate to Low impact and covering any probability level. Inspection findings categorized as "E" priority corrective notifications are considered equivalent to "moderate, and low…risk to safety and reliability" as per GO 95, Rule 18. As described in response to PGE-15, in PG&E's 2020 WMP filing we oversimplified by grouping all "E" Priority tags into Level 3 for Tables 1-1 and 1-2; this does not reflect PG&E's actual treatment of "E" priority tags. Instead, Priority "E" tags can meet either GO 95 Rule 18 Level 2 or 3 criteria and are managed according to the timeline appropriate to each tag's assigned criterion level.
- Priority "F" regulatory conditions are deemed able to wait until "next inspection" cycle based on Low impact of occurrence. "F" priority tags are considered equivalent to "low…risk to safety and reliability" under GO 95, Rule 18.

Under GO 95 Rule 18 for HFTDs, action to address any Corrective Notification of assets located within the HFTD must occur within 3 months for Priority "B" tags, 12 months for Priority "E" tags, and 60 months for Priority "F" tags. Although PG&E may classify a specific facility issue as lower Priority "E", its location within an HFTD will impose a maximum corrective duration of "6 months for Tier 3 structures, and 12 months for Tier 2 structures."

In the field, QCRs compare the field condition against guidance provided during their annual training, and with reference to EDPM, TD-2305M, provided as part of the 2020 WMP at: https://www.pge.com/pge_global/common/pdfs/safety/emergency-preparedness/natural-disaster/wildfires/wildfire-mitigation-plan/reference-docs/TD-2305M.pdf and Electric Transmission Preventive Maintenance Manual (ETPM), TD-1001M, provided as part of the 2020 WMP at: https://www.pge.com/pge_global/common/pdfs/safety/emergency-preparedness/natural-disaster/wildfires/wildfire-mitigation-plan/reference-docs/TD-1001M.pdf.

PG&E's CIRT members review and validate field QCR submissions of facility problems and proposed corrective notifications, comparing field notes, photographs and other locational information against the EDPM and ETPM and associated Job Aids.

ii. How it utilizes its models that produce outputs measuring impact to people, structures or the environment, as detailed in Table 7 of its WMP, to assess the potential between high, moderate, and low risk on safety and reliability for the purposes of classifying priority levels in accordance with Rule 18; and

Beyond creation of the corrective notifications, PG&E leverages several risk models to cross-prioritize the execution of asset repairs and other corrective actions. PG&E's 2020 WMP Table 7 models operate under the planning scenario time period, that is, they assess worst case conditions, such as for fire season, in a planning view. The planning scenarios provide the basis for work planning on an annual and multi-year schedule. Planning scenarios enable the optimization of multi-year work plans to reduce risk.

Table 7 includes two models used to calculate the impact of potential ignitions. The first model—the S-MAP conforming model—was developed to assess ignition-based drivers and consequence outputs, conforming with the S-MAP settlement agreement. This modelling provided as part of the S-MAP settlement agreement, or RAMP models, is used to calculate program RSEs as it informs the Company's risk on the risk register. RSEs are currently used to inform and augment the Risk-Informed Budget Allocation process, to help prioritize programs across organizations and across the Company. As PG&E continues to develop RSEs for programs, this model will help inform PG&E on the appropriate investments between program funding or corrective actions.

The second model, the Reax Engineering model, is used to quantify the likelihood of wildfire spread and consequences. This model uses a fire modeling methodology similar to one used for development of the HFTDs included in CPUC's Fire Map 2, Data Source 4. The Reax model is used to rank the distribution circuits at the protection zone level based on potential fire consequences and subsequently to prioritize the proposed work during annual and in-year planning.

PG&E is evaluating a third model, developed by Technosylva, to determine how it might best fit into our overall Risk Modeling analysis.

Finally, PG&E is improving the maturity of our risk models from relative risk models at the circuit level with system-level risk reduction and RSE capabilities to move toward automated, quantitative risk models that include risk reduction and RSE evaluations at the asset level. The purpose of these models is to provide analytical insights to contribute to wildfire risk mitigation decisions by: (1) using thoughtful measurement to communicate risk levels and track progress in improving grid safety by drawing-down risk; (2) estimating the risk reduction impacts of proposed mitigations to inform optimization of workplans; and (3) enhancing our situational awareness of risk. Separate composite risk models each for the electric transmission (Tx) and distribution (Dx) systems are being developed. These aim to combine the capabilities of the 2020 RAMP model and REAX model at more granular levels, eventually estimating risk reduction values by asset and tag type.

iii. If PG&E does not utilize its models for such a purpose, PG&E shall develop a plan for doing so.

As explained in subpart ii, PG&E's current consequence model (the REAX model) has the capability to prioritize tags with relative risk of circuit segments at the protection zone level for the planning scenario time period. However, we are now developing a tag prioritization model that runs under the operational scenario; this model could run more frequently than the annual REAX analysis to prioritize the execution of asset repairs and other corrective actions and thus reduce the risk of equipment-caused wildfires. This refined tag prioritization model is a sub-model that will be part of the composite distribution risk models described in the response to Condition Guidance-3. This tag prioritization sub-model will quantify the increased risk impact of an identified tag and the passage of time since the last inspection and estimate how risk would decrease when the tag is closed due to asset repair or replacement.

We plan to improve the tag prioritization model over time to capture failure modes and consequences associated to each tag level and type (for example, the risk increase and subsequent risk reduction associated with a ‘B’ tag for a broken cross-arm and its replacement will likely differ from an ‘E’ tag for a guy-wire). This model could be used to prioritize asset management and asset repairs in near-real-time and be updated over time as tags are created or closed to recognize changes in risk for relevant portions of the electric distribution system. As described in the response to Condition Guidance-3, the risk values can be viewed at a granular level such as asset or span or at a higher level such as circuit, region, or system. Over time, knowledge about tag status and the condition of underlying electric assets could inform everything from maintenance priorities to judgments about the functionality of a circuit and the health of a region or system. In the long run, this tag prioritization sub-model could be used to prioritize wildfire risk reduction work like system hardening, EVM, PSPS impact reduction activities and others.

The first version of the tag prioritization model is under development in 2020 and will form the basis for more frequent electric system risk scoring. As described above, as more failure modes are better related to types of repair tags, the ability of the model to distinguish levels of risk for different tags will improve.

While PG&E has a general roadmap and approximate timeline laid out for the maturation of our risk modeling, we also recognize that this process is iterative. Learnings from one step in the process will influence and even change the direction of future steps or could require revisions to previous steps or developed tools. The primary steps and approximate timeline for improving the frequency of our risk modeling are outlined below, but this timeline and its elements will be dynamic and updated over the next several years. These steps and timelines should be viewed as directional, rather than confirmed.

- Develop tag prioritization model to quantify impact of maintenance tags (open and complete) on asset risk—Q2 2021.
- Update on tag risk reduction values based individual distribution asset models—end of 2022.
- Determine risk model update frequency that will add value for the identified use cases—targeting end of 2022.

CONDITION PG&E-17

EFFECTIVENESS OF INSPECTIONS USING INFRARED TECHNOLOGY

Deficiency: PG&E does not explain in detail how its IR inspections will incrementally mitigate ignitions, especially since it does not tie its IR inspections to changes to its existing initiatives or inspection practices or report IR inspection findings separately.

Condition: In its first quarterly report, PG&E shall:

i. ***Provide a detailed description of how its IR inspections incrementally identify issues or faults along PG&E's grid that lead to ignitions, including evidence for the number of inspection findings uncovered by IR inspections that would not have been uncovered in detail and patrol inspections; and***

PG&E performs targeted overhead IR inspections on distribution circuits to identify asset hot spots (abnormally high temperatures) requiring corrective action. Using IR to pinpoint high risk locations for proactive maintenance and conductor replacement may prevent later wire-down equipment failures and possible fire ignitions in HFTDs. During the IR inspections, team members identify any potentially hazardous conditions near the IR examination locations; identified conditions are called in for immediate examination. These instances can include problems such as a broken cross-arm, frayed conductor, or damaged equipment that may have occurred since the last inspection cycle for the relevant assets.

The IR camera technology offers a non-invasive review of distribution assets, detecting abnormal temperatures from a distance. IR is routinely used because many of the electrical problems it spots are not visible to the naked eye and would be missed by a human observer performing visual inspection only. Industry experience indicates that about 70 percent of the problems identified with IR were not visible using visual-only means.

In 2019, IR inspections covered 14,600 circuit-miles of distribution assets, with a 1.9 find rate for 100 miles (i.e., total hot spots identified). Within this find rate there were 139 potential hot spots noted that resulted in B Tags being generated. Priority "B" is defined as "urgent" with a short duration of 0-3 months for corrective action, reflecting High impact and Moderate to High probability of occurrence (e.g., probability of failure). Also found were 132 potential hot spots that resulted in E tags being generated. Priority "E" is applied to situations with Moderate to Low impact and may include any probability level.

ii. If it has no evidence that IR inspections identify findings that would not have been identify in other inspections, describe and provide evidence for the expected outcomes in the context of risk reduction or cost savings that its IR Inspection Program is expected to generate.

As noted above, IR inspection is a valuable technology that complements field patrol inspections to identify asset problems. PG&E began using IR patrols in 2012 using them to identify conductor splices (among other things). Starting in 2012, splice counts found through IR patrols were tracked in a MapGuide database. This splice inventory database was combined with wire-down information to create a strategy to identify and replace our highest-risk conductors.

CONDITION PG&E-18

PG&E DOES NOT DESCRIBE IN DETAIL HOW ITS HAZARD TREE ANALYSIS FOCUSES ON AT-RISK TREES.

Deficiency: PG&E does not describe in detail how its hazard tree analysis focuses on at-risk areas (based on wind conditions, outage history and the link) and specific species that pose a high risk (due not only to fast growth rate but other risk factors) to focus its current proposal. That is, PG&E's hazard tree program should focus on at risk trees first, rather than on every tree within striking distance.

PG&E also now accounts for removal of hazard trees under both its EVM Program and an existing Tree Mortality Program. Trees that are dead or that will die as a result of trimming are removed under the Tree Mortality Program. PG&E's memorandum account for Tree Mortality work is separate from the memorandum account allowed in Assembly Bill 1054 for WMP work.

Condition: In its first quarterly report, PG&E shall detail:

i. ***How it will ensure its hazard tree program prioritizes the highest risk areas and types of trees; and***

ii. ***How it accounts for hazard tree programs in its memorandum accounts.***

Definitions Used in This Response

- Hazard Trees: Trees that are dead or show signs of disease, decay or ground or root disturbance, which could fall into or otherwise impact distribution and non-NERC facilities before the next inspection cycle.
- Strike Trees: A healthy tree that has the potential to strike the line or the facility should it fall.
- Green Trees: A healthy tree, any tree not dead, dying, or diseased.
- Green Hazard Tree: An otherwise healthy tree that is a hazard because of other reasons (uprooting from rain, wind, or struck by a vehicle). This is a very particular and unusual circumstance.

  PG&E implements hazard tree identification and removal across multiple programs for complete coverage of the system. We consider numerous factors to prioritize VM work, as described below.

- Routine Vegetation Maintenance: We perform Routine Vegetation Maintenance on an annual cycle to ensure all circuit miles in the system are evaluated each year, and therefore PG&E does not have a specific set of criteria for work plan prioritization. However, if VM Pre-Inspectors identify a hazard tree (dead, diseased, dying, leaning, or otherwise compromised which could impact any Distribution or

Transmission line should it fall) that is an imminent threat as defined by Hazard Notification (TD-7103P-09) procedure (see Attachment 2020WMP_ClassB_PGE-18_Atch01), they prescribe and prioritize tree per the Hazard Notification procedure. During routine maintenance, Pre-Inspectors use the TAT as described below to recommend a tree-specific mitigation method if the tree is not an obvious imminent threat but does show signs prompting additional evaluation.

- Enhanced Vegetation Management: As with routine maintenance, PG&E's EVM Program also removes trees that pose an imminent threat to our assets under Hazard Notification (TD-7103P-09) procedure. The EVM Program has a more targeted approach than the Routine Maintenance program in prioritizing high-risk trees.

