BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Electric Utility Wildfire Mitigation Plans Pursuant to Senate Bill 901 (2018).	Rulemaking 18-10-007 (Filed October 25, 2018)

COMMENTS OF THE UTILITY REFORM NETWORK ON 2021 WILDFIRE MITIGATION PLAN UPDATES

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March 29, 2021

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- The WSD/Commission should eliminate "conditional approval" going forward. Alternatively, the WSD/Commission should clarify that a "conditional approval" is not an approval under the statute until each identified condition is met in full.

Issues Impacting All Wildfire Mitigation Plans:

- When reviewing the Wildfire Mitigation Plans, the Wildfire Safety Division (WSD)/Commission must carefully weigh the balance between affordability and safety.
- The WSD/Commission should eliminate the "conditional approval" going forward. Alternatively, the WSD/Commission should clarify that a "conditional approval" is not an approval under the statute until each identified condition is met in full.
- The WSD/Commission should state in the WMP decision or resolution that, in the case of any divergence between an approved WMP and the programs approved in a final GRC Decision, the utility's cost recovery is bound by the program budget and unit costs approved in the GRC Decision.
- For the purposes of administrative efficiency and ratepayer protection, the WSD/Commission should direct that, going forward, utilities should consolidate requests for WMP-related cost recovery in GRC proceedings and any follow-on proceedings directed by GRC decisions (such as applications to recover above-authorized amounts in a balancing account).

The WSD/Commission should reject the 2021 Wildfire Mitigation Plan (2021 WMP) update submitted by Pacific Gas and Electric Company (PG&E). The WSD/Commission should inform PG&E that its 2021 WMP will not be approved unless and until it makes the following changes:

- PG&E modifies its catastrophic wildfire risk analysis to include operational failures with respect to vegetation management and asset inspection as a risk driver;
- PG&E either removes the relatively low Risk Spend Efficiency (RSE) Enhanced Vegetation Management (EVM) from its WMP or proposes a 2021-2022 EVM program of reduced mileage and scope of sub-programs that is justified by an incremental risk analysis;
- PG&E provides a proposal for mileage and scope of System Hardening activities for 2021-2022 that: (i) is justified by an incremental risk analysis and (ii) takes into account the potentially groundbreaking and more cost-effective Rapid Earth

Fault Current Limiter (REFCL) technology, and any other technologies that are ready for near-term implementation.

The WSD/Commission should make clear that PG&E WMP Update for 2022 will not be approved unless PG&E makes each of the changes described in the previous recommendation above. In addition, in its 2022 Update, PG&E should be required to provide a tranche-level Risk Spend Efficiency (RSE) analysis of proposed WMP programs, based on tranches that meet the requirements of the settlement adopted in D.18-12-014, which should be used to justify its proposals for the EVM and System Hardening programs.

Regarding system hardening activities of the three major utilities:

- The WSD/Commission should require that the utilities and staff, in collaboration with all stakeholders, hold technical workshops over the course of 2021 in order to improve and standardize the risk analyses for covered conductor so as to better understand the significant differences in the risk spend efficiency results for covered conductor installation among the utilities, and the differences in the program activities and costs of the covered conductor installation programs among the utilities.
- The WSD/Commission should require the utilities to explain why almost 90% of SCE's "grid design and system hardening" spending targets covered conductor installation, while less than 20% of PG&E's and SDG&E's spending targets covered conductor installation.

Regarding PG&E's covered conductor program

- The WSD/Commission should require PG&E to justify the replacement of useful assets other than the conductor, including justifying the need for pole replacements with data and The WSD/Commission should require PG&E to provide detailed disaggregated data for overhead covered conductor installation, including the costs of all assets replaced (poles, transformers, fuses, switches, etc.), the number of assets replaced per mile, the age of the assets replaced, and the percentage of each asset replaced on individual circuits;
- engineering analyses;
- The WSD/Commission should find that PG&E's covered conductor program is unduly costly because PG&E appears to be unnecessarily replacing useful and non-deteriorated pieces of equipment in addition to the necessary pole and wire replacement. The Commission should issue clear guidance to PG&E to modify its program to replace only those assets necessary to support covered conductor or reduce wildfire ignition risk.

SCE's Covered Conductor Proposal

- The SCE WMP should be rejected pending the utility resubmitting a more narrowly scoped program targeting deployment of covered conductor program based on risk scores of individual segmets.

- The WSD/Commission should direct SCE to continue to study the impact of multiple mitigations in one location. To the extent that the investment in one more expensive mitigation can adjust the frequency or scope of another, such adjustments should be made.
- The WSD/Commission should direct that before SCE uses a MARS PSPS Risk Score to justify or deploy covered conductor, it must quantify the impact on potential PSPS events or commit to a reducing reliance on PSPS as a mitigation

Regarding SDG&E's covered conductor program

- The WSD/Commission should require SDG&E to provide detailed data concerning the components and costs of its covered conductor programs, including asset-level data, and to justify the replacement of all wood poles and other useful assets based on valid engineering and risk analyses.

The Utility Reform Network ("TURN") hereby submits these comments on the 2021 Wildfire Mitigation Plan (WMP) Updates.

I. THE COMMISSION MUST VIEW AFFORDABILITY AS A CONSTRAINT WHEN REVIEWING THE WILDFIRE MITIGATION PLANS

A. California Utility Rates Are Already Among the Highest in the Nation and Are Projected to Be Even Higher in the Midst of an Unprecedented Affordability Crisis

Utility customers in California are facing an affordability crisis. In 2018, even prior to the COVID pandemic, the California Public Utilities Commission (CPUC or Commission) was concerned about the affordability of utility services and initiated a proceeding to comprehensively measure and assess affordability.[1] Today, as noted by the Commission, the importance of ensuring the affordability of utility services has been magnified by COVID-19, which has placed great financial stress on millions of Californians.[2] In April and May 2020, California's unemployment rate reached 16.4% due to pandemic-related job loss.[3] Even though the unemployment rate dropped to 8.8% as of January 2021, it still far exceeds the pre-pandemic March 2020 rate of 5.5%.[4] Furthermore, those who are least able to afford utility services have been hit the hardest – unemployment rate for households with less than $30,000 annual income increased from an average of 12.2% to a high of 30.3%, before falling slightly to 25.8%.[5] There

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[1] Order Instituting Rulemaking to Establish a Framework and Processes for Assessing the Affordability of Utility Service, R.18-12-005.
[2] D.20-07-032, p. 3.
[3] Available at:
https://www.edd.ca.gov/newsroom/unemployment-december-2020.htm
[4] Current Month Unemployment Rate and Labor Force Summary
https://www.labormarketinfo.edd.ca.gov/data/unemployment-and-labor-force.html
[5] "Income Inequality and Economic Opportunity in California," Sara Bohn, Dean Bonner, Julien Lafortune, and Tess Thorman, Public Policy Institute of California https://www.ppic.org/wp-content/uploads/incoming-inequality-and-economic-opportunity-in-california-december-2020.pdf (December 2020). The cited figures are California data from the Basic Monthly Current Population

is no telling how long it will take for these households to regain their financial footing and be able to afford the basic necessities of life, such as utility services.

Yet, at the same time, utility rates in California are projected to increase at an alarming rate. On February 24, 2021, the Commission held the Energy Rates and Costs En Banc and issued a supporting White Paper prepared by the Commission's Energy Division. The White Paper pointed out that the Commission faces "multiple intersecting policy mandates" that, if handled incorrectly, could result in "overall energy bills becoming unaffordable for some Californians."[6] The White Paper also showed that rates for California utilities are already among the highest in the nation,[7] and the rates for all three major electric utilities are forecasted to grow at a pace that exceeds inflation for many years in the coming decade.[8] For high energy usage households in hot climate zones, monthly energy costs are projected to rise at an even steeper rate.[9] As the White Paper explained, "if household incomes are expected to generally increase at the rate of inflation, energy bills will become less affordable over time."[10]

In fact, the reality is likely to be even worse than the White Paper's forecast because while it assumed a 4.5% annual revenue requirement escalation, the utilities' revenue requirements have grown at a faster rate historically, and the utilities are also projecting a far

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Survey published by the Bureau of Labor Statistics on a monthly basis covering a period from January 2020 through September 2020.

[6] CPUC, *Utility Costs and Affordability of the Grid of the Future: An Evaluation of Electric Costs, Rates and Equity Issues Pursuant to P.U. Code Section 913.1*, Feb. 2021 ("White Paper"), p. 3, found at https://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/ContentUtilities_and_Industries/Energy/Reports_and_White_Papers/Feb%202021%20Utility%20Costs%20and%20Affordability%20of%20the%20Grid%20of%20the%20Future.pdf

[7] White Paper, p. 11.

[8] White Paper, pp. 4-5.

[9] White Paper, pp. 5-6.

[10] White Paper, p. 5.

higher growth rate – e.g. PG&E projects rate base growth of 7% to 8% through 2024.[11] In addition, the White Paper used the mid demand sales forecast case which results in relatively flat residential sales with a slight decline over the 10 years 2020-2030. Given the recent usage trend, CEC's low demand sales forecast case is more likely, which would result in a roughly 1% annual decline in bundled sales. Furthermore, under normal tax ratemaking treatment, the benefit of the tax deduction "flows-through" to customers in the first year the capital asset is in service, with the tax benefit paid back over time as the utility receives revenue to amortize the capital asset (the "flow-back"). As a result, the first-year revenue requirement impact of certain capital additions can be negative. In a period of heightened capital spending, much of which is eligible for the tax benefits, the overall revenue requirement impact can be substantially dampened in the first year as a result, in a manner that will not persist through the remaining life of the new capital asset. Due to the large expected capital expenditures in the upcoming years, the rate increases projected by the White Paper could be dampened.

Thus, utility rates in 2030 are likely to be even higher than those forecasted by the White Paper, which is already nearly $0.45/kWh for SDG&E, $0.35/kWh for PG&E, and $0.30/kWh for SCE.

B. The Utilities' Wildfire Mitigation Efforts Must Be Focused and Cost-Effective and Must Consider Affordability as a Constraint

Given the crisis facing Californians in the next decade, the Wildfire Safety Division (WSD)/Commission must view affordability as a constraint when reviewing the IOUs' WMP. As seen from the White Paper, wildfire mitigation costs are unmistakably becoming a significant

[11] PG&E 4Q Earnings Presentation Slide Deck, p. 13. Available at: https://s1.q4cdn.com/880135780/files/doc_financials/2020/q4/EC-Q4-2020-Earnings-Presentation-Feb-25.pdf

portion of residential rates,[12] making rates that are already among the highest in the nation even higher. The IOUs must carefully assess the cost-effectiveness of each proposed mitigation, and IOUs should prioritize the mitigations that are more cost-effective. Without affordability as a guiding constraint, the IOUs' WMP could quickly become wish lists with no regard to the fact that many ratepayers simply cannot afford the increasing electric rates imposed by the wish list. Only if affordability is properly used as a constraint would the IOUs' WMP be focused and cost-effective. When reviewing the WMP, the WSD/Commission must carefully weigh the balance between affordability and safety, keeping in mind that every dollar that is spent by the IOUs, even in the name of wildfire mitigation, is a dollar spent that makes electric rates less affordable.

