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March 29, 2021 **Via Electronic Mail**

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Subject: **Comments of the Public Advocates Office on the 2021 Wildfire Mitigation Plan Updates of the Large Investor-Owned Utilities**

Dear Director Thomas Jacobs,

The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) respectfully submits the following comments on the 2021 Wildfire Mitigation Plan Updates of Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E), as well as general wildfire mitigation issues. Please contact Nathaniel Skinner (Nathaniel.Skinner@cpuc.ca.gov) or Henry Burton (Henry.Burton@cpuc.ca.gov) with any questions relating to these comments. We respectfully urge the Wildfire Safety Division to adopt the recommendations discussed herein.

Respectfully submitted,

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I. INTRODUCTION

Pursuant to the Rules of Practice and Procedure of the California Public Utilities Commission (Commission) and Resolution WSD-011, the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) submits these comments on the 2021 Wildfire Mitigation Plan (WMP) Updates submitted by large investor-owned utilities (IOUs or utilities).[1]

Resolution WSD-011, the *Resolution implementing the requirements of Public Utilities Code Sections 8389(d)(1), (2) and (4), related to catastrophic wildfire caused by electrical corporations subject to the Commission's regulatory authority*, established guidelines and a schedule for WMP submissions in 2021. Pursuant to Resolution WSD-011, Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) submitted 2021 WMP Updates on February 5, 2021. PG&E, SCE, and SDG&E all submitted Supplemental WMP Filings on February 26, 2021.

Resolution WSD-011 permits interested persons to serve opening comments on the large IOUs' 2021 WMPs by March 17, 2021 and reply comments by March 24, 2021. On February 23, 2021, Cal Advocates, Green Power Institute (GPI), Mussey Grade Road Alliance, the Protect Our Communities Foundation, The Utility Reform Network, and Will Abrams requested an extension of the comment deadline to March 29, 2021. On February 26, 2021, the Wildfire Safety Division (WSD) approved the deadline change.

In these comments, Cal Advocates addresses the WMPs of SCE and SDG&E. We then provide technical recommendations applicable to all utilities. We conclude with recommendations for future improvements in the WMP guidelines and process.

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[1] Many of the Public Utilities Code requirements relating to wildfires apply to "electrical corporations." *See, e.g.*, Public Utilities Code Section 8386. These comments use the more common term "utilities" and the phrase "electrical corporations" interchangeably to refer to the entities that must comply with the wildfire safety provisions of the Public Utilities Code.

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III. SCE

A. The WSD should require SCE to revise its covered conductor workplan to focus on high-risk circuits.

SCE may not be appropriately prioritizing is covered conductor projects based on risk. SCE's risk model indicates that a small minority of HFTD circuit-miles constitute the bulk of the wildfire risk on SCE's distribution system.[2] SCE's workplan for covered conductor does not reflect this fact.

Less than a third of the circuit-miles in SCE's covered conductor workplan are on SCE's high-risk circuits.[3] Of the 1,883 miles of covered conductor planned projects,[4] only 581 miles are on the circuits that create most of the significant risk.[5] For context, SCE's highest-risk circuits encompass 1,269 miles of conductor that has not yet been replaced with covered conductor. This means that SCE's workplan will treat less than half of the circuit-miles on the riskiest circuits in the HFTD.[6] (SCE may treat more of the high-risk circuit-miles in 2022 or later.)[7] This level of prioritization indicates that SCE is not dedicating sufficient attention to the riskiest areas.

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[2] SCE's wildfire risk models show that 71 circuits account for approximately 75 percent of the total wildfire risk on the distribution system. Our analysis excludes circuit-miles categorized as "other" in SCE's risk model, because these miles are not associated with specific circuits that are prioritized for mitigation.

[3] This workplan includes more projects than SCE can complete in 2021, so it should be viewed as a workplan for the next year and a half. See SCE's responses to Data Request CalAdvocates-SCE-2021WMP-07, Questions 1 and 2, March 8, 2021, and Data Request CalAdvocates-SCE-2021WMP-12, Question 1, March 16, 2021.

[4] SCE's covered conductor workplan includes 1,883 miles of covered conductor projects that SCE may complete in 2021. However, SCE does not expect to complete all of these projects. SCE states that it "expects to install 1,000 circuit miles of covered conductor in 2021 but will strive to install as many as 1,400 circuit miles." *See* SCE responses to Data Request CalAdvocates-SCE-2021WMP-07, Question 2, March 8, 2021 and Data Request CalAdvocates-SCE-2021WMP-12, Question 1, March 16, 2021.

[5] Analysis of SCE's workplan for covered conductor, per SCE's response to Data Request CalAdvocates-SCE-2021WMP-07, Question 2, March 8, 2021.

[6] 581 miles out of 1,269 miles is 46 percent.

[7] In response to a request for planned projects specifically on the 71 riskiest circuits, SCE identified planned projects that total approximately 1,156 miles. (*See* SCE responses to Data Request CalAdvocates-SCE-2021WMP-07, Question 1, March 8, 2021.) However, there are a number of discrepancies between this list of projects and SCE's covered conductor workplan (which encompasses 1,883 miles of work and will take about 1.5 years to complete). Some of the discrepancies are due to timing: projects that are not expected to occur in 2021 are excluded from SCE's covered conductor workplan. There are other discrepancies between the two lists, where SCE identifies different amounts of

Notably, if SCE focused its efforts on the riskiest circuits, it could treat all of them in about a year.[8] The number of overhead miles on these circuits is less than SCE's aspirational goal for covered conductor in 2021. This would sharply reduce wildfire risk and considerably alleviate the burden of de-energization on customers, as SCE can use higher wind thresholds if all targeted segments are covered.

Therefore, the WSD should require SCE to submit a revised covered conductor workplan that prioritizes mitigation on its highest-risk circuits. SCE should be required to demonstrate that its workplan is guided by risk to the greatest extent practicable. To the extent that operational considerations or access limitations prevent SCE from hardening its 71 most risky circuits in the HFTD, SCE should explain those factors and explain what other mitigation measures it is adopting, addressing each circuit individually. SCE should submit this revised workplan and explanation within 30 days from when the WSD issues an action statement on SCE's WMP.[9]

B. SCE should provide greater clarity on how it uses field observer input for de-energization decision-making.

SCE may not be effectively using its Live Field Observations (LFOs) to improve its implementation of de-energization events. Specifically, SCE does not appear to take full advantage of the LFOs to improve its decision-making about which circuits to de-energize and when.

During weather conditions that increase the risk of fire, SCE deploys qualified personnel to perform patrols and live field observations.[10] SCE's LFO program includes monitoring prior to and during a weather event to inform a decision to de-energize, as well as patrolling after a weather event to ensure that it is safe to restore service to the de-energized lines.[11]

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covered conductor installation on the same circuit, with the same completion date. Based on the totality of SCE's data request responses, revised responses, and explanatory emails, Cal Advocates finds that the most reliable and complete source of information is SCE's covered conductor workplan (which SCE provided in response to Data Request CalAdvocates-SCE-2021WMP-07, Question 2, March 8, 2021).

[8] The 71 riskiest circuits (which constitute three-quarters of total risk on SCE's distribution system) have 1,269 uncovered circuit miles, whereas SCE expects to install 1,000 to 1,400 miles of covered conductor in 2021.

[9] Pursuant to Public Utilities Code Section 8386.3(a), the WSD is expected to issue an action statement on SCE's WMP by May 5, 2021.

[10] SCE's 2021 WMP Update, p. 202.

[11] SCE 2021 WMP Update, p. 203.

SCE states that live field observers have the authority to contact its switching center directly to request immediate de-energization.[12] Additionally, the SCE Incident Management Team stated that it solicits input and recommendations from its live field observers.[13] However, the final decision over whether a circuit is deenergized lies with the Incident Management Team. For example, the SCE Incident Management Team may choose to de-energize a target circuit against the recommendation of a live field observer if there is a concern that a connected segment of that target circuit is still at risk.[14]

However, SCE does not track instances in which a live field observer recommends against de-energization, even though it states that those instances are common.[15] By failing to track these instances, affected communities and other stakeholders cannot determine if SCE is aware of the local, real-time conditions that are affecting targeted areas.

Additionally, SCE does not modify wind speed triggers as a result of the information provided by LFOs during de-energization events.[16] Instead, SCE uses pre-event patrols to provide information about the status of grid hardening projects in a targeted area, which in turn can affect wind speed thresholds.[17] However, the thresholds are otherwise decided by largely static conditions including the number of Priority 2 (moderate risk) inspection findings,[18] the number of long spans,[19] the wildfire risk score, and whether all the overhead distribution lines of the target circuit are covered conductor.[20] While Cal Advocates supports the collection of

[12] SCE response to CalAdvocates-SCE-2021WMP-09, Question 11, March 9, 2021.

[13] SCE response to CalAdvocates-SCE-2021WMP-09, Question 12, March 9, 2021.

[14] SCE response to CalAdvocates-SCE-2021WMP-09, Question 12, March 9, 2021.

[15] SCE response to CalAdvocates-SCE-2021WMP-09, Question 12, March 9, 2021.

[16] SCE response to CalAdvocates-SCE-2021WMP-09, Question 13, March 9, 2021.

[17] SCE response to CalAdvocates-SCE-2021WMP-09, Question 13, March 9, 2021.

[18] Pursuant to General Order 95, Rule 18B, Level 2 findings have "moderate potential impact to safety or reliability." Electric utilities are required to remedy Level 2 findings within six months if the asset is in HFTD Tier 3, within 12 months if it is in HFTD Tier 2, and within 36 months otherwise.

[19] Defined by SCE as distribution circuit spans of certain length or configuration that can have a high chance of conductor clash in adverse weather conditions.

[20] Attachment A of Acton Town Council Comments on the Southern California Edison's Post-Event Report, February 4, 2021, served in Rulemaking 18-12-005.

weather data during PSPS events, it does not appear that the data collected by LFOs during PSPS results in an adjustment of wind thresholds for future events.

The WSD should direct SCE to evaluate the effectiveness of its LFO program not only for its ability to identify high-risk conditions, but also for its ability to reduce shutoffs of circuits that its risk model erroneously identifies as high-risk. Providing more clarity regarding interactions between live field observers and the Incident Management Team would enable SCE to demonstrate to stakeholders and local communities affected by PSPS that SCE is aware of the local conditions that those targeted communities are experiencing. SCE should explain whether the Incident Management Team has a process, or will create a process, to utilize live-monitoring to improve decision-making.

C. The WSD should direct SCE to evaluate expanding its drone inspection programs.

In 2020, SCE continued to study the feasibility, effectiveness, and efficiency of using drones for inspections.[21] This initiative started as a pilot program in 2019.[22]

SCE claims its drone program (the Advanced Unmanned Aerial Systems Study) was a success in multiple areas. For example, video quality and wireless streaming consistency have improved enough to allow inspectors to issue an all-clear designation following circuit patrols, and the average time to reach an all-clear designation decreased with the use of drones.[23] The deployment and operations of SCE's vendors has also improved, such that vendors can reach a designated area within 48 hours of SCE's request. Also, vendors did not experience any problems controlling the drones during SCE's study.[24, 25]

Despite the apparent success of the pilot, SCE's 2021 program proceeds with caution. SCE has retained only two contract drone operators qualified to collect photographs of transmission towers.[26] However, SCE should clarify its rationale for retaining only two drone operators for transmission towers despite the demonstrated benefits of the technology. It may be

[21] The program is called the Advanced Unmanned Aerial Systems (AUAS) Study.

[22] SCE's 2021 WMP Update Supplemental Filing, p. 337.

[23] SCE's 2021 WMP Update, p. 172.

[24] SCE's 2021 WMP Update, p. 172.

[25] SCE's 2021 WMP Update Supplemental Filing, p. 337.

[26] SCE Response to Data Request CalAdvocates-SCE-2021WMP-02 Question 2(b).

that it is more efficient for SCE to invest directly in drone equipment, rather than relying on contractors to provide the equipment, because drone technology has reached sufficient maturity for broad use in commercial applications.

SCE explains that technical, regulatory, and resource challenges require further evaluation before it can determine that some patrols can be efficiently supplemented using drones.[27] Some of these challenges were addressed in the pilot program, including video quality and command-control issues.[28] SCE justifies the program's continuation by claiming that it has successfully moved out of the pilot phase, stating that the image quality and communications connectivity issues have greatly improved since the pilot.[29]

This improvement seems promising. If drone inspections are feasible and effective, Cal Advocates recommends that SCE use the lessons it has learned from the pilot program to supplement its patrols in areas that are well-suited to the use of drones and should not limit its use of drones to emergency response programs.

The WSD should direct SCE to submit a report that evaluates the drone pilot program and analyzes the potential for broader use of and investment in drones. This study should provide support for either broader application, continuation, or termination of the drone inspection effort.

D. SCE should inventory all C-hooks in HFTD areas to ensure aged C-hooks are replaced.

C-hooks are a type of connector hardware on transmission structures. A worn C-hook contributed to the ignition of the Camp Fire.[30] SCE has not had any specific issues with its C-hooks, but recognizes that C-hooks are difficult to inspect and can cause wildfires when ignored.[31]

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[27] SCE's 2021 WMP Update, p. 172.

[28] SCE's 2021 WMP Update, p. 172.

[29] SCE's 2021 WMP Update Supplemental Filing, p. 337.

[30] "A Summary of the Camp Fire Investigation." Butte County District Attorney, p. 2. Available at https://www.buttecounty.net/Portals/30/CFReport/PGE-THE-CAMP-FIRE-PUBLIC-REPORT.pdf?ver=2020-06-15-190515-977. Per pp. 2-3 of this report, a C-hook supporting an energized line had worn through, allowing the line to contact the tower structure.

[31] SCE's 2021 WMP Update, p. 223. All C-hooks in SCE territory were inherited from Cal Electric.

SCE plans to replace all C-hooks in its service territory over the next two years.[32] Currently, based on statistical modeling, SCE estimates that there are 60 C-hooks in SCE's HFTD areas.[33] SCE plans to replace 40 of the known C-hooks in 2021 and the remainder in 2022.[34]

In light of the potential risks posed by a single eroded C-hook, SCE should carry out inspections of its entire service territory to identify all C-hooks, starting with HFTD zones and proceeding to lower-risk areas. This inventory can be integrated into SCE's other transmission inspection programs. Performing an inventory alongside the replacement program will contribute to efficiency and ensure that no C-hooks are missed. The catastrophic risk posed by old C-hooks is best addressed now by ensuring every aged C-Hook is identified and replaced.

E. SCE should demonstrate that its inspection programs have planned for foreseeable obstacles.

In 2020, SCE fell far short of its target for pole loading assessments. SCE had forecast completing 1,205 pole loading assessments but in actuality completed only 29 percent (or 345) of its assessments.

In SCE's 2021 WMP Update Supplement, SCE attributes the shortfall to (1) customers denying access to property; (2) customers being unavailable to grant access to property; (3) access issues due to COVID-19; and (4) weather and fires complicating access to poles.[35] SCE does not specify the magnitude of impact of any of these factors.

SCE's explanation merely shows that SCE is not conducting planned pole loading assessments.[36] It does not provide the Commission with information sufficient to evaluate SCE's efforts or its chances of improving in the future. Furthermore, the first two reasons SCE cited were foreseeable and the fourth was also somewhat predictable. Consequently, SCE's explanation calls into question other aspects of SCE's asset inspection capabilities, including its ability to obtain customers' consent to enter onto their property for purposes of completing

[32] SCE's 2021 WMP Update, p. 224.

[33] SCE's 2021 WMP Update, p. 224.

[34] SCE's 2021 WMP Update, p. 224.

[35] SCE's 2021 WMP Update Supplemental Filing, p. 356.

[36] SCE's 2021 WMP Update Supplemental Filing, p. 356.

compliance inspections, and its ability to create accurate program forecasts in the face of foreseeable obstacles.

The WSD should require SCE to detail how it has addressed or will address each of the four issues noted above that prevented SCE from completing pole loading assessments.

F. The WSD should require SCE to explain the substantial disparities in its WMP cost forecasts.

The WSD's approval or denial of WMPs does not confer approval of the projected expenditures contained within the WMPs;[37] however, costs are a relevant consideration when evaluating the efficiency and efficacy of the mitigations proposed by the utilities.

Cal Advocates is concerned that SCE's cost forecasts are significantly higher than the projections that SCE provided in its 2020 WMP. The shifting forecasts affect some of SCE's most expensive programs.[38] Table A, below shows a few examples of disparities in project cost forecasts between 2020 and 2021. Appendix A provides additional examples (though not an exhaustive list).

Table A
Comparison of SCE's 2020 Forecasts to 2021 Forecasts
(millions of dollars)

Mitigation Program	2020 Costs		2021 Costs		2022 Costs	
	Forecast in 2020 WMP	Actual 2020 spending	Forecast in 2020 WMP	Forecast in 2021 WMP	Forecast in 2020 WMP	Forecast in 2021 WMP
Distribution Detailed Inspections	$2.3	$9.0	$3.0	$4.2	$2.6	$4.3
Transmission Detailed Inspections	$1.1	$3.6	$1.2	$7.6	$1.1	$7.8
Covered Conductor	$454.4	$546.2	$656.4	$753.7	$771.8	$883.8

As this table shows, SCE's projected costs are significantly higher in 2021 than they were in 2020. Drastic changes in forecasted costs may be indicative of factors such as changes in

[37] See, D.19-05-036, p. 20-25; Resolution WSD-002, p. 4.