  EVM starts by ranking all PG&E circuits in HFTD based on the risk of catastrophic wildfire and uses this risk ranking to prioritize high-risk areas of work (see Guidance-3 for more details on the Veg Management Risk sub-model). EVM evaluation considers tree species as one factor in the risk ranking model (please see PG&E's response to Condition PGE-7 for more details on the various factors), as well as factors such as tree height, distance from the PG&E line, and the likelihood of an ignition event. Within the prioritized risk areas, during the vegetation inspection process, Pre-Inspectors use the TAT to determine if the strike tree should be abated (hazard tree) or not (healthy strike tree). Tree species and other factors are incorporated as data inputs to the TAT.

- Catastrophic Emergency Memorandum Account (CEMA): The CEMA Program is a compliance requirement per CPUC Resolution ESRB-4. CEMA (also referred to as "second patrol or mid-cycle") inspections follow approximately six months after the routine maintenance schedule. This allows CEMA inspections to identify and mitigate conditions that have changed since the routine inspection, and to address conditions that are not safe to leave unresolved until the next routine inspection.

  Since routine maintenance occurs on an annual cycle, the addition of the CEMA inspections starting in 2014 has helped reduce risk by increasing the frequency of overhead distribution line inspections to approximately every 6 months. This bi-annual inspection frequency helps identify and mitigate dead or dying hazard trees in a timely manner in accordance with CPUC Resolution ESRB-4, which directs “increasing vegetation inspections and removing hazardous, dead and sick trees and other vegetation near the IOUs’ electric power lines and poles.”

CEMA inspections are performed on distribution overhead lines in the following designated high fire risk areas including: State Responsibility Areas (SRA), Federal Responsibility Areas, and HFTDs. Within the Local Responsibility Areas, CEMA inspections are conducted where locations have been designated as Wildland Urban Interface and Fire Hazard Severity Zones.

The CEMA inspections and remediation address the following conditions:

– Dead, dying and declining trees, or dead portions of trees, including dead overhangs that could contact PG&E facilities if they fail;
– Green trees observed within the Minimum Distance Requirement (MDR) or with the potential to encroach the MDR before the next patrol cycle;
– Green hazard trees with the potential to impact the electric facilities;
– Trees causing strain or abrasion on secondary lines; and
– Abnormal field conditions (per our Utility Procedure: TD-7102P-09, see Attachment 2020WMP_ClassB_PGE-18-Atch02).

Tree Assessment Tool

PG&E Pre-Inspectors use the PG&E TAT to determine if a strike tree (a tree tall enough to strike electrical facilities should it fall) should be abated (because it is a hazard tree) or just inventoried (healthy strike tree). The TAT tool has various data inputs that inform the assessment, including but not limited to historical data and statistics on tree failures, tree species, lean, health, terrain, slope, and local wind gust data. In this way, the TAT tool serves as a risk prioritization tool that recognizes high-risk areas and tree species. The TAT is used by inspectors in the field on a per-tree basis to inform Pre-Inspectors on abatement decisions. For further details on the TAT, please see our TAT White Paper, Attachment 2020WMP_ClassB_PGE-18_Atch03.

ii. How it accounts for hazard tree programs in its memorandum accounts

Below is a description of how PG&E accounts for its various VM programs in memorandum accounts:

Catastrophic Event Memorandum Account

Commission Resolution ESRB-4 issued in June 2014 permits PG&E to seek CEMA recovery for proactive mitigations we perform to address fire risks in response to the State Drought State of Emergency and the Tree Mortality and Bark Beetle Emergency Proclamations, and to reduce fire risks related to PG&E's facilities.

The CEMA Program was established to reduce the risk associated with the increase in tree mortality from the drought and recovery for the costs associated with activities taken to reduce risk from the increased tree mortality is done through the CEMA memorandum account. There are several elements to the CEMA Program for how dead or dying hazard trees are tracked and paid for. During the routine maintenance inspection, any tree that is identified as dead and dying is classified as "first patrol" and has a unique work request and order number to separate it from routine maintenance work. During the CEMA inspection (or second patrol), trees identified as dead or dying are listed as "second patrol" and are given a unique work request and order number. Using these unique order numbers by type of patrol and division of work, the CEMA Program tracks and accounts for the expenses incurred where cost recovery is sought through the CEMA memorandum account.

PG&E's Business Finance team creates separate order numbers for this work: fire hazard prevention—tree mortality management. Business Finance monitors actual costs and monthly and year-end budgets. PG&E uses operational and financial performance measurement processes/reviews to update leadership regarding the performance of different "sub-budgets" within the CEMA Program. During these reviews, Business Finance and/or SMEs provide a description of actuals, relative to plan and what is projected at year-end, and factors impacting business performance.

Related costs are tracked using a non-earnings expense MWC and MAT (MWC IG, MAT IGI). These MWC and MAT codes are used for other types of work, so a separate Receiver Cost Center (RCC) 15345 is used for all CEMA related orders, unique current year organization designation, and rolls up to Major Project and Programs.

Routine Distribution VM (Excluding CEMA)

Outside of CEMA, the cost recovery mechanism for Routine VM Distribution is the Vegetation Management Balancing Account (VMBA)

Routine VM Distribution partners with PG&E Business Finance to create and monitor program spend via stand-alone planning orders and separate order numbers for this work. Routine VM Distribution and Business Finance monitor actual costs and monthly and year-end budgets. Routine VM Distribution has operational and financial performance measurement processes/reviews to update leadership regularly regarding the performance of different “sub-budgets” within the Routine VM Distribution Program. During these reviews, Business Finance, and/or SMEs provide a description of actuals relative to plan and what is projected at year-end, and factors impacting business performance.

PG&E tracks related costs using a non-earnings expense MWC and MAT (MWC HN, MAT HNA, HN#). These MWC and MAT codes are used for other types of work, so a separate RCC 14737 is used for all VMBA-related orders, with unique current year organization designation that rolls up to Major Project and Programs.

Business Finance will monitor adherence to program cost caps and charging guidelines through the integrated planning process, annual detail planning, monthly re-forecasting, and monthly variance analysis. SAP is PG&E’s system of record for financial reporting purposes.

Enhanced Vegetation Management

<u>2019</u>: The cost recovery mechanisms for EVM for 2019 are the Fire Risk Mitigation Memorandum Account (FRMMA) and Wildfire Mitigation Plan Memorandum Account (WMPMA). The FRMMA covers the time period before the 2019 WMP was approved (June 4). The WMPMA covers the time period from 2019 WMP approval through the end of the calendar year.

<u>2020</u>: The cost recovery mechanism for 2020 EVM will be the “new VMBA.” This balancing account will be formally enacted if the 2020 GRC settlement is approved by the CPUC. This “new VMBA” will encompass routine distribution VM and enhanced distribution VM.

As with CEMA and Routine Distribution VM, EVM partners with PG&E Business Finance to create and monitor program spend using stand-alone planning orders and separate order numbers for this work. EVM and Business Finance monitor actual costs and monthly and year-end budgets. EVM has operational and financial performance measurement processes/reviews to update leadership regarding the performance of different “sub-budgets” within the EVM Program. During these reviews, Business Finance and/or SMEs provide a description of actuals relative to plan and what is projected at year-end, and factors impacting business performance.

Related costs are tracked using a non-earnings expense MWC and MAT (MWC IG, MAT IGJ). These MWC and MAT codes are used for other types or work, so a separate RCC 14481 is assigned to all EVM-related orders with unique current year organization designation; it rolls up to Major Project and Programs.

Business Finance will monitor adherence to program cost caps and charging guidelines through the integrated planning process, annual detail planning, monthly re-forecasting, and monthly variance analysis. SAP is PG&E's system of record for financial reporting purposes.

CONDITION PG&E-19

LOW PASS RATE ON ENHANCED VEGETATION MANAGEMENT QUALITY ASSURANCE

Deficiency: PG&E is falling far short of meeting its stated 92 percent pass rate in EVM inspections, leading to a large volume of re-work and repetitive QA testing that consumes limited resources and lengthens the time required to complete EVM initiatives.

Condition: In its first quarterly report, PG&E shall detail:

i. ***Its EVM QA process, including identifying what type of process was used to determine the 60 percent pass rate and the 98 percent pass rate, as well as the credentials and experience of the employees that did the inspections (title, rank, and number of employees); and***

Background

In PG&E's 2019 WMP, we proposed a goal of 92 percent first-pass rate for EVM QA review. QA review in the context of the 2019 WMP refers to Work Verification (WV).

Definitions Used in This Response

- Pre-Inspectors: Pre-inspectors inspect all trees in order to prescribe tree work to the tree crew companies. The Pre-Inspector is also responsible for listing all strike trees for the EVM Program. The Pre-Inspector uses PG&E's TAT (as described in the response to Condition PGE-18) to complete a tree assessment to inform abatement decisions.
- Hazard Trees: Trees that are dead or show signs of disease, decay or ground or root disturbance, which could fall into or otherwise impact distribution and non-NERC facilities before the next inspection cycle.
- Strike Trees: Healthy tree that has the potential to strike the line or the facility should it fall.
- Work Verification: This is an independent review of all EVM work to verify: (1) the Pre-Inspector prescribed tree work that is needed, per compliance requirements, (2) Tree work is completed as prescribed; (3) Pre-Inspector has listed out all strike trees (applicable to PG&E's EVM only), and (4) all hazard trees are mitigated or removed. Currently, this team is comprised of a group of contractors that are independent and are not part of any tree or Pre-Inspector vendor. In late 2020 or 2021, the WV team will also be comprised of PG&E employees.

Response

This section describes: (1) process used to determine a 60 percent pass rate; (2) process used to determine 98 percent pass rate; and (3) the credentials and experience of the employees that did the inspections.

The inspection process for EVM has two phases. In the first phase, the VM Pre-Inspector prescribes all necessary tree work and then the tree work is completed by the tree vendor. Phase two is a second pass by the Pre-Inspectors in which they list all strike trees. Finally, PG&E's WV team conducts QC surveys of all completed EVM. The WV Team's primary responsibility is to verify that all work has been completed to scope, and all trees have been inventoried as vegetation points.

1) WV "First Pass" 60 Percent Performance Calculation for 2019:

- The calculation used to determine 60 percent is: Number of first passes/ (first passes + first fails).
  - First Pass = Mileage of Segments that have WV Pass for the first time during a period.
  - First Fail = The mileage of all segments that have had a WV Fail during the period.

In 2019, the 60 percent first-pass rate was due to several reasons (these issues have since been addressed and are described below in subparts ii/iii):

a) Training Gaps Leading to an Inaccurate Inventory of Strike Trees: In late 2019, we realized there were some training gaps with the Pre-Inspectors listing strike trees. Pre-inspectors would often miss listing some of the trees in the inventory; with some strike trees missing in the inventory, this caused the "first pass rate" to be lower because our EVM standard requires 100 percent inventory of all strike trees.

b) Lack of Coordination Between WV Team and Tree Crew and Pre-Inspector Team: In 2019, the WV team's site visits to the various segments were not planned in conjunction with the completion of the tree work. WV inspectors occasionally surveyed segments that had not yet received VM and were not ready to be surveyed. In 2019, this happened more frequently and was one of the factors that helped to account for the first pass rate of 60 percent, since the WV team member arrived to review work that had not yet been performed. As detailed in the next section (subpart ii), we have improved coordination and training to address these issues and make sure that the EVM process moves in a coordinated fashion and the WV team conducts a valid survey.[22]

c) Changes in EVM Scope: PG&E's EVM scope published in March of 2019 identified the top 10 species that should be removed if they qualify as strike trees. Pursuant to CPUC Rulemaking 18-10-007, which provided new direction and limitations associated with the removal of healthy trees in June 2019, we revised EVM scope to assess all strike trees regardless of species, but only remove those that are hazard trees. These scope changes led to some training gaps and misunderstandings about how to treat specific tree species.

2) EVM WV Audit (98 Percent Pass Rate):

The EVM WV Audit was initiated in late August 2019, under the direction of PG&E's EO Compliance and Quality organization and with the cooperation of the PG&E VM Organization. The purpose of the audit was to determine whether the EVM WV field personnel were working in conformance with the WV field process. We hired an external contractor to perform this EVM WV Audit. They used a sampling equation to determine the number of miles needed for a statistically valid audit; based on the parameters of 97 percent confidence, 3 percent error and 95 percent estimated compliance, the sample size was calculated at 227 miles.