II. A WILDFIRE MITIGATION PLAN SHOULD ONLY BE DEEMED "APPROVED" ONCE THE UTILITY HAS MET ALL IDENTIFIED CONDITIONS IN FULL; THE "CONDITIONAL APPROVAL" CATEGORY SHOULD BE ELIMINATED OR CLARIFIED TO AVOID CONFUSION

The statutory framework for WMP provides for only one of two outcomes from the WSD's review of each utility's plan: "The Wildfire Safety Division shall <u>approve</u> or <u>deny</u> each wildfire mitigation plan . . . ." (Emphasis added.) While WSD may "[b]efore approval … require modifications of the plan,"[13] nothing in the statute suggests WSD has the authority to approve a WMP before all such modifications or other conditions have been met in full. The WSD/Commission seemed to acknowledge as much in the final words of Resolution WSD-002:

> Each electrical corporation shall meet the listed conditions in its individual Resolution <u>in full</u> in order for its Wildfire Mitigation Plan to be deemed in compliance with Public Utilities Code Section 8386 and Wildfire Mitigation Plan Guidelines.[14]

[12] White Paper, pp. 4-5.
[13] PU Code, Section 8386.3(a).
[14] Resolution WSD-002, Ordering Paragraph 12 [emphasis added].

However, in the same resolution, the WSD/Commission also described a "conditional approval" as a third outcome that may be reached with regard to a utility's WMP.

> A conditional approval of a WMP identifies each missing or inadequate element in the WMP and requires specific action to remedy the problem according to particular timelines.15

TURN urges the WSD/Commission to eliminate this category altogether going forward. Alternatively, the WSD/Commission should clarify that a "conditional approval" is not an approval under the statute until each identified condition is met in full.

The "conditional approval" outcome should be eliminated because it is not specifically contemplated in the statute, and is not consistent with the statutory framework for WMP review. As noted, the Legislature provided for a binary outcome in Section 8386.3(a): After its review, the WSD is to either approve or deny each WMP. This is, in effect, a pass/no pass grading structure, and until WSD has the necessary information to permit it to assign a passing grade to a utility's WMP, that WMP must be understood to have not yet passed. The "conditional approval" nomenclature effectively adds an additional category, which should be the equivalent of a grade of "incomplete." That is, a "conditional approval" signals that WSD does not yet have the quantity and quality of information it needs in order to determine whether a passing grade is in order. And until the necessary information has been provided and deemed satisfactory, a utility has not sufficiently demonstrated that its plan is eligible for approval. As interpreted by the WSD/CPUC, however, "conditional approval" has lost this common-sense meaning and has somehow been turned into a passing grade of approval.[16] This treatment of a "conditional

[15] *Id.*, Finding 8.

[16] For example, in its 2020 Safety Certification for PG&E (issued January 14, 2021), WSD treated its "conditional approval" of PG&E's WMP as satisfying the requirement for "an approved Wildfire Mitigation Plan" under Section 8389(e)(1). WSD Issuance of PG&E's 2020 Safety Certification (January 14, 2021), p. 3.

approval" as effectively the same as an approval without conditions is contrary to the statute and common sense.

The recent experience with PG&E's 2020 WMP illustrates the potential problems from creating an additional "conditional approval" designation as if it confers some status before the utility has satisfied the associated conditions. In Resolution WSD-003, issued in June of 2020, the Commission ratified WSD's conditional approval of PG&E's 2020 WMP.[17] The identified deficiencies in PG&E's WSD led to the utility submitting a Remedial Compliance Plan (RCP) and a Quarterly Report. In December 2020 and January 2021, WSD issued analyses finding that each of PG&E's responses to eight Class A deficiencies were insufficient, as were 23 responses out of 30 Class B deficiencies.[18] WSD also issued "Notices of Non-Compliance" regarding PG&E's insufficient responses.[19] Under such circumstances, PG&E's 2020 WMP should not be treated as meriting or having attained "approval" under the statute, particularly during the period between when WSD first identified "deficiencies and conditions" in Resolution WSD-003, and when WSD deemed PG&E's responses "insufficient" and issued "Notices of Non-Compliance." But from June 2020 through WSD's notices of insufficiency and non-compliance, PG&E continued to hold a "conditional approval." There should be no dispute that, at least during the period from mid-2020 through the end of the year, PG&E's WMP did <u>not</u> qualify for "approval." In sum, the "conditional approval" designation seems intended to confer some additional status on the utility as compared to a denial under Section 8386.3(a), but in a manner that would

[17] Resolution WSD-003, p. 2, and Ordering Paragraphs 1 and 2.
[18] Wildfire Safety Division Evaluation of PG&E's Remedial Compliance Plan (December 30, 2020); Wildfire Safety Division Evaluation of PG&E's First Quarterly Report (January 8, 2021).
[19] Notice of Non-Compliance Identified During 2020 WMP Remedial Compliance Plan Review (December 30, 2020) CPUC-WSD ID: 2020-RCP_PGE-01; Notice of Non-Compliance Identified During 2020 WMP Quarterly Report Review (January 8, 2021) CPUC-WSD ID: 2020-QR_PGE-01.

impermissibly relieve the utility of at least some portion of the requirement to satisfactorily address all deficiencies or conditions before achieving approval of its WMP.

The uncertainty around the "conditional approval" designation must be addressed now, to ensure that WSD's review of the WMPs is conducted and achieves outcomes more consistent with the language of Section 8386.3(a). TURN recommends elimination of the "conditional approval" designation. Consistent with the statute, WSD would either approve or deny each WMP, as provided for in the statute. And it would continue to have authorization to require modifications of the plan, and to review all such modifications to determine when all identified deficiencies and conditions have been satisfactorily addressed. However, until WSD has determined that the identified deficiencies and conditions are, in fact, satisfactorily addressed, the WMP must be understood to not yet be approved under Section 8386.3(a). Alternatively, the WSD/Commission should clarify that a "conditional approval" is not an approval under the statute until WSD has determined that the identified deficiencies and conditions are, in fact, satisfactorily addressed.

III. FINAL GUIDANCE ON THE WILDFIRE MITIGATION PLANS SHOULD CLARIFY THAT GOING FORWARD THE GRC IS THE VENUE FOR RECOVERY OF WILDFIRE MITIGATION COSTS.

A. Approval of a WMP Is Not Equivalent to the Review of a Program in the General Rate Case and the WSD Should Clarify that in the Event of Conflict Due to Timing of Review the GRC Decision Prevails

The need to accelerate wildfire mitigation spending to prevent another utility-caused wildfire led to the creation of the WMP process in SB 901, later amended by AB 1054. The statute divides responsibilities for the review of wildfire mitigation plans and costs between the WSD, soon to be housed within the California Natural Resources Agency, and the CPUC. The WSD will review the proposed WMP for compliance with the requirements of Public Utilities

Code 8386(c), but the statute leaves to the California Public Utilities Commission the responsibility for determining whether wildfire spending is consistent with just and reasonable rates.[20]

While WMP review occurs annually, the traditional proceeding for the review of utility costs, the General Rate Case (GRC), occurs every four years. Recognizing this initial misalignment between accelerated spending and cost recovery, the statute allows utilities to track costs of implementing the WMP in a memorandum account.[21] Public Utilities Code § 8386.4 directs that review of tracked costs would occur via either the General Rate Case or an application for the recovery of costs tracked in the memorandum account "at the conclusion of the time period covered by the plan."[22]

Past WMP decisions and resolutions have acknowledged the division of labor between the WMP and the GRC and included language identifying the GRC as the proper venue for considering whether programs included in the WMP meet the just and reasonable requirement for cost recovery. In 2019, the Guidance Decision stated: "approval of a WMP here is not dispositive of an IOU's ultimate cost recovery for the operations and maintenance costs of hardening its system, managing vegetation, increasing situational awareness and taking the other steps to mitigate wildfire risk."[23] In 2020, the Guidance Resolution confirmed:

> Nothing in this Resolution constitutes approval of the costs associated with electrical corporations' Wildfire Mitigation Plan (WMP) efforts. As set forth in Public Utilities Code §8386(g), and confirmed by Decision 19-05-036, the Commission will consider cost[] recovery related to WMPs in the electrical corporations' General Rate Cases or application permitted by Section 8386.4(b)(2).

[20] Cal. Pub. Util. Code § 8386.4.
[21] Cal. Pub. Util. Code § 8386.4(a).
[22] Cal. Pub. Util. Code § 8386.4(b)(2).
[23] D.19-05-036, p. 20.

Any decision or resolution on the 2021 WMP Updates should include similar language putting the utilities on explicit notice that simply because a program is included in an "approved" WMP, cost recovery is not assured.

TURN recommends that WSD/Commission state in the WMP decision or resolution that, in the case of any divergence between an approved WMP and the programs approved in a final GRC Decision, the utility's cost recovery is bound by the program budget and unit costs approved in the GRC Decision. For example, the 2021 WMP Review is occurring after SCE's 2021 GRC was litigated but while a decision is outstanding. Even if the WSD approves a program in the WMP update, the SCE GRC decision could find that the program has not been sufficiently justified or that a different scope of work than what was described in the WMP is justified (See Section VI). Unless the Commission expressly directs otherwise, as it did in PG&E's 2020 GRC (discussed further below), the utility cannot and should not rely on WMP approval as a basis for cost recovery for wildfire mitigation work beyond the scope, budget or unit costs approved in the GRC.[24]

B. To Protect Against Potential Double Recovery and to Ensure Administrative Efficiency, the WSD/Commission Should Recommend that the Utilities Consolidate Cost Recovery in the GRC

As noted above, the statute directs the utility to track costs of implementing its WMP in a memorandum account and allows the utility to seek recovery of these costs either in the GRC or in a separate proceeding at the end of the time covered by the WMP.[25] In its 2020 Resolution on PG&E's WMP, the WSD warned:

> All electrical corporations should ensure they carefully document their expenditures in these memorandum accounts, by category, and be prepared for Commission review and audit of the accounts at any time.26

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[24] D.20-12-005, CoL 32, p. 397.
[25] Cal. Pub. Util. Code § 8386.4(b)
[26] WSD-003, p. 3.

Despite this direction, when asked by TURN to identify the amounts authorized in the rate case for different programs identified in Table 12 of Attachment 1 of its WMP Filing, PG&E stated that this would "require PG&E to perform a novel analysis not performed previously."[27] To the extent that the utility is properly tracking its costs it should be able to identify what costs have been authorized without "a novel analysis."

The inability of PG&E to identify where and what costs have been authorized highlights TURN's concern that the utility may attempt to forum-shop its costs or seek double recovery. The current bifurcated approach to wildfire cost recovery means that the full ratepayer impact of wildfire spending may not be reflected in the GRC proceeding. Continuing to track costs across a variety of accounts for recovery in a variety of proceedings also creates practical and substantive difficulties in reviewing the reasonableness of such costs, and exacerbates the potential for double recovery. It forces intervenors to either create duplicative evidentiary records to assess the reasonableness of total costs, or to evaluate only a portion of the costs for the same program, which makes actual reasonableness review of the entire scope of work almost impossible and creates administrative inefficiency. Tracking costs for the same programs in multiple accounts, even if they are technically "not duplicative," is a misuse of Commission and intervenor resources.