[38] Comparison table based on Table 12 of SCE's 2021 WMP Non-spatial tables and Tables 21-25 of SCE's 2020 WMP submission ("SCE 2020-2022 WMP Tables 1 – 31").

program scope, an alteration of cost assumptions, or changes in forecast methodologies. Understanding the causes of these changes is necessary to ensure that the utilities' plans are realistic. Additionally, it is important to ensure that the forecasted costs, and the methods used to determine those forecasts, are transparent to stakeholders. As currently presented in the WMP, there is little transparency regarding the reasons for any revisions to the forecasted costs.

While the WSD will not approve the costs associated with SCE's WMP, it would be valuable for the Commission and interested stakeholders to gain an understanding as to why these forecasted costs increased from one year to the next. Significant changes in costs affect work planning and the feasibility of programs, and ultimately affect the utility's ability to promptly mitigate risks.

The WSD should direct SCE to submit supplemental information that explains the reasons for large changes in program cost forecasts, within 30 days of the WSD's action statement on SCE's WMP. SCE should address each program where the cost forecasts that have changed by more than 25 percent since last year's WMP submission.

IV. SDG&E

A. SDG&E should improve the efficiency and effectiveness of system hardening mitigations.

SDG&E should use its resources efficiently to mitigate risk by prioritizing high-risk circuits as well as selecting measures with the broadest impact.[39] SDG&E's 2021 WMP Update is similar to its 2020 WMP in that it lacks focus on implementing the most cost-effective system hardening programs in terms of risk reduction per dollar spent. SDG&E's WMP relies on very expensive measures, deployed at a small scale, which do not serve to substantially reduce wildfire risk across SDG&E's entire system.

One example is SDG&E's hardening strategy. As discussed below, SDG&E plans to harden more circuit miles through undergrounding than through installation of covered conductor. This is despite the large cost difference between the two mitigations and SDG&E's own conservative estimation that covered conductor is 70 percent effective at reducing ignitions overall, and 90 percent effective at reducing ignitions cause by animal, balloon, and vegetation

[39] Public Utilities Code Section 8386(a) requires that an electrical corporation "construct, maintain, and operate its electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire posed by those electrical lines and equipment."

contacts.[40] SDG&E's grid hardening resources are finite, and undergrounding is one of the most costly and resource-intensive mitigations in SDG&E's portfolio.[41] [42] Relying heavily on undergrounding means that SDG&E's hardening efforts reach fewer residents and locations than a more balanced portfolio.

Similarly, in its comments submitted on SDG&E's 2020 WMP, Cal Advocates expressed concern that SDG&E's system hardening efforts did not focus on implementing the most cost-efficient and risk-efficient mitigations, and did not maximize the number of customers benefiting from its proposed system hardening programs.[43] As an example, Cal Advocates expressed concern about SDG&E's proposed standby power program (then called the whole-home generation program).[44] Cal Advocates recommended that SDG&E prioritize resiliency programs that widely benefit communities and vulnerable customers, rather than programs that only help a small number of individual customers. Resolution WSD-005, which approved SDG&E's 2020 WMP, did not address this issue.

SDG&E's inefficient spending is especially concerning in light of SDG&E's residential electric rates, which are far above the state and national averages. As of February 1, 2021, SDG&E's current residential class average rate is 30.5¢ per kWh,[45] significantly higher than the national residential average rate of 13.2¢ per kWh, and California's residential average rate of 20.5¢ per kWh.[46]

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[40] SDG&E 2021 WMP Update, p. 192.

[41] Underground lines are more difficult to repair than overhead lines. Popular Science, "Why don't we put power lines underground?," June 7, 2018, https://www.popsci.com/why-dont-we-put-power-lines-underground/

[42] Underground lines may have a shorter useful life than overhead lines, at least at higher voltages. The utility Xcel Energy notes that "Underground high-voltage transmission lines have a life expectancy of 40+ years, while overhead lines have a life expectancy of more than 80 years." Xcel Energy, "Overhead vs. Underground: Information About Burying High-Voltage Transmission Lines," https://www.xcelenergy.com/staticfiles/xe/Corporate/Corporate%20PDFs/OverheadVsUnderground_FactSheet.pdf

[43] *Comments of the Public Advocates Office on the 2020 Wildfire Mitigation Plans*, pp. 27-31.

[44] Cal Advocates stated that the program appears to be "primarily a reliability program, [which] raises serious concerns regarding safety, environmental impact, and equity." *Comments of the Public Advocates Office on the 2020 Wildfire Mitigation Plans,* p. 30.

[45] SDG&E Advice Letter 3669-E-A, Supplemental: Consolidated Filing to Implement Electric Rates Effective February 1, 2021.

[46] U.S. Energy Information Administration, Average retail price of electricity for the year 2020.

While the WMP process does not approve cost recovery for any of the proposed wildfire risk mitigations, the potential cost implications, including the impact on electric rates, are relevant considerations.[47] In particular, the WSD should examine whether SDG&E is using its resources wisely to obtain the greatest feasible reduction in wildfire risk.

Moreover, SDG&E began its grid hardening after the 2007 fires in its service territory and has already accomplished many grid hardening measures to date.[48] As such, SDG&E should implement only the most cost-effective mitigations in terms of customers served and risks mitigated. The prudence of SDG&E's mitigation measures should be carefully scrutinized to ensure reasonable costs, sustainable rates, and the utility's ability to provide safe and reliable electric service in the next General Rate Case.

B. The WSD should direct SDG&E to focus its strategic undergrounding program on high-risk circuits.

SDG&E has not adequately targeted its strategic undergrounding efforts to high-risk circuits in its HFTD areas. The program has a very narrow scope: only 25 circuit-miles in 2021 and expanding to 80 miles in 2022.[49] Since the undergrounding program focuses on a tiny fraction of SDG&E's circuit-miles in HFTD areas, targeting extremely risky locations is the only way this program can make a meaningful difference in systemwide risk. SDG&E should prioritize its undergrounding program to the riskiest circuits.

Unfortunately, SDG&E has not demonstrated such focus. In 2021, SDG&E expects to perform only 70 percent of its strategic undergrounding in the riskiest quartile of its circuits.[50] These high-risk circuits include 2,814 miles of circuits in HFTD areas (including 1,574 miles in Tier 3). Thus, at the 2021 rate of 25 miles per year, it would take over 100 years to underground all high-risk circuits. SDG&E has not appropriately identified why it should be performing *any*

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[47] D.19-05-036, *Guidance Decision on 2019 Wildfire Mitigation Plans*, p. 24.

[48] SDG&E 2021 WMP, p. xiii.

[49] SDG&E 2021 WMP Update non-spatial data filing, Table 12.

[50] CalAdvocates-SDGE-2021WMP-05, question 9, March 4, 2021. SDG&E's WINGS risk model ranks 190 circuits that traverse HFTD areas. The top quartile by risk comprises the 48 highest-ranked circuits. SDG&E's responses show the expected spending on each group of circuits. However, SDG&E assumes that unit costs are constant wherever a project occurs, so these spending estimates translate directly to miles of hardening work.

undergrounding projects outside of these high-risk circuits, yet nearly a third of SDG&E's effort is directed elsewhere.

Furthermore, more than 15 percent of strategic undergrounding in 2021 will occur in the lower half of HFTD circuits by risk.[51] Undergrounding the circuits that score in the bottom half of SDG&E's risk model is plainly not the most effective way to reduce wildfire risk.

The WSD should direct SDG&E to revise its system hardening workplan to better focus on high-risk circuits. The WSD should direct SDG&E to submit a detailed workplan, with an explanation of how the plan optimizes SDG&E's resources to expeditiously and substantially reduce wildfire risk. SDG&E should submit this workplan within 30 days of the WSD's action statement on SDG&E's WMP.

The WSD should also direct SDG&E to submit, as part of its 2022 WMP, a detailed workplan for the strategic undergrounding program that focuses on high-risk circuits.

C. The WSD should direct SDG&E to focus its covered conductor program on high-risk circuits.

As with the strategic undergrounding program, SDG&E has not adequately targeted its covered conductor installations to high-risk circuits in its HFTD areas. The covered conductor program has a similarly narrow scope, with 20 miles planned in 2021 and 60 miles planned in 2022.[52] Since the program does not make an impact at a broad scale, its impact can only come from targeting high-risk locations.

SDG&E has not demonstrated a focus on efficiently reducing risk. SDG&E plans to perform less than a third of covered conductor installations in 2021 on the riskiest half of circuits in the HFTD, with the rest taking place on the lower half of HFTD risk ranked circuits.[53], [54]

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[51] SDG&E's response to data request CalAdvocates-SDGE-2021WMP-05, question 9, March 4, 2021.

[52] SDG&E 2021 WMP Update non-spatial data filing, Table 12.

[53] SDG&E reports that 32.7 percent of capital expenditures and 24.9 percent of operating expenses for covered conductor will be dedicated to work performed on the first two quartiles of risk ranked circuits in the HFTD. The remaining work will take place on circuits in the lower half of the risk ranking. SDG&E notes that it approximated these percentages by assuming that unit costs remain constant across all circuit miles. This means that spending estimates directly reflect the miles of system hardening that will occur in each quartile of circuits.

[54] CalAdvocates-SDGE-2021WMP-05, question 9, March 4, 2021; and CalAdvocates-SDGE-2021WMP-05, question 9 revised response, March 22, 2021.

As with the strategic undergrounding program, the WSD should direct SDG&E to revise its covered conductor workplan to better focus on high-risk circuits. The WSD should direct SDG&E to submit a detailed workplan within 30 days from when the WSD issues its action statement on SDG&E's WMP.[55] This workplan should include an explanation of how the plan optimizes SDG&E's resources to expeditiously and substantially reduce wildfire risk.

Similarly, the WSD should direct SDG&E to submit a detailed covered conductor workplan with its 2022 WMP that identifies the specific circuit-segments where projects will occur. SDG&E should demonstrate that it has prioritized its projects, to the greatest degree feasible, to expeditiously reduce wildfire risk.

D. The WSD should direct SDG&E to phase out the Standby Power Program, which does not effectively reduce wildfire risk.

SDG&E's Standby Power Program illustrates SDG&E's overall lack of focus on risk in system hardening efforts. The program provides backup generation for an individual household in the event of a de-energization event.

In comments on SDG&E's 2020 WMP, Cal Advocates expressed concern that the proposed program lacked key implementation details.[56] SDG&E began implementation of the program in 2020 and the program is already substantially behind schedule, which SDG&E attributes to difficulties with the timeliness of obtaining necessary permits.[57] In 2020 SDG&E forecast completing 300 generator installations in the HFTD; however, only 75 were operational by the end of 2020.[58] As a result, SDG&E is proposing 413 installations in 2021 to clear the backlog.[59] SDG&E states that it is taking steps to address the unexpectedly long timelines for permitting.[60] However, the fact that the program already has a substantial backlog at the end of

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[55] Pursuant to Public Utilities Code Section 8386.3(a), the WSD is expected to issue an action statement on SDG&E's WMP by May 5, 2021.

[56] *Comments of the Public Advocates Office on the 2020 Wildfire Mitigation Plans*, April 7, 2020, p. 20.

[57] SDG&E 2021 WMP Update, p. 212.

[58] SDG&E 2021 WMP Update, p. 212.

[59] SDG&E 2021 WMP Update, p. 212.

[60] SDG&E 2021 WMP Update, p. 212.

year one supports Cal Advocates' past concerns that the implementation details for the program were not well thought-out.

The Standby Power Program is narrowly targeted and provides resilience benefits to only a very small number of customers at a substantial cost. SDG&E has implemented two other programs to improve resilience for customers at risk of experiencing a de-energization event, which are much more efficient in terms of both the number of customers served and cost. SDG&E's Generator Grant Program provides customers with portable battery units with solar charging capability, which are sized appropriately to charge personal devices and to sustain the function of medical devices in the event of a power loss. The program targets Medical Baseline customers who have experienced a previous de-energization event.[61] SDG&E's Generator Assistance Program provides rebates to incentivize customers in HFTDs to purchase their own portable generators.[62]

The Standby Power Program is expected to cost nearly as much over the three-year WMP cycle ($22.5 million) as both the Generator Assistance Programs and the Generator Grant Programs combined ($25.3 million). Yet the Standby Power Program currently serves only 75 customers, with SDG&E projecting a total of 900 customers will be served by the program over the WMP cycle. By comparison, SDG&E projects that 3,774 customers will take advantage of the Resiliency Assistance Program, and 5,420 customers will benefit from the Resiliency Grant Program. The per customer cost of each program is shown in Table B.

[61] With respect to the Generator Grant Program, SDG&E states that "in 2020, approximately 1,864 [medical baseline] customers with a previous 2019 PSPS outage were invited to participate in the program, and 1,409 portable battery units were delivered to customers between May and October 2020." SDG&E 2021 WMP Update, p. 208.

[62] The Generator Assistance Program was targeted at 28,256 HFTD customers in 2020, and about 5 percent of those (1,274 customers) "redeemed a rebate and purchased a portable generator, including 249 CARE customers." SDG&E 2021 WMP Update, p. 214.

Table B **Comparison of SDG&E Resilience Programs Spending per Customer Served**[63]			
	Total expenses (millions)	Customers	Expense per Customer
Resiliency Grant Program	$20.9	5,420	$3,852
Resiliency Assistance Program	$4.4	3,774	$1,170
Standby Power Program	$22.5	900	$24,948

As shown above, SDG&E's Standby Power Program is behind schedule, costly compared to other programs, and benefits very few customers. SDG&E should prioritize resilience spending based on program efficacy, and relative cost efficiency. SDG&E's generator assistance grants have served more customers, and thus improved community resiliency at lower per customer cost, without the complexity and hurdles causing a backlog in the Standby Power Program.

The WSD should direct SDG&E to phase out the Standby Power Program, which is not delivering benefits proportionate to its costs. This program is absorbing staff time, management attention, and ratepayer funding that could better be allocated elsewhere. To improve its systemwide risk reduction, SDG&E needs to refocus on proven and cost-efficient programs.

E. The WSD should require SDG&E to explain significant cost forecast discrepancies between its 2020 WMP and its 2021 WMP.

For some system hardening programs, the cost forecasts in SDG&E's 2021 WMP Update vary substantially from those provided in SDG&E's 2020 WMP, and SDG&E provides limited explanation for the variation. The WSD should require SDG&E to provide a rational explanation for the substantial inconsistencies between SDG&E's cost forecasts in the 2020 and 2021 WMPs.

Accurate cost forecasts are vital to the calculation of risk-spend efficiency (RSE), and forecasts that vary substantially year over year could result in changes to RSE which would have

[63] Source: SDG&E 2021 WMP Update non-spatial data filing, Table 12.

an effect on SDG&E's selection of risk mitigations. Further, SDG&E's cost forecasts are one basis on which the Commission may review future cost recovery applications.

Three programs constitute the bulk of SDG&E's ongoing system hardening spending: bare conductor hardening, covered conductor installations and strategic undergrounding. Combined, these programs make up about 55 percent of SDG&E's actual 2020 system hardening capital expenditures, and about 70 percent of forecast capital expenditures in 2021 and 2022.[64]

These are the three largest programs in SDG&E's system hardening portfolio, yet SDG&E only addresses the changes in overall forecast cost for one (bare conductor hardening) – and in that instance, SDG&E does not address the equally large increases in per mile cost. For the other two (covered conductor installations and strategic undergrounding), SDG&E provides limited information on how and why it has made large changes to overall forecast spending and cost per mile between the two WMP filings. SDG&E's WMP should provide more explanation of changes in program scope and forecast cost for these and other programs where forecasts have been substantially revised.

1. Covered Conductor

SDG&E's covered conductor program was initiated in 2020 as a pilot program with the installation of an initial 1.9 miles of conductor. SDG&E states that "given the success of the pilot installation, SDG&E is moving forward with the program and has plans to harden 20 miles of covered conductor in 2021, and 60 miles of covered conductor in 2022."[65]

On a per mile basis, SDG&E's forecast cost to install covered conductor has risen sharply. In 2021, SDG&E's forecast cost per mile of covered conductor is more than 2.5 times what SDG&E expected a year ago. SDG&E's 2021 and 2022 forecasts reflect unit cost estimates far in excess of those reported by PG&E and SCE. SDG&E forecasts a cost of $2.8 million per mile in 2021, whereas PG&E reported costs of $1.3 million per mile and SCE reported costs of $0.57 million per mile in 2020.[66, 67]

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[64] SDG&E 2021 WMP Update non-spatial data filing, Table 12.

[65] SDG&E 2021 WMP, p.193.

[66] PG&E installed 333 miles of covered conductor in 2020 at a total cost of $439 million in capital expenditures, resulting in an average per mile cost $1.3 million. PG&E response to Data Request CalAdvocates-PGE-2021WMP-12, Question 2, March 8, 2021.