EVM circuit samples were randomized and assigned for audit. The audit population was limited to EVM segments with a WV "Double Pass" status in the ArcGIS database. A WV "Double Pass" status means that tree work consistent with the EVM Scope (Utility Bulletin: TE-7012B-020, Rev 2, July 25, 2019, see Attachment 2020WMP_ClassB_PGE-19_Atch01) has been identified and completed, risk trees were identified and documented, the work was reviewed as passing by two different WV field personnel, and a final desk review was completed.

In order to determine WV "correctness", the audit was designed to mirror the WV process, and to answer the question: Is it true that the vegetation in the audit segment is in conformance with the EVM Scope and therefore the segment qualifies

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22 Valid Survey = A survey that has been performed after all of the inspection work and tree work on a segment has been marked as completed by the working crews. Valid Survey as a qualifying metric was introduced in 2020 to address the issues detailed above in subpart i, 1-b.

as WV "Pass?" The sample segments were assigned to the Contractor Field Managers and their Senior Auditor teams to perform the field audits. The Senior Auditors, using Arc Collector and Survey 123, would review and assess the data against the field conditions and EVM WV process to determine if the line segments met EVM Scope. All findings were field verified by the Audit Field Manager before being submitted to Veg Operations.

The table below shows that overall the WV miles audited had a 2.06 percent failure rate. The pass rate of 97.9 percent consisted of 89.7 percent clear pass and 8.22 percent of the miles with one or more medium to low-risk findings.

TABLE 21
EVM POST-WORK VERIFICATION AUDIT RESULTS

Audit Result by Category	Miles	Percent
Pass	203.99	89.72 percent
Pass w/Observation	18.69	8.22 percent
Failure	4.69	2.06 percent
Total	227.37	100.00 percent

3) For the credentials, the experience of employees that completed the WV (including title, rank, and list of employees), please see attached documents: 2020WMP_Class B_PGE-19_Atch02 (WV team personnel) and 2020WMP_ClassB_PGE-19_Atch03 (contractors who performed the audit as described above in subpart i.part2).

ii. ***How PG&E plans to achieve its stated goal of a 92 percent rate of "meets expectations" on the "first pass" of inspections going forward, including the specific capabilities that PG&E plans to build or acquire and the timeline against which PG&E will build these, and the cost savings and other resource efficiencies that would be achieved by meeting this goal; and***

iii. When PG&E plans to meet its stated goal of a 92 percent rate of "meets expectations" on the "first pass" of inspections.

In early 2020, to resolve the issues as described in subpart i, PG&E built a regional partnership with Pre-Inspector and WV teams to give real-time feedback to help ensure that segments will have a higher "first pass." One change in the process included having the Pre-Inspector join the WV team member in the field for the site review. With the Pre-Inspector and WV reviewing the segment at the same time during the second phase of the inspection process, WV provides crucial real-time feedback to VM Pre-Inspectors to explain what is not passing at that segment. This partnership has let Pre-Inspectors learn quickly from the mentorship with the more experienced WV Team member, improving WV pass rates thereafter.

Our new reporting method calls out if the segment was failed because tree work was incomplete or trees were missed. This reporting visibility allows the regional team to review these failures with the tree crew as part of warranty work or to further assist Pre-Inspectors with training. This new reporting improves visibility into EVM performance issues and identifies any performance deficiencies among tree crews or Pre-Inspectors. Since implementing this new process of partnership and more accurate reporting to the local teams, we have already seen a huge increase in the first-time pass rate.

Overall, these improvements have been cost-efficient for PG&E in reducing the need for WV resources by half, letting us re-allocate approximately $150,000 per month to other programs.

Although PG&E did not set a first pass rate goal of 92 percent as part of the EVM 2020 plan, performance has been trending much higher than in 2019. Our year to date pass rate is averaging at 88 percent, but since May, WV has been trending monthly at approximately 92 percent or better.

CONDITION PG&E-20

PG&E IS REDISTRIBUTING RESOURCES TO FOCUS MORE ON TRANSMISSION CLEARANCES

Deficiency: In a change from its 2019 WMP, PG&E is redistributing resources to focus more on transmission clearances, without sufficient explanation of the impact or benefit of this decision. Some recent wildfires have been attributed to a failure in transmission assets, which could be driving this redistribution.

Condition: In its first quarterly report, PG&E shall:

i. ***Explain in more detail why it made the change to transmission clearance, including whether the change was caused by recent fire(s) involving PG&E transmission lines;***

Since both the Camp Fire and Kincade Fire started on transmission corridors, we recognize the need to minimize tree-related hazards in preparation for extreme fire weather conditions.

PG&E has been conducting ROW expansion projects to increase vegetation clearance around transmission corridors since 2017. Our response to Condition PGE-23 provides details of ROW expansion work. One of the early ROW expansion projects completed in the Colfax area was selected because it had a history of high numbers of tree-caused outages each year. Following ROW expansion, the number of annual tree-caused outages was significantly reduced—in the 10 years prior to completion, there were 14 vegetation-caused outages, but there were no outages on the same line in the three years after ROW expansion.

This demonstrated improvement in safety and reliability has motivated increasing the size of the Right-of-Way Expansion Program since 2017 and for the more dramatic increase from 2019-2020. As shown in Table 25, Line Item 16, PG&E plans to perform 262 miles of transmission ROW Expansion work in 2020 as compared to 141 miles completed in 2019.

Another reason to increase ROW line clearance efforts was the significant impact to customers and electric system stability caused by the 2019 PSPS events. Avoiding transmission line shutdowns during PSPS events can help reduce transmission-caused customer and community outages.

As part of our wildfire mitigation and PSPS reduction efforts, PG&E developed a transmission-level vegetation risk model to assign relative risk scores to individual trees near transmission lines during extreme weather events, using extensive geospatial data derived from LiDAR. The model characterizes the threat posed by each of the trees located on transmission corridors and identifies those trees that, if mitigated, would reduce the threat of a tree strike or fall. Trimming these trees would likely allow those lines to remain energized and be excluded from PSPS events.

PG&E's Asset Strategy group has identified 42 transmission lines that could potentially be kept energized during PSPS if the vegetation risk was mitigated. We have trimmed those trees and mitigated risks on 20 of these lines in 2020. The remaining identified lines have work planned for future years because of the need to secure agency approvals for the high numbers of trees that would need to be removed. Performing this work reduces wildfire risk at all times and reduces the need to de-energize these lines in PSPS events.

ii. Identify all ignitions that resulted in spread on transmission assets; and

Table 11 of PG&E's 2020 WMP filing, showing the total number of CPUC reportable fire ignitions associated with PG&E Transmission Assets as well as the subset associated with vegetation contacts, is copied below:

TABLE 22
TRANSMISSION RELATED IGNITIONS FROM 2020 WMP TABLE 11

	2015	2016	2017	2018	2019
Total Transmission-Related Ignitions	13	16	24	24	27

iii. Explain what VM will not occur as result of the change in focus

PG&E's 2020 WMP explains that the target for Distribution EVM work dropped from 2,450 miles in 2019 to 1,800 miles in 2020. This change was driven by several factors, including moving more focus and work volume from distribution to the transmission ROW Expansion Program. While there is not a direct trade-off between transmission ROW work and distribution EVM work, these programs do rely on the same general pool of safe, well-trained, line clearance-qualified tree workers. In addition to the increased focus on Transmission ROW work in 2020, we continue to assess the impacts and effectiveness of EVM efforts to refine the EVM Program, and use our resources effectively to sustainably execute this multi-year program.

CONDITION PG&E-21

PG&E FAILS TO DESCRIBE WHY ADDITIONAL PROGRAMS FOR TRANSMISSION CLEARANCES ARE NECESSARY

Deficiency: Vegetation-caused incidents are more common at the distribution level, since lines have shorter required clearances and typically use shorter poles. This fact is verified through data reported in Tables 11-1 and 11-2 in PG&E's WMP, as the 5-year annual average of vegetation contact near miss incidents is nearly 5,600 on the distribution system compared to about 61 annual incidents on the transmission system. For some of PG&E's VM measures on transmission lines, especially its ROW Expansion Program, PG&E fails to adequately describe why additional programs for transmission clearances are necessary or effective.

Condition: In its first quarterly report, PG&E shall explain:

i. The reason for PG&E's VM focus on transmission;

PG&E's VM focuses on keeping our facilities, both distribution and transmission assets, safe and able to operate reliably under any weather conditions. Vegetation continues to naturally grow and replant itself along all facility corridors, so VM is a cyclical program that must revisit areas previously worked. In our response for PGE-20, we detail several reasons why PG&E has been working to widen vegetation clearance around transmission lines. These projects reduce wildfire risk by reducing vegetation that could fall or blow into transmission lines, and by managing the vegetation in the ROW reducing the risk of fuel that could enable an ignition to grow into a catastrophic wildfire.

The deficiency language accurately notes that transmission lines have a historically lower frequency of incidents compared to distribution lines; PG&E's wildfire risk reduction VM work largely reflects this:

TABLE 23
WILDFIRE VEGETATION MANAGEMENT WORK VOLUME BY ASSET GROUP

	Total OH Miles in HFTD	Miles in the 2020 Wildfire Risk Reduction Workplan	Percent of HFTD Assets With Additional Risk Reduction Exceeding Routine Vegetation Maintenance in 2020
Distribution	25,598	1,800	7.0 percent
Transmission	5,542	262	4.7 percent

Even if the relative frequency of vegetation contacts with transmission assets is low, it is still important to proactively and continually manage the vegetation around PG&E's transmission lines. It has become clear in recent years that current ROW clearance requirements are insufficient to avoid tree contacts and fuel proliferation, and that fire safety and risk reduction necessitates that we expand horizontal and vertical vegetation clearance zones around transmission assets.

Our VM focus on transmission is also motivated by the reality that transmission de-energization has disproportionately greater impacts on customers than distribution de-energization. If we are forced to declare a PSPS affecting a single transmission line, that line can cut service to many thousands of customers downstream, even though they are outside the HFTD area and are not directly at fire risk; this became painfully clear during the 2019 PSPS events. In contrast, although distribution-associated ignition risks are higher, a distribution line de-energization affects only those customers served by that line within the HFTD, and rarely has spill-over effects beyond the immediate fire threat area. If we shift some VM resources from distribution to transmission ROW clearances, we expect to reduce catastrophic wildfire risk by reducing the probability of ignitions for transmission lines all the time, and to reduce the need to include transmission lines and customers in PSPS de-energization events.

ii. Why this is an effective use of resources, and how PG&E has reached this conclusion, supported by quantitative data;

Transmission corridor expansion is an effective use of resources for several reasons. The additional clearances can help reduce the likelihood of tree contacts with transmission lines leading to fire or electrocution, reduce the need for PSPS, and reduce facility damage during a wildfire resulting in the faster restoration of electric service. As described in the response to Condition PGE-23 subpart iv, ROW expansion projects have the added benefit of improving access for fire control agency crews, providing fuel breaks to increase the effectiveness of aerial fire-retardant drops, and supplying back-fire anchor lines for wildfire suppression efforts. Line crew safety is also increased when they are managing the vegetation in a wider ROW. Past transmission corridor clearing has averaged 50 feet width for 60-70 kilovolt (kV) and 75 feet for 115 kV ROWs, depending on easement descriptions. PG&E is now working to expand these corridor widths to 80 feet for 60-70 kV ROWs and 100 feet for 115 kV for the reasons outlined above.

As described in the response to Condition PGE-20, a ROW expansion pilot project completed in 2017 did reduce vegetation-caused outages. For the 10 years before the

2017 ROW expansion pilot, there were 14 vegetation-caused outages, but no outages occurred on the same line in the three years after the expansion.

iii. Whether the focus on transmission level VM is driven by short-term goals related to PSPS or long-term goals to reduce ignition risk,

As noted in the response to Condition PG&E-20, the performance of Transmission ROW expansion VM work is focused on reducing wildfire risks at all times, reducing the need for PSPS events on transmission lines, and increasing reliability. Reducing the need for PSPS on a transmission line is not a "short-term goal." Our long-term goal is to reduce ignition and wildfire risks and to use the PSPS tool as little as possible, in a manner that affects the fewest customers possible. Both of these goals require extensive work to: expand transmission ROWs, remove vegetation overhangs, and expand distribution clearances, with ongoing maintenance to maintain those clearances. Both ROW expansion and on-going VM work are essential for the long term to reduce wildfire risk and reduce PSPS impacts on customers.

iv. The amount of labor and resources being allocated to the program; and

The transmission ROW expansion and PSPS risk-tree work currently employs a working group of 3-4 full-time PG&E employees, 25-30 contractor project setup and administrative personnel, and 180-200 tree crew personnel.

v. The opportunity costs of its transmission clearance program on its broader VM efforts for the distribution system.