For example, PG&E expects to record in its Fire Risk Mitigation Memorandum Account (FRMMA) and Wildfire Mitigation Plan Memorandum Account (WMPMA) almost $2 billion for projects in its WMP that "are incremental to the costs approved in the 2020 GRC."[28] It is unclear the extent to which the costs reflected in the FRMMA and WMPMA are truly "incremental." The "incremental" costs are primarily for maintenance and inspection. These

[27] PG&E Data Response TURN_019-Q01.
[28] PG&E Data Response TURN_021-Q02, Data Response TURN_021-Q03.

programs were included in the utility's GRC request, but PG&E explains that these costs are anticipated due to "Change in volume, change in unit cost." [29] Such changes represent typical rate case cost overruns.

It is especially concerning to see that PG&E intends to continue tracking costs in the FRRMA and WMPMA despite the fact that the Decision in its GRC explicitly authorized the Wildfire Mitigation Balancing Account (WMBA), a two-way balancing account for tracking wildfire costs with an opportunity to file an application for recovery of amounts beyond the adopted forecast.[30] The WMBA was adopted to track the capital and expense related to PG&E's Community Wildfire Safety Program, "an integrated wildfire mitigation strategy that incorporates a risk-based approach to identify and address PG&E's assets that are most at risk from the threat of wildfires."[31] Given this opportunity to seek additional wildfire related costs in the WMBA, in order to streamline future proceedings all wildfire costs should be tracked in one account.

For the purposes of administrative efficiency and ratepayer protection, the WSD/Commission should direct that, going forward, utilities should consolidate requests for WMP-related cost recovery in GRC proceedings and any follow-on proceedings directed by GRC decisions (such as applications to recovery above-authorized amounts in a balancing account). A utility seeking cost recovery outside of the GRC process should have a heavy burden to justify the use of such of an extra-GRC process, given the attendant issues of administrative inefficiency and increased risk of double recovery.

[29] *Id*.
[30] D.20-12-005, CoL 32, p. 397.
[31] *Id*., p. 4.

IV. PG&E'S RISK ANALYSIS FAILS TO JUSTIFY ITS PROPOSED LEVEL OF CONTINUED MASSIVE SPENDING ON ENHANCED VEGETATION MANAGEMENT AND SYSTEM HARDENING

A. Notwithstanding Massive Spending on Its 2019 and 2020 WMPs, PG&E Has Bungled Its WMP Implementation and Caused Catastrophic Outcomes

PG&E has devoted massive amounts of money to WMP activities in 2019 and 2020 and proposes even higher levels of spending in 2021 and 2022. The following table shows PG&E's recorded and planned WMP expenditures for the period 2019-2022.

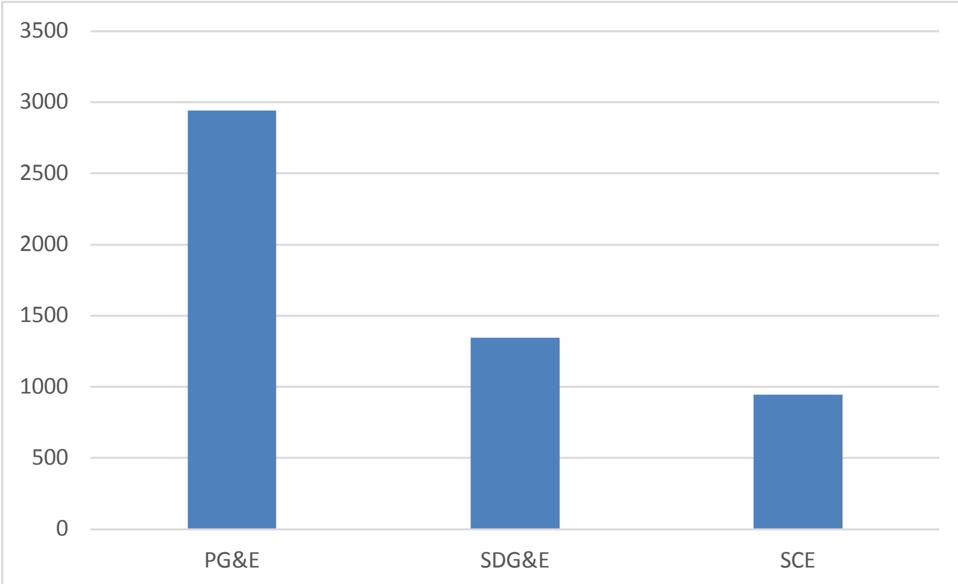
Table 1– PG&E's Recorded/Planned WMP Expenditures (2019-2022)[32]

2019 Recorded	2020 Recorded	2021 Planned	2022 Planned
$2,846,000	$4,862,464	$4,955,161	$5,197,811

With respect to total WMP spending for 2020-2022 (recorded and planned), PG&E's per customer spending significantly exceeds that of Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E), as shown in the figure below.

[32] Sources: 2019: Sum of 2019 actual costs from Tables 21-30 in 2020 WMP; 2020-2022 – Table 3.1 in PG&E's 2021 WMP.

Figure 1– 2020-2022 WMP Spending Per Customer for Large Utilities[33]



Thus, PG&E is on pace to significantly outspend its peer utilities even taking into account differences in utility size, miles of overhead other facilities, and prevalence of red flag warning conditions.

Notwithstanding its much higher WMP spending to date, PG&E has had much worse outcomes than its peers. The 2019 Kincade Fire burned over 77,000 acres, destroyed or damaged 424 structures and injured four firefighters.[34] According to media reports, Cal FIRE has found that reckless conduct by PG&E is responsible for that fire and has referred the matter for criminal prosecution.[35] In 2020, the Zogg Fire caused 4 deaths and 1injury, destroyed or damaged 231 structures, and burned over 56,000 acres.[36] Cal FIRE has found that a hazardous gray pine falling on a PG&E transmission line caused that fire, and those findings have also been

[33] Table 3.1 data from PG&E, SCE and SDG&E 2021 WMPs, divided by customer counts.
[34] https://www.fire.ca.gov/incidents/2019/10/23/kincade-fire/
[35] https://www.nbcbayarea.com/news/local/kincade-fire-tied-to-pge-failure-to-decommission-an-unneeded-high-voltage-line/2384828/ CalFIRE's Kincade Fire report is not public because it has been referred to Sonoma County prosecutors for criminal prosecution of PG&E.
[36] https://www.fire.ca.gov/incidents/2020/9/27/zogg-fire/

referred for criminal prosecution. In addition, Shasta and Tehama counties have sued PG&E for negligence, saying that the tree that caused the fire had been flagged for removal two years before.[37]

Moreover, the Federal Court Monitor, appointed as a condition of the probation arising out of PG&E's San Bruno convictions, has issued two detailed reports – one in 2019 and another in October 2020 -- finding serious deficiencies in how PG&E has carried out its vegetation management work and its facility inspections under its WMPs.[38] In the October 2020 report, the Monitor found that (1) PG&E's already unsatisfactory vegetation management work did not meaningfully improve in 2020;[39] and (2) PG&E failed to execute its own plan to perform earmarked inspections of 967 transmission towers in HFTD prior to the 2020 peak fire season, owing to "human error, lack of oversight, miscommunications, and failure to appropriate escalate matters."[40]

Furthermore, in a November 24, 2020 letter to PG&E, CPUC President Batjer expressed concern about "a pattern of vegetation and asset management deficiencies that implicate PG&E's ability to provide safe, reliable service to customers."[41] And most recently, in Draft Resolution M-4852, the Commission proposed to place PG&E in Step 1 of the Enhanced Oversight and Enforcement process because PG&E failed to sufficiently prioritize its Enhanced Vegetation Management (EVM) work in 2020, instead doing most of its work on relatively low-risk lines.[42]

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[37] https://www.sacbee.com/news/california/fires/article250134899.html
[38] October 16, 2020 and July 26, 2019 Letters from Mark Filip, Federal Monitor, to Judge William H. Alsup.
[39] Ex. TURN-7, Monitor Letter, p. 1.
[40] Oct. 16, 2020 Monitor Letter, pp. 3-4.
[41] Ex. TURN-8, Batjer Letter, p. 1.
[42] Draft Resolution M-4852.

Given this track record, PG&E's focus should be on competently performing its basic wildfire mitigation work, such as routine vegetation management and required asset inspections. As the *San Francisco Chronicle* said in a 2020 editorial, PG&E's "Plan A should be maintaining its power lines and other infrastructure while clearing nearby vegetation" but "PG&E is still struggling to tend to this basic task."[43] For costly discretionary programs that would go beyond this "Plan A," the WSD and Commission should require PG&E to make a compelling showing that the work would provide significant benefits at reasonable cost and not distract PG&E's attention from carrying out its fundamental work more competently. The state of California and PG&E's customers cannot afford to allow PG&E to spend large sums of money that fail to deliver meaningful safety benefits.

B. PG&E's Failure to Recognize Operational Failures as a Driver of Wildfire Ignitions Undermines the Validity of Its Entire Wildfire Risk Analysis and Hence Its Decisions About Its Mitigation Plan

A key to the risk analysis that is supposed to inform PG&E's WMP is an identification of the drivers of the ignitions that can cause catastrophic wildfire. PG&E's identified drivers include equipment failure, vegetation, third-party contact, animals, and seismic activity.[44]

However, despite PG&E's lengthy track record of wildfires that would not have occurred but for operational failures in its vegetation management and asset inspection programs, PG&E fails to model operational failure as a risk driver.[45] Indeed, most of the catastrophic wildfires of

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[43] *San Francisco Chronicle*, "Editorial: PG&E Still Can't Seem to Do Its Job," October 27, 2020, found at: https://www.sfchronicle.com/opinion/editorials/article/Editorial-PG-E-still-can-t-seem-to-do-its-job-15676777.php

[44] PG&E WMP, pp. 95-95.

[45] PG&E's WMP (p. 94) only discusses the "top-level" drivers identified by PG&E and notes that the utility has also identified 35 sub-drivers that are not discussed in the WMP. From TURN's extensive participation in PG&E's current RAMP (A.20-06-012), TURN knows that the sub-drivers for the wildfire risk do not include operational failure.

the last four years were caused by PG&E operational failures. In 2017, Cal FIRE determined that 11 of the 17 North Bay fires resulted from PG&E violations of tree trimming requirements. With respect to the 2018 Camp Fire, PG&E pled guilty to the crime of involuntary manslaughter – which means acting with a reckless disregard for public safety. And, as noted above, PG&E has been charged with recklessness and negligence in starting the 2019 Kincade and 2020 Zogg fires. With this track record, TURN expects that an honest reckoning (a.k.a. root cause analysis) by PG&E of the causes of ignitions in the past several years that did not lead to catastrophic wildfires would show that many of those non-catastrophic ignitions –like PG&E's catastrophic ignitions -- would not have occurred but for operational failures.