[67] SCE installed 965 miles of covered conductor in 2020 at a total cost of $546.2 million in capital expenditures, resulting in an average per mile cost $566,000. SCE 2021 WMP Update, non-spatial data,

Tables C and D below show the increase in SDG&E's cost forecasts for covered conductor installation between the 2021 WMP Update and the initial forecast in the 2020 WMP, both in absolute terms and in terms of cost per mile.

Table C **SDG&E Covered Conductor - Total Forecast Cost** (millions of dollars)[68]			
	2020 Forecast	2021 Forecast	Percentage Change
Sum of 2020-2022 Capital Expenditures	$27.2	$152.8	462%

As shown above, SDG&E's 2021 cost forecast for covered conductor over the three-year WMP cycle has increased more than five-fold from the prior year's WMP. This is an alarming increase in costs.

Table D **SDG&E Covered Conductor - Forecast Cost per Mile** (thousands of dollars)[69]			
	2020 Forecast	2021 Forecast[70]	Percentage Change
2020 Capital Expenditures	$1,071	$946	-12%
2021 Capital Expenditures	$1,080	$2,750	155%
2022 Capital Expenditures	$1,080	$1,600	48%

SDG&E's forecasted increase in the per mile cost of covered conductor installation is equally alarming. SDG&E does not explain the substantial upward revision of the cost per mile

Table 12.

[68] 2020 forecast costs from SDG&E 2020 WMP, Appendix A, Table 23; 2021 forecast costs from SDG&E 2021 WMP Update non-spatial data filing, Table 12.

[69] 2020 forecast costs from SDG&E 2020 WMP, Appendix A, Table 23; 2021 forecast costs from SDG&E 2021 WMP Update non-spatial data filing, Table 12.

[70] For 2020, the "2021 Forecast" refers to actual expenditures in 2020, as reported in the 2021 WMP.

in 2021, nor SDG&E's substantially higher cost per mile of covered conductor installation compared to its peer utilities.

Moreover, the scope of the covered conductor program is set to increase (as the bare conductor hardening program is phased out) in 2022. The combination of increasing output and increasing per mile costs means that the overall magnitude of SDG&E's covered conductor costs is set to grow.[71]

SDG&E's covered conductor program makes up a substantial portion of the cost of its overall grid hardening program in 2021 and 2022. Given the expense of the program overall, and the large increases in the forecast unit cost, SDG&E's WMP should provide more explanation of changes to program scope and forecast cost.

2. Bare Conductor Hardening

SDG&E's bare conductor hardening program combines several legacy asset hardening programs into a single circuit-based hardening program that is to address issues such as small conductor replacement and wood-to-metal pole replacement.[72] Overall for the 2020 to 2022 cycle, SDG&E's 2021 WMP anticipates a considerable increase (as much as doubling) in miles of bare conductor hardening compared to SDG&E's 2020 WMP.[73]

SDG&E states that beginning in 2022 it will transition to using more covered conductor and strategic undergrounding to achieve greater risk reduction, and that the bare conductor hardening program will be ramped down. SDG&E notes it had intended to make this shift in 2021, but ultimately delayed the shift for one year, "resulting in a substantial increase in forecast cost for the program in the 2021 WMP Update"[74] SDG&E states that "while SDG&E's updated hardening strategies call for more covered conductor and strategic undergrounding, the added cost of redesigning [2021 overhead hardening projects in progress] would have lowered the risk

[71] SDG&E 2021 WMP Update, p. 220.

[72] The bare conductor hardening program hardened 99.5 miles of circuit in 2020. SDG&E forecasts hardening an additional 100 miles in 2021 and then 5 miles in 2022 (as SDG&E transitions to hardening with covered conductor). SDG&E 2021 WMP Update non-spatial data filing, Table 12.

[73] SDG&E's 2020 WMP had forecast hardening between 82 and 122 miles in 2020, between 11 and 17 miles in 2021, and between 7 and 10 miles in 2022, for a total of 100 to 149 miles over the 2020-2022 period. SDG&E's 2021 submission shows 204.5 miles in the same period, which represents an increase of between 37 percent and 104.5 percent. SDG&E 2020 WMP, Appendix A, Table 23.

[74] SDG&E 2021 WMP Update, p. 220.

spend efficiency of those mitigations… below overhead hardening."[75] In this instance, SDG&E provides sufficient detail to explain why its forecasts of outputs changed.

SDG&E should provide more of an explanation for programs where overall cost forecasts change substantially between WMP updates. In particular, SDG&E is forecasting higher costs per mile of bare conductor hardening than those included in the 2020 WMP.[76] Indeed, SDG&E's forecast per mile cost for bare conductor hardening is now nearly double SCE's actual 2020 per mile cost to install covered conductor.[77]

SDG&E does not explain why it is forecasting greater per mile costs than it did in 2020. SDG&E's WMP should address unit cost increases, especially where those unit cost forecasts are substantially higher than SDG&E's prior forecast and recent actual unit costs at comparable utilities.

3. Undergrounding

SDG&E's strategic undergrounding program "nearly [eliminates] wildfire risk for the areas where overhead system is converted to underground and it eliminates the need and impacts of PSPS for customers fed by underground systems." However, as SDG&E states, undergrounding is "the most expensive major hardening alternative on a per mile basis."[78]

SDG&E's strategic undergrounding program hardened 15.6 miles of circuit in 2020, and SDG&E forecasts hardening 25 miles in 2021.[79] SDG&E's overall program cost estimates have declined slightly in the 2021 WMP Update as compared to the high miles-treated scenario in SDG&E's 2020 WMP.[80] However, this may be attributable to SDG&E forecasting a large decrease in miles hardened in 2021.[81]

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[75] SDG&E 2021 WMP Update, p. 220.

[76] 2020 forecast costs from SDG&E 2020 WMP, Appendix A, Table 23; 2021 forecast costs from SDG&E 2021 WMP Update non-spatial data filing, Table 12.

[77] SCE 2021 WMP Update, non-spatial data, Table 12.

[78] SDG&E 2021 WMP Update, p. 215.

[79] For comparison, SDG&E's 2020 WMP had forecast undergrounding between 8 and 12 miles in 2020, between 40 and 60 miles in 2021, and between 48 and 72 miles in 2022. SDG&E 2020 WMP, Appendix A, Table 23.

[80] 2020 forecast costs from SDG&E 2020 WMP, Appendix A, Table 23; 2021 forecast costs from SDG&E 2021 WMP Update non-spatial data filing, Table 12.

[81] SDG&E revises its forecast total miles of undergrounding for 2021 to 25 miles rather than the prior forecast of 40-60 miles, and 80 miles in 2022 rather than the prior forecast of 48-72 miles. 2020 forecast

In reality, there has been a significant increase in per mile costs. Indeed, SDG&E's 2021 cost forecast of $4.8 million per mile of undergrounding is more than a 50 percent increase from its prior WMP, and nearly double SDG&E's actual 2020 cost per mile of $2.5 million. SDG&E has not addressed this change.

Table E
SDG&E Undergrounding - Forecast Cost per Mile
(thousands of dollars)[82]

	2020 Forecast	2021 Forecast[83]	Percentage Change
2020 Capital Expenditures	$3,100	$2,494	-20%
2021 Capital Expenditures	$3,140	$4,810	53%

As stated above, WMP forecasts should not be radically different from year to year where circumstances have not substantially changed. Where legitimate changes in scope or cost do result in substantial changes to forecasts, it is only reasonable that utilities be as transparent as possible as to how and why those forecasts have changed. Similarly, it is reasonable to require further explanation where forecast costs are out of scale with those experienced by other large utilities for similar work. The WSD should require future WMPs to explain any substantial variation in cost forecast between annual WMP filings.

F. The WSD should require SDG&E to report on non-communicative remote-controlled switches.

SDG&E's 2020 de-energization post-event reports indicate that SDG&E experienced several incidents in which non-communicative Supervisory Control and Data Acquisition (SCADA) switches caused customers to be de-energized without notice, contrary to Commission requirements.[84]

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milage from SDG&E 2020 WMP, Appendix A, Table 23; 2021 forecast milage from SDG&E 2021 WMP Update non-spatial data filing, Table 12.

[82] 2020 forecast costs from SDG&E 2020 WMP, Appendix A, Table 23; 2021 forecast costs from SDG&E 2021 WMP Update non-spatial data filing, Table 12.

[83] The "2021 Forecast" on this line refers to actual expenditures in 2020, as reported in the 2021 WMP.

[84] SDG&E's November 26 – December 9, 2020 post-event report, p. 38; and SDG&E's December 23-24,

In response to Cal Advocates' discovery, SDG&E indicated that it has "no plans to alter the existing practices" in 2021 or 2022 in order to validate that existing SCADA capacitors are functioning as intended.[85] SDG&E indicates that existing operating procedures call for testing SCADA switches annually, and that it has "instituted a process to minimize customer impacts of devices being inoperable," which includes "identifying devices out of communication and identifying bypassed SCADA switches prior to the start of an event."[86]

Despite these alleged practices, SDG&E's existing internal operating procedures did not prevent customers from experiencing de-energization events without notice in 2020.

While SDG&E indicates that it has taken some steps to identify non-functional SCADA devices prior to potential de-energization events in the affected area,[87] it is not clear that any proactive steps have been taken at the system level to validate that existing SCADA switches remain operational. Similarly, it is not evident that SDG&E has taken any steps to ensure that newly installed SCADA switches are fully functional. This means that non-communicative devices could cause some customers to be de-energized not only without notice, but without need. As shown by its failure to prevent customers from experiencing de-energization events without notice in 2020,[88] SDG&E's hardware failures are causing SDG&E to de-energize customers not as a last resort, but because of equipment problems – problems that SDG&E is aware of and should address.

The WSD should require SDG&E to document the steps it is taking to inspect or test SCADA switches. SDG&E should take reasonable precautions to ensure that customers are not de-energized without notice in future years and are not de-energized because SDG&E failed to address its SCADA switch problems.

2020 post event report, p. 12.

[85] CalAdvocates-SDGE-2021WMP-05, question 11, March 4, 2021.

[86] CalAdvocates-SDGE-2021WMP-04, question 11, March 4, 2021.

[87] In response to Cal Advocates discovery, SDG&E states that moving forward it "has instituted a process to minimize customer impacts of devices being inoperable… [which includes] identifying devices out of communication and identifying bypassed SCADA switches prior to the start of an event. Any devices that may impact SDG&E's ability to PSPS will have mitigation measures applied, which include stationing someone to manually switch the device or adjusting the forecasted customer notification lists." See CalAdvocates-SDGE-2021WMP-04, question 11, March 4, 2021.

[88] Non-spatial data Table 11 of SDG&E's 2021 WMP shows that fewer customers were notified than were affected by de-energization events. See Table 11, lines 4(a) through 4(f).

G. SDG&E should present comprehensive inspection data.

SDG&E's inspections data provided in WMP Table 1 is not comprehensive and does not provide a complete picture of SDG&E's inspections programs in HFTDs.[89] The WSD's guidelines for completing Table 1 direct that inspection findings be split into three categories: patrol inspections, detailed inspections, and other inspections.[90] SDG&E interprets each of these inspection types to refer to a discrete inspections program, rather than using "other" as a catch-all category for all inspections beyond patrol and detailed inspections.[91]

SDG&E's interpretation provides an incomplete overview of its inspection programs. For example, SDG&E does not include inspection findings for programs such as drone inspections, despite finding far more issues through drone inspections than through the inspections it includes in Table 1.[92]

In future non-spatial data filings, SDG&E should provide a comprehensive accounting of the number of inspections performed in the HFTD across all inspection programs, and the number of findings by type from each inspection, in order to provide a complete picture of the effectiveness of SDG&E's inspection portfolio. Each inspection program which is performed in the HFTD should be represented as a line item, with associated findings. This will provide a more complete picture of the scope and efficacy of SDG&E's inspection programs.

V. GENERAL RECOMMENDATIONS ON TECHNICAL ISSUES

A. The WSD should require the large IOUs to provide specific workplans showing where and when mitigation work will take place.

Since risk levels vary dramatically across the geography of each utility service territory, it is vital to know exactly where a utility is performing wildfire mitigation work. Targeting work to the places with the most acute wildfire risk can make the difference between a lifesaving project and a waste of resources. The three large IOUs provide differing levels of detail and

[89] SDG&E 2021 WMP Update, non-spatial data filing, Table 1.

[90] Resolution WSD-011 Attachment 2.3.

[91] SDG&E 2021 WMP Update, non-spatial data filing, Table 1.

[92] In 2020, SDG&E reports completing 37,310 drone inspections in Tier 3 of the HFTD, resulting in 132 "emergency" findings, 1,823 "priority" findings, and 7,522 "non-critical" findings. In Table 1, SDG&E reports 32 level 1 findings, 1,121 level 2 findings, and 0 level 3 findings. SDG&E 2021 WMP Update, p. 248 and non-spatial data Table 1.

commitment on where and when they will prioritize mitigations such as vegetation management, asset inspections, and grid hardening.

As noted in our comments on PG&E's WMP,[93] PG&E's workplans for EVM and system hardening do not provide sufficient assurances that PG&E is targeting its narrow-scope mitigation programs to maximize risk reduction. Furthermore, while PG&E commits to completing detailed inspections of distribution and transmission assets in HFTDs by July 31, 2021,[94] PG&E fails to provide similar commitments to complete routine or enhanced vegetation management prior to fire season (typically late summer to winter).

The WSD should require the large IOUs to submit specific workplans detailing where they plan to perform mitigation activities, the start date of those activities, and by what date these activities will be complete.[95] These workplans should include all mitigation work that is in scope or being planned. Cal Advocates recommends these workplans cover, at a minimum, asset inspections, vegetation management, and system hardening work in HFTDs. For narrow-scope programs (e.g., system hardening and enhanced vegetation management), the workplans should provide mitigation activity forecasts at the circuit level at a minimum.

Utilities should strive to complete asset inspections and vegetation management inspections before fire season begins around August 1st of each year. If it is not feasible to complete 100 percent of the work by this date, utilities should be required to target at least 75 percent completion, prioritizing the highest-risk areas of their systems.

The utilities should be required to prioritize their work in accordance with their risk models. For example, when reviewing SCE's planned work for 2021, Cal Advocates noted that less than a third of SCE's covered conductor installation would occur on the high-risk circuits that make up 75 percent of the wildfire risk in SCE's distribution system.[96] Similarly, out of a

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[93] See *Comments of the Public Advocates Office on the 2021 Wildfire Mitigation Plan Update of Pacific Gas and Electric Company*, March 29, 2021, Section III.C.

[94] PG&E's 2021 WMP, Table PG&E-7.1-2, p. 293.

[95] See Cal Advocates' Straw Proposal for WMP Templates (Proposed Non-Spatial Table 16).

[96] Per SCE response to Data Request CalAdvocates-SCE-2021WMP-07, Question 2, March 8, 2021, SCE has planned 1,883 miles of covered conductor projects, of which only 581 miles are planned on the high-risk circuits that account for 75 percent of the wildfire risk on the distribution system.

It is reasonable to view SCE's covered conductor workplan as representing roughly 1.5 years of work and to expect that some of these projects will be completed in 2022. Although SCE has stated that this covered conductor workplan includes 1,883 miles of covered conductor projects that SCE forecasts to total of 421 total expected fuse replacements, SCE expects to replace non-exempt fuses at only 111 locations in those same high-risk circuits.[97, 98]

Receiving detailed workplans as described above will allow the WSD and the Commission to determine if the utilities are planning their work around the highest-risk circuits to achieve the greatest risk reduction. Upon receiving the workplans, interested parties can compare the proposed work against the risk scores assigned to each circuit (or circuit-segment) by the utilities. Ideally, the utilities will plan their work to focus on the circuits that disproportionately drive wildfire risk. If the planning of mitigation work does not align with the risk scores of the circuits, the WSD and the Commission can require an explanation of the circumstances that led to the disparity between planned work and the risk scores.

B. The WSD should convene a technical working group to examine the large IOUs' risk modeling practices.

The three large IOUs rely on complex models to estimate the risk posed by their assets, and the amount of risk reduced by various mitigation initiatives. These models drive the prioritization of high-stakes initiatives, including system hardening efforts projected to cost in the hundreds of millions of dollars. Risk models also influence the location, scope and duration of de-energization events, which can be the difference between life and death for customers in an area at high risk for ignition and for Access and Functional Needs (AFN) customers who are more vulnerable during power interruptions.

The large IOUs' WMPs do not provide sufficient detail to assess the quality of their modeling practices or validation methods. Below, Cal Advocates provides a non-exhaustive list of concerns with several specific modeling products.

In the summer (after approving or denying the current WMPs), the WSD should convene a technical working group to examine the risk models discussed below and others that the utilities rely on.

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complete in 2021, SCE admits it actually "expects to install 1,000 circuit miles of covered conductor in 2021 but will strive to install as many as 1,400 circuit miles." *See* SCE response to Data Request CalAdvocates-SCE-2021WMP-12, Question 1, March 16, 2021.

[97] SCE's 2021 WMP, Table 12.