PG&E chose to increase funding, management, and tree crew resources for transmission clearance independently from the decision to reduce EVM work and resources. We did not redeploy tree crew and management resources already working on EVM to work on ROW expansion. However, we estimate that approximately 700-725 of additional EVM distribution line-miles could have been mitigated[23] with the resources used to handle the increased level of ROW expansion and PSPS risk-tree resources discussed above.

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23 This estimate uses our current (July 31, 2020) estimate of annual performance of about 3.82 veg points/per Full-Time Equivalent employee/per weekly mile for EVM work.

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 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 certifications. PG&E assumes that the question above is referring to ISA Certified Arborists. Approximately 29 percent of PG&E's Pre-Inspectors are ISA Certified Arborists. Additionally, about 3 percent of Pre-Inspectors are Registered Professional Foresters in the State of California.

PG&E disagrees that any of our VM Pre-Inspectors lack proper certification for the requirements of the job. While being an ISA Certified Arborist may be helpful, PG&E does not agree that this credential alone sufficiently qualifies or determines 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 trees and did not understand California 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. That is why PG&E's pre-inspection focuses on: (1) 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.

The Structured Learning Path

The Structured Learning Path (also referenced in our response to Condition PGE-25) for Pre-Inspectors includes completion of a nine-course comprehensive training program 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, which is also a requirement for contractors performing EVM inspections. 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

100 percent of EVM pre-inspection work is reviewed by the WV team, approximately 50 percent of whom are ISA Certified Arborists. The other 50 percent of the WV team generally have years of experience in forestry and/or utility line clearance work. As explained in our response to PGE-19, the WV team reviews the completed pre-inspection work (doing this with the Pre-Inspector who performed the work beginning in 2020, 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. Additionally, because the work is being verified by professionals who in the vast majority are ISA certified arborists, we do not believe our approach provides risk.

Tree Assessment Tool

Finally, Pre-Inspectors using the TAT are less likely 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 found 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, and formally endorsed, 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 tool that removes biases and judgment with subjective individual 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 to become ISA Certified Arborists.

We estimate the portion of Pre-Inspectors who will be ISA certified by the 2021 WMP filing, to increase by about 1-2 percent from the current 29 percent total.

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. This effort began in 2020 and will continue, although we anticipate completing and distributing the bulk of these efforts this year.

Currently, we verify the quality performance of 100 percent of our EVM work and 10 percent of Routine Maintenance work. VM is planning to increase the percentage of work verified for Routine Maintenance to 25 percent beginning in November 2020. 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-23

VEGETATION WASTE AND FUEL MANAGEMENT PROCESSES UNCLEAR

Deficiency: PG&E's description of "Fuel management and reduction of 'slash' from VM activities" states the utility will continue to assess effectiveness to determine whether to continue or adjust work. This response is generic and does not give detail on how much fuel reduction occurs, whether vegetation is cleared to bare soil, or how wide the zone of clearance will be. PG&E also does not discuss the criteria it uses to identify what areas are treated to effectively enhance defensible space. Based on the information given it is not possible to determine how effective this work will be. Finally, PG&E does not discuss how slash is treated during its VM work. PG&E also states in its Utility Survey that it does not remove slash from its ROWs and does not plan to remove vegetation waste from its ROWs across its entire grid, citing constraints. However, PG&E does not describe the practices it uses to reduce risk where it does not remove slash/vegetation waste.

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

i. ***The criteria it uses to identify and prioritize areas for fuel management to enhance defensible space;***

Definitions Used in This Response

- <u>Slash</u>: Slash is branches, limbs, stems, trunks, and woody debris less than four inches in diameter left on the ground as a result of VM operations.
- <u>Fuel Reduction</u>: Refers to treating slash and/or the main stems of trees left on the ground following previous or current utility VM activities, or treating vegetation currently growing in the ROW. It may include removal to an off-site location, chipping and dispersing the chips back onsite, or grinding vegetation and slash in place with mastication machinery. The wood chips keep low vegetation from growing back as quickly (much like using mulch) and retain water that slows the likelihood of a spark creating an actual ignition. Through tree-trimming, the vertical continuity of vegetation fuels is changed to a horizontal layer which reduces flame height and makes wildfire control more manageable. It eliminates fuel "ladders" to prevent low flames from growing into "crown" fires. It may also include "lop and scatter," which is cutting the slash with chainsaws and scattering it, so it is left at an average depth of less than 18 inches from the ground surface. PG&E's fuel management practices exceed the California Forest Practice Rules, which requires

that slash resulting from timber operations be reduced to less than 30 inches from the ground.

- Utility Defensible Space (UDS): PG&E defines UDS as creating an area around our electrical facilities that in an event of a wire-down scenario would reduce the likelihood of the ignition and/or spread of a fire. It has the added benefit of protecting PG&E facilities during a wildfire. It also creates a potential fuel break that can assist fire control agencies in the event of a wildfire.

The following two VM programs are focused specifically on fuel reduction and have specific criteria for prioritization:

1) Transmission UDS (Pilot): PG&E is developing a separate program specifically focused on UDS and fuel reduction that creates a defensible space around our facilities.

    a) Our Focus for the Program Includes:

        - Target the removal of trees with elevated risk characteristics (not always tall enough to strike our facilities, but have defects, dead, diseased, dying, leaning, or otherwise compromised trees);
        - Create a 40 to 50-foot radial clearance of woody vegetation and slash around selected transmission structures as defensible space; and
        - Apply fire retardant within this 40 to 50-foot radial clearance (pending the permit/work approvals across the different agencies and recurrent environmental assessment by PG&E's Environmental Team).

    b) Criteria Used to Identify Priority Areas for UDS Pilot: The criteria for selection are those poles or towers on transmission lines in HFTD Tier 2 and 3 areas that could remain energized during PSPS events. The first areas selected for treatment have been cleared through PSPS tree-risk reduction or ROW expansion work. Treatment areas include poles and towers cleared of low vegetation during Integrated Vegetation Management (IVM) corridor maintenance work.

2) Transmission ROW Expansion: The goal of this program is to widen transmission corridors by removing vegetation along the corridor edges, as well as cutting reinvading vegetation within the corridor.

a) Some of These Efforts Include:

- Trees and woody vegetation are removed in 60-70 kV transmission corridors to widen the corridor out to 80 feet, and 115 kV corridors are widened out to 100 feet;
- Vegetation is removed to obtain 40 feet of radial clearance around poles and 50 feet of radial clearance around towers in Tier 2 and Tier 3 HFTD areas;
- Most of the slash and fuels from previous VM work is chipped onsite with an off-road tracked chipper machine or masticated in place;
- Areas inaccessible to machinery have fuel treatments of lop and scatter; and
- All trees outside of the ROW that could fall and touch a PG&E line are inspected and all trees identified as hazard trees or "danger" trees are mitigated.

b) Criteria to Identify Priority Areas for Reducing Fuels:

Transmission Asset Strategy specified priority areas in 2017, identifying the 67 worst-performing circuits based on vegetation-related outages and gave a timeline of seven years to complete corridor widening and fuel reduction. In 2018, the list was re-prioritized to complete those lines in HFTD Tier 3 and Tier 2 first, and work Tier 1 portions in later years.

In addition to the two programs stated above that are focused on fuel reduction and ignition prevention, PG&E conducts fuel management as a part of a normal process for its various VM programs. These programs do not use criteria for prioritization since fuel reduction is part of standard operating procedure.

1) Routine VM Scope – Distribution:

- Every mile of distribution in the HFTD areas is patrolled and trees worked as necessary, twice a year to maintain compliance with California PRC Section 4293.
- GO 95 Rule 35 – Annual Routine Patrol, and Biannual Second patrol in SRA areas of HFTD.
- Under routine VM, PG&E chips all woody debris and limbs less than 4 inches diameter created by work within 100 feet of chipper access
- Beyond 100 feet of chipper access, limbs and tops are cut and left on-site at less than 18 inches deep and in contact with the ground.

2) Routine VM Scope – Transmission:

- Routine VM is performed once a year on every circuit, removing trees from the ROW and pruning trees along the edges of the ROW.
- Every mile of transmission line on the system receives an aerial LIDAR patrol. Follow-up ground patrols inspect all locations with trees that could grow into or fall into the facilities.
- Every mile of transmission line in the HFTD receives a second LIDAR patrol to identify encroaching vegetation during the fire season.
- Under routine VM, PG&E chips all woody debris and limbs less than 4 inches diameter created by the work within 100 feet of chipper access.
- Beyond 100 feet of chipper access, limbs and tops are cut and left on-site at less than 18 inches deep and in contact with the ground.

3) EVM – Distribution:

- EVM projects are selected based on Asset Management Risk Ranking and historical VM fire data analysis.
- As part of this EVM work, fuel loads are reduced through chipping of brush and woody debris less than 4 inches in diameter as well as the removal of wood from sites where the site meets specific accessibility criteria.
- Within the ROW, there are projects designed to trim and cut down vegetation and expand the existing utility ROW using cutting, chipping, and in some instances masticating remaining vegetation on the ground to reduce fuel loads to chips piled in depths typically less than 6 inches deep.

4) Transmission IVM: Refers primarily to the follow-up maintenance that takes place after routine VM or ROW widening.

- IVM field conditions are monitored annually and maintenance activities occur at varying intervals ranging from 2-10 years.
- The goal of IVM is to maintain low growing, compatible, sustainable vegetation communities that are less fire-prone (e.g., with vegetation that holds higher moisture content) and are free of incompatible tree species capable of growing into overhead lines.
- Vegetation and fuels treatment may include one or all the following: (1) cutting and chipping, (2) cutting, lopping/scattering, (3) mechanical mowing and (4) selective herbicide treatments.

5) Vegetation Control Program (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 SRAs during designated fire season and such designation is a priority in performing this defensible space activity.

ii. What specific areas were treated during the previous reporting period, including supporting GIS files;

PG&E is enclosing the GIS files and Excel lists on the specific areas that were treated during the previous reporting period (May 1, 2020 – July 31, 2020), see Attachment 2020WMP_ClassB_PGE-23_Atch01:

1) Transmission UDS (Pilot) Circuits Treated:
   - Briones Tap 60 kV
   - Halsey Placer 60 kV
   - Windsor – Fitch 60 kV
   - Mountain Gate Tap 60 kV
   - Delta – Mtn. Gate Junction 60 kV
   - Volta – South 60 kv
2) Transmission ROW Expansion Circuits Treated:
   - Colgate – Alleghany 60 kV
   - Pit 5 – Rnd Mtn #1 230 kV

iii. What specific areas are planned to be treated during the upcoming reporting period, including supporting GIS files;

PG&E is enclosing the GIS files and an Excel list on the specific areas that will be treated in the upcoming reporting period (August 1, 2020 – October 31, 2020), see Attachment 2020WMP_ClassB_PGE-23_Atch01:

1) Transmission ROW Expansion Circuits to Be Treated:
   - Drum – Spaulding 60 kV
   - Spaulding Summit 60 kV
   - Deer Creek – Drum 60 kV
   - Donnells – MiWuk 115 kV
   - Drum – Higgins 115 kV
   - French Meadows- Middle Fork 60 kV

- Fulton-Calistoga 60 kV
- Fulton – Pueblo 115 kV
- Gold Hill #1 60 kV
- Humboldt – Trinity 115 kV
- Keswick – Trinity 60 kV
- Kilarc – Deschutes 60 kV
- Mi Wuk-Curtis 115 kV
- Middle Fork #1 60 kV
- Monte Rio-Fulton 60 kV
- Philo Jct. – Elk 60 kV
- Pit 1- Cottonwood 230 kV
- Trinity – Maple Creek 60 kV

iv. The types of vegetation waste treatments it uses across its grid, including how it chooses where to use each treatment, and how effective each of these vegetation waste treatments are in the location where they are deployed; and

PG&E has described the types of vegetation waste treatments we use across the grid and how we choose where to apply each treatment in subpart i.