By excluding operational failure as a driver, PG&E's risk mitigation analysis ignores what is likely the most important mitigation of all – ensuring that the fundamental baseline work of vegetation management and asset inspections is done properly. If operational failure were included as a driver, PG&E's leadership would be forced to pay more attention to relatively low-cost measures, such as better managerial processes and improved quality assurance and quality control, that would provide a major risk reduction benefit. A true and correct portrait of PG&E's Wildfire Risk requires that the considerable risk resulting from PG&E's operational failures be recognized and that the risk reduction benefits from fixing those problems be quantified. Absent inclusion of operational failures as a driver, the risk analysis is incomplete and insufficient, to the detriment of both safety and reasonable rates.

Notably, in its review of PG&E's 2020 RAMP report, the Commission's Safety Policy Division (SPD) agreed that TURN had "raised very valid concerns about operational failures as risk drivers that are missing in PG&E's wildfire risk analysis." SPD recommended that "PG&E

determine an appropriate solution to model operational failures as a risk driver" for its upcoming GRC filing in June 2020.[46]

One way to make the change recommended by SPD would be to break down the "vegetation" driver into "vegetation - operational failure" – which would reflect vegetation contacts that would not have occurred but for an operational failure at some point in PG&E's operations -- and "vegetation – other." The same could be done for the "equipment failure" driver, creating drivers for "equipment failure resulting from operational failure" and "equipment failure – other."

By including such operational failure drivers, PG&E's risk analysis would likely compel a very different WMP, as it would accurately capture the fact that significant risk reduction would be gained simply by devoting more time and resources to improved management and execution of routine vegetation management and required asset inspections. A clue to this outcome is given by the fact that, even under PG&E's deficient risk analysis that omits operational failure as a driver, quality assurance and quality control type activities achieve some of the highest RSEs. For example, PG&E's RSE of 89,375 for Initiative 7.3.4.3, Improvement of Inspections, is its highest ranking RSE by far. Another high-ranking RSE is the score of 3,449 for Initiative 7.3.4.14, Quality Assurance/Quality Control of Inspections.[47] In contrast, as will be further discussed in the following sections, the RSEs for two of PG&E biggest and most expensive programs, Enhanced Vegetation Management (EVM) and System Hardening (SH) are

[46] SPD Staff Evaluation Report PG&E's 2020 RAMP, Nov. 25, 2020, p. 54.

[47] PG&E WMP Att. 1, Table 12 (corrected 3/17/21). PG&E did not provide an RSE an equivalent initiative related to vegetation management, Initiative 7.3.5.13, Quality Assurance/Quality Control of Vegetation Inspections, for reasons that PG&E attempts to explain in response to TURN DR 22-5, but which are not clear to TURN.

approximately 4.0, i.e. orders of magnitude lower than the RSEs for Improvement of Inspections and QA/QC.

In sum, by correcting its risk analysis to reflect operational failure as a risk driver, PG&E's analysis would more accurately reflect the significant benefits from focusing more on improved performance of baseline wildfire mitigation work. The result would likely be a significantly different WMP that produces the win-win outcome of higher risk reduction at significantly lower cost.

C. PG&E's Risk Spend Efficiency Analysis Fails to Break Down Its System into Granular Tranches with Homogeneous Risk Characteristics, Which Prevents Examination of Whether PG&E Has Reasonably Scoped the Programs in Its WMP

Another serious problem with the risk analysis that purports to support its WMP is the failure to break down its Risk Spend Efficiency (RSE) analysis into granular tranches with homogenous risk characteristics. This was one of SPD's major criticisms of PG&E's 2020 RAMP submission and is contrary to one of the fundamental expectations of the risk analysis that PG&E agreed to in the S-MAP settlement adopted in 2018.

Sufficiently granular tranches are necessary to achieve the goal of providing accurate information for WSD/Commission decision-making about the cost-effectiveness of proposed programs in the WMP. When assets with different risks are lumped together, the resulting average RSE values will mask differences in individual asset RSEs. This problem is important because a key objective of quantitative risk analysis is to identify mitigations that will provide the greatest risk-reduction value. Using average RSE values that do not account for individual asset differences prevents the WSD/Commission from having a record that allows it to make informed decisions about whether the mitigations proposed in WMPs are appropriate to include and, if so, in what scope, given affordability and other constraints.

Granular tranche level RSE analysis is a key feature of the risk analysis required by the D.18-12-014 risk assessment methodology. The settlement adopted in that decision requires each tranche in the RSE analysis to "have homogeneous risk profiles," meaning the same likelihood and consequences of a risk event.[48] In other words, to comply with that settlement, all of the assets in each tranche should be grouped so that there are no significant differences in either the likelihood or consequence values for those assets. If there is a meaningful difference, the asset group needs to be broken out into more granular tranches. <u>PG&E agreed to this requirement in 2018 and has been on notice since that time that this level of granularity is an essential element of RSE analysis</u>.

As noted, SPD identified insufficient granularity of tranches as a serious problem in PG&E's 2020 RAMP:

> . . . given the highly variable environments and conditions within PG&E's territory, risk analysis should be substantially more granular in many instances. Specifically, SPD staff finds that wildfire risk tranches should be much less expansive. Given the diverse environments and conditions covered by the over 99,000 overhead circuit miles, staff finds it unreasonable to assume a homogenous risk profile across the tranches used for this RAMP Report and particularly for the three highest . . . wildfire HFTD tranches.[49]

SPD added that, ideally, PG&E would make improvements in granularity in this WMP and prior to filing their 2023 GRC.[50]

In this WMP, PG&E's RSE analysis does not make any improvements in granularity compared to the 2020 RAMP. In fact, in Attachment 1, Table 12, for most initiatives, PG&E does not even provide different RSE calculations for the different HFTD regions, which, even if provided, would be less granular than its RAMP analysis.

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[48] D.18-12-014, Attachment, Row 14.
[49] SPD Staff Evaluation Report PG&E's 2020 RAMP, Nov. 25, 2020, pp. 4-5.
[50] *Id.*, p. 14.

PG&E touts a new 2021 Wildfire Distribution Risk Model as a means of targeting and prioritizing work in some of PG&E's largest WMP programs, including EVM, System Hardening and Asset Inspections.[51] However, this new model has failed to yield any transparent analysis that PG&E has shared that shows the RSE for its different WMP programs broken down by homogenous tranches. In fact, the new modeling does not have the capability to measure risk reduction for specific mitigations,[52] and <u>is therefore of no use for calculating RSEs at any level of granularity</u>.

PG&E – the multiple-time convicted felon that repeatedly bungles WMP implementation – is asking the WSD/Commission to trust that it has optimally designed its WMP programs based on a new model that produces no RSE values that the WSD/Commission and the parties can examine. Needless to say, the last company that warrants such trust is PG&E. PG&E has had ample time since the negotiation and adoption of the 2018 S-MAP settlement to develop that granular risk analysis that it committed – and is required – to implement. It is time for the WSD/Commission to tell PG&E that such delays are no longer acceptable and that, beginning in 2022, it will not accept a WMP that fails to include an RSE analysis that meets the granularity requirements of D.18-12-014.

D. PG&E's Risk Analysis Fails to Justify Continued High Levels of Spending on Enhanced Vegetation Management

PG&E's WMP breaks down its Vegetation Management (VM) work into four main programs: Routine Distribution VM, Routine Transmission VM, Enhanced Vegetation Management (EVM), and Tree Mortality (sometimes called "CEMA").[53] PG&E states that its

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[51] PG&E WMP, p. 5.
[52] PG&E WMP, p. 131.
[53] PG&E Response to WSD DR 10, Q.19(a).

compliance-based Routine VM programs "inspect[] all of our approximately 100,000 miles of overhead electric facilities at least annually to identify and clear vegetation that might grow or fall into utility equipment to reduce the risk of contact and ignition."[54] EVM is a discretionary program that is designed to exceed PG&E's Routine Distribution VM program and consists of three primary types of activities: radial clearances, overhang trimming, and assessing/removing trees with the potential to strike.[55] The Tree Mortality/CEMA program, which is described as initiative 7.3.5.9, is another program that PG&E characterizes as a compliance requirement and addresses risks associated with dead and dying trees.[56]

In response to a TURN data request, PG&E provided a breakdown of the costs and RSEs for the main VM programs (which was not done clearly in PG&E's Attachment 1, Table 12), as follows.

Table 2– Costs ($ Million) and RSEs of VM Programs[57]

	2020 Costs (Actual)	2021 Costs (Projected)	2022 Costs (Projected)	RSE[58]
Routine Dist. VM	$736M	$668M	$609M	9,236
Tree Mortality/CEMA	$88M	$68M	$69M	24,695
EVM	$431M	$508M	$527M	4

[54] PG&E WMP, p. 11.
[55] PG&E WMP, pp. 623-624.
[56] PG&E WMP, p. 651.
[57] Source: WildfireMitigationPlans_DR_TURN_022-Q03Supp01Atch01.xlsx
[58] PG&E provides the same RSE for all three HFTD tiers.

As the table shows, compared to the Routine VM and Tree Mortality/CEMA initiatives, EVM has a conspicuously low RSE – the EVM score of 4 is several orders of magnitude lower than the scores of 9,236 for Routine VM and 24,695 for the Tree Mortality program.

PG&E has already performed EVM for a significant percentage of its Tier 2 and 3 HFTD overhead distribution miles. PG&E says it completed 2,498 miles in 2019 and 1,878 miles in 2020, for a total of 4,376 miles,[59] which is almost 20% of the approximately 25,000 distribution miles in HFTD areas. PG&E proposes to perform an additional 1,800 miles of EVM work in each of 2021 and 2022.[60]

Given the egregiously low RSE for EVM, PG&E's WMP should provide a compelling explanation of the need to continue to perform EVM at the rate of 1,800 miles per year at a cost of over $500 million per year. PG&E does not.

If done properly, the EVM work performed in 2019 and 2020 should have been performed on the circuit miles where EVM would produce the most risk reduction benefit. Unfortunately, as recounted in Draft Resolution M-4852, that is not what PG&E did in 2020.[61] Still, one would expect that a considerable amount of the aggregate 2019 and 2020 work would have been targeted to the highest risk circuit miles. With a more granular analysis, the WSD/Commission and parties would be able to see the incremental impact on RSE of extending EVM deeper into PG&E's system. Such a granular analysis would provide useful RSE data to show just how much the cost-effectiveness of EVM diminishes with incremental units of work. Without such information, even though it is required by D.18-12-014, PG&E deprives the

[59] PG&E WMP, p. 238, Table 5.3-1.
[60] *Id.*
[61] In its comments on Draft Resolution M-4852, TURN sought modifications that would put PG&E on notice that it faces disallowance of the cost of the EVM work that was not properly prioritized. PG&E should not be allowed to pass on costs to ratepayers of unprioritized and unauthorized work.

WSD/Commission and the parties of the necessary tools to provide judgments about the appropriate scope of the EVM program.