[98] SCE's response to Data Request CalAdvocates-SCE-2021WMP-07, Question 1, March 3, 2021.

1. PG&E's Weather Model – PG&E Operational Mesoscale Modeling System (POMMS 3.0).

The PG&E Operational Mesoscale Modeling System (POMMS) is a foundational element of PG&E's risk modeling. Cal Advocates has not identified any immediate problems; however, PG&E is making crucial decisions based on a model that requires further validation.

POMMS was utilized to produce a 30-year, hour-by-hour historical weather and fuels climatology at a 2 x 2 km resolution.[99] To develop these models, PG&E used a "standard technique of downscaling the [National Centers for Environmental Prediction (NCEP)] Climate Forecast System Reanalysis data for the period of interest."[100] The NCEP Climate Forecast System Reanalysis (CFSR) and the CFSv2[101] are global models that represent the interaction between Earth's oceans, land, and atmosphere, offering hourly data with a horizontal resolution down to one-half of a degree (approximately 56 km).[102] To develop PG&E's climatology models, this data was downscaled from a 56 km resolution to a 2 km resolution. This level of downscaling requires a significant amount of interpolation to translate data from a single cell to nearly 800 cells. Additionally, at these smaller resolutions, the effects of local terrain and surface roughness can create local climates that may not be accurately represented by the model.[103] For further discussion of the POMMS model, please refer to Appendix B (Confidential) of these comments.

PG&E uses its modeled 30-year climatology as one input into its models to determine where and when to initiate a de-energization event.[104] The decision to initiate or not initiate a de-energization event can have dramatic consequences for residents. In extreme examples, both the

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[99] PG&E's 2021 WMP, p. 70.

[100] PG&E's response to Data Request CalAdvocates-PGE-2021WMP-09, Question 1, March 2, 2021.

[101] The CFSR offers data over the 32-year period of record from January 1979 to March 2011. It has been extended as an operational real-time product known as CFSv2. https://www.ncdc.noaa.gov/data-access/model-data/model-datasets/climate-forecast-system-version2-cfsv2

[102] From a description of the Climate Forecast System (CFS). https://www.ncdc.noaa.gov/data-access/model-data/model-datasets/climate-forecast-system-version2-cfsv2

[103] Anecdotal evidence from an ABC10 investigation suggests the wind speeds in the area of the Zogg Fire may have been higher than reported by the nearest weather station, due in part to differences in terrain. https://www.abc10.com/article/news/investigations/investigation-pge-shutoff-decisions-zogg-fire/103-273163f6-c0f6-4404-b36b-9053b2980d3d

[104] PG&E's 2021 WMP, p. 71.

Kincade Fire in 2019 and the Zogg Fire in 2020 occurred during a nearby de-energization event, on lines PG&E thought it was unnecessary to de-energize.[105], [106] On the other hand, excessive de-energization events place heavy burdens and other safety risks on residents and businesses.

To verify that PG&E's de-energization-related decisions are based on valid models, a deeper analysis of PG&E's modeling practices is necessary. A technical working group could advance this goal.

Furthermore, the public should have the opportunity to examine PG&E's modeling practices. When asked to provide a publicly accessible version of documentation on the POMMS model, PG&E stated, "PG&E does not possess public versions of the three documents, nor is redaction practicable because the proprietary methodology, analysis, and data are described and identified throughout the documents."[107]

2. PG&E's 2021 Wildfire Distribution Risk Model.

Starting in 2021, PG&E substantially updated its previous risk model with new models for both the probability and consequence of ignition.[108] The outputs from the new risk model differ significantly from the previous model, which resulted in PG&E "pausing" some system hardening projects and launching new ones.[109]

To demonstrate the difference in models, PG&E presented the following chart during the WSD workshop on grid design and system hardening held on February 23, 2021. The chart shows that the highest-risk circuit-segments under the new model were all ranked relatively low by the old model, and vice versa. Moreover, the shape of the curves is very different, which

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[105] On October 23, 2019, PG&E de-energized distribution lines, but not transmission lines, in the region where the Kincade Fire ignited. PG&E, *Electric Incident Report Filed with CPUC in Response to Kincade Fire*, October 24, 2019, available at https://www.pge.com/en/about/newsroom/newsdetails/index.page?title=20191024_electric_incident_report_filed_with_cpuc_in_response_to_kincade_fire

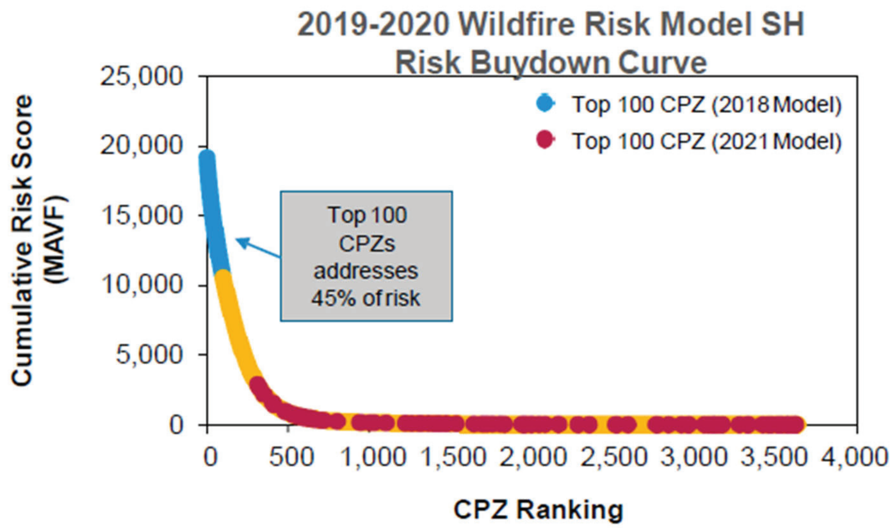
[106] On September 27, 2020, PG&E de-energized lines in Shasta County near where the Zogg Fire ignited, but the Girvan Circuit (the circuit suspected of igniting the Zogg Fire) was left energized. PG&E, *Response to Order Requesting Information Regarding Zogg Fire and Order for Further Information Regarding Zogg Fire* (Case No. 14-CR-00175-WHA Doc. No. 1250), October 26, 2020.

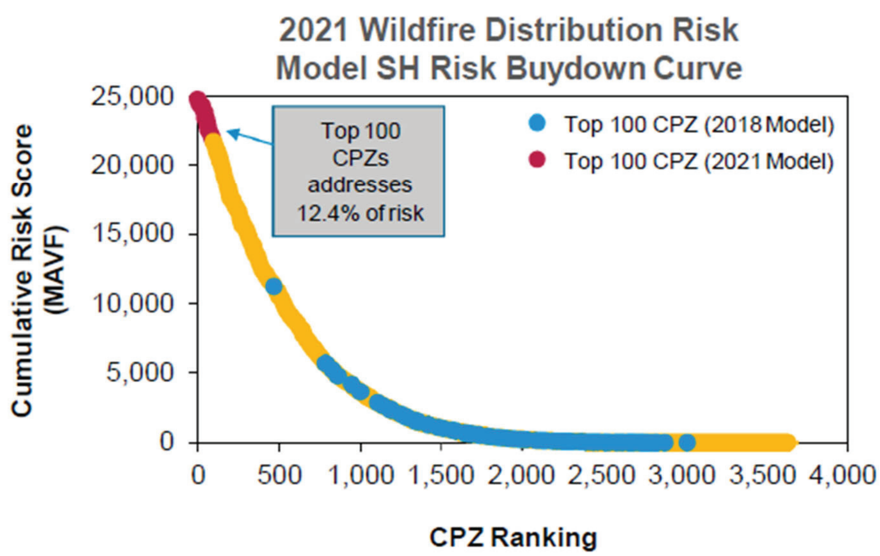
[107] PG&E's response to Data Request CalAdvocates-PGE-2021WMP-16, Question 7, March 10, 2021.

[108] PG&E's 2021 WMP, Section 4.3 "Change in Ignition Probability Drivers," pp. 94-103.

[109] PG&E's 2021 WMP, p. 12.

indicates different understandings of the extent to which the risk is concentrated on a few high-risk circuit-segments.





Such a dramatic change in risk ranking of distribution circuit segments raises concern about the validity of PG&E's modeling practices. It is unclear to what extent prior mitigation work was actually targeted to high-risk circuit segments, and whether the new 2021 Wildfire Distribution Risk Model is truly more accurate in determining which circuit segments are high-risk.

It may be that PG&E's 2021 Wildfire Distribution Risk Model is correct, while the 2018 model was deeply flawed. However, this remains to be proven. It is also possible that the 2018 model was more accurate, or that both models are flawed. In either event, a workshop would clarify these uncertainties.

3. PG&E's EVM tree-weighted prioritization list.

On February 8, 2021, the WSD issued an audit report of PG&E's enhanced vegetation management (EVM) program.[110] In this audit report, the WSD raised concerns regarding PG&E's Risk Overlay Model and the utility's apparent use of multiple, conflicting EVM prioritization models.[111]

In response, PG&E stated, "The 2021 EVM workplan was developed beginning with the 2021 Wildfire Distribution Risk Model, but included three modifications to develop a workplan to focus on high-risk circuit segments."[112] These modifications result in the EVM tree-weighted prioritization list, which is used to prioritize EVM work in 2021.[113] However, the "EVM tree-weighted prioritization list" is not mentioned in anywhere in PG&E's 2021 WMP.[114]

It is concerning that PG&E is using models to prioritize critical wildfire mitigation work that it does not discuss in its WMP. PG&E's failure to explain this model in its WMP obscures the processes PG&E uses to prioritize EVM; PG&E has not demonstrated that this is the best tool for planning EVM work. A workshop would also give stakeholders the opportunity to examine the EVM tree weighted prioritization list and other models that were not discussed in the WMP.

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[110] The WSD's audit of PG&E's EVM program was conducted from October 21, 2020 through February 5, 2021. Wildfire Safety Division's Audit Report on PG&E's Implementation of their Enhanced Vegetation Management Program in 2020, p. 1.

[111] Wildfire Safety Division's Audit Report on PG&E's Implementation of their Enhanced Vegetation Management Program in 2020, p. 17.

[112] Pacific Gas and Electric Company's Response to Audit of Implementation of Enhanced Vegetation Management Program in 2020, p. 10.

[113] Pacific Gas and Electric Company's Response to Audit of Implementation of Enhanced Vegetation Management Program in 2020, p. 11.

[114] Cal Advocates utilized the search function in PG&E's 2021 WMP for the terms "tree-weighted," "weighted," and "prioritization list," and was unable to find mention of the "EVM tree-weighted prioritization list."

4. The WSD should convene a technical working group to examine the large IOUs' risk modeling practices.

As noted above, there are a number of concerns with PG&E's models. PG&E's uses these models for activities such as de-energization decisions and wildfire mitigation program prioritization. While the issues listed above all relate to PG&E, Cal Advocates recommends that the WSD and the Commission further investigate the modeling practices of all the large IOUs. Risk modeling issues are also addressed in the SMAP rulemaking proceeding (R.20-07-013), but that proceeding does not specifically consider the application of risk models to wildfire mitigation planning and improvements may not be timely enough to inform planning for the next fire season.

The WSD will be an agency independent of the Commission as of July 1, 2021,[115] and will share responsibility for overseeing utility risk models to address wildfire risk. If stakeholders are to have insight into the risk models before the 2022 WMP submissions, these issues must be addressed outside the SMAP proceeding.

The WSD should convene a series of technical working groups in the summer or fall of 2021 to examine the modeling practices of the large IOUs. These working groups should be open to any stakeholders who want to participate (potentially including the Safety and Enforcement Division, the Safety Policy Division, and the Governor's Office of Emergency Services). The group should review each model, including their data sources, modeling methods, and validation methods.

Prior to these working groups, the WSD should require the large IOUs to produce a list of every model associated with their wildfire mitigation practices, and to produce public technical papers that describe, step-by-step, how each modeling product works.[116]

Additionally, if a large utility makes substantial changes to its modeling practices, the WSD should require the utility to include a detailed explanation of the changes and the justifications for such changes, as well as public technical papers on the new model, no later than 60 days prior to its next WMP submission. Submitting these technical papers in advance of a

[115] California Public Utilities Code Section 326 (b).

[116] This approach is consistent with the CPUC's Rules of Practice and Procedure Sections 10.3 and 10.4 governing computer models.

WMP submission would allow stakeholders to become familiar with the analytical foundations of the WMP before examining the specific workplans.

C. The WSD should require IOUs to implement a maximum de-energization delay time setting on distribution lines during high fire-risk weather.

Research on Australia's electric grid shows that "sustained ignition is 50% probable for arc durations around 60 [milliseconds] at 200 amps."[117] To put this in context, 60 milliseconds is roughly the time it takes for a recloser set to "no intentional delay" to completely de-energize a line after the actual moment of overcurrent.[118] A current of 200 amps represents a current that is far higher than the typical line current towards the end of a distribution line[119] and far higher than the ground current on a single-grounded[120] network anywhere on the distribution circuit.[121] In other words, a current of 200 amps would typically occur only in a fault condition.

At the same time, faults below 200 amps but above the detection threshold represent a small,[122] but real[123] portion of all faults. Given all these facts, utilities can prevent some ignitions by implementing a de-energization setting with short delays on distribution reclosers.

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[117] Dick Coldham, Andrew Czerwinski, and Tony Marxsen. "Probability of Bushfire Ignition from Electric Arc Faults." December 2011, p. 3. Available at https://www.researchgate.net/publication/283486798_Probability_of_Bushfire_Ignition_from_Electric_Arc_Faults

[118] "Technical Guide – Clearing Time For Viper S." G&W Electric Co, p. 2. Available at https://www.gwelectric.com/webfoo/wp-content/uploads/GWTG04-2019-Clearing-Time-For-Viper-S-10-19.pdf

[119] See the Commission's Safety Enforcement Division reports on the 2017 fire siege, the SCADA data prior to the fires, and the location of the SCADA measuring device. Available at ftp://ftp.cpuc.ca.gov/I19-06-015/I.19-06-015%20October%202017%20NorCal%20Fires/

[120] PG&E, SCE, and SDG&E all have a substantial portion of their distribution lines in this configuration. See utilities responses to Data Request CalAdvocates-GroundTechniques-01.

[121] Scott Hayes, Daqing Hou, and Normann Fischer. "Understanding Ground Fault Detection Sensitivity and Ways to Mitigate Safety Hazards in Power Distribution Systems." Figure 8. Available at https://cms-cdn.selinc.com/assets/Literature/Publications/Technical%20Papers/6934_UnderstandingGround_DH_20190923_Web.pdf

[122] Since a portion of wires down do not produce the current to trigger a fuse or circuit breaker, a portion of faults will be below 200 Amperes. *See* Scott Hayes, Damon Thayer, Shawn Holder, and Emili Scaief. "Wires Down Improvement Program at Pacific Gas and Electric." Figures 23, 24. Available at https://www.electrocuted.com/wp-content/uploads/2018/06/Wires-Down-Improvement-Program-at-PGE.pdf

[123] PG&E's response to Data Request CalAdvocates-PGE-NonCase-Zogg-01, Question 01, February 2,

As shown in PG&E's response to Judge William Alsup regarding the Zogg Fire,[124] PG&E delays its reclosers by 20 to 25 seconds for 20-Amp and 25-Amp faults.[125] Shorter delay time settings (for example, 320 milliseconds) could reduce fault energy by over 50-fold[126] and result in fewer ignitions.

Shortening the de-energization delay time settings may cause additional unnecessary outages because some faults will not cause ignitions regardless of the de-energization delay time settings. However, since high impedance faults are a minority of faults,[127] most outages that would result from this proposal will likely result from miscoordination between fuses and reclosers. Miscoordination between fuses and reclosers should only increase the number of outages by around one-third.[128] When a fault caused outage occurs on a high fire-risk day, the

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2021.

[124] The Zogg Fire began almost three years after the 2017 Northern California fire siege.

[125] "Response To Order Requesting Information Re Zogg Fire And Order For Further Information Re Zogg Fire*."* PG&E*,* October 26, 2020, p. 3. Available at https://www.courthousenews.com/wp-content/uploads/2020/10/PGEZoggFire-RESPONSE.pdf.

[126] According to PG&E's 2021 GIS data submitted with its WMP, there is one recloser downstream of the nearest recloser upstream of the Zogg Fire location. The nearest upstream recloser was set to a 20 second delay and tripped after detecting a fault for 20 seconds. *See* PG&E's response to Data Request CalAdvocates-PGE-NonCase-Zogg-01, Question 1, February 2, 2021.

PG&E could have instead set its nearest upstream recloser to have a delay of 200ms over the 60ms necessary for the downstream recloser to operate. 200ms is a reasonable time difference between reclosers according to "Distribution System Protection" by Hesam Hosseinzadeh at p. 14. Available at https://www.eng.uwo.ca/people/tsidhu/Documents/ES586B-Hesam%20Hosseinzadeh-250441131.pdf. 60ms is a reasonable time for a recloser to operate according to "Technical Guide - Clearing Time For Viper-S" on p. 2. Available at https://www.gwelectric.com/webfoo/wp-content/uploads/GWTG04-2019-Clearing-Time-For-Viper-S-10-19.pdf.