The effectiveness of various waste treatments as part of our VM programs is realized in a number of ways:

- Increased Vegetation Distance to Conductors: This helps reduce heat damage to the facilities if a wildfire passes through, reducing repairs and allowing faster restoration of electrical service.
- Improved Access for Fire Control Agency Crews: The cleared corridor provides a safer route during a wildfire for fire crews to create and access firebreaks.
- Existing Fuel Breaks for Fire Control Planes and Helicopters to Drop Fire Retardant: The cleared corridor provides a ready-made location cleared of most fuels to increase the effectiveness of aerial fire-retardant drops.
- Back-Fire Anchor Lines: During wildfire suppression efforts, back-fires are lit along areas of reduced fuels such as the cleared ROW corridors to burn out forest fuels ahead of advancing fires. In 2012, the Pittsburgh-San Mateo 230 kV line corridor on the East flanks of Mount Diablo was used as a fire break to stop a wildfire and protect a residential area.

The attached set of before and after photos, taken April-May 2018 on the Weimar #1 60 kV transmission line, illustrates the effectiveness of transmission VM Reliability projects that deliver fuel hazard reduction, hazard tree removal, and ROW expansion (see Attachment 2020WMP_ClassB_PGE-23_Atch02).

v. ***Its work with federal and state landowners, including the USFS, on fuel reduction programs, including a listing of all programs it has in place with these entities, and the end date of each program, if applicable.***

With regards to fuel reduction program, PG&E implemented a cost recovery program with the USFS (see Attachment 2020WMP_ClassB_PGE-23_Atch03 for PG&E-USFS Program timeline and workflow). In 2019, this program provided $2.7 million to complete fuels reduction on approximately 3,500 acres outside of PG&E's ROWs in four different forests. For 2020, the program provided $4.9 million aiming to reduce fuel reduction over approximately 5,000 acres (per USFS proposals) in six forests. These funds enable the Forest Service to acquire much-needed machinery, which will support additional fuels reduction work over multiple years on acreages above and beyond this initial funding amount. This opens a new way to complete additional fuels reduction work that could protect PG&E assets within areas where PG&E does not have land rights or authorization to complete key fuel reduction activities.

PG&E leadership meet with Forest Service leadership twice a year to explore opportunities where we can continue to collaborate to reduce wildfire risk within California. In coming meetings, we will look at clarifying the process for disposition/treatment of felled trees (e.g., timber sale, lop and scatter, chipping), funding Forest Service positions to assist with the review of PG&E work requests, and the IVM approach that would allow the use of Forest-approved herbicides to control utility incompatible vegetation while seeking to encourage a low-growing stable plant community around powerlines.

PG&E partners with a number of federal and state landowners, including the USFS, to ensure compliance with regulations for fuel reduction activities by working with agencies to streamline permitting/process agreements. Our permitting/process agreements with federal and state agencies include:

United States Forest Service

- For many years, utility ROWs were added, authorized, and renewed on a piece-meal basis. Through this partnership, PG&E and Region 5 of the USFS were able to successfully complete the reissuance and consolidation of hundreds of utility permits on National Forest System Lands. Now the USFS is able to monitor and renew utility permits with a single permit and single easement per forest. The backlog of permits caused delays in the approval of critical wildfire prevention work. The reauthorization effort helped further the forests national goals of addressing the backlog of expired and expiring permits and will make it easier for both the Forest Service and PG&E to monitor further expirations.
- The updated permits are accompanied by a Programmatic Operations and Maintenance Plan (O&M Plan), that describes the facilities and activities, establishes the activity review process, defines the environmental review and protection process and establishes communication and monitoring protocols. The O&M Plan has reduced the amount of time staff spends reviewing and processing routine operation and maintenance activities. Where before it could take 6-12 months to obtain approval to address a potential wildfire hazard, it now takes only 5-15 days to obtain approval to move forward with the activity.
- The O&M Plan helps maintain PG&E's facilities in a safe and reliable manner. The plan creates greater consistency and certainty across the region for reviewing and approving O&M activities. It lays out when, where, and how we can conduct vital work. The streamlined process helps assure electric facilities are regularly maintained, thereby reducing fire hazards. The plan ensures maintenance work is done quickly and efficiently to protect the National Forest System Lands.
- The O&M plan is necessary to ensure that facilities are maintained in compliance with applicable federal, state, and local laws, including the CPUC requirements and regulations. The O&M plan also outlines procedures to avoid effects on plants, animals, aquatic features, endangered and sensitive species habitats, areas of resource concern, and other areas of potential effect.
- As part of the permitting assessment and evaluation process, the Forest Service requested that PG&E prepare and submit an inventory of those roads required by PG&E to safely operate and maintain its authorized facilities. PG&E also committed to complete a condition assessment to determine the actions and time needed to bring all utility roads to Forest Service Maintenance Level 2 standards. We will

complete the inventory, assessment, and required maintenance within 5 years of Forest Service execution of the Master Permits and Easements.

California State Parks

- We have finalized a process agreement that will streamline work across all PG&E departments working throughout the 97 California State Parks within our service territory. This partnership with State Parks enables non and minor ground-disturbing work (where existing easement rights exist) and emergency work to proceed without notification. It also allows for wildfire fuels reduction and more significant ground-disturbing work to proceed after a 2-week notification a process, if existing land rights exist. Major wildfire work would follow the typical permitting requirements and process flow.

Bureau of Land Management

- Building on ongoing efforts to reduce the threat of wildfires through active management, the Bureau of Land Management (BLM) California State Office worked with SCE and PG&E to issue a new Instruction Memorandum (IM) to limit fire risk from power lines crossing BLM-managed public lands. The new IM, enacted May 20, 2019, and extended through 2020, allows PG&E to facilitate and expedite O&M activities necessary to reduce the risk of wildfire by conducting the activities without prior authorization instead requiring us to notify the appropriate BLM Field Office within 30 days of completing such work. Meanwhile, we continue to work with the BLM Bakersfield Field Office on a Programmatic ROW renewal process and O&M Plan which may be used by other field offices within PG&E's service territory.

National Park Service

- In 2019, PG&E worked with the National Park Service (NPS), Pacific West Region, to put in place eight park-specific 1-Year Special Use Permits (SUP) which will allow PG&E to expedite critical routine O&M activity within NPS-managed land. The permits require park approval within 15 days for most routine O&M activity. It will also authorize drone usage within the parks. The SUPs became effective on February 1, 2020.

Habitat Conservation Plan

- PG&E has also entered a Habitat Conservation Plan (HCP) with the U.S. Fish and Wildlife Service within the nine counties of the Bay Area, the San Joaquin Valley, and has just executed the Multi-Region HCP, which provides federal endangered species coverage for the entire service territory. Each HCP has a term of 30 years. These HCPs have allowed PG&E to streamline permitting activity for O&M and wildfire related work. This will reduce permitting time down to weeks from 18-36 months, which would be the time required if we had to obtain individual permits for these O&M activities.

CONDITION PG&E-24

IMPROVING PRIORITIZATION

Deficiency: While PG&E expresses plans to expand its prioritization capabilities for better targeting mitigation activities, it provides scant information on how this will be achieved or timelines for doing so.

Condition: In its first quarterly report, PG&E shall explain its method and process for:

i. Prioritizing between system hardening and VM efforts in a single location;

Generally, the current prioritization models for both programs are based on relative risk ranking scores, which compare risk scores between circuits. As detailed in the 2020 PG&E WMP, Section 5.3.1.1, relative risk ranking scores are calculated for each circuit based upon three components: likelihood of failure, likelihood of wildfire spread and consequence, and egress. These components are defined as:

1) Likelihood of Failure: Relative risk of a circuit causing an outage and ensuing ignition;

2) Likelihood of Wildfire Spread and Consequence Score: Relative ability of ignition spread and quantity of structures or timber affected if ignition occurs; and

3) Egress Score: Ease of access to a community exit and extent of exit, for a mass evacuation.

PG&E's distribution-level and transmission-level system hardening and EVM programs currently leverage distinct prioritization models based on factors specific to each program, as explained below.

Because each program is assessed differently, we are not currently able to assess the absolute risk of a circuit at this time. This means that, currently, prioritization for system hardening and EVM work is determined independently by the two programs and does not occur in a single location. This highlights the need to develop a risk assessment methodology that applies consistent risk factors, can assess absolute risk of each circuit consistently, and will allow PG&E to align the prioritization of a circuit for wildfire mitigation work across programs in a single location.

To that end, we are developing a consequence-of-risk model that uses the MAVF. Additional information about how PG&E will be implementing the MAVF and how the MAVF informs relative risk scoring can be found in the 2020 WMP in Section 4.2. By utilizing the MAVF framework, we will align the factors considered in both prioritization models in a single location. PG&E believes this alignment in risk factors will yield consistent calculations across both programs, thereby demonstrating the benefits of having a one prioritization process for system hardening and EVM. We expect to have this developed by mid-2021.

ii. Leveraging past initiative performance data and lessons learned for improving future prioritization decisions;

PG&E evaluates past and present prioritization decisions to inform and improve future prioritization modeling. Our SMEs and contractors evaluate our models by routinely scrutinizing the different aspects of the model process, including data collections, data ingestion, data processing, data cleansing, exploratory data analysis, model and algorithm selections and model outputs.

In scrutinizing our models, PG&E SMEs and contractors identified issues with existing software systems, which were purpose-built to support specific capabilities and were not easily accessible or able to integrate with other systems. For example, customer data, asset data, work management data, GIS data, operations data, and event data have traditionally been managed using separate software systems and data stores and were not integrated centrally. This utilization of separate data systems meant that we were not able to benefit from sharing data streams from new technologies requiring specific data storage and processing needs such as remote sensing and LiDAR.

PG&E has responded to these challenges by developing strategies for data governance, management, integration and access. This includes exploring using advanced analytics (i.e., artificial intelligence and machine learning technology), which offer the potential to leverage data to better manage risk and predict events before they happen.

PG&E SMEs and contractors also identified a need to incorporate model performance metrics for the distribution line risk scoring model that better inform whether the analytics generated by the model are statistically significant and stable. To that end, we have identified performance measurements that help identify areas that should be prioritized for work. We are working to fully incorporate these updated model performance metrics by Q2 2021.

PG&E will continue utilizing our process of scrutinizing existing models and leveraging past initiative performance to improve future versions of the prioritization model. These efforts are ongoing and are critical to refining our predictive models as PG&E acquires additional data on initiative performance in the future.

iii. Balancing hardening and remediation work to reduce ignition probability related to asset failure; and

In reviewing the question, PG&E determined that the term "remediation work" lends itself to two different interpretations.

If the term "remediation work" refers to balancing system hardening and "repair" efforts, PG&E has several on-going efforts to balance system hardening work with other "repair" or "maintenance" efforts. One of those efforts was the EC Optimization Program. The EC Optimization Program was an end-to-end process which reviewed and prioritized the work that was conducted by Distribution Wildfire Safety Inspection Program. The program prioritized the execution of open lower-priority tags (E and F tags) in Tier 2 or Tier 3 HFTD areas and incorporated these tags into the existing system hardening workplan. These tags were then repaired in alignment with both existing and new system hardening projects. This year, PG&E is expanding this process to include and align other asset strategy programs (i.e., the Non-Exempt Surge Arrestors and Non-Exempt Fuse Replacement programs) with the overall system hardening program to similarly optimize system hardening workplans.

On the other hand, if the term "remediation work" refers to balancing system hardening with other "mitigation" efforts, at this time, PG&E's methods and process to balance system hardening and other mitigation work (i.e., wildfire mitigation efforts to reduce ignition probability related to asset failure) are undergoing a significant transformation. Our balancing methodology is moving from a semi-quantitative process heavily dependent on SMEs to a system that uses internally- and externally-developed technology and tools to collect data and evaluate risk across programs.

In shifting our approach to evaluating risk across numerous efforts (using tools such as the RSE), we have determined that system hardening should be the primary focus of our wildfire mitigation work. We will progressively increase the pace of system hardening work over the 2020-2022 period, while schedules for other programs progress according to the current plan (notably, the Non-Exempt Surge Arrester Program will complete replacements by 2021 as planned, and the Expulsion Fuse Replacement Program continues on-track to replace 625 non-exempt fuses per year for seven years on poles located in high fire-threat areas).

iv. Determining the quantitative effect on PSPS thresholds from hardening initiatives.