PG&E should not be allowed to benefit from failing to provide this essential information, especially given the low RSE for the EVM program. PG&E should be required to explain why its VM program should not focus on the high RSE Routine VM and Tree Mortality Programs, buttressed by more effective management and QA/QC, particularly as PG&E considers performing EVM in lower priority areas.

In addition, PG&E fails to explain why each component of EVM needs to continue to be conducted as the program extends into lower risk circuit miles. As noted, EVM actually consists of three sub-programs -- radial clearances, overhang trimming, and assessing/removing at-risk trees. In the 2020 RAMP, when PG&E was pushed to provide RSE data broken down by these sub-programs, it became evident that they have significantly different RSEs. The relative differences were similar in all scenarios, although the absolute RSE values differed depending on the scenario. In one scenario that illustrates the relative differences, the results were as follows:

Table 3 – Relative RSE for EVM Sub-Programs[62]

Sub-Program	RSE
EVM Aggregated	1.6
Overhang Trimming	4.6
Enhanced Radial Clearance	0.5
At-Risk Trees	0.1

These illustrative results show that Overhand Clearing is almost 10 times more cost effective than Enhanced Radial Clearance and 46 times more effective than the At-Risk Tree sub-program. If PG&E is to continue performing EVM at all, these relative RSEs make the case for focusing on overhang trimming. And they certainly raise questions about the costly

[62] RAMP Scenario Analysis – Tranching (TURN), Oct. 22, 2020, p. 19 (EVM - RSEs).

programs to remove trees that are neither dead nor dying (those are removed under the CEMA/Tree Mortality program), which have a particularly low relative RSE. PG&E's WMP ignores these obvious questions, even though PG&E knows about these RSE differences from RAMP.

PG&E's WMP should not be approved when it fails to answer such basic questions about whether it has proposed a cost-effective mileage target and whether it should reduce its use of relatively low RSE sub-programs.

E. PG&E's Risk Analysis Fails to Justify the Planned Scope Of System Hardening Work

System Hardening (SH) is another expensive program with a relatively low RSE. PG&E's WMP describes its distribution SH program as fully encompassed by Initiative 7.3.3.17.1[63] and gives the following costs and mileage information for this initiative for 2020-2022.

Table 4 – 2020-2022 Costs and Mileage for System Hardening Initiative 7.3.3.17.1

2020 Cost (Actual)	2020 Miles (Actual)	2021 Cost (Planned)	2021 Miles (Planned)	2022 Cost (Planned)	2022 Miles (Planned)	Total Cost 2020-2022	Total Miles 2020-2022
$460M	342	$338M	180	$872M	470	$1,670M	992

For the broader Grid Design and System Hardening program, which appears to include activities related to PG&E's SH program, PG&E's projected 3-year cost is significantly higher, $8.4 billion.

[63] PG&E WMP, pp.547-548.

Like EVM, the RSE for SH Initiative 7.3.3.17.1 is the relatively low value of 4.1.[64] To put this in context, consider that for PG&E's other highest cost initiatives, Routine Distribution VM, Transmission Inspections, and Distribution Inspections, the RSEs are 9,236,[65] 120 and 52.[66] Thus, like EVM, with such a relatively low RSE and such high cost, PG&E needs to make a strong showing to justify the scope of SH it plans to perform for 2021 and 2022.

As is the case with EVM, the lack of tranche granularity in PG&E's WMP prevents any assessment of the extent to which the RSE of SH declines as the program extends deeper into PG&E's system. In 2019 and 2020, PG&E completed a total of 513 miles of SH,[67] which presumably was targeted to the highest risk areas. In a data request response, PG&E acknowledges that "if you prioritize the highest risk work first, the remaining work will have lower priority and risk reduction benefits."[68] However, PG&E did not do any analysis of the reduction in benefits with additional incremental units of work.[69] By failing to perform any such incremental analysis -- PG&E has deprived the WSD/Commission and the parties of the data necessary to assess whether it is cost-effective to execute SH in the scope and pace planned by PG&E.

Assessing the incremental cost-effectiveness of the expensive SH initiative is particularly important because of other promising technologies that are already being piloted that could obviate the need for expensive covered conductor installation and related work. In PG&E's 2020 RAMP, SPD has particularly highlighted the Rapid Earth Fault Current Limiter (REFCL)

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[64] PG&E WMP Att. 1, Table 12 (corrected 3/17/21).
[65] WildfireMitigationPlans_DR_TURN_022-Q03Supp01Atch01.xlsx
[66] PG&E WMP Att. 1, Table 12 (corrected 3/17/21). The Transmission and Distribution Inspection RSEs given are for HFTD Tier 3.
[67] PG&E WMP, p. 236, Table 5.3-1.
[68] PG&E response to TURN DR 22, Q01Supp 01(d)(v).
[69] PG&E response to TURN DR 22, Q01Supp 01(c).

technology as potentially "groundbreaking for PG&E."[70] REFCL is much lower cost than covered conductor because most of the equipment installation occurs at the substation and does not need replacement of overhead powerlines.[71] Reflecting this lower cost, in RAMP, PG&E calculated an RSE of 126 for REFCL. (In its WMP, PG&E shows a lower RSE of 36 – still much higher than the RSE of 4 for the current SH program -- without explaining the difference from RAMP.) SPD states that PG&E informed it that there is potential for utilizing REFCL on a widespread basis -- for 5,700 miles in HFTD Tier 3 and 16,000 circuit miles in Tier 2.[72] Because of REFCL's significant promise, SPD recommended that PG&E's upcoming GRC include an analysis of REFCL as an alternative to PG&E's current SH activities.[73]

In light of the evident near-term promise of REFCL as a potentially "groundbreaking" means of avoiding the more expensive current SH activities in many locations, it is particularly troubling that PG&E fails to show how the incremental cost-effectiveness of its planned covered conductor centered SH program declines with incremental mileage. It is entirely likely that it would be much more cost-effective to limit relatively expensive covered conductor focused work in 2021 and 2022, particularly in areas where REFCL is a promising and more cost-effective alternative.

PG&E also deprives the WSD/Commission and the parties of necessary information to assess whether PG&E's SH plans should be approved when it fails to provide RSEs for the various sub-programs that PG&E aggregates under the label System Hardening. As discussed further in Section V(E) below, PG&E's SH initiative includes very different types of work -- covered conductor installation, undergrounding, and relocating or removing circuits. This

[70] SPD Staff Evaluation Report PG&E's 2020 RAMP, Nov. 25, 2020, p. 65.
[71] *Id.*, p. 64.
[72] *Id.*, p. 65.
[73] *Id.*

aggregation of mitigations in the risk analysis is another problem that SPD criticized in its report on PG&E's RAMP, recommending that the RAMP equivalent of the SH initiative be divided into individual initiatives.[74] Notwithstanding this recommendation, PG&E reports in its WMP that its highly touted new Wildfire Distribution Risk Model does not yet provide risk reduction values for each of these separate activities, which surely have different RSEs.[75]

Thus, just as with EVM, PG&E fails to provide the necessary information for the WSD/Commission to make an informed decision about whether PG&E's SH plan for 2021-2022 is reasonable or whether those plans should be curtailed in scope and focused on certain activities with higher relative RSEs.

F. The Serious Deficiencies in PG&E's Risk Analysis Compel Rejection of PG&E's WMP

The foregoing has shown that, because of the deficiencies in PG&E's risk analysis, PG&E has failed to justify two of the main pillars of its WMP plans for 2021 and 2022 – the high-cost and low-RSE EVM and System Hardening initiatives. Because these initiatives are so central to PG&E's WMP, and because PG&E's normalized WMP spending significantly exceeds that of SCE and SDG&E, the WSD/Commission should reject PG&E's WMP.

The WSD/Commission should inform PG&E that its 2021 WMP will not be approved unless and until it makes the following changes:

- PG&E modifies its catastrophic wildfire risk analysis to include operational failures with respect to vegetation management and asset inspection as a risk driver;
- PG&E either removes the relatively low Risk Spend Efficiency (RSE) Enhanced Vegetation Management (EVM) from its WMP or proposes a 2021-2022 EVM

[74] SPD Staff Evaluation Report PG&E's 2020 RAMP, Nov. 25, 2020, pp. 62-63.
[75] PG&E WMP, p. 145. PG&E claims that its new model will do so for 2022.

program of reduced mileage and scope of sub-programs that is justified by an incremental risk analysis;

- PG&E provides a proposal for mileage and scope of System Hardening activities for 2021-2022 that: (i) is justified by an incremental risk analysis and (ii) takes into account the potentially groundbreaking and more cost-effective Rapid Earth Fault Current Limiter (REFCL) technology, and any other technologies that are ready for near-term implementation.

Even if the WSD/Commission does not reject PG&E's 2021 WMP, the WSD/Commission should make clear that PG&E's WMP Update for 2022 will not be approved unless PG&E makes each of the above-described changes. In addition, in its 2022 Update, PG&E should be required to provide a tranche-level Risk Spend Efficiency (RSE) analysis of proposed WMP programs, based on tranches that meet the requirements of the settlement adopted in D.18-12-014, which should be used to justify its proposals for the EVM and System Hardening programs.

The WSD/Commission need to recognize that it is not in the financial interest of PG&E (or the other utilities) to justify the cost-effectiveness of each increment of their discretionary WMP programs based on a granular risk analysis. For capital programs like system hardening that increase rate base, higher cost programs mean higher profits for shareholders. As in each of its previous WMPs, PG&E makes it sound like it is improving its risk analysis, but somehow all the changes that are discussed never get to the granular RSE values that the D.18-12-014 risk analysis settlement requires. Instead, PG&E says it will make improvements such as improving the granularity of the model "[o]ver the next 3 to 10 years."[76] Three to ten years!

[76] PG&E WMP, p. 741 (emphasis added).

The WSD/Commission should find such statements appalling. Clearly, PG&E will not fix the serious problems with its risk analysis unless it is directed to do so by the WSD/Commission. While PG&E is spinning its wheels with its risk analysis, the company is spending $5 billion a year on its WMPs – a pace of spending that is simply unaffordable for too many ratepayers. It is time for the WSD/Commission to direct PG&E to stop the dithering. PG&E must be required to produce a truly granular risk analysis and show how that analysis supports the planned scope of its WMP programs. Such an analysis is overdue and should be required before this 2021 WMP, and future WMPs, are approved.