With these settings, the upstream recloser could have operated within 320 ms, allowing 60ms for the downstream recloser to operate, a 200 ms delay, and another 60ms for the upstream recloser to operate. Thus, dividing the actual delay of 20 seconds by 320ms gives a factor of 62. Fault energy is proportional to time, so a shorter delay in this case could reduce the fault energy significantly.

[127] *See* Jakov Vico, Mark Adamiak, Craig Wester, Ashish Kulshrestha. "High impedance fault detection on rural electric distribution systems." May 16, 2010.

[128] Suppose a downstream recloser has half of its downstream line protected by fuses and customers are evenly distributed on the distribution line. In the proposed scheme, almost all faults will be caught by the recloser, causing an outage for all customers on the segment. In the previous scheme half of faults would be caught by the fuses, producing an outage for half of the customers on the segment, and the other half by the recloser (again causing an outage for all customers on the segment). The expected percentage of customers losing power per fault is then (50 %)×(50 %) + (50 %)×(100 %) = 75%. Taking the ratio of (100 %):(75 %), gives a ratio of 4:3. Therefore, neglecting minor factors, this proposal will on average

utility would then have to decide whether to re-energize once it finds the fault location or wait until the fire weather passes. However, for a 10 to 200 Amp fault, the safety benefits of de-energizing more quickly (that is, possibly preventing an ignition) are likely to exceed the harm of unnecessary outages on high fire threat days.

Another advantage is that rapid de-energization settings do not require significant capital expenditures since they use already existing reclosers or relays. SDG&E gives "Recloser protocols" the second-highest RSE of all its programs where RSEs were calculated.[129]

The WSD wrote in its attachment to Resolution WSD-011[130] that to get to a maturity level of one out of four for "protective equipment and device settings," a utility must increase the "sensitivity of risk reduction elements ii) during high threat weather conditions." Table F shows the state of large electric utilities' distribution protection practices during high fire-threat days.

Table F
Distribution protection practices during high fire threat days

Utility	Ensures distribution lines are de-energized relatively fast for a fault?
PG&E	No[131]
SCE	Yes, but does not give details[132]
SDG&E	Yes, but does not give details[133]

The WSD should require all large IOUs to reduce de-energization delay times for distribution lines on high fire-threat days. Although SCE and SDG&E already implement short de-energization delay times similar to this suggestion, these two utilities have not provided

add roughly one third more outages on high fire-threat days.

[129] SDG&E's 2021 WMP, Table 12, program 7.3.6.1.1 "Recloser protocols."

[130] *Resolution WSD-011. Resolution implementing the requirements of Public Utilities Code Sections 8389(d)(1), (2) and (4), related to catastrophic wildfire caused by electrical corporations subject to the Commission's regulatory authority*, Attachment 2.4: 2021 Maturity Model, issued January 24, 2020, p. 37.

[131] PG&E's response to Data Request CalAdvocates-PGE-NonCase-Zogg-01, Questions 7 and 8, January 15, 2021.

[132] SCE's 2021 WMP, p. 283.

[133] SDG&E's 2021 WMP, pp. 291-292.

evidence that their protective devices are set to minimize the probability of an ignition due to a fault.

Based on a preliminary analysis, Cal Advocates recommends a maximum de-energization delay time of two seconds at twice the maximum predicted load[134] on distribution lines during National Weather Service issued Red Flag Warnings, and within a specified number of miles of an active de-energization event (this distance should be developed through input from the utilities, stakeholders, and independent subject matter experts). Furthermore, the farthest downstream recloser on each circuit should be set to nearly instantaneous de-energization on detecting abnormal current.

D. The WSD should require utilities to calculate RSEs with a unified methodology.

Currently, each utility determines the risk reductions and costs associated with mitigation programs. The result is that RSEs are difficult to compare across utilities for similar programs. The process for determining the effectiveness of a mitigation initiative, the consequence of a risk event, or the likelihood of a risk event, can all be vastly different between utilities. In addition, as noted in our comments on PG&E's 2021 WMP Update, Cal Advocates has identified several issues with PG&E's reported RSEs and the assumptions underlying them.

Robust and accurate methods for determining RSEs are critical to ensure that the utilities focus on programs that effectively reduce risk at a reasonable cost to ratepayers. The ability to compare RSEs across utilities would provide valuable insights into the most effective programs, perhaps eventually leading to the discontinuation of programs found to be ineffective, and a pressure for utilities to reallocate resources to the most efficient initiatives. However, when each utility is left to develop its own RSE methodology, the ability to compare across utilities is significantly diminished.

The WSD should convene a technical working group to develop a standard methodology for estimating RSEs. These working groups should involve the large IOUs, and all stakeholders who wish to participate. It would also be beneficial for the WSD to retain technical consultants who can provide insight into the best methods for calculating RSEs. Subsequently, the WSD

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[134] This includes twice the maximum unfaulted ground current on single-grounded distribution feeders even though this current is not customer load. See IEEE C62.92.4-2014 - IEEE Guide for the Application of Neutral Grounding in Electrical Utility Systems--Part IV: Distribution.

should require the large IOUs to use the standard RSE methodology that the working group develops for all future WMP submissions.

E. The WSD should convene a technical working group to examine the cost-effective deployment of covered conductor.

Covered conductor has been the cornerstone of SCE's system hardening efforts. Covered conductor has a lifespan of 40 to 60 years, whereas the impact of enhanced vegetation management lasts only for a season or a few years at most. Installation of covered conductor on overhead circuits is by far the greatest cost component of SCE's 2021 WMP. SCE estimates that the cost for 2021 is $754 million to install approximately 1,400 miles of covered conductor.[135] Therefore, the average cost of covered conductor installation per mile is approximately $0.54 million per mile.[136]

SCE's cost for covered conductor is in stark contrast to those of the other large utilities. In 2021, PG&E expects to spend approximately $1.6 million per mile and SDG&E expects to spend approximately $2.8 million per mile on covered conductor installation.[137, 138]

When asked about the cause of this disparity in workshops, utility representatives stated that there were likely multiple contributing factors, including differences in terrain and the number of poles that were being replaced during covered conductor installation. However, pole replacements cannot account for the full cost difference. Using SCE's pole remediation data, the cost of pole remediations is approximately $20,000 per remediation.[139, 140] This means that, all other factors being equal, SCE would need to remediate 52 more poles per mile than PG&E to equalize the cost of covered conductor installation. This defies reasons since the average distribution span length is approximately 193 feet, or roughly 27 poles per mile.[141] Similarly,

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135 Table 12 of SCE 2021 WMP Update.

136 This operational efficiency is also reflected in risk-spend efficiency as the relatively low cost of installation raises the RSE considerably.

137 PG&E Response to data request CalAdvocates-PGE-2021WMP-12, Question 2, March 8, 2021.

138 SDG&E's 2021 WMP, Table 12. SDG&E's forecast costs for covered conductor in 2021 may include some planning and design costs for projects that will be completed in later years.

139 SCE's 2021 WMP, Table 12.

140 For SCE in 2020, pole replacements added about $127,000 per mile to the cost of covered conductor installation.

141 This figure is based on a count of all distribution poles per SCE file "Response TURN-SCE-003 - Q01.xlsx" and a summation of overhead distribution circuit miles in SCE's response to WSD-SCE-02,

SCE would need to perform roughly 112 more pole remediations than SDG&E to equalize the costs.

While Cal Advocates does not dispute that there are some differences in the cost to implement covered conductor in different environments, it is doubtful that the administrative differences or the logistics of installing covered conductor in different service territories would result in a two to threefold increase in cost.

The lower unit cost of SCE's method of installing covered conductor raises the question of whether the other utilities could attain similar efficiencies in system hardening. Reducing costs would improve the RSE of system hardening plans and could allow the utilities to mitigate risk over a considerably larger number of circuit-miles at the same cost.

Moreover, if the other utilities could install covered conductor at the same cost as SCE, there should be renewed discussion of whether it is wiser to install covered conductor, which could have a lifespan of 40 to 60 years, as opposed to other mitigations.

The WSD should consider holding a workshop among the utilities and stakeholders to discuss ways to improve the efficiency of system hardening initiatives, especially covered conductor. The workshop should examine whether the other utilities can emulate SCE's deployment of overhead covered conductor at a relatively low cost.

F. The WSD should convene a working group to evaluate the efficacy of climbing inspections on transmission structures.

The three large IOUs have varying approaches to using climbing inspections on transmission structures. The WSD should convene a working group to consider different approaches to inspecting transmission structures and develop best practices.

SCE inspects its transmission assets with ground-based detail and patrol inspections and aerial inspections.[142] SCE does not conduct climbing inspections of its transmission towers.[143] Additionally SCE has stated that it never implemented a climbing inspection program, because it found that climbing inspections are less efficient than ground and aerial inspections.[144]

Question 3. Note than in calculating data for Table 1, utilities estimated slightly longer average spans, which would imply about 20 poles per mile.

[142] SCE response to CalAdvocates-SCE-2021WMP-02,Question 7a.

[143] SCE Response to CalAdvocates-SCE-2021WMP-07, Question 3.

[144] SCE Response to CalAdvocates-SCE-2021WMP-07, Question 3.

Similarly, SDG&E does not conduct routine climbing inspections of all transmission lines.[145] With limited exceptions, SDG&E only conducts climbing inspections on an "as-needed" basis for its transmission structures.[146] Consistent with that practice, in 2020, SDG&E conducted climbing inspections of 48 transmission towers.[147] SDG&E found eight Level 2 issues as a result of those inspections.[148, 149, 150] SDG&E does not reference climbing inspections in its 2021 WMP "due to their as-needed, supplemental nature."[151]

Unlike the utilities in southern California, PG&E does have a climbing inspection program for its 500kV (kilovolt) transmission towers. PG&E performed 2,931 climbing inspections on its transmission assets in 2020.[152] Of those inspections, PG&E identified 35 Priority A and B findings.[153, 154, 155] For comparison, PG&E found Priority A and B issues at

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[145] Cal Advocates estimates that SDG&E has 15,610 transmission structures, based on an analysis of the GIS data that SDG&E provided with its 2021 WMP.

[146] SDG&E conducts routine annual climbing inspections only on transmission structures that are part of the Sunrise Powerlink. SDG&E reports performing climbing inspections on a minimum of 10% of Sunrise Powerlink structures each year, and an average of 42 such inspections annually. SDG&E Response to CalAdvocates-SDG&E-2021WMP-04, Question 8.

[147] SDG&E Response to CalAdvocates-SDGE-2021WMP-02, Question 4e.

[148] SDG&E Response to CalAdvocates-SDGE-2021WMP-02, Question 7b.

[149] The lowest Priority Level that SDG&E uses is Level 2. All findings are resolved within twelve months, therefore some of the Level 2 findings may be equivalent to GO 95, Rule 18 Level 3 Findings.

[150] Level 2 means the designation used by SDG&E, which includes issues that are Level 2 and Level 3 per GO 95, Rule 18.

[151] SDG&E Response to CalAdvocates-SDG&E-2021WMP-04, Question 8.

[152] PG&E Response to CalAdvocates-PGE-2021WMP-02, Question 4.

[153] PG&E's Response to data request CalAdvocates-PGE-2021WMP-02, Question 7.

[154] Priority A findings are equivalent to CPUC GO 95, Rule 18 Level 1 Findings. Priority B findings are similar in severity to GO 95, Rule 18 Level 2 Findings.

[155] This largely aligns with the findings that PG&E noted in response to the Federal Monitor, in which PG&E stated that it had opened 34 Priority A and B work orders for 500kV transmission tower climbing inspections. *U.S.A v. Pacific Gas and Electric Co.*, No. 3:14-cr-00175, PG&E *Response to Order Re Monitor Letter* (Doc. No. 1258).

about the same rate on its detailed ground inspections of transmission towers: about one high-priority finding for every 100 structures inspected.[156, 157, 158]

The fact that PG&E's climbing inspection program could identify findings that are undetectable from the ground strongly suggests that the other utilities should consider implementing similar programs, or at a minimum conduct a study of whether climbing inspections would be effective in detecting issues undetected by ground and aerial inspection.

The WSD should consider these findings and establish a working group to consider the efficacy of deploying climbing inspections in conjunction with aerial and ground inspections of transmission structures. This would allow the WSD to determine if climbing inspections should be a mandatory component of WMPs. If the working group concludes that climbing inspections are worthwhile, it should also consider the appropriate inspection cycles.

VI. RECOMMENDATIONS FOR FUTURE WMP GUIDELINES

A. The WSD should modify the WMP schedule to encourage more proactive planning.

The current WMP submission and review schedule is infeasible. While only in its third year, the WMP cycle has progressively grown in complexity and volume by the year. These additional developments inevitably compress timeframes for meaningful review and resolution of the year's WMPs.

Going forward, the WSD should modify the WMP submission schedule to encourage more proactive planning by the IOUs. Effective and meaningful planning should occur in advance of implementation. However, the current WMP schedule has the utilities submitting plans during the same year when implementation is already underway, with the result that the plans may be approved or denied halfway through the plan implementation year. Currently, the earliest timeframe for the WSD to act on the large utilities' WMPs is in May, with Commission ratification in June.[159] This is only two or three months before the peak wildfire season.

[156] In 2020, PG&E performed 61,606 detailed ground inspections of transmission structures, including those at lower voltages than 500 kV. PG&E identified 620 Priority A and B work orders as a result of those inspections, or about one high-priority issue for every 100 transmission structures inspected.

[157] PG&E Response to CalAdvocates-PGE-2021WMP-02, Question 6.

[158] Attachment 2 of PG&E Response to CalAdvocates-PGE-2021WMP-10, Question 11.

[159] Wildfire Safety Division, WMP updated schedule guidance, providing updates to Tables 1 and 2 in WSD-011 Attachment 3, January 22, 2021.

Should the WSD or other stakeholders find flaws or deficiencies in a WMP, the current schedule provides little time for the utility to revise and adjust its mitigation activities. The WSD should consider requiring the utilities to submit their WMPs in the third or fourth quarter of the year prior to the year covered by the plan. This would provide the WSD and stakeholders a meaningful opportunity to review and revise plans well in advance of wildfire season.

Cal Advocates recommends that the WSD hold a workshop to consider alternative schedules for the submission and review of WMPs. The goal should be to correct the issue of reviewing plans that are already being implemented. Additionally, the WSD and stakeholders should work toward a schedule that is workable for all parties and provides meaningful opportunities for course correction when needed.

Cal Advocates provides two alternative calendars for the WSD's consideration (see Appendix C for details). Calendar A would keep the submission date approximately the same but change the period covered by each WMP. With this approach, the "planning year" covered by each WMP would run from July of a given year through the following June. The utilities would submit WMPs at the beginning of February for the period beginning July 1. As it does now, the WSD would review WMPs in the spring and issue determinations (including any required changes) at the beginning of May.

Calendar B would have the utilities submit WMPs around August 1st of each year. The plans would cover the year beginning the following January. This would allow the WSD and stakeholders to review and analyze the plans five months before the implementation year begins. The WSD would issue its evaluations, and approve or deny the plans, around November 1.

An August 1 submission date is workable. For one thing, the utilities could submit quarterly data reports for the second quarter in early August, as well. This would allow stakeholders to evaluate each utility's mitigation efforts in the first half of the current calendar year as part of the WMP review process. This is important because many wildfire mitigation activities (such as inspections and vegetation management) should occur in the first half of the year.

Additionally, an August 1 submission would allow intervenors to perform most WMP-related analysis and discovery in August and September, prior to the months of October to

January when most de-energization events occur.[160] De-energization events and the related post-event reports demand staffing resources for both utilities and intervenors.

In Appendix C, Cal Advocates offers proposed schedules for the WMP review process, for both Calendars A and B described above. The dates listed are approximate.[161] For simplicity of presentation, these calendars omit reply comments, which should be scheduled 14 days after each set of comments.

Either Calendar A or B would provide sufficient time to revise or improve the plans if the WSD or stakeholders identify concerns, or if the utilities identify errata, during the course of the review. Each possible schedule has its own logistical obstacles that would need to be weighed against the benefits of reviewing plans further in advance of a given wildfire season. The WSD and interested parties should discuss those benefits and obstacles in a workshop immediately after this WMP review cycle, ideally in May or June 2021.

B. The WSD should create a process for determining whether each utility needs to submit a comprehensive WMP in the subsequent year.

The WSD should establish a process to evaluate whether each utility should submit a comprehensive WMP or an update in the subsequent year. This decision should depend on each utility's level on the Maturity Model and progress in wildfire mitigation.

The WSD should set a date in the summer for all stakeholders (including the utilities) to submit comments on this issue. The WSD should then issue direction to each utility at least four months before the next annual submission is due.

Certain types of problems should generally require a utility to submit a new comprehensive WMP in the following year. For example, if a utility's most recent WMP has major or numerous deficiencies, then an annual update is not appropriate. If the WSD's Compliance Branch identifies serious or numerous instances of non-compliance with the approved WMP, or the utility's equipment causes a major wildfire, or the utility experiences an

[160] According to Table 11 of the large IOUs' Non-spatial Data Tables, only three PSPS events occurred during Quarter 3 of 2020, out of 20 events over the course of the entire calendar year. Ten events occurred in the fourth quarter and seven events occurred in the first quarter.