The distribution line exclusion model shows the threshold improvement for system hardening and EVM. The model determines the quantitative effect of system hardening by analyzing all historical outage types and qualitatively assessing the degree to which system hardening has the potential to reduce the probability of each outage type.

The model is based on SME identification of whether system hardening would eliminate, reduce significantly, reduce moderately, reduce minimally or will not have an effect on the likelihood of a certain type of outage (e.g., vegetation contact or different types of equipment failures) occurring when an asset has been hardened. PG&E then developed five reduction thresholds to assign to the outage types:

1) **All** = Eliminates likelihood of a certain type of outage occurring
2) **High** = Reduces likelihood significantly of a certain type of outage occurring
3) **Medium** = Reduces likelihood moderately of a certain type of outage occurring
4) **Low** = Reduces likelihood minimally of a certain type of outage occurring
5) **None** = Will not have an effect on likelihood of a certain type of outage occurring

Each of these five thresholds were assigned a quantitative value, which measured the likelihood of outage reduction:

1) **All** = 90 percent
2) **High** = 70 percent
3) **Medium** = 40 percent
4) **Low** = 20 percent
5) **None** = 0 percent

The table below presents examples of different outage types (vegetation outage types) and their respective assigned effectiveness levels:

TABLE 24
EXAMPLE MODELED SYSTEM HARDENING EFFECTIVENESS BY OUTAGE CAUSE

Basic Cause	Supplemental Cause	Failed/ Involved Equipment	Equipment Condition	System Hardening Effectiveness	System Hardening Percent Effectiveness	System Hardening Effectiveness
Vegetation	Other Ground Vegetation	Conductor – Overhead	Arcing	All	90 percent	Covered conductor will eliminate the line slap and risk associated with this outage.
Vegetation	Tree – Bark Fell Into Line	Connector or Splice (OH)	Arcing	High	70 percent	System Hardening will make circuit more robust.
Vegetation	Other Ground Vegetation	Conductor – Overhead	Broken – Wire on Ground	Medium	40 percent	Circuit Hardening will temporarily eliminate splices. Still allowed for emergency repairs. Splices, clamps, and connectors still pose a risk.
Vegetation	Tree – Branch Fell on Line	Service Conductor	On Ground	Low	20 percent	System hardening projects will change out pre-2014 transformers and changeout services based on age and condition or not meeting current Standards.
Vegetation	Tree – Grew Into Line	Customer Equipment	Broken	None	0 percent	No work is being completed on customer equipment.

As more system hardening work is completed on a given electric line, the number of circuit segments that could be excluded from a predicted PSPS footprint will increase. In order for a segment of electrical line to be excluded from the predicted PSPS footprint, the entire segment would need to be hardened.

The transmission line exclusion model differs in that certain lines are excluded based on whether repairs are needed and have been completed on the line. After inspections are conducted on the transmission lines, PG&E prioritizes repairs on lines where completing repairs would result in a healthy line. A healthy line would be able to stay energized during a PSPS event; and thus, be excluded from a predicted PSPS footprint.

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 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;***

PG&E acknowledges that there were significant issues with communications and coordination with local communities during PSPS events in 2019. Despite conducting over 1,000 individual stakeholder meetings, workshops with local emergency managers and direct outreach to key critical service providers, communications problems arose during PSPS events that hampered local response efforts. In 2020, we have changed the way we engage with local communities, and the resources we provide, to give better information before wildfire season and to improve coordination for PSPS events. This began in late 2019 with listening to direct feedback from customers, agencies and stakeholders on the ways that we could improve and creating 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.

Following are the steps that we are taking to improve local coordination in 2020.

Listening Sessions

In November 2019, PG&E began outreach to the counties and tribal governments impacted by 2019 PSPS events, along with other key stakeholders, to schedule in-person listening sessions with PG&E leadership. These sessions provided an open forum for PG&E to listen to concerns, gather important feedback and identify ways to improve coordination and partnership with local communities going forward. The feedback is being used to guide improvements to our PSPS processes and procedures and help prioritize key focus areas for 2020.

We coordinated with county and tribal emergency managers to schedule each meeting and to determine the appropriate meeting participants. In some instances, cities, special districts and other stakeholders participated. In all, we completed 36 listening sessions with counties, cities, and tribal governments. Below is a list of the host county, city or tribal governments and corresponding session dates.

TABLE 25
COUNTY, CITY, AND TRIBAL PSPS LISTENING SESSIONS

Alameda County 12/10	Humboldt Tribal 12/11	Merced County 12/18	Santa Cruz County 1/30
Alpine County 12/9	Kern County 12/11	Monterey County 12/12	Shasta County 12/12
Amador County 1/27	Lake County 2/24	Napa County 1/27	Sierra County 2/13
Butte County 1/21	Lake Tribal 1/8	Nevada County 2/13	Solano County 12/3
Calaveras County 1/29	Madera County 12/13	Placer County 12/20	Sonoma County 1/29
Colusa County 12/5	Marin County 12/9	San Mateo County 12/12	Sonoma Tribal 1/29
El Dorado County 2/24	Mariposa County 1/29	Santa Clara County 1/9	Trinity County 12/12
Fresno County 12/13	Mendocino County 1/9	City of Cupertino 12/11	Yolo County 12/3
Humboldt County 12/9	Mendocino Tribal 1/7	City of San Jose 1/17	Yuba County 1/14

PG&E provided a report on the Listening Sessions to the CPUC in March 2020, please see Attachment, 2020WMP_ClassB_PGE-28_Atch01 – Listening Sessions Report.[24]

PG&E also held listening sessions with large commercial customers and critical facilities, as noted in the chart below.

24 2020WMP_ClassB_ PGE-28_Atch01 is the same file as "2020WMP_ClassA_RCP_PGE-27_Atch01," which is referenced in Condition PGE-27.

TABLE 26
PSPS LISTENING SESSIONS WITH LARGE COMMERCIAL CUSTOMERS AND CRITICAL FACILITIES

Audience	Date
Bay Area Rapid Transit PSPS Listening Session	Jan 6, 2020
Macpherson	Jan 22, 2020
Hospital Council	Jan 24, 2020
Comcast PSPS Listening Session	Jan 29, 2020
Telecommunication Providers PSPS Listening Session	Jan 30, 2020
US Department of Energy, National Labs	Feb 7, 2020
National Retailers PSPS Listening Session	Feb 26, 2020
Telecommunication Providers Workshop	Feb 27, 2020
California Large Energy Consumers Association	Mar 3, 2020
Macpherson Follow-Up	Mar 12, 2020
Bay Area Refinery Council	Mar 12, 2020
Telecommunication Providers Workshop Follow-Up	Apr 13, 2020
Rail Industry PSPS Workshop	Apr 14, 2020

Wildfire Safety Working Sessions

In March 2020, PG&E began reaching out to counties and tribes within its service territory to share county-specific plans for wildfire mitigation, system resiliency and the steps we are taking to address the feedback received during the listening sessions. Since then, PG&E's dedicated agency representatives have been working with county and tribal Offices of Emergency Services to co-host Wildfire Safety Working Sessions for their respective jurisdictions. Invitees to these events have included regional key stakeholders, such as cities, tribes, Community Choice Aggregators (CCA), telecommunication providers, water agencies, as well as local CAL FIRE and California Governor's Office of Emergency Services representatives.

The purpose of the sessions is to provide local agencies with an opportunity to have detailed conversations regarding PG&E's wildfire safety work planned in their community and PSPS improvements for 2020. The sessions also provide an opportunity for local officials to learn about the electric system in their community and discuss their needs and suggest any further improvements to the CWSP and PSPS Program. Feedback from the sessions has helped to shape local planning for PSPS events, including critical facility locations, CRC locations and local contacts for emergency response.

Wildfire Safety Working Sessions began in April 2020 and are expected to be completed by August 2020. A total of 31 session have been held as of July 17, 2020.

Standardized Emergency Management System 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 have better emergency management training. This year, everyone who supports PSPS events in PG&E's EOC is being trained in Standardized Emergency Management Systems (SEMS). 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 Incident Command System 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.

Trainings have been ongoing throughout 2020. As of August 13, 2020, 550 PG&E employees had completed the training. Training is pending for approximately 217 additional employees, which includes employees who are new to the Company, employees who were previously engaged in COVID response planning and those who were unavailable for training originally (i.e., on family leave). All employees supporting the EOC will be required to have completed the training.

PSPS Advisory Boards

PG&E's advisory boards provide hands-on, direct advisory functions related to PSPS. This includes helping PG&E develop best practices for PSPS protocols, community preparedness, regional coordination, and the optimal use of existing and emerging technologies.

PG&E established a PSPS Advisory Board in February 2020, which includes representatives from the following seven rural and urban cities or counties, two tribal agencies, and the League of Cities and California State Association of Counties (CSAC):

- Butte County
- California State Association of Counties
- City of Santa Rosa

- Hopland Band of Pomo Indians (Mendocino County)
- Kern County
- League of California Cities
- Marin County
- Placer County
- Robinson Rancheria Pomo Indians of California (Lake County)
- Santa Cruz County
- Sonoma County

To date, PG&E hosted six advisory board meetings (March 5, 2020; April 1, 2020; April 8, 2020; May 27, 2020; July 2, 2020; and August 27, 2020). The meetings average two hours in length and provide a forum for participants to weigh in on a variety of PSPS Program updates such as customer notification scripts, wildfire safety working session content and meeting outlines, and PSPS full-scale exercises, among other topics. PG&E plans to continue to host these meetings periodically to gather feedback on PSPS-related topics, including PSPS planning for 2020 and coordination with local communities and shared resources.

PG&E developed additional advisory boards based on feedback from representatives of AFN communities and communications providers:

1) People with Disabilities and Aging Advisory Council (PWDAAC): Provides insight into the needs of AFN populations related to emergency preparedness and to facilitate co-creation of solutions and resources to serve the customers reliant on power for medical needs before, during and after a PSPS event in PG&E's territory.

2) Energy and Communications Providers Coordination Group: Provides a forum for communications providers to provide feedback on PG&E's current PSPS implementation protocols and coordinate engagement before and during PSPS events.

PG&E also worked in partnership with SCE and SDG&E to establish the Statewide Investor-Owned Utility (IOU) AFN Advisory Council with a 2-day kickoff meeting on June 15 and 18. The IOUs hosted additional advisory group working sessions on July 24 and August 14. The council is composed of a diverse group of recognized Community-Based Organizations (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. More information about the AFN-related councils can be found in PG&E's 2020 PSPS AFN Plan (Attachment 2020WMP_ClassB_PGE-28_Atch03) and Progress report (Attachment 2020WMP_ClassB_PGE-28_Atch05.

PG&E will continue to meet with these stakeholders and will periodically bring these groups together, along with other stakeholder groups outlined in D.20-05-051, to solicit feedback on the PSPS Program.

PSPS Portal Improvements

PG&E has a PSPS Portal for public safety partners to access planning and event-specific information to support emergency management efforts prior to and during a power shutoff. Access to the Portal is available to Public Safety Partners, including federal, state, local, and tribal agencies, as well as telecommunications providers, water agencies, publicly-owned utilities, and emergency hospitals.

PG&E made several improvements to the PSPS portal in 2020 to make it more useful before and during a PSPS event. PG&E launched the revamped PSPS Portal on June 1, 2020, which includes the following enhancements:

- Expanding portal access to all public safety partners to help local response efforts, including telecommunication providers, water agencies, emergency hospitals and publicly owned utilities. Local and state agencies, as well as tribes and CCAs, will continue to have access;
- Coordinating with local and tribal governments to ensure access to and usability of the updated tool;
- Developing a live, interactive map to show anticipated outage areas at a parcel level, as well as locations of critical facilities and Medical Baseline Program customers;
- Providing circuit-level maps of the electric infrastructure serving specific communities, as well as updated PSPS planning maps that highlight those areas more likely to experience a PSPS event;
- Enabling the ability to update event-specific information after real-time event decisions are made, ensuring portal users have the latest event-specific information;
- Providing access to critical facilities and Medical Baseline customer lists; and

- Enabling the ability to access portal information via mobile phones.