V. THE WSD AND THE COMMISSION SHOULD CLOSELY EVALUATE PG&E'S AND SDG&E'S COVERED CONDUCTOR INSTALLATION PROGRAMS TO ENSURE THE PROGRAMS ACTIVITIES ARE JUSTIFIED AND CAN BE MEANINGFULLY REVIEWED

A. Grid Design and System Hardening Is the Largest Cost Component of Utility Wildfire Spending, but PG&E Appears to Include Extraordinary Amounts of Compliance Repair Work as Wildfire Mitigation

1. Grid Design and Hardening Are the Largest Cost Component of the Utilities' Planned Mitigation Spending

The largest cost component of each utilities' planned wildfire mitigation plan is the "Grid Design and System Hardening" program, as illustrated in the following compilation from the utilities' Tables 3-1 and 3-2:

Table 5: Summary of Total 2020-2022 Costs for All Utilities

	PG&E	SCE	SDG&E
2020-2022 Actual and Planned			
Vegetation Management	$4,408,867,000	$1,048,624,000	$222,543,000
Grid Design and System Hardening	$8,407,881,000	$2,454,887,000	$1,218,772,000
Asset Management and Inspections	$807,738,000	$896,150,000	$208,693,000
All Other Activities	$1,390,950,000	$428,036,000	$235,564,000
Total	$15,015,436,000	$4,827,697,000	$1,885,572,000
Miles of OH Circuit in HFTD	30,750.0	9,715.0	3,500.0
2020-22 Actual and Planned Circuit Miles for Grid Hardening	992	3,965	205

The table above illustrates that PG&E plans to spend about three times as much as SCE. However, it is difficult to reach substantive conclusions regarding the benefits of the program based solely on total spending. PG&E has a larger HFTD area, and a greater number of circuit miles in HFTD, though it plans to do about a quarter of the amount of covered conductor installation as SCE. As noted previously, one useful method of comparing utility risks and programs is to normalize by both overhead circuit miles and red flag warning days, to account both for system size and wind conditions. Moreover, while WSD has taken major steps to standardize the classification of wildfire mitigation activities among the utilities, the utilities do not define their initiatives in system hardening programs or categorize costs in the same way, making both substantive work scope comparisons as well as spending comparisons difficult.

The largest component of grid hardening is the overhead hardening program that replaces bare conductor with conductor covered with a plastic sheathing to reduce the risk of faults or ignitions due to contact with bare wires, known as the "covered conductor" program. TURN will focus its comments on this program. However, TURN will first discuss two very troubling aspects of utility classifications of system hardening initiatives.

2. PG&E, Unlike SCE or SDG&E, Classifies Compliance Repair Work as Part of the WMP, Apparently In Order to Evade Rate Case Cost Accounting

Unlike the other utilities, PG&E appears to classify an extraordinary amount of compliance repair work as part of the "other corrective action" initiative 7.3.3.12. SCE explains in Initiative 7.3.3.12 that it "does not consider other corrective actions to be WMP activities but will continue to do this as part of SCE's role as a prudent operator of the grid."[77] SDG&E appears to take the same position, and explains that inspection and repair activities are included in initiative 7.3.4.1.[78] PG&E, on the other hand, labels its Initiative 7.3.3.12 as being an "in compliance" activity in Table 12, but forecasts a capital spend of **$1.943 billion** for 2020-2022 for transmission and distribution "other corrective actions" (initiatives 7.3.3.12.3 and 7.3.3.12.4), or approximately 23% of grid design and system hardening costs. These costs are in addition to inspection and repair costs included by all the utilities in initiative 7.3.4.1.

While TURN has not fully analyzed all the inspection and repair costs included in the WMP, it appears that PG&E is planning to spend significantly more (as in two billion dollars more) "repairing" its transmission and distribution system, and intends to record all of these costs in the WMP memorandum account as "incremental" to its authorized rate case costs.[79] While distribution and transmission repair work is obviously essential to wildfire prevention, it should not be considered as part of the WMP for purposes of recording costs in memorandum

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[77] SCE 2021 WMP, p. 221.
[78] SDG&E 2021 WMP, p. 215.
[79] WMP DR TURN 021-02 and 021-03.

accounts, since this accounting potentially allows PG&E to avoid the “just and reasonable” cost recovery determinations made in rate cases. As discussed further in the Section III.B. above, the Commission and WSD should not allow PG&E to use the WMP as an excuse to evade the comprehensive review of compliance costs that has already occurred in PG&E’s rate case.

3. Utilities Define Various Asset Replacement Programs Differently, Making Comparison and Analyses Difficult

A second problem in evaluating grid hardening programs is that the utilities do not consistently segregate and define asset replacement programs. For example, even a critical program such as covered conductor installation is not consistently defined across the utilities. SCE classifies its covered conductor program as initiative 7.3.3.3.1, while PG&E includes it as just one component of “system hardening” in initiative 17.3.3.17.1, and SDG&E has a separate “covered conductor” initiative 7.3.3.3 as well as a “bare conductor hardening program” initiative 7.3.3.17.1.

Another complication arises from the fact that utilities categorize a number of separate asset repair and replacement programs differently. For example, SCE classifies its crossarm replacement program (initiative 7.3.3.5) as being a compliance program, whereas PG&E classifies it as “exceeding” compliance. More importantly, the utilities repair or replace poles pursuant to three different programs – the regular pole inspections and repair program (initiative 7.3.3.6), the pole loading program (7.3.3.13), and as part of covered conductor installation. It is difficult to parse out how these programs address the entire stock of utility poles in order to optimize reduction of ignition risk.

TURN has not fully evaluated the impacts of these differences in definitions and categorizations in this WMP review. TURN encourages WSD and the Commission to require that the utilities, at least for reporting purposes, consistently identify the various programs that address similar assets so as to explain when and why utilities repair or replace the same asset.

B. Cost Control Is Necessary to Promote Safety

TURN appreciates that the WSD is primarily focused on the efficacy of the utilities' programs in reducing ignition and wildfire risk. TURN has consistently pushed for the utilities to conduct robust data collection and risk analyses, and in our evaluations we carefully consider the various ignition and risk data provided by the utilities.

TURN suggests that focusing on cost effectiveness, in addition to risk reduction efficacy, matters greatly for safety. First, spending money on less effective or unnecessary activities likely displaces spending on more effective risk mitigation measures, and thus delays implementation of effective measures. This criticism is especially relevant for PG&E's covered conductor program. If PG&E is spending almost one million dollars per mile for circuit hardening on unnecessary asset replacements, it will cost much more to install covered conductor, likely take more time to do the work, and possibly reduce the total amount installed. Similarly, if PG&E determines that an emerging technology such as REFCL is more effective than covered conductor and can be installed more quickly, wildfire ignition risk might be better mitigated by focusing spending on that program. Inappropriately implementing programs without prioritizing highest risk areas or accounting for the full risk reduction potential of different programs will result in a misallocation of resources. As the Commission has stated, "[v]irtually everything a utility does has some nexus to safety and can be deemed to have some safety impact, but the emphasis should be on those initiatives that deliver the optimal safety improvement in relation to the ratepayer dollars spent."[80]

[80] D.14-08-032, p. 28.

Second, the utilities' apparent position that "we have to do it all" is not tenable from a practical perspective. For example, at $1.5 million per mile, it would cost almost $40 billion to replace all HFTD conductor in PG&E's service territory, and over $8 billion to install covered conductor on the 5,000-6,000 circuit miles that PG&E's modeling shows as having the vast majority of wildfire risk. It is not clear that such a program is financially feasible. From a broader societal perspective, while utility wildfire work is focused on utility equipment, the State should consider whether it would not be more effective to raise taxes and direct $40 billion to other wildfire mitigation measures instead of installing covered conductor on 30,000 miles of wire, since it is almost certain that other ignition sources, besides utility equipment, may well spark the next deadly wildfire.

C. The Scope, Costs and Risk Spend Efficiency Results of the Covered Conductor Programs Are Fundamentally Different for the Three Utilities, and the WSD/Commission Must Require the Utilities to Improve and Standardize the Risk Evaluation of Covered Conductor Programs

The utilities all plan to install "covered conductor," yet the actual work conducted as part of replacing existing bare wire with covered conductor, and adding necessary poles to support additional weight, is quite different among the three utilities. As mentioned above, each of the utilities includes covered conductor work in somewhat different initiatives. More importantly, the utilities conduct different work activities in installing covered conductor, resulting in very different levels of spending per mile of installation, as shown in the table below.[81]

[81] Because PG&E does not disaggregate costs and mileage for overhead covered conductor versus undergrounding, TURN used the data in PAO-DR-046-02.

Table 6: Costs and Scope of Covered Conductor Installation

	PG&E	SCE	SDG&E
2020 Actual Costs for CC	$439,337,000	$546,151,289	$1,797,691
2020 Actual Mileage	333.0	965.0	1.9
2020-22 Costs for CC	$1,375,337,000	$2,183,623,148	$156,798,000
2020-22 Mileage	918.0	3,965.0	81.9
2020-22 Total CC Costs per Mile	**$1,498,188**	**$550,725**	**$1,883,977**
2020 Actual CC Cost per Mile	**$1,319,330**	**$565,960**	**$946,153**
Sources:	PAO DR 046-02; TURN DR 016-01Supp01	Table 12 - 7.3.3.3.1	Table 12 - 7.3.3.3
Total 2020-2022 Grid Design and System Hardening (from Table 1)	$8,407,881,000	$2,454,887,000	$1,218,772,000
Percentage of Grid Design and SH Spent on Covered Conductor	16.4%	89.0%	12.8%

The following general conclusions can be drawn from the table above:

- First and foremost, the majority of SCE's spending (89%) is for covered conductor installation, while less than 20% of PG&E's and SDG&E's spending is on covered conductor. TURN cannot conclusively determine whether this extraordinary difference reflects a fundamental difference in risk analyses and mitigation approaches between the utilities, or a difference in cost accounting and program definitions. However, TURN recommends that the WSD and the Commission should question the allocation of spending by PG&E and SDG&E on grid design and system hardening activities.
- As a result of its focus on covered conductor, SCE intends to install dramatically more covered conductor than either PG&E or SDG&E. If it continues at the same pace as 2020-2022, SCE could theoretically replace all its HFTD conductor within eight years. It would take PG&E about one hundred years to replace all of its HFTD conductor, and SDG&E almost as long. Even if PG&E increases its deployment to 500 miles per year, as

it apparently intends to do in 2022, it would take it 50 years to complete all HFTD circuits.

- The unit cost per mile of covered conductor installation for PG&E and SDG&E is about three to four times that of SCE's unit cost.

Moreover, not only does the scope and cost of the programs differ greatly, but so do the relative risk reductions calculated by the utilities. PG&E's risk spend efficiency for "distribution system hardening" is about 4.1,[82] whereas SCE's risk spend efficiency for covered conductor is over 3,500, and SDG&E's RSE is about 32.[83] The utilities do not explain these significant differences. It is unclear to what extent the low RSEs for PG&E and SDG&E reflect low risk reduction benefits and/or high unit costs. Given that both PG&E and SDG&E believe covered conductor significantly reduces ignition risk,[84] and both PG&E and SDG&E intend to substantially increase their covered conductor deployment starting in 2022, TURN assumes that a significant driver of low RSEs for these utilities is the high unit costs.

The WSD and the Commission must ensure that, over the course of the coming year, there is sufficient focus on standardizing and improving the risk analyses to understand why there are such significant differences in the risk analyses, scope of activities, and costs of covered conductor installation. In order to accomplish this, the WSD and the Commission should require the utilities and staff, in collaboration with all stakeholders, to hold technical workshops in 2021 in order to improve and standardize the risk analyses for covered conductor. These workshops should be structured so as to address the following questions:

[82] PG&E does not disaggregate the RSE for covered conductor, overhead system hardening or undergrounding, and lumps all of these very different programs together as "system hardening."
[83] TURN appreciates that the lack of a standardized methodology for RSE calculation makes comparison of RSE values among utilities almost impossible. However, at least for PG&E, the RSE for covered conductor is low compared to its other mitigation measures.
[84] PG&E 2021 WMP, p. 551; SDG&E 2021 WMP, p. 192.