[161] Any dates that fall on a weekend or holiday would roll over to the following business day.

unusual number of worker fatalities and injuries, then the utility should be required to submit a new comprehensive plan that discusses how the utility will remedy these problems.

C. The WSD should set a staggered schedule of comprehensive WMP submissions.

The WSD should move toward a schedule that has utilities submit comprehensive WMPs in different years. If all three large utilities submit comprehensive plans in the same year, it is very challenging for stakeholders and the WSD to thoroughly review the submissions.

The specific schedule of comprehensive WMP submissions should depend on the factors and the stakeholder input discussed in the previous section. However, in general, the WSD should aim to avoid having more than two large utilities submit comprehensive plans in the same year.

The next large utility to submit a comprehensive WMP should be PG&E. As discussed previously, the WSD should deny PG&E's 2021 WMP and require PG&E to resubmit within 90 days, which implies a submission in July or August 2021. Following a denial, PG&E's resubmission cannot be a continuation or "update" of PG&E's previous WMPs. It should be substantially new and refocused, to rectify the flaws in PG&E's current submission. Therefore, this must be a new, comprehensive plan. It should address the period from 2021 through December 2023.

Currently SCE and SDG&E are both required to submit comprehensive WMPs by 2023, since their current WMPs only address the 2020-2022 period.

Beyond these considerations, the timing of comprehensive WMP submissions will depend on whether the WSD adopts Calendar A or Calendar B, discussed above in Section A. For the moment, Cal Advocates offers the following recommendations.

1. Proposed schedule of WMP submissions with Calendar A.

If the WSD adopts Calendar A, we recommend that SDG&E submit a comprehensive WMP in early 2022, covering the period from July 2022 to June 2025.

SCE should submit an annual update in February 2022 (covering the period from July 2022 to June 2023), then a comprehensive WMP in February 2023, covering the period from July 2023 to June 2026.

Table G **Recommended Schedule of WMP Submissions** According to Calendar A			
Utility	**July 2021**	**February 2022**	**February 2023**
PG&E	**Comprehensive** (through 2023)	Update (through 6/23)	**Comprehensive** (7/23 to 6/26)
SCE	None	Update (through 6/23)	**Comprehensive** (7/23 to 6/26)
SDG&E	None	**Comprehensive** (7/22 to 6/25)	Update (through 6/25)

2. Proposed schedule of WMP submissions with Calendar B

If the WSD adopts Calendar B, Cal Advocates proposes the following schedule of submissions.

Table H **Recommended Schedule of WMP Submissions** According to Calendar B			
Utility	**July 2021**	**August 2022**	**August 2023**
PG&E	**Comprehensive** (through 2023)	Update (through 2023)	**Comprehensive** (2024-2026)
SCE	None	**Comprehensive** (2023-2025)	TBD
SDG&E	None	**Comprehensive** (2023-2025)	TBD

D. The WSD should hold workshops in summer 2021 to develop revised WMP guidelines.

The WSD should convene a series of workshops or working group meetings in summer 2021 to consider improvements to the WMP guidelines. The WSD, the utilities, and other stakeholders should work together to develop WMP guidelines that meet everyone's information needs. The goals should be:

a) To differentiate the content of comprehensive three-year WMP submissions from the annual update submissions;

b) To ensure that WMPs provide pertinent and specific information; and

c) To ensure that WMPs are accessible and well-organized.

In Appendix D of these comments, Cal Advocates offers a straw proposal as a starting point for discussion.

1. The WSD and stakeholders should collaborate to develop a shortened WMP template for annual update submissions.

Currently, the WMP templates are the same for comprehensive three-year plans and for annual update submissions. The WSD should aim to create a shortened template for annual updates. This will make the WMP process less onerous for all stakeholders and avoid redundant review of the same information every year.

Some topics should be addressed in full detail in the annual updates. This includes cross-cutting issues such as resource allocation, the utility's approach to quality assurance, and how the utility is performing relative to the previous year's commitments. These topics are fundamental to the entire plan.

Other chapters should be presented in shortened form in the annual updates. In particular, the chapters on each mitigation initiative should focus on the changes since the utility's previous approved submission, rather than presenting a top-to-bottom description of the program. If a program has not significantly changed, the narrative in the annual update can be brief and stakeholders can refer to the most recent approved WMP.

Other chapters can be omitted entirely from annual updates. The WSD should identify chapters that are either unlikely to change substantially from year to year or are not as central to the overall strategy and execution of the WMP. For example, trends affecting wildfire risk is an important topic, but it is unlikely to dramatically change each year. In fact, it may be better to address this issue less frequently, because more new data will be available. Rather than making slight adjustments each year, it would be more informative to approach this topic with fresh eyes once every three years.

The annual updates should place particular focus on the utility's implementation progress.[162] In the annual updates, each utility should discuss its performance in the past year compared to expectations. The utility should identify and explain any meaningful changes in the scope, scale, or timeline of an initiative. Additionally, the utility should address how such deviations from the previous year's plan have influenced its planning for the upcoming years.

2. Stakeholders can collaborate to reorganize and clarify the WMP templates.

The current WMP templates are thorough and detailed. However, in some cases, closely linked topics are spread across multiple sections when it would be preferable to consolidate the discussion. For example, risk analysis is addressed in several sections of the WMP. The template should be revised to include a stand-alone chapter on risk analysis and modeling. The same is true of trends affecting wildfire risk.

By contrast, other topics are currently addressed in a broad, cross-cutting manner, but should be discussed in the sections on specific mitigation initiatives. Examples include emerging technologies, how the utility is addressing previously identified deficiencies, and the utility's plan for quality assurance and quality control. These issues should be addressed in each chapter, because the responses will differ for each mitigation initiative.

WMP Section 7 (Mitigation Initiatives) is currently lengthy, comprising numerous sub-sections and sub-sub-sections. This chapter should be split into separate chapters for each mitigation program area (e.g., system hardening, asset inspections, and vegetation management). Each mitigation program chapter should include:

- Key program metrics;
- Program commitments and vision for improvement; and
- A section on each initiative within the program area (first the mature initiatives, then the pilot or emerging technology initiatives).

For each initiative, the narrative should address the following issues:

a) Description of the initiative, including the risk factors it addresses;
b) Key metrics for evaluating the success of the initiative;
c) Output targets, timeline and budget, including how these have changed from the previous year;

[162] See *Comments of the Public Advocates Office on the Wildfire Safety Division's August 2020 Workshops and Staff Proposals*, August 26, 2020, pp. 6-7.

d) How the initiative is guided by risk analysis and modeling;

e) Discussion of recent or expected implementation challenges;

f) Staffing and contracting requirements for the initiative;

g) Progress on remedying deficiencies previously identified by the WSD (currently in section 4.6); and

h) Quality control and quality assurance plan for the initiative, including how the utility will gauge the quality of work provided by contractors, if applicable.

E. Future WMP guidelines should require utilities to submit detailed workplans and data on mitigation work completed.

Currently, the WMP submissions tend to describe in general terms how programs will be implemented – for example, stating that a program is "risk informed." Such statements do not demonstrate that a utility is efficiently, expeditiously reducing risk. For the current year, the WSD should require the utilities to submit detailed workplans (see Section V.A above).

For future years, the WMP guidelines should require utilities to submit geographically granular data on mitigation work completed, risk levels, and planned mitigation work. Each utility should submit a spreadsheet listing each circuit or circuit-segment in its system (depending on how the utility currently performs risk analysis). For each circuit-segment, this spreadsheet should include basic attributes such as mileage, the risk score, the amount of wildfire mitigation work completed in previous years (disaggregated by HFTD tier as well as circuit-segment), and the amount of wildfire mitigation work planned for the year of submission (disaggregated by HFTD tier as well as circuit-segment).[163]

Such detailed workplans will be extremely useful for evaluating whether the utility has developed a feasible and effective plan to reduce wildfire risk. While a narrative may spend dozens of pages discussing how the utility's programs are informed by risk, a detailed workplan will reveal whether the utility has in fact prioritized its projects according to risk.

The WSD should convene a working group in summer 2021 to further develop these granular data requirements for future WMP submissions. One issue to be resolved is how to report outputs for system hardening projects that span multiple years (i.e., should the work be reported in the year when the project is started or finished?).

[163] The data on completed and planned mitigation work should include each type of vegetation management, each type of system hardening, and any inspection types that are performed on a minority of circuit-miles each year.

F. The WSD should convene a workshop to standardize the criteria used for reporting inspection findings.

All the large utilities reported the number of findings that they identified as a result of inspections in HFTDs. However, Cal Advocates has found discrepancies when comparing each utility's reported number of findings. These discrepancies, when taken as a whole, make it impossible to directly compare the performance of the different utilities to each other, despite the use of a common template. Table I below is a comparison of the percentage of Level 3 (low potential impact to safety or reliability) findings[164] reported for each utility based on their respective WMP Table 1 submissions.

Table I

Percentage of all inspection findings that are Level 3

	2015	2016	2017	2018	2019	2020
PG&E	97.1%	97.3%	91.9%	93.1%	95.3%	92.9%
SCE[165]	41.5%	46.5%	43.1%	34.5%	55.6%	41.2%
SDG&E	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Source: PG&E, SCE, and SDG&E's WMPs, Non-spatial Table 1.

SCE's tracking of inspection findings is the simplest because it assigns priority levels that align with General Order 95 (Levels 1, 2, and 3).[166, 167] PG&E internally categorizes findings as Priorities A, B, E, and F. These priorities do not necessarily line up with Levels 1, 2, and 3 in General Order 95.[168] When reporting findings for WMP Table 1, PG&E reports all Priority B

[164] Pursuant to General Order 95, Rule 18B, Level 3 findings have "low potential impact to safety or reliability." Electric utilities are generally required to take corrective action within five years.

[165] SCE's Table 1 data for 2019 may include an error. A large number of Level 2 findings in 2019 were incorrectly entered as Level 3 when SCE completed Table 1. This would explain why SCE reports a larger percentage of Level 3 findings in 2019 than any other year.

[166] General Order 95, Rule 18B.

[167] SCE Response to CalAdvocates-SCE-2021WMP-09, Question 5, attachment "Mod1_Intro_New_ESI_Training_ODI_PPT," p. 12.

[168] Per General Order 95 Rule 18, Level 1 means an immediate risk of high potential impact to safety or reliability. Level 2 means any other risk of at least moderate potential impact to safety or reliability. Level

and E findings as Level 2.[169] Conversely, SDG&E does not treat any findings as Level 3. Instead, SDG&E internally categorizes findings as Level 1 (same as GO 95) and Level 2. However, SDG&E's policy is to resolve all findings within 12 months. As a result, SDG&E treats conditions that might otherwise be equivalent to GO 95's Level 3 as Level 2. Given the discrepancies in the reported data, Cal Advocates cannot use the figures from WMP Table 1 of the large utilities' WMP non-spatial tables to compare the number of minor findings across the utilities.

Similarly, data in WMP Table 1 on findings from detailed inspections is not comparable across the utilities because the utilities are reporting fundamentally different kinds of information. Table J below shows a comparison of critical (Level 1) findings for detailed inspections of distribution lines reported by the large utilities in their respective WMP Table 1 submissions.[170]

Table J
Level 1 findings from detailed inspections

	2015	**2016**	**2017**	**2018**	**2019**	**2020**
PG&E	3	6	1,067	239	352	1,868
SCE	2,163	3,146	3,114	2,834	4,144	2,680
SDG&E	242	100	50	45	24	14

Utility practices make this data incomparable. PG&E reports the number of electric corrective tags, which may combine several conditions identified at a location or structure. For example, if a guy wire, a cross arm and a fuse need to be replaced at the same pole, PG&E will report all of those issues as one combined finding in Table 1.[171] However, SCE reports each individual condition identified as a finding in Table 1. Therefore, the number of findings in

3 means any risk of low potential impact to safety or reliability.

[169] PG&E's 2021 WMP, p. 262.

[170] SCE numbers updated per CalAdvocates-SCE-2021WMP-09, Question 8.

[171] Additionally, PG&E's numbers are very low for 2015 and 2016 due to differences in how it recorded findings before inspection forms were digitized.

PG&E's Table 1 report will be far lower than what SCE would report for the same number of assets that require corrective action.

SDG&E's data differs in another way. SDG&E only includes finding from a single detailed ground inspection program, which inspects all distribution poles within the HFTD on a five-year cycle as required for compliance,[172] whereas PG&E reports on its enhanced ground inspections[173] and SCE includes four types of detailed inspections (including ground-based and aerial).[174] Again, these differences in reporting criteria makes it impossible to make like-for-like comparison across the utilities.

The differences mentioned above prevent any attempt to use the aggregated data in WMP Table 1 template to compare utility performance. A key component in applying a common template across all the utilities is the expectation that each utility is applying an identical set of criteria to the findings that need correction in their respective systems. If a common process or criteria is not used to fill out the WSD's templates, then stakeholders have no means to deduce which parts of California's electrical grid are in greatest need of remedial action or which utility's inspection methods are most effective.

Cal Advocates recommends that the WSD host a technical working group to bring all the utilities into alignment when reporting numbers of inspection findings.

G. The WSD should require utilities to disaggregate the costs of individual initiatives.

The large IOUs aggregate and report their costs differently, making it difficult to make meaningful comparisons across the large IOUs. The WSD should remedy this problem for future WMP submissions.

For example, PG&E combines the costs of several system hardening initiatives into one entry:

- "Updates to grid topology to minimize risk of ignition in HFTDs, System Hardening, Distribution" (program 7.3.3.17.1) aggregates the costs and the RSEs associated with covered conductor, undergrounding, and remote grids, rather than separating these into individual initiatives.[175]

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172 SDG&E's response to data request CalAdvocates-SDGE-2021WMP-05, question 11, March 4, 2021.

173 PG&E's response to data request CalAdvocates-PGE-2021WMP-12, question 4, March 10, 2021.

174 SCE's 2021 WMP, Table 1, line 1.b.

175 PG&E's 2021 WMP, pp. 548-563 and Table 12.

- All of PG&E's detailed transmission inspections (section 7.3.4.2), including ground, aerial, and climbing inspections, are similarly combined under one program.[176]

Combining costs in this manner makes it impossible to compare the costs and RSEs of aerial transmission inspections across utilities. This comparison would be useful to inform decisions about whether PG&E should perform more climbing inspections of transmission towers or should expand its aerial inspections to the distribution system (discussed in our comments on PG&E's WMP). Similarly, it would be useful to compare costs and RSEs of covered conductor installation across utilities; major cost differences are an issue we discuss elsewhere in these comments. The lack of comparable data also makes it impossible to determine the cost-effectiveness of various inspection or system hardening methods.

Moreover, it is unclear what many costs in PG&E's WMP represent. For example, PG&E's transmission hardening program (section 7.3.3.17.2) suggests that transmission inspection, maintenance, and sectionalizing devices are all included of this section.[177] However, the programs of transmission inspection,[178] maintenance,[179] and sectionalizing devices[180] each have their own sections and Table 12 cost lines, which implies that these costs are not included in the cost for the transmission hardening program.[181] Therefore, a program being mentioned or explained in detail in a specific section of the WMP does not seem to imply that program is included in the Table 12 costs associated with that section.

In addition, PG&E's crossarm maintenance section does not correspond to "a formal program."[182] PG&E suggests that the work and costs for this program are recorded as parts of other programs. This apparently means that informal programs, like crossarm maintenance, may have inaccurate cost information due to the costs possibly being attributed to other programs.

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[176] PG&E's 2021 WMP, pp. 588-591 and Table 12.

[177] PG&E's 2021 WMP, pp. 564-568.

[178] PG&E's 2021 WMP, section 7.3.4, pp. 582-622.

[179] PG&E's 2021 WMP, p. 533.

[180] PG&E's 2021 WMP, p. 492.

[181] The sum of costs for capital expenses and operating expenses in Table 12 are the same as PG&E's response to Data Request CalAdvocates-PGE-2021WMP-05, Question 2, February 26, 2021. This suggests that Table 12 costs are mutually exclusive.

[182] PG&E's 2021 WMP, p. 481.

Formal programs, like distribution or transmission maintenance, may likewise have inaccurate costs due to the costs of informal programs being removed from them.

The practice of aggregating costs under one program, unclear explanations of exactly what each entry in Table 12 represents, and the removal or inclusion of "informal" programs all complicate a meaningful analysis of PG&E's costs, and make cross-utility comparisons difficult, if not impossible.

The WSD should require all large IOUs to disaggregate combined costs into granular cost estimates wherever possible. Cal Advocates recommends that, for future WMP templates,[183] the WSD define specific program names and scopes in order to facilitate comparison across utilities. For example, a line item for "transmission inspections" could be disaggregated into patrol, detailed ground, detailed aerial, detailed climbing, and other inspections. The narrative sections in the WMP should also clearly correlate to the data tables, such that it is clear which programs or activities a single entry in Table 12 is associated with.