County Report

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

- 2020 Engagement Milestones: Outreach efforts we have conducted with each county, tribe and community and when these efforts were conducted or are scheduled. These efforts include PSPS Listening Sessions, Wildfire Safety Working Sessions, PSPS Full-Scale Exercises, Wildfire Safety Open House Webinars and quarterly regional working group meetings.
- 2020 Information Sharing and Coordination: 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 installation, system hardening, EVM projects and temporary microgrid (as applicable) projects.
- PSPS Tools, Products, and Actions: Status updates regarding the various PSPS-related tools, products and actions which require coordination with local communities, including CRC locations, PSPS Agency Portal Access, critical facilities and Medical Baseline customer lists, contact rosters for PSPS notifications and PSPS event and planning maps.
- Follow-Up Items and Feedback: 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 Reports are planned to begin in the third quarter of 2020.

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 are reaching out to customers through multiple touchpoints to provide communities with CWSP/PSPS-related information via:

- Wildfire Safety Webinars: PG&E hosted webinars to provide county-specific information to customers throughout PG&E’s services area. These events were held every Wednesday evening from late April through September 2020, with 19 total events completed.

TABLE 27
WILDFIRE SAFETY WEBINARS

Counties invited				Date
Butte	Plumas	Lassen		April 29, 2020
Sonoma	Napa			May 6, 2020
Placer	Nevada	Sierra	Yuba	May 13, 2020
Colusa	Yolo	Solano		May 20, 2020
El Dorado	Amador	Calaveras		May 27, 2020
San Mateo	Santa Clara			June 3, 2020
Alameda	Contra Costa	Marin		June 10, 2020
Mendocino	Lake			June 17, 2020
Santa Cruz	Monterey	San Benito		June 24, 2020
Humboldt	Trinity	Siskiyou		July 1, 2020
Glenn	Tehama	Shasta		July 8, 2020
Alpine	Tuolumne	Mariposa		July 15, 2020
Merced	San Joaquin	Stanislaus		July 22, 2020
San Luis Obispo	Santa Barbara			July 29, 2020
Tulare	Madera	Fresno	Kern	Aug 5, 2020
All PG&E Customers				Aug 12, 2020
All PG&E Customers				Aug 26, 2020
In-language All PG&E Customers – Chinese				Aug 31, 2020
In-language All PG&E Customers – Spanish				Sept 2, 2020

- Direct to Customer Mailings/E-Mails: To help customer prepare for emergencies and a potential PSPS event, PG&E is conducting a multi-channel outreach and awareness campaign including letters, e-mails, emergency preparedness resources, tenant education kits, postcards and more. These include:
  – Large customer "Update your contact information" e-mail – April 10;
  – Public safety partner e-mails (Water, Telecom, Transportation) – May 4;
  – PSPS awareness bill package – May 5;
  – Residential customer "Update your contact information" postcard – May 6;
  – Master Meter Medical Baseline tenant e-mail – May 11;
  – Master Meter tenant education e-mail, tenant education kit – May 21;
  – "No Contact Information" bill packaging/envelope messaging – May 27;

- PSPS awareness e-mail – May 30;
- Medical Baseline acquisition letter/e-mail – June 20;
- PSPS awareness bill insert/envelope messaging – June 26;
- Backup power education e-mail – July 3; and
- PSPS preparedness brochure/Medical Baseline brochure – July 21.

- Informational Videos: PG&E is developing a series of long-form videos about the CWSP and PSPS events. Topics include:
  - What is a PSPS?;
  - 2020 PSPS Improvements;
  - Decision-Making for a PSPS;
  - EVM;
  - Microgrids;
  - PSPS Power Restoration Steps; and
  - System Hardening.
- Social Media: PG&E regularly provides customer preparedness resources through its official social media channels, including:
  - Twitter;
  - Facebook; and
  - Nextdoor.

Website Improvements

Since the 2019 PSPS events, PG&E has made significant content, user experience, stability, and capacity improvements to its website. PG&E has built a new standalone, cloud-based website specifically for emergencies with the following functionalities and content:

- Automatically redirects traffic from pge.com to alert site when an event is active;
- Developing an “all-in-one” map that includes both PSPS planned outages and actual outages (previously two separate maps and webpages);

- Developing more precise event maps at the parcel-level (not buffered polygons that may falsely indicate certain addresses are included or excluded from the event);
- Developing lower bandwidth options, including "no map" outage tools on the website;
- Using more concise language and layouts;
- Establishing a web performance protocol;
- Making the site Americans with Disabilities Act accessible on both web and mobile views; and
- Establishing a fully multilingual site that mirrors the English site with translated content currently available in six additional languages, with plans to offer 12 non-English languages in Q3 2020, and adding three additional languages (Portuguese, Hindi, and Thai) in October 2020, as required by the recent Administrative Law Judge ruling issued on August 21, 2020 regarding compliance filings submitted in response to D.20-03-004.

The new standalone website launched in June 2020. PG&E details its website improvements in its PSPS Phase 2 Progress Report, filed on August 4, 2020. Please see Attachment 2020WMP_ClassB_PGE-28_Atch02.

Meetings with Key Stakeholders

PG&E regularly meets with key stakeholders including city/county/tribal officials, community groups and business associations. In 2020, meeting topics include additional information about PSPS mitigation efforts, local progress on wildfire safety measures and expanded resources available to prepare for PSPS events. To date, in 2020 PG&E has conducted meetings with nearly 300 individual stakeholders (in addition to the other meetings referenced here).

AFN Community Outreach

On June 1, 2020, PG&E filed its 2020 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 vulnerable populations, and the in-event customer communications that serve AFN populations. Please see Attachment 2020WMP_ClassB_PGE-28_Atch03.

PG&E is actively collaborating with the AFN community in multiple ways, including:

- Conducting External Feedback and Research: Through consultation with PG&E PWDAAC, Statewide AFN Council, Disadvantaged Communities Advisory Group, Low Income Oversight Board, 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 Program, continuous power programs, Medical Baseline program, Energy Savings Assistance Program, California Alternate Rates for Energy Program, Family Electric Rate Assistance Program, Tribal Engagement Program, CRC Program and 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, master meter tenant education with both owners and tenants, healthcare industry outreach, Wildfire Safety Open House webinars, educational videos, CBO engagement and accessibility and translation of communications; and
- Bolstering In-Event Customer Communications: Such as customer notifications, Medical Baseline customer door knocks, PGE.com, the dedicated CBO Liaison process, customer contact center support, media engagement, ZIP Code alerts and smartphone SOS alerts.
- Working With CBOs: For both resources in an event, such as backup power solutions, and communication for those with access and functional needs. To date, PG&E has approximately 250 partnerships with CBOs for information sharing and is in the process of securing contracts with over 50 CBOs to provide additional resources to customers during PSPS events (e.g., food replacement and translation services/event communications in indigenous languages).

Please see attachment *PG&E AFN CWSP/PSPS Communications Tactics, Timing of Implementation, Translation Approach and Progress* (2020WMP_ClassB_PGE-B_Atch04) for more information regarding the status of these various efforts. Additionally, on September 1, 2020, PG&E filed its first 2020 Quarterly PSPS AFN Progress Report, which includes further information about the activities and progress of these various efforts. Please see Attachment 2020WMP_ClassB_PGE-28_Atch05.

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;

TABLE 28
WILDFIRE SAFETY WORKING SESSIONS

Agency	Date
Colusa County	April 8, 2020
Sonoma County	April 9, 2020
Humboldt County	April 23, 2020
Butte County	April 30, 2020
Trinity County	May 6, 2020
Lake County	May 7, 2020
Mariposa County	May 12, 2020
Mendocino County	May 12, 2020
Lassen County	May 14, 2020
Shasta County	May 19, 2020
Yolo County	May 19, 2020
Napa County	May 20, 2020
Calaveras County	May 21, 2020
Plumas County	May 21, 2020
Siskiyou County	May 26, 2020
Placer County	May 27, 2020

Agency	Date
City of San Jose	May 28, 2020
Contra Costa County	May 28, 2020
Santa Clara County	May 29, 2020
Tehama County	June 1, 2020
Nevada County	June 2, 2020
Alameda County	June 2, 2020
Marin County	June 3, 2020
Madera County	June 5, 2020
Santa Cruz County	June 11, 2020
San Benito County	June 23, 2020
Tuolumne Band of Me-Wuk Indians and Tuolumne County	June 25, 2020
Fresno	July 2, 2020
Santa Barbara County	July 9, 2020
Kings County	July 10, 2020
Tulare County	July 21, 2020

TABLE 29
CUSTOMER-FOCUSED WEBINARS

Counties Invited				Date
Butte	Plumas	Lassen		April 29, 2020
Sonoma	Napa			May 6, 2020
Placer	Nevada	Sierra	Yuba	May 13, 2020
Colusa	Yolo	Solano		May 20, 2020
El Dorado	Amador	Calaveras		May 27, 2020
San Mateo	Santa Clara			June 3, 2020
Alameda	Contra Costa	Marin		June 10, 2020
Mendocino	Lake			June 17, 2020
Santa Cruz	Monterey	San Benito		June 24, 2020
Humboldt	Trinity	Siskiyou		July 1, 2020
Glenn	Tehama	Shasta		July 8, 2020
Alpine	Tuolumne	Mariposa		July 15, 2020
Merced	San Joaquin	Stanislaus		July 22, 2020
San Luis Obispo	Santa Barbara			July 29, 2020
Tulare	Madera	Fresno	Kern	Aug 5, 2020
All PG&E Customers				Aug 12, 2020
All PG&E Customers				Aug 26, 2020
In-Language All PG&E Customers—Chinese				Aug 31, 2020
In-Language All PG&E Customers—Spanish				Sept 2, 2020

PG&E also recorded the presentation portion of the webinar in 13 languages,[25] as well as in American Sign Language, and is posting these translated presentations their website in September 2020.

25 13 languages include: Spanish, Mandarin, Cantonese, Vietnamese, Tagalog, Korean, Russian, Japanese, Arabic, Punjabi, Farsi, Japanese, Khmer, and Hmong.

TABLE 30
STAKEHOLDER MEETINGS

Event/Audience	Date
Tuolumne County – Microgrid Discussion	April 9, 2020
PG&E and Telecommunications Providers Resiliency Collaborative	April 13, 2020
Railway Industry Webinar	April 14, 2020
Western Energy Institute (WEI) Conference – PSPS Panel	April 16, 2020
Tuolumne County Pre-Wildfire Season Planning Meeting	April 17, 2020
Agriculture Workshop – North Valley	April 23, 2020
East Bay Municipal Utility District and Contra Costa Water District PSPS Update	April 30, 2020
Peoples with Disabilities and Aging Advisory Council	April 30, 2020
Placer County Operational Area Annual Fire Season Coordination	May 1, 2020
El Dorado County Microgrid Discussion	May 7, 2020
Statewide Tribal Assistance Coordination Group	May 8, 2020
California Environmental Dialogue	May 13, 2020
Eastern Madera County Emergency Preparedness Task Force	May 14, 2020
American Indian Chamber of Commerce of California	May 15, 2020
Emergency Management GIS Coordination Group Webinar	May 18, 2020
Cybersecurity and Infrastructure Security Agency	May 19, 2020
CBO Engagement Meet and Confer	May 20, 2020
Placer County Small Water Purveyors	May 20, 2020
Paradise Valley Estates	May 22, 2020
Rural County Representative of California	May 27, 2020
Santa Clara County West Valley City Managers and Mayors	May 27, 2020
Sonoma and Napa County Ag and Wine Industry PSPS Update	May 28, 2020
CSAC	May 29, 2020
Peoples with Disabilities and Aging Advisory Council	May 29, 2020
Wildfire Management Summit Online (June 3-4)	June 3, 2020
Placer County Office of Education - District Safety Committee Meeting	June 9, 2020
City of Ripon	June 9, 2020
Orland City Council	June 15, 2020
Statewide IOU AFN Advisory Council	June 15, 2020
City of Red Bluff	June 16, 2020
Napa County Board of Supervisors	June 16, 2020
Napa County Volunteer Organizations Active in Disaster (VOAD)	June 16, 2020
Central Marin Neighborhood Response Group	June 17, 2020

TABLE 30
STAKEHOLDER MEETINGS
(CONTINUED)