- Is covered conductor a key risk reduction strategy that is necessary in addition to other compliance activities (vegetation management, asset inspection and replacement) that would be performed on the same circuits in the normal course of business?
- Why are PG&E's and SDG&E's covered conductor programs so much more expensive per mile than SCE's?
- Is PG&E's and SDG&E's pace of covered conductor installation too slow, or is SCE's deployment too fast, in light of the relative risk reduction benefits of covered conductor?
- Is expediting covered conductor deployment reasonable considering that emerging technologies, such as REFCL, that may provide most of the same benefits are presently being tested and evaluated?

These are complex, but critical, questions. It makes no sense to continue spending billions of dollars a year on a program if we cannot be sure that the program is effective at reducing wildfire risk better than much cheaper alternative measures.

D. SCE's Pace of Covered Conductor Deployment May Be Too Fast Given the Uncertainty in Risk Reduction and the Deployment on Low Risk Circuits

As discussed in Section VI below, the Commission should be concerned that SCE's pace of deployment may result in using an expensive mitigation method in low risk areas. PG&E's risk modeling showed a surprising and troubling reversal in the circuit segments identified as highest risk.[85] SCE likewise found differences when it changed its consequence modeling in 2020 from the Reax to the Technosylva model. As discussed in the Section VI, SCE's proposed pace of installing about 1,300 miles of covered conductor each year results in installation on circuits with very low risk reduction benefits. It would likely behoove SCE to slow down its covered conductor deployment and focus greater energies on prioritizing the riskiest circuits for

[85] Presentation of Mark Esguerra, Feb. 23, 2021 WMP Workshop. TURN does not believe the IOU presentations have been posted on the CPUC WMP website.

program deployment and on testing and developing new emerging technologies that may result in much more cost-effective risk reductions.

E. The WSD/Commission Must Order PG&E and SDG&E to Minimize the Unit Costs of their Covered Conductor Programs, to Track and Report Data on the Components of the Programs, and to Justify the Replacement of Useful Distribution Assets

1. PG&E Appears to Be Unnecessarily Replacing Useful Assets that Pose Very Little Ignition Risk and Significantly Increase Program Costs

TURN has reviewed PG&E's covered conductor program in three separate proceedings and believes that that the program is extremely costly because PG&E is unnecessarily replacing useful and non-deteriorated pieces of equipment as part of this activity. The WSD/Commission should issue clear guidance to PG&E to modify its program so as to reduce unit costs and to replace only those assets necessary to support covered conductor or reduce wildfire ignition risk. Such a modification would provide the opportunity to increase the pace of the program in the future, if warranted based on a robust risk spend efficiency analysis.

The Commission should also ensure that PG&E properly tracks and records the multi-billion dollar cost of the program. To date, it has been difficult to obtain clear and accurate data concerning PG&E's covered conductor installation. At a high level, PG&E combines three very different activities in its "system hardening" program - undergrounding circuits, relocating or removing circuits, and installing covered conductor (aka overhead system hardening). The aggregation of these three different programs obfuscates costs for each program and hides the fact that covered conductor is by far the primary program component. In 2020, 95% of total costs and 97% of total mileage was for covered conductor replacement.[86] For 2020-2022, 78% of

[86] 2021 WMP DR PAO 046-02.

the total system hardening cost of $1.67 billion and 93% of the total 992 miles are for covered conductor.

PG&E has repeatedly refused to disaggregate costs for the "overhead system hardening" program. PG&E has explained that in addition to replacing covered conductor, its program essentially replaces most or all of the existing poles, transformers, switches, fuses and crossarms, even if those assets are totally functional and not deteriorated or failing.[87] But PG&E maintains that it cannot disaggregate the costs for these various assets.[88]

During the WMP workshop held on February 23, 2021, PG&E panelist Mark Esguerra explained that one of the primary drivers of the higher cost of PG&E's program was the need to replace more poles due to the smaller size of PG&E's poles, and the need to meet wind loading. PG&E claims that "often the majority or all poles on a circuit segment will need to be replaced to support the new, heavier covered conductor and associated equipment."[89] TURN takes seriously PG&E's explanation, but finds that PG&E has failed to justify its claims.

TURN agrees that PG&E does have more "small poles"[90] in its HFTD, but this cannot explain a 300% difference in unit costs. At the end of 2019, PG&E had approximately 20% more small poles in HFTD than SCE; and by the end of 2020, the difference was reduced to approximately 15%,[91] as illustrated in the table below:

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[87] PG&E 2021 WMP, p. 552; See, also, A.20-09-019, WMCE DR TURN-009-07(a), (b) and (f); A.18-12-009, PG&E 2020 GRC DR TURN 03-31(d).
[88] For example, A.20-09-019, WMCE DR TURN-003-05(b) and 009-05.
[89] PG&E 2021 WMP, p. 552.
[90] PG&E defined poles in class categories 3 or smaller (i.e. a higher class number) as "small." See, A.18-12-009 (PG&E 2020 GRC), Ex. 20 (PG&E-18), pp. 9-20:31 – 9-21:4. TURN does not contest this categorization.
[91] In 2018, 88.6% of PG&E's wood poles in HFTD were Class 3 or smaller, as compared to 67.4% of SCE's wood poles, a difference of about 20%. In 2020, 86.1% of PG&E's wood poles in HFTD were smaller than Class 3, versus 70.8% of SCE's poles, a difference of less than 10%. DR TURN-PG&E-018-01Atch01; DR TURN-SCE-003-01.

Table 7: Number of Wood Poles by Size Classification in HFTD in 2020

Pole Size Class	SCE Number	SCE %	PG&E Number	PG&E %
6			42,815	6.81%
5	89,291	31.26%	220,715	35.08%
4	91,949	32.19%	191,023	30.36%
3	21,067	7.37%	86,973	13.83%
2	31,863	11.15%	30,593	4.86%
1	25,177	8.81%	29,561	4.70%
H1	9,596	3.36%	3,149	0.50%
H2	6,555	2.29%	1,710	0.27%
H3	3,520	1.23%	554	0.09%
H4	1,891	0.66%	136	0.02%
H5	961	0.34%	38	0.01%
H6	532	0.19%	0	0.00%
Unknown	14,936	5.23%	26,199	4.16%
TOTAL	297,338		633,466	
% in Classes 10-3		70.82%		86.08%

TURN appreciates that the need for additional poles depends on the size of existing poles, the size and weight of the existing versus new conductor, and specifications regarding wind speed used on pole loading analyses. However, despite numerous attempts by TURN to obtain any engineering analyses that justify replacing each and every pole, PG&E has consistently refused to provide actual data or analyses that would substantiate its claim that all poles need to be replaced due to the weight of covered conductor.[92]

Even accounting for the need to replace more poles than SCE due to a 15% higher portion of small poles in HFTD, and potentially smaller existing conductor and higher wind speeds, it seems unlikely that PG&E's unit cost for covered conductor installation should be

[92] For example, A.20-09-019, WMCE DR 03-16(e), DR 009-07(c) and (d); A.18-12-009, DR 036-01(b).

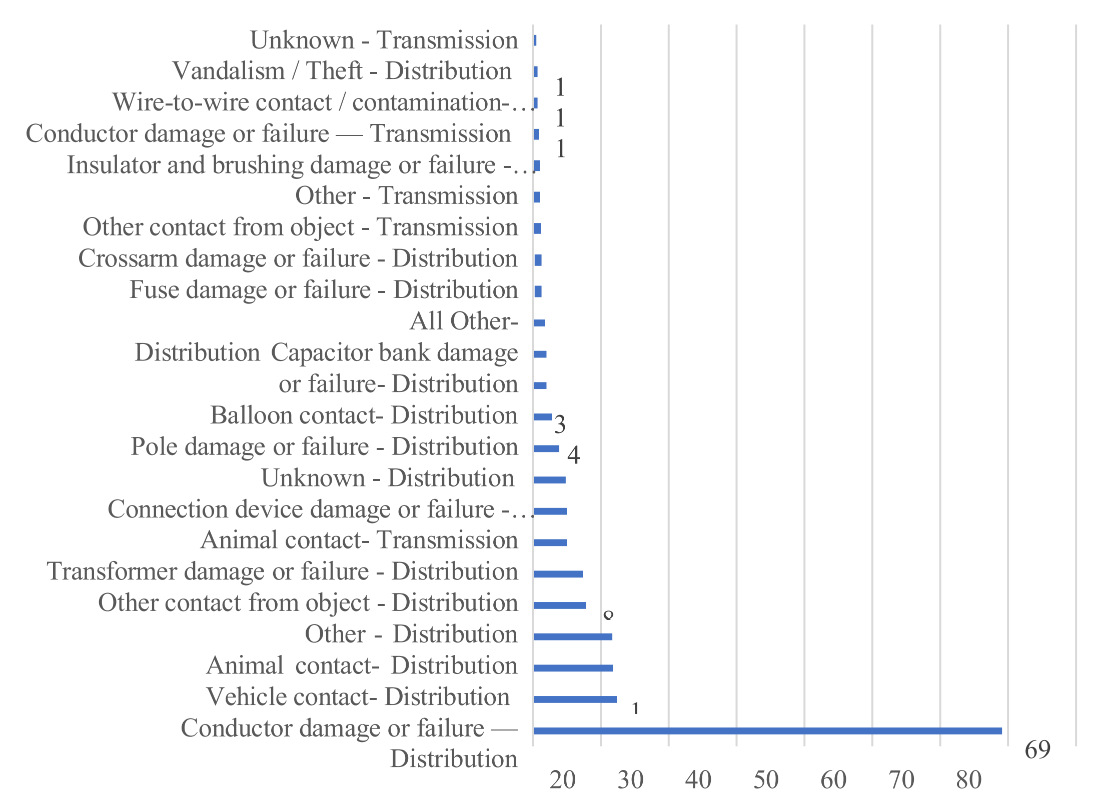
three times that of SCE's cost. Even a 50% premium would result in a unit cost of about $800,000 per mile, a little more than half of PG&E's forecast of $1.5 million per mile for 2020-2022.

The WSD and the Commission should require in this WMP review that PG&E provide much better information documenting the rationale for pole replacements.

Another likely explanation for the extremely high cost of PG&E's (and likely also SDG&E's) covered conductor program is that PG&E is replacing many other existing useful assets as part of overheard grid hardening. PG&E has failed to justify the need to replace all other assets – including fuses, switches, crossarms and mineral oil transformers - as a necessary component of system hardening. PG&E has argued in general that replacing all assets with "exempt" equipment reduces ignition risk. However, PG&E does not track risk mitigation at the "activity level."[93] Historical ignition data in PG&E's Table 7.2 show that the risk of ignitions from most of these assets is trivial.