The revised WMP requirements should additionally clarify whether inspection programs include the costs of remediating equipment problems identified during inspections. As an example, SDG&E includes the cost of all repairs related to findings from its drone inspections program under that program.[184] Over half of the operating expenses and over 80 percent of the capital expenditures that SDG&E attributes to the drone inspection program are for repairs, not the cost of inspections themselves.[185] This results in the appearance that drone inspections are vastly more expensive than they actually are, which in turn makes it difficult to judge the relative value of various types of inspections. In fact, with this method of accounting, the more useful an inspection program is, the more it appears to cost. Therefore, the WSD should direct the utilities to identify the costs of performing inspections separately from the costs of repairs related to inspection programs.

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[183] See Cal Advocates' Straw Proposal for WMP Templates (Proposed Non-Spatial Table 13).

[184] SDG&E's responses to Data Request CalAdvocates-SDG&E-2021WMP-04, Question 7, March 4, 2021.

[185] SDG&E reports that $27.7 million of 52 million in 2020 operating expenses are attributable to repairs, and that $12.9 million out of $15.9 million capital expenses were likewise for repairs. SDG&E's responses to Data Request CalAdvocates-SDG&E-2021WMP-04, Question 7, March 4, 2021.

H. The WSD should require additional explanation of significant year-to-year changes in cost forecasts.

Accurate forecasts of future expenditures are vital to the development and implementation of utility WMPs, as they are used to help to inform decision-making through calculation of RSEs. Forecast expenditures can reasonably be expected to change over time as lessons are learned, plans are modified, and programs are expanded, competed, or phased out; however, those changes in forecast should be presented transparently and explained in context of the overall WMP. The WSD should require that future WMP update filings provide an explanation where forecast costs have substantially changed and should consider adopting a percentage threshold for this requirement.

The changes to forecast expenditures from the 2020 WMP occur across utilities, both in terms of individual initiatives and overall WMP spending. As discussed previously, several of SDG&E's forecast costs have increased substantially in its 2021 WMP Update as compared to the 2020 WMP forecasts. SCE has also increased its forecasted costs in some larger programs. Finally, PG&E's forecast of total WMP expenditures for 2021 has increased by more than 50 percent from the forecast provided in 2020.[186]

While there may be legitimate reasons to revise forecasts year over year, the WSD should require that the origin of the new forecast and reason for the change be transparent. Cal Advocates has previously recommended that "update filings should include not only the updated forecasts, but information on the change in forecasts between filings. This inclusion will further highlight the change between the 2020 filings and the 2021 updates."[187]

The WSD should engage stakeholders to develop an appropriate percentage standard threshold for what constitutes a "substantial change." As a starting point, Cal Advocates recommends setting a trigger where forecast costs for an individual program have changed more than 25 percent or $1 million. For each program, the higher threshold would apply, which would allow stakeholders to identify and focus on the most impactful changes. Likewise, the WSD

[186] In its 2020 WMP, PG&E forecast spending $3.19 billion in 2021. In its 2021 WMP update, PG&E forecasts spending $4.96 billion in 2021. See PG&E's responses to data request CalAdvocates-PGE-2021WMP-05, question 2, February 26, 2021; also PG&E's 2021 WMP, Table 12.

[187] *Comments of the Public Advocates Office on the Wildfire Safety Division's August 2020 Workshops and Staff Proposals*, August 26, 2020, p. 7.

should require additional scrutiny where forecast costs for the overall WMP have changed more than 15 percent.

Where these thresholds are met, utilities should report as much in their plan updates and explain the factors that drive the modification of their cost forecasts year over year. This will ensure that changes to cost forecasts in future WMP are addressed transparently within the context of the overall WMP.

I. The WSD should hold a technical working group to develop a unified approach to developing rate and bill impact estimates for the WMPs.

Section 3 of the WMPs addresses the costs of both utility-ignited wildfires and wildfire mitigation activities. The impact on customers is a serious concern and should be calculated in a manner that is transparent and consistent across utilities. However, these calculations are inherently complex and require utilities to make assumptions both in terms of inputs to be used and in how calculations are performed. The resulting metrics in Table 3-3 of each utility's 2021 WMP Update are inconsistently calculated and difficult to compare across utilities.

In its November 2, 2020 comments on Resolution WSD-011, Cal Advocates expressed concern with the implementation of these metrics and recommended that the WSD "convene a working group to develop a common methodology for calculating bill impacts, involving utility rate design experts, stakeholders, and the [Commission's] Energy Division."[188] Cal Advocates stated at the time that "without additional detail [on requirements for how metrics are calculated] or the development of a consensus methodology, utilities are unlikely to provide data that is useful or comparable."[189]

PG&E, SCE, and SDG&E each make varying assumptions in calculating these outcome metrics. PG&E provides the most thorough documentation of how these calculations were performed, outlining the assumptions it made to develop an estimate of the revenue requirements associated with the costs of both utility-ignited wildfires and wildfire mitigation activities; and

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[188] *Comments of the Public Advocates Office on the Wildfire Safety Division's August 2020 Workshops and Staff Proposals*, August 26, 2020, p. 7.

[189] *Comments of the Public Advocates Office on the Wildfire Safety Division's August 2020 Workshops and Staff Proposals*, August 26, 2020, p. 7.

explaining the assumptions used to convert those revenue requirements into estimated bill impacts.[190]

The calculation of estimated revenue requirements is an illustrative example of the differing approaches to the calculation of these output metrics taken by the utilities. For the calculation of total increases in costs to electric ratepayers due to wildfire mitigation activities, PG&E's revenue requirement estimate includes both costs currently in rates and costs that have not yet been approved for recovery.[191] In contrast, SCE's estimated revenue requirement only includes costs that are currently in rates, and excludes any costs that have not yet been approved for recovery.[192] SCE's estimate of revenue requirement therefore obscures the probable extent of actual future bill impacts by excluding substantial portions of WMP-related costs from the calculation.

Cal Advocates recommends that these methodological differences be addressed in a technical working group, where utility and intervenor parties can develop a shared understanding of the intent behind the metrics and a common approach to their calculation. In addition to WMP stakeholders, the technical working group should include subject matter experts from the Commission's Energy Division and Cal Advocates who have substantial experience in performing similar estimation of forecast future rate and bill impacts. Prior to the next WMP update, the WSD should convene such a technical working group to address the standardization of calculations for the metrics in Table 3-3.

J. The WSD should modify the non-spatial data tables.

The non-spatial data tables are a rich source of information about the safety issues each utility faces and the mitigation programs it is undertaking. However, the WSD should make several changes to the non-spatial data tables to make them easier to use.

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[190] See PG&E 2021 WMP Update, pp. 40-44.

[191] PG&E's estimate of costs not currently in rates includes costs currently proposed in applications but not included in rates (using the proposed cost recovery periods from each application), and costs for which PG&E has not yet filed for recovery (using "assumptions around the recovery periods based on the expected timing of the applications") PG&E 2021 WMP Update, p. 44.

[192] SCE's revenue requirement estimate "[does] not include wildfire mitigation activity costs that are either still under review, that will be reviewed by the Commission for later cost recovery or are otherwise not currently included in customer rates." SCE 2021 WMP Update, p. 32.

1. The WSD should restructure the non-spatial tables to improve usability.

Several of the non-spatial tables should be restructured with more rows and fewer columns. For example, Table 7.2 (ignition causes) currently includes a separate column for each HFTD tier in each year. Instead, the table should include one column for each year and multiple rows for the different HFTD tiers. This would make it easier to sort and manipulate the data.

Additionally, in several non-spatial tables, the metric names include more than one piece of information. Each piece of information should be reported in a separate column, to facilitate sorting. For example, in Table 7.2, the first line is "Veg. contact – Distribution." The table should have separate columns for the risk driver (i.e., vegetation contact) and the circuit type (transmission or distribution). In Table 1 on inspections, the metric "Level 1 findings in HFTD for patrol inspections - Distribution lines" contains four pieces of information: level (severity) of finding, whether it was in an HFTD or non-HFTD area, the type of inspection, and whether it was a distribution or transmission circuit. These should be reported in four different columns.

In many of the columns, the utilities have left most cells in the left-hand columns blank. This inhibits readability and prevents the user from sorting the data.

Every table should include a "Utility" column. In each utility's submission, every cell should be identical. However, this simple change would enable the user to easily merge tables and compare utilities.

Additionally, the WSD should split Table 12 (program data) into two tables. Currently, Table 12 is large and cumbersome, because it includes both quantitative data and descriptive information. One table should include exclusively quantitative data about each program, including actual and forecast spending, actual and forecast program outputs, and risk-spend efficiency estimates. The other table should include the descriptive information, such as the risk factors that the program addresses, the relevant compliance requirements, and related proceedings.

2. The WSD should remove outcome metric forecasts from all WMP tables.

The WSD requires utilities to track outcome metrics, such as numbers of ignitions, outages, and de-energization events for past years, which is vital to analyzing the effectiveness of utility wildfire mitigation efforts. However, forecasting outcome metrics for future years is inherently speculative and provides little value in the WMP.

For example, in developing the forecast rate of future ignitions, SDG&E uses a rate of ignitions which declines year over year but is consistent across all quarters within a year.[193] The assumption that ignitions will be constant across seasons is unrealistic, as actual ignitions show a consistent seasonal variation. PG&E also makes dubious approximations of future ignitions.[194] In a similar vein, PG&E forecasts three PSPS events per year in 2021 and 2022, after having nine in 2019 and six in 2020.[195] However, PG&E's narrative predicts no change in frequency of PSPS over the next 10 years.[196]

These outcome forecasts are highly speculative, opaque in their reasoning, and ultimately provide little to no analytical value. The WSD should remove these outcome metric forecasts from the WMP data tables.

3. The WSD should modify WMP Table 1 to align with how utilities currently track inspections.

WMP Table 1, which reports the outcomes of utility inspection programs, is highly useful. However, Cal Advocates recommends a few improvements to better align with how the utilities actually track and quantify inspection work.

The 2021 WMP guidelines for Table 1 require that for each inspection type, the utilities report the number of findings by inspection type and level, and the number of circuit miles inspected.[197] For vegetation clearance findings, the utilities are required to report the number of spans inspected and the number of spans found to be non-compliant.[198]

However, current utility practice does not track these programs by circuit mile or span. PG&E, SCE, and SDG&E each track asset inspection programs by pole or structure rather than

[193] SDG&E assumes a rate of 7.114 ignitions per quarter in 2021, and 6.9062 ignitions per quarter in 2022. See SDG&E 2021 Attachment B, Table 2.

[194] PG&E's 2021 WMP, Attachment 1 – All Data Tables Required by 2021 WMP Guidelines sheet Table 2.

[195] PG&E's 2021 WMP, Attachment 1 – All Data Tables Required by 2021 WMP Guidelines sheet Table 11.

[196] PG&E's 2021 WMP, p. 865.

[197] Resolution WSD-011, Attachment 2.1, p. 16.

[198] Resolution WSD-011, Attachment 2.1, p. 16.

by mileage,[199] and vegetation management inspections by trees rather than by number of spans.[200] In this case, the reporting requirements should align with utility practices.

Converting into circuit miles or spans inspected requires utilities to manipulate the data, which introduces error and complicates the analysis without adding clarity. In order to complete the current template, each utility has discretion to determine an average span length, or similar metric, that is unique to its service territory in order to convert its recorded figures into an approximate value in Table 1. While average span lengths and average number of trees per circuit mile may be similar across utilities, this methodology requires an additional step by intervenors to verify the extent to which the reported figures are comparable.

Using the same units that the utilities track (assets and hazard trees) produces a straightforward reporting of facts, which can be cleanly compared across utilities, rather than a calculation subject to utility staff judgement. (It appears that all three large utilities are recording inspections in the same manner.) It eases the reporting burden on the utilities and is more accurate in conveying program results over time than the current figures which are converted to circuit mile or span.

Additionally, Table 1 asks utilities to report asset inspection data (miles inspections completed and number of inspection findings) by category: patrol, detailed, and other. These categories obscure the original data. Since multiple types of inspections are aggregated, it is impossible to tell which types of inspections are revealing critical safety problems. Moreover, the utilities do not all use the categories in the same way. For example, PG&E and SCE both reported intrusive pole inspections in the "other" category, but SDG&E omitted intrusive pole inspections from Table 1. SDG&E reported detailed ground inspections that are supplemental (more frequent than compliance requirements) as "other" inspections, while PG&E and SCE both categorized this type of inspection as "detailed."

The WSD should ask utilities to provide a separate line of data for each type of inspection performed, rather than aggregating data in categories. This would provide the clearest and most accurate data and would facilitate apples-to-apples comparisons across utilities.

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[199] See, e.g., PG&E 2021 WMP Update, p. 262; SCE 2021 WMP Update, non-spatial data Table 1; SDG&E 2021 WMP Update, p. 231.

[200] See, PG&E 2021 WMP Update, p. 629; SCE 2021 WMP Update, non-spatial data Table 1; SCE 2021 WMP Update, non-spatial data Table 1.

4. The WSD should structure WMP Table 12 to enable year-to-year comparisons of program performance.

WMP Table 12 currently includes program-specific data on spending and program outputs. For each program, this non-spatial table includes actual spending for 2020, forecast spending for 2021 and 2022, actual program outputs for 2020, and forecast program outputs for 2021 and 2022.

Table 12 should be modified to include all spending and output forecasts that were included in the previous year's WMP submission.[201] This information will allow the reader to easily see how the utility's forecasts are changing and how actual performance compares to forecasts.

As discussed previously in section V.H, it is informative to view how programs are performing relative to expectations. For example, if the utility's output forecasts have decreased substantially relative to the forecasts submitted a year ago, that may indicate that the program is performing poorly. If a program persistently underperforms relative to forecasts, it may indicate that a utility's forecasting is unrealistic, that the forecasting methodology is flawed, or that the utility suffers from weaknesses in the execution of its wildfire mitigation plan.

The utilities can easily include previous years' forecasts in WMP Table 12. By contrast, it is burdensome for members of the public to find the relevant document from the previous year and match up programs, especially when program names and numbers change frequently.[202]

To incorporate the previous forecasts discussed above while making Table 12 user-friendly, Table 12 should be structured with multiple rows for each program. Each row would indicate a program entry from a specific year's WMP submission. This format allows the user to filter and sort the spreadsheet as needed.[203] Table K below provides an example (completed as it would appear in 2022, with three years of program data submissions). Due to space constraints,

[201] See *Comments of the Public Advocates Office on the Wildfire Safety Division's August 2020 Workshops and Staff Proposals*, August 26, 2020, pp. 6-7.

[202] If a program's scope has changed since the previous year, with the result that forecasts are not directly comparable, the utility should make a note of this and explain it in the WMP narrative.

[203] Showing all rows for a particular activity would enable easy comparisons of how both the utility's actual performance is evolving over time and how well the actual performance corresponds to the utility's forecasts. On the other hand, the user could focus on the current year's submission by filtering out rows that show data from previous submissions.

this sample shows only a few columns. However, the actual WMP Table 12 should include similar columns for all years: outputs, operating expenses, and capital expenditures.

Table K

Sample Table of Quantitative Program Data Structured to Allow Year-to-Year Comparisons

Initiative activity	WMP Submission	Forecast or Actual	2020 Initiative #	2021 Initiative #	2021 Initiative #	2020 output	2021 output	2022 output	2020 capital expend. ($ M)	2020 operating expenses ($ M)
Covered conductor installation	2020	Forecast	5.3.3.4.	7.3.3.3	18.2	200	250	300	$108.0	$12.0
Covered conductor installation	2021	Forecast	5.3.3.4.	7.3.3.3	18.2	200	500	600	$108.0	$12.0
Covered conductor installation	2022	Forecast	5.3.3.4.	7.3.3.3	18.2	200	500	200	$108.0	$12.0
Covered conductor installation	All	Actual	5.3.3.4.	7.3.3.3	18.2	180	190		$161.5	$14.1

K. The WSD should require utilities to discuss how they have addressed the root cause of recent catastrophic fires caused by their equipment.

In the past three years, utility-related fires have resulted in significant property destruction, injury, and death. Notable among these were the 2018 Camp Fire, the 2018 Woolsey Fire, the 2019 Kincade Fire, and the 2020 Zogg Fire.[204]

The large IOUs submitted lengthy 2021 WMPs totaling over 2,000 pages and describing their efforts in system hardening, vegetation management, asset inspections, and other programs designed to mitigate the risk of future catastrophic wildfires. However, these plans do not specifically address recent catastrophic fires that have affected communities. In order to raise the public's confidence that the utilities are meaningfully trying to prevent a recurrence of past tragedies, the WMPs should specifically address the root causes of recent fires, and list detailed

[204] CAL FIRE, *News Release: CAL FIRE Investigators Determine Cause of the Zogg Fire,* March 22, 2021: "After a meticulous and thorough investigation, CAL FIRE has determined that the Zogg Fire was caused by a pine tree contacting electrical distribution lines owned and operated by Pacific Gas and Electric (PG&E) located north of the community of Igo." https://www.fire.ca.gov/media/u2kh4nyd/zogg-fire-press-release.pdf

actions that the utilities have taken to prevent those causes from igniting another catastrophic fire.