Event/Audience	Date
Rotary Club of Fremont	June 17, 2020
Statewide IOU AFN Advisory Council	June 18, 2020
Silicon Valley Leadership Group Energy Committee	June 18, 2020
PG&E and Telecommunications Providers Resiliency Collaborative	June 22, 2020
Solano County Board of Supervisors	June 23, 2020
Joint AFN Work Group – City of Fresno and Fresno County Public Health	June 24, 2020
Antioch Chamber of Commerce Zoom Mixer	June 25, 2020
Peoples with Disabilities and Aging Advisory Council	June 26, 2020
PG&E PSPS County PIO Communications Webinar	June 30, 2020
Calpine	July 2, 2020
Town of Windsor	July 6, 2020
Access and Functional Needs PSPS Preparedness Webinar (1 of 2)	July 8, 2020
Santa Rosa Metro Chamber of Commerce	July 8, 2020
PG&E PSPS County PIO Communications Webinar	July 9, 2020
California Hospital Association (CHA) and the Hospital Council (HC) Board of Directors of Northern and Central California	July 10, 2020
Access and Functional Needs PSPS Preparedness Webinar (2 of 2)	July 13, 2020
Auburn City Council	July 13, 2020
University of California, Davis	July 14, 2020
Stanford Healthcare PSPS Working Group	July 15, 2020
Greater Auburn Area Firesafe Council	July 17, 2020
Rotary Club of San Rafael	July 20, 2020
El Dorado County Board of Supervisors	July 21, 2020
US Congressional Staff Webinar	July 23, 2020
Statewide IOU AFN Advisory Council	July 24, 2020
Water Agency Members of the Association of California Water Agencies	July 29, 2020
Peoples with Disabilities and Aging Advisory Council	July 31, 2020
City of Santa Maria	August 4, 2020
Avila Valley Advisory Council	August 10, 2020
Statewide IOU AFN Advisory Council	August 14, 2020
Mendocino County Board of Supervisors	August 18, 2020
Kiwanis Club of Napa	August 18, 2020
Mendocino County Board of Supervisors	August 18, 2020

TABLE 30
STAKEHOLDER MEETINGS
(CONTINUED)

Event/Audience	Date
Sausalito City Council	August 18, 2020
San Benito County Board of Supervisors	August 18, 2020
San Juan Bautista City Council	August 18, 2020
Monte Sereno City Council	August 18, 2020
San Luis Obispo	August 18, 2020
Town of Windsor	August 19, 2020
Sonoma County Hospitality Association	August 20, 2020
Lake County Economic Development Board	August 20, 2020
City of Concord VOAD	August 20, 2020
Rotary Club of El Cerrito	August 20, 2020
Town of Ross – Public Works Director and Police Chief	August 25, 2020
Nevada County Board of Supervisors	August 25, 2020
Town of San Anselmo	August 25, 2020
PG&E and Telecommunications Providers Resiliency Collaborative	August 26, 2020
Peoples with Disabilities and Aging Advisory Council	August 28, 2020

TABLE 31
MAILINGS

Event/Audience	Date
Large Customer "Update Your Contact Information" E-Mail	April 10, 2020
Public Safety Partner E-Mails (Water, Telecom, Transportation)	May 4, 2020
PSPS Awareness Bill Package	May 5, 2020
Residential Customer "Update Your Contact Information" Postcard	May 6, 2020
Master Meter Medical Baseline Tenant E-Mail	May 11, 2020
Master Meter Tenant Education E-Mail, Tenant Education Kit	May 21, 2020
"No Contact Information" Bill Packaging/Envelope Messaging	May 27, 2020
PSPS Awareness E-Mail	May 30, 2020
Medical Baseline Acquisition Letter/E-Mail	June 20, 2020
PSPS Awareness Bill Insert/Envelope Messaging	June 26, 2020
Backup Power Education E-Mail	July 3, 2020
CBO Outreach Kit E-Mail	July 7, 2020
PSPS Preparedness Brochure/Medical Baseline Brochure	July 31, 2020
Update Your Contact Info Envelope Messaging	July 26, 2020
PSPS Customer Resources E-Mail	August 8, 2020
PSPS Notifications Overview Postcard/E-Mail	August 11, 2020
Master Meter Resources Postcard/E-Mail	August 11, 2020
PSPS Customer Resources Bill Insert	August 26, 2020

TABLE 32
REGIONAL WORKING GROUP

Event/Audience	Date
<u>North Coast</u>: Colusa, Glenn, Humboldt, Lake, Mendocino, Napa, Sacramento, Siskiyou, Solano, Sonoma, Trinity, Yolo counties	July 28, 2020
<u>Sierra</u>: Alpine, Amador, Butte, El Dorado, Lassen, Nevada, Placer, Plumas, Shasta, Sierra, Sutter, Tehama, Yuba counties	July 29, 2020
<u>Bay Area</u>: Alameda, Contra Costa, Marin, San Francisco, San Mateo	July 27, 2020
<u>South Bay/Central Coast</u>: Monterey, San Benito, San Luis Obispo, Santa Barbara, Santa Clara, Santa Cruz counties	July 27, 2020
<u>Central Valley</u>: Calaveras, Fresno, Kern, Kings, Madera, Mariposa, Merced, San Joaquin, Stanislaus, Tulare, Tuolumne	July 28, 2020

iv. Actions planned for completion in the following quarter (Q4 2020).

TABLE 33
STAKEHOLDER MEETINGS

Event/Audience	Date
Lake County Board of Supervisors	Sept 1, 2020
Resources for Independence – Central Valley	Sept 3, 2020
Statewide IOU AFN Advisory Council	Sept 18, 2020
California Society of Healthcare Engineers	Oct 14, 2020
Statewide IOU AFN Advisory Council	Oct 23, 2020
Statewide IOU AFN Advisory Council	Nov 20, 2020
North Coast Regional Working Group: Colusa, Glenn, Humboldt, Lake, Mendocino, Napa, Sacramento, Siskiyou, Solano, Sonoma, Trinity, Yolo counties	Week of Nov 30
Sierra Regional Working Group: Alpine, Amador, Butte, El Dorado, Lassen, Nevada, Placer, Plumas, Shasta, Sierra, Sutter, Tehama, Yuba counties	Week of Nov 30
Bay Area Regional Working Group: Alameda, Contra Costa, Marin, San Francisco, San Mateo	Week of Nov 30
South Bay/Central Coast Regional Working Group: Monterey, San Benito, San Luis Obispo, Santa Barbara, Santa Clara, Santa Cruz counties	Week of Nov 30
Central Valley Regional Working Group: Calaveras, Fresno, Kern, Kings, Madera, Mariposa, Merced, San Joaquin, Stanislaus, Tulare, Tuolumne	Week of Nov 30
Statewide IOU AFN Advisory Council	Dec 11, 2020

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

TABLE 34
MAILINGS

Event/Audience	Date
Medical Baseline resources postcard/e-mail	Quarter 4 2020
PSPS mitigation progress e-mail	September 12, 2020
Safety Action Center resources e-mail	October 10, 2020
Outage resources e-mail	November 10, 2020

CONDITION PG&E-29

COOPERATION AND SHARING OF BEST PRACTICES

Deficiency: PG&E's cooperation and best practice sharing with agencies outside California also does not contain details over the prescribed timeline. PG&E states it will continue to engage partners from inside and outside California to share PG&E's experience and identify tools and technology that are effective at mitigating utility-caused wildfire risk.

Such information sharing is useful in allowing PG&E and others to identify new solutions and assess the effectiveness of solutions used by other entities.

At the WMP workshops held in February 2020 and described in this Resolution, several parties asked whether the electrical corporations are sharing information about pilots of new technology with each other and with other entities

Condition: In its first quarterly report, PG&E shall:

i. Provide a report detailing its progress regarding best practice sharing with entities outside of California;

PG&E has participated in multiple benchmarking and data sharing environments, both to share our perspectives and to hear best practices and perspectives from utilities, vendors, experts and others. We have leveraged existing industry groups and forums as well as ad hoc relationships and engagements. Focusing on engagements outside of California, a number of specific examples include:

- <u>Australian Utilities (including AusNet and PowerCor) and safety regulators (including Energy Safe Victoria)</u>: PG&E Officers visited in the first half of 2019 to share and learn; Australian utility Officers visited California in Q3 2019; virtual meetings and calls have continued
- Nationwide Utility industry organizations and engagements where PG&E has presented, attended, or received and shared information include with the Utility Analytics Institute, Edison Electric Institute (EEI), Western Electricity Coordinating Council (WECC), WEI, North American Transmission Forum, T&D World, Centre for Energy Advancement through Technological Innovation, and UAA.
- <u>Research Institutions and Vendors</u>: PG&E continues to partner with research institutions and vendors from beyond California. Examples include:
  - Acquiring system protection technology from Australian vendors;
  - Partnering with Oak Ridge and Lawrence Livermore National Laboratories to research system sensors and fault signatures; and

– Partnering with EPRI on industry-wide research and analysis.

- As one recent example, PG&E presented and answered questions, alongside other California and Western utilities, about the wildfire tools and technologies we are using and considering at a meeting facilitated by WECC. The meeting on August 13 was marketed by WECC to its members and partners as:

> …a technical exploration into wildfire preparedness and best practices, including system hardening, technology deployment, advanced weather modeling, weather stations, predictive fire spread modeling, and high-definition camera installations. The webinar will focus on lessons learned and best practices for a technical audience and anyone interested in how to prepare for and prevent wildfires.

ii. Include a description of how such interactions have changed or improved, including specific examples; and

PG&E has more lessons learned and tools to share with industry partners than ever before, including those lessons we learned from the 2019 wildfire and PSPS season. Second, in 2020 we are working to mature broad best practices for wildfire risk mitigation by establishing an "International Wildfire Risk Mitigation Consortium" as a facilitated consortium of utilities to focus on wildfire risk mitigation activities, including California and Australian utilities as founding/sponsoring utilities. Development of this consortium is underway; its successful operation will formalize international partnership and collaboration on wildfire risk mitigation activities.

iii. Include a description of how it has applied lessons learned into its 2020 WMP.

Through benchmarking, best practice sharing and general partnerships with entities inside and outside of California, PG&E gathers ideas and improvements large and small. Some have yielded completely new programs and tools, while others produced adjustments or continuous improvements to existing tools, processes and programs. Specific examples of lessons learned from outside California that have been incorporated into our 2020 WMP include:

- <u>Sections 5.1.D.3.2 and 5.3.2.1.5</u>: Partnering with the Space Science and Engineering Center at the University of Wisconsin-Madison on the Satellite Fire Detection and Alert System;
- <u>Section 5.1.D.3.6</u>: Rapid Earth Fault Current Limiter leveraged from Australia;
- <u>Sections 5.1.D.3.19 and 5.3.2.2.4</u>: Distribution Fault Anticipation Technology developed by Texas A&M University's College of Engineering;

- Section 5.3.2.2.8 – Partnering with Oak Ridge and Lawrence Livermore National Laboratories to research system sensors and fault signatures;
- Section 5.3.4 – Drone Inspections of Assets: PG&E benchmarked with a number of entities outside California, including Australian utilities about their process and tools for performing aerial/drone inspections, these learnings were incorporated into our WSIP in 2018 & 2019 and leveraged in our ongoing asset inspection practices for 2020 and beyond;
- Sections 5.3.4.9 and 5.3.4.10 – Ultrasonic Inspection Tools: PG&E is testing this technology which has been commercialized by an international firm and is used by other United States (US)-based utilities;
- Sections 5.3.5.7 and 5.3.5.8: PG&E has leveraged partners outside of California, some international, on the tools, process, software and use cases associated with LiDAR data collection and use; and
- We are evaluating further deployments of Unmanned Aircraft Systems (UAS) to support electric system operations and/or wildfire risk reduction. PG&E is participating in a Technical Assist Project for UAS Solution for Linear Infrastructure Inspections with the Federal Aviation Administration, EEI, and other partner utilities.

Through these benchmarking engagements, PG&E continues to source ideas that are being reviewed, further developed or incorporated into PG&E's wildfire safety efforts and, potentially, future WMPs. We will continue to leverage these forums and the relationships developed to share our learnings to date and to cast a broad net for best practices, lessons learned, tools, technologies and ideas that can help PG&E and California reduce wildfire risk.