The WSD should require IOUs to include in future WMPs a section discussing the root causes of recent catastrophic fires where a determination has been made by California Department of Forestry and Fire Protection (Cal Fire) or another investigatory agency that it was caused by utility equipment. In each case, the utility should describe the specific actions the utility plans to take to address these causes systemwide to prevent a recurrence. This section should only be required in the 3-year comprehensive plans, as it takes time for investigating agencies to determine whether a utility's equipment is the cause of a fire.

L. The WSD should direct utilities to submit ignition reports with future quarterly data submissions.

The Commission established reporting requirements for emergencies in Resolution E-4184 and established criteria to define reportable ignitions in D.14-02-015.[205, 206] When a reportable event occurs, the utility is required to report the incident to the Safety Enforcement Division (SED) immediately and then submit a more detailed report to SED within 20 days. The "twenty-day reports" provide useful and current information about utility-related ignition incidents.

The utilities should submit these twenty-day reports to the WSD and the WMP stakeholders. Allowing the WSD and stakeholders to review this information would serve the public interest by facilitating understanding of the current or emerging risks that affect each utility's infrastructure. The WSD should require electric utilities to include recent twenty-day reports in their future quarterly data submissions to the WSD. Each quarterly data report should include all twenty-day reports on ignitions occurring during that quarter. The first such submission should include all twenty-day reports on ignitions in 2020.

Utilities may need to redact customer names, addresses, and other personal information to protect confidential information. However, the utility should provide precise GPS coordinates for each ignition incident, if this information is not already included in the report. Additionally, for each incident, the utility should state whether it has received questions or requests for

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[205] Resolution E-4184, pp. 13 and 17.

[206] D.14-02-015, *Decision Adopting Regulations to Reduce the Fire Hazards Associated with Overhead Electrical Utility Facilities and Aerial Communications Facilities*, p. C-2 to C-3.

information from any firefighting or law enforcement authority related to the possibility that its facilities ignited a fire, and if so, state which authority or authorities have requested information.

M. The WSD should use an advice letter process for WMP change orders.

In 2020, the WSD directed utilities to submit "change orders" on fixed schedules to "make adjustments" to WMPs when there is "demonstrable quantitative and qualitative justification for doing so."[207] The WSD provided criteria and guidelines for change orders.[208]

The change order process should be streamlined. The WSD should use an advice letter process for change orders, following the rules and procedures set out in the Commission's General Order 96-B. Advice letters must comply with prior statutory guidance and Commission orders, but utilities may submit advice letters at any time. General Order 96-B also provides timeframes for public input and a straightforward process for review and approval.

The WSD should direct utilities to submit change orders when needed, rather than on a fixed schedule. This will tend to space out change orders and avoid the burden that arises when utilities submit multiple substantial documents simultaneously. The WSD should permit the utilities to submit change orders any time after the Commission ratifies the approval of a WMP, except within the two months before the next WMP submission (at which point, any changes can be included in the next WMP submission). A utility should submit a change order as soon as it determines that a programmatic change is necessary.

The WSD can also set criteria for determining the appropriate advice letter tier for a change order. Most change orders should be treated as tier 2, including changes that meet any of the following triggers:

(a) Substantive changes in how an initiative is designed or how work is prioritized;
(b) Substantive changes in the goals of an initiative;
(c) More than a 15 percent deviation in a given initiative's outputs from the WMP forecast;
(d) More than a 15 percent deviation in expected spending on a particular initiative, relative to the WMP forecast;
(e) More than a three-month shift in the implementation timeline,

[207] Resolution WSD-001, pp. 32-33.

[208] Resolution WSD-001, pp. 32-34.

(f) Any new activities, where the new activity constitutes less than one percent of expected WMP spending for the year; or

(g) Termination of a WMP activity.

Small changes in a WMP activity that do not meet any of the triggers above should be treated as tier 1 advice letters.

The WSD should strongly discourage utilities from implementing major changes to a WMP through the change order process. This would include any of the following triggers:

a) Changes to overall wildfire mitigation strategy, risk modeling practices, resource allocation approach, or data governance;

b) Changes to specific initiatives that are not consistent with the overarching goals and strategy described in the most recent approved WMP;

c) More than a 40 percent deviation in a given initiative's outputs from the WMP forecast;

d) More than a 40 percent deviation in expected spending on a particular initiative, relative to the WMP forecast; or

e) New activities that constitute more than one percent of expected WMP spending for the year.

Major changes should require a higher burden of justification, including an explanation of why the change cannot wait for the next annual WMP submission. Any change order that meets one or more of the criteria above should be clearly labeled as a "major change order" and should identify which of the major change triggers it implicates.

Establishing these guidelines will ensure that utilities are accountable to their plans. Utilities should be held responsible to implement their approved wildfire mitigation plans, except when there are good reasons to make adjustments. These guidelines will also make the change order process more transparent and straightforward for all parties.

VII. CONCLUSION

Cal Advocates respectfully requests that the Wildfire Safety Division adopt the recommendations discussed herein.

Respectfully submitted,

/s/ ***Nathaniel W. Skinner***

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March 29, 2021

Cc: Service List of R.18-10-007
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VIII. Appendix A: SCE's Program Cost Forecasts

Comparison of SCE's 2020 Forecasts to 2021 Forecasts (not an exhaustive list)				
Mitigation	**WMP Year**	**2020**	**2021**	**2022**
Distribution Detailed Inspection	2020	$2,276,063	$2,983,443	$2,631,287
Distribution Detailed Inspection	2021	$8,960,000	$4,223,000	$4,332,000
Transmission Detailed Inspection	2020	$1,149,897	$1,192,214	$1,059,111
Transmission Detailed Inspection	2021	$3,567,000	$7,604,000	$7,802,000
Covered conductor	2020	$454,368,671	$656,352,963	$771,814,574
Covered conductor	2021	$546,151,000	$753,659,000	$883,813,000
Vegetation management to achieve clearances around electric lines and equipment	2020	$76,281,452	$64,169,652	$60,868,687
Vegetation management to achieve clearances around electric lines and equipment	2021	$253,193,477	$242,081,275	$249,081,131
Distribution pole replacement and reinforcement, including with composite poles: composite poles and crossarms	2020	$121,728,393	$94,051,269	$90,148,819
Distribution pole replacement and reinforcement, including with composite poles: composite poles and crossarms	2021	$181,874,339	$306,564,840	$219,403,236
Other discretionary inspection of distribution electric lines and equipment, beyond inspections mandated by rules and regulations	2020	$157,860	$162,262	N/A
Other discretionary inspection of distribution electric lines and equipment, beyond inspections mandated by rules and regulations	2021	$191,175	$252,438	$180,304
Pole loading infrastructure hardening and replacement program based on pole loading assessment program	2020	$45,097,094	$15,475,673	$29,344,168
Pole loading infrastructure hardening and replacement program based on pole loading assessment program	2021	$97,292,420	$209,875,430	$307,949,234
Transformer maintenance and replacement	2020	$2,598,020	$2,466,851	$2,504,398
Transformer maintenance and replacement	2021	$100,200,420	$101,966,071	$104,232,390

IX. Appendix B (Confidential): PG&E Operational Mesoscale Modeling System (POMMS)

This attachment is confidential and will be submitted separately.

X. Appendix C: Proposed Calendars for WMP Submissions

A. Calendar A: WMP submissions in February for a WMP Planning Year of July 1 to June 30

Date	Utility Filing	Intervenor Filing	WSD Action	Comment/ WSD Response
February 1	**WMP**			Intervenors: 60 days WSD: 90 days
February 10	Q4 data			Integrated into WMP review
April 1		**Comments on WMPs & Q4 data**		
May 1			**Approval/denial of WMPs; Identification of deficiencies**	Utility response in 45 days
May 15	Q1 data			Intervenors: 30 days
June 15		Comments Q1 data		
June 15	Responses to WMP deficiencies			Intervenors: 30 days WSD: 50 days
July 15		Comments on responses to deficiencies		
August 5			Determinations re: responses to deficiencies	
August 15	Q2 data			Intervenors: 30 days
September 1	Annual compliance report			Intervenors: 45 days
September 15		Comments Q2 data		
October 15		Comments on compliance report		
November 15	Q3 data			Intervenors: 30 days
December 15		Comments Q3 data		

B. Calendar B: WMP submissions in August for a WMP Planning Year of January 1 to December 31

Date	Utility Filing	Intervenor Filing	WSD Action	Comment/ WSD Response
<u>August 1</u>	**WMP**			Intervenors: 60 days WSD: 90 days
August 10	Q2 data			Integrated into WMP review
<u>October 1</u>		**Comments on WMPs & Q2 data**		
<u>November 1</u>			**Approval/denial of WMPs; Identification of deficiencies**	Utility response in 45 days
November 15	Q3 data			Intervenors: 30 days
December 15		Comments Q3 data		
December 15	Responses to WMP deficiencies			Intervenors: 35 days WSD: 50 days
January 20		Comments on responses to deficiencies		
February 5			Determinations re: responses to deficiencies	
February 15	Q4 data			Intervenors: 30 days
March 1	Annual compliance report			Intervenors: 45 days
March 15		Comments Q4 data		
April 15		Comments on compliance report		
May 15	Q1 data			Intervenors: 30 days
June 15		Comments Q1 data		

XI. Appendix D: Straw Proposal for WMP Guidelines

Key for annual update submissions:

Green = the section should be complete in annual updates
Yellow = in annual updates, the section should explain changes from previous approved WMP submission
Red = the section can be omitted from annual updates

Wildfire Mitigation Plan Overview

Volume	Chapter #	Topic	Description	Current section numbers	Approx. length in full 3-year plans	Approx. length in annual updates
A: Overview	2	Executive Summary		0	15	10
	3	Persons responsible		1	5	5
	4	Adherence to Statutory Requirements		2	5	5
	5	Overview of WMP strategy and objectives	What is the utility's overall strategy for wildfire risk reduction? What specific objectives does the utility expect to achieve over the next 1, 3, and 10 years?	5.1 to 5.3	25	
	6	Costs and bill impacts	The methodology for estimating rate & bill impacts requires further development in workshops.	3	10	10
B: Foundations	7	Lessons from recent experience	Describe lessons and how the utility is adapting, based on (a) recent wildfires, (b) large PSPS events, (c) other safety lapses, and (d) successes and challenges in the implementation of WMP initiatives	4.1	15	5
	8	Current research proposals and findings	Description of research proposals, research projects currently underway, and findings, as currently specified in Section 4.4.	4.4	15	5
	9	Trends affecting wildfire risk	Combine several sections that relate to trends affecting wildfire risk, including cimate trends and drivers of ignition probability.	4.2, 4.3, 6.5, 6.6, 6.7	25	
	10	Risk analysis and modeling	A detailed description of each risk modeling product used to guide WMP initiatives, including data sources, modeling methods, validation methods, and validation results	4.3, 4.5 and 7.3.1	60	30
	11	RSE analytical methods	Detailed description of the methods the utility uses to estimate RSE scores for each program. If methods differ by program area, describe each method used.	???	20	
	12	Performance metrics		6.1 to 6.4	10	
C: Cross-cutting Issues	13	Resource Allocation Methodology	Explanation of how the utility makes decisions about allocating resources (including money, personnel, and management attention) among wildfire mitigation initiatives	7.3.8	7	7
	14	Addressing resource constraints	Explanation of how the utility is building resource constraints and operational constraints into its WMP. How does the WMP account for limited resources and foreseeable obstacles?	5.4, 7.1.C	18	18
	15	Implementation success	Detail performance relative to the prior year's commitments. See Table PG&E-7.2-1 at pages 353-363 of PG&E's WMP. Every utility should provide a similar table.	7.2	15	15
	16	Quality assurance strategy	Describe the utility's overall approach to ensuring consistency and quality of program delivery, including audit findings & quality control problems identified in the previous year.	7.2	15	15
	17	Data Governance		7.3.7	15	
D: Mitigation Program Details	18	Situational Awareness & Forecasting	See details below on how each mitigation chapter should be organized. Some topics (such as progress on deficiencies) that are currently presented at an overarching level should instead be addressed in the section on each initiative.	7.3.2	40	10
	19	Grid Design & System Hardening		7.3.3	60	15
	20	Grid Operations & Protocols		7.3.6	20	5
	21	Asset Management & Inspections		7.3.4	40	10
	22	Vegetation Management & Inspections		7.3.5	40	10
	23	Emergency Planning & Preparedness		7.3.9	25	5
	24	Stakeholder Cooperation & Community Engagement		7.3.10	25	5
	25	Public Safety Power Shutoffs		8	50	10
Appendices	26	Definitions				
	27	Glossary of acronyms and abbreviations				
	28	Confidentiality Declarations				
				Total:	**575**	**195**

Outline for Mitigation Program Chapters (e.g. System Hardening)	
Sub-section	**Description**
Key Program Metrics	
Program Commitments and Vision for Improvement (currently in Section 7.1)	
Mature initiatives	
A sub-section for each mature initiative: -- Mature Initiative 1 -- Mature Initiative 2 -- Mature Initiative 3 -- etc.	For each initiative, the narrative should address: (a) description of the initiative, including the risk factors it addresses; (b) key metrics for evaluating the success of the initiative; (c) program output targets, timeline and budget, including how these have changed from the previous year; (d) how the initiative is guided by risk analysis/modeling; (e) discussion of recent or expected implementation challenges; (f) staffing and contracting needs for the initiative; (g) progress on remedying deficiencies previously identified by WSD (currently in section 4.6); and (h) quality assurance plan for the initiative
Pilot or Emerging Technology Initiatives	
A sub-section for each emerging initiative: -- Emerging Initiative 1 -- Emerging Initiative 2 -- Emerging Initiative 3 -- etc.	For each initiative, the narrative should address: (a) description of the initiative, including the risk factors it addresses; (b) key metrics for evaluating the success of the initiative; (c) program output targets, timeline and budget, including how these have changed from the previous year; (d) how the initiative is guided by risk analysis/modeling; (e) discussion of recent or expected implementation challenges; (f) staffing and contracting needs for the initiative; (g) progress on remedying deficiencies previously identified by WSD (currently in section 4.6); and (h) quality assurance plan for the initiative

Non-Spatial Data Tables

Table #	Subject	Description / Recommended Changes	Current Table #	Include in Annual Updates
1	Inspection findings: distribution, transmission, and vegetation	The utilities should include separate lines for each type of inspection they perform, rather than aggregating them into categories. The table should encompass all inspection types. Output data should be reported in its raw form (i.e., number of inspections performed) rather than converted to circuit-miles based on approximations. Restructure the table to make it sortable. Every cell should be completed. The metric names currently contain several types of information (e.g., level of finding, type of inspection, distribution/transmission, HFTD/Non-HFTD). Each piece of information should be provided in a separate column, to facilitate reability and sortability. There should be a "Utility" column, which will enable merging the tables to compare utilities.	Table 1	Yes
2	Adverse outcomes		Table 2	Yes
3	Additional Metrics		Table 3	Yes
4	Fatalities		Table 4	Yes
5	Serious Injuries	Add data on OSHA-recordable as well as OSHA-reportable injuries	Table 5	Yes
6	Weather patterns		Table 6	Yes
7	Outage data, by cause	Data on outages by cause and year. Move the ignition data from Table 7.1 to a separate table.	Table 7.1	Yes
8	Ignition data by cause and HFTD tier	Combine ignition data from Tables 7.1 and 7.2. Restructure the Excel sheet with a row for each combination of year and HFTD tier, which will allow filtering and sorting by HFTD tier. Eliminate forecast outcomes for future years.	Tables 7.1 and 7.2	Yes
9	Features of service territory (circuit miles, customers, etc)	Restructure the table to allow for filtering. Eliminate forecast outcomes for future years.	Table 8	No
10	Planned equipment additions and removals	Restructure the table to allow for filtering. Eliminate forecast outcomes for future years.	Table 9	No
11	Planned infrastructure upgrades by location	Restructure the table to allow for filtering. Eliminate forecast outcomes for future years.	Table 10	No
12	PSPS metrics	Eliminate forecast outcomes for future years	Table 11	Yes
13	Quantitative program data	Actuals and forecasts for spending, program outputs, and RSE estimates. This data should disaggregate activities as much as possible; for example, utilities should not combine costs for various types of inspections into one "inspection" program. This table should exclusively contain numerical entries, to facilitate sorting and filtering. Any comments, notes, and narrative should be provided in the next table.	Table 12	Yes
14	Qualitative program data: compliance info	For each program, information on targeted risk drivers, compliance requirements, related proceedings, memo accounts, and other notes	Table 12	Yes
15	Detailed circuit data and program outputs	Data on each circuit or circuit-segment, provided at the same level of granularity that the utility performs risk analysis. Circuit attributes including overhead and underground mileage in each HFTD tier, current risk score(s) from the utility's risk model, and risk ranking. Data on mitigations completed since 2018, at the circuit or circuit-segment level (similar to Cal Advocates' data request 01).	new	Yes
16	Detailed program workplans	Detailed list of projects to be completed in the coming year, at the circuit-segment level, for programs that touch a minority of HFTD circuit-miles (e.g. system hardening and vegetation management programs)	new	Yes