[93] A.20-09-019, WMCE DR TURN-003-07.

Figure 2: Annual Ignitions by Driver, PG&E, Average for 2015-2020[94]



As shown in the Figure, the failure of assets such as fuses, crossarms and poles causes less than three ignitions per year. Reclosers and switches caused zero ignitions from 2015-2020, yet PG&E replaces them under overhead hardening guidelines.[95] Moreover, all transformers are exempt,[96] so there is no apparent justification for wholesale replacement of transformers. Calculations presented in the RAMP proceeding illustrate that the RSE for crossarms and transformers is a factor of ten lower than the RSE for covered conductor or fuses/switches.[97] The bottom line is that PG&E has devised a completely new design standard for its HFTD

[94] Source: PG&E 2021 WMP, Attachments, Table 7.2.
[95] A.20-09-019, WMCE DR TURN-009-07Atch01.
[96] WMP DR TURN-PG&E-005-015. Conventional transformers could also have non-exempt fuses associated with the transformer.
[97] PG&E Presentation, "RAMP Scenario Analysis – Tranching (TURN)," October 22, 2020, p. 18.

distribution system[98] that appears to be divorced from its ignition risk analysis results. TURN does not oppose replacing damaged or failing assets, but these are identified and replaced under the separate multiple asset inspection and replacement programs.

Another indication that PG&E's covered conductor program is overly expensive is the large difference in costs between "rebuild" versus "base" projects conducted in 2020. PG&E spent about $0.95 million per mile in 2020 to rebuild about 195 miles of circuits damaged by wildfires with covered conductor, but spent about $1.9 million per circuit mile to complete about 150 miles of "planned circuit hardening projects."[99] PG&E explained that "the work done under emergency response is executed at a lower cost" due to four factors, including the fact that "the time frame of a fire (or any emergency) response project is much less, generally 2-6 months, and therefore the overhead costs are reduced." TURN has not had the opportunity to thoroughly evaluate PG&E's explanations, but the whole concept that "emergency response work" done on an accelerated basis is less expensive than planned work runs counter to explanations we have seen in GRCs and CEMAs over many years that unplanned emergency work is always much more expensive.

In this WMP, PG&E explained that it has decided to reduce its planned covered conductor installation from about 340 miles replaced in 2020 to about 180 miles forecast for 2021; but then intends to ramp up covered conductor installation to about 450-500 miles per year starting in 2022.[100] TURN cannot determine whether PG&E's deployment plans are reasonable for wildfire risk mitigation, as PG&E has not justified any specific mileage with reference to risk modeling results or prioritization of circuits based on a risk analysis. It may be that a slower pace

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[98] A.20-09-019, WMCE DR TURN-009-07Atch01.
[99] WMP DR TURN-025-01.
[100] PG&E 2021 WMP, p. 558.

for covered conductor is warranted based on more effective allocation of resources to other programs that presently have a higher RSE. On the other hand, if it turns out that covered conductor is necessary to protect against wildfires in HFTD, then continuing even at PG&E's proposed 2022 pace would take decades to complete the work. The approximate per mile difference between SCE's and PG&E's cost for covered conductor is about one million dollars, which results in an incremental twenty-five billion dollars to harden PG&E's HFTD distribution lines.

The WSD and the Commission should therefore order PG&E to:

- Provide detailed disaggregated data for overhead covered conductor installation, including the costs of all assets replaced (poles, transformers, fuses, switches, etc.), the number of assets replaced per mile, the age of the assets replaced, and the percentage of each asset replaced on individual circuits;
- Justify the replacement of useful assets other than the conductor, including justifying the need for pole replacements with data and engineering analyses, and justifying the replacement of other useful assets based on sound engineering analyses;

Furthermore, the WSD and the Commission should find that PG&E's covered conductor program is unduly costly because PG&E appears to be unnecessarily replacing useful and non-deteriorated pieces of equipment in addition to the necessary pole and wire replacement. The Commission should issue clear guidance to PG&E to modify its program to replace only those assets necessary to support covered conductor or reduce wildfire ignition risk.

2. The WSD/Commission Should Evaluate Whether SDG&E Needs to Continue Replacing All Wood Poles as Part of System Hardening

TURN has historically not evaluated SDG&E's grid hardening activities, due to both resource constraints and the presence of at least three other intervenor groups which have address

SDG&E's grid hardening activities in various proceedings.[101] TURN thus offers only limited comments based on the data contained in this WMP.

SDG&E has had a bare wire system hardening program for several years. Under this program, SDG&E replaced small conductor with larger conductor (the PRiME program element), and replaced wood poles with steel or fiberglass poles (the FiRM program element). These programs have been in existence since 2013 and 2019 respectively,[102] though pole and conductor replacement activities likely started even earlier. SDG&E has already "hardened" 850 miles of its HFTD circuits.[103] In 2020, SDG&E spent approximately $1.4 million per mile to harden 99.5 miles.

SDG&E states that it will consolidate its Distribution Overhead System Hardening Program and determine whether to install covered conductor or bare wire using its WiNGS model.[104] However, SDG&E's Table 12 shows a forecast of only 5 miles for bare wire conductor replacement in 2022, implying that SDG&E plans to transition to installing primarily covered conductor.

In 2020, SDG&E initiated its covered conductor program and spent $1.8 million on two miles in Initiative 7.3.3.3. SDG&E forecasts spending a total of $157 million in 2020-2022 to install covered conductor on about 62 miles, or a unit cost of over $2.5 million per mile, significantly higher than even PG&E's, and about five times higher than SCE's unit cost.

TURN has not evaluated the reasons for this extraordinarily high unit cost. SDG&E intends to continue replacing all wood poles with steel poles during its covered conductor

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[101] Those groups are the Mussey Grade Road Alliance (MGRA), the Utility Consumers' Action Network (UCAN), and Protect Our Communities Foundation (POC).
[102] SDG&E 2020 WMP, p. 73.
[103] SDG&E 2021 WMP, p. 191.
[104] SDG&E 2021 WMP, pp. 217-218.

installation.[105] TURN recommends that WSD require SDG&E to demonstrate the usefulness of replacing all wood poles with steel poles. SDG&E explained that it "does not perform pole loading studies on wood poles that will be replaced for fire hardening projects," but has selected to use steel poles because:

> Steel and fiberglass poles are built with materials that are heat resistant. Should a pole be exposed to a wildfire, a steel or fiberglass pole will be more likely to withstand the heat, thus increasing SDG&E's ability to bring the services back on in the area with reduced impact. Wood poles have an increased likelihood of being damaged or destroyed during a wildfire. Additionally, steel and fiberglass poles are built in a factory that ensure consistent material properties. The material properties of wood can vary, since it is grown and not manufactured. By installing steel or fiberglass poles, SDG&E has more confidence that the pole will be able to withstand the designed environmental events. In addition, pole replacements are often necessary due to different sag and clearance requirements of the new wire being strung. SDG&E often installs new poles that are 5-10 ft taller than the existing pole.[106]

SDG&E's explanation is not convincing in light of the joint utilities' findings that wood poles with mesh are as resilient as steel poles. TURN is concerned that SDG&E has not quantified the risk that wood poles would be "damaged and destroyed" during a wildfire and compared the resulting costs and impacts to the costs of pre-emptively replacing all wood poles. Whether to install taller poles, rather than increasing the number of poles, in order to accommodate the weight of covered conductor, is an engineering choice that can be evaluated by proper analyses and resulting cost/benefit calculations.

Even if SDG&E were continuing the same pole replacements as under its existing bare wire hardening program, it seems unlikely that merely using covered conductor rather than large bare wire should add **two million dollars per mile**, given that SCE can install covered conductor as any necessary additional poles for $0.5 million per mile. The Commission should require

[105] SDG&E 2021 WMP, p. 218; DR TURN 003-04(a).
[106] DR TURN 003-04(b).

SDG&E to track costs by all relevant program assets and explain and justify the extremely high costs, for its covered conductor program.

VI. THE SCE WMP SHOULD BE REJECTED UNTIL THE UTILITY PROVIDES A PROPERLY SCOPED COVERED CONDUCTOR PROGRAM

A. SCE's WMP Update Doubles Down on its All-In Approach to Covered Conductor

SCE's WMP Update continues the utility's "'all in' approach to the deployment of covered conductor at a significant cost" first proposed in its 2020 WMP.[107] SCE's WMP targets the installation of over 4,000 miles of covered conductor installed by 2022.[108] In WSD-004 resolving SCE's 2020 WMP, the WSD/Commission found that "SCE [had] not sufficiently justif[ied] the relative resource allocation of its WMP initiatives to its covered conductor program with any quantifiable risk reduction information."[109] Rather than identify a new, targeted program that ensures each mile of covered conductor installed provides a risk reduction benefit commensurate with its cost, SCE has doubled down on its 2020 plan. TURN recommends that the WSD/Commission reject SCE's WMP as drafted and direct the utility to identify a more targeted covered conductor program with a scope determined by the concentration of risk within the High Fire Risk Area (HFRA).

The WMP target is "aligned" with the covered conductor proposal made in SCE's 2021 GRC Phase 1 Application, where a decision is outstanding (reply briefs were submitted on October 2, 2020):[110]

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[107] WSD-004, p. 10.
[108] SCE 2021 WMP, p. 108.
[109] WSD-004, p. 49.
[110] TURN-SCE-004, Q2

> SCE's 2021 GRC proposes 1,400 circuit miles in 2021 and 1,600 circuit miles in 2022 and SCE's 2021 WMP Update proposes 1,000-1,400 miles in 2021 and 1,600 miles in 2022.111

TURN fully litigated the proper scope and budget for the covered conductor program in SCE's GRC. TURN proposed an alternate scope for covered conductor installation in SCE's 2021 GRC that would target its highest risk segments at a budget more consistent with affordability concerns.[112] Using SCE's own risk analysis, TURN demonstrated that, given the concentration of risk in a limited number of circuit miles, a reduced installation of covered conductor, around 2,500 miles, would address over 90% of the riskiest circuit miles at a more reasonable price tag.[113]

TURN has worked to understand how SCE's 2021GRC and WMP proposals compare and whether the utility's WMP proposal addresses the concerns identified by TURN in its GRC. The primary difference between the two proceedings appears to be reliance on a new risk model, Technosylva, in the WMP that reprioritized the circuit miles for hardening.[114] It remains the case, however, that risk is concentrated in a more limited number of segments. TURN's GRC arguments for a more targeted approach to covered conductor remain applicable to the reprioritized list of circuits presented in the WMP.

The WSD/Commission should reject the SCE proposed covered conductor program and direct the utility to resubmit the WMP with a smaller covered conductor program targeted at its riskiest segments. If the WSD/Commission does not deny the WMP, it should limit any

[111] *Id*.
[112] TURN Opening Brief, A.19-08-013 (September 11, 2021) p. 83 (hereinafter TURN Opening Brief) (attached): "On a relative risk basis, despite costing ratepayers $2 billion dollars less than SCE's proposal, TURN's proposed budget is sufficient to deploy covered conductor on circuits representing more than 90% of wildfire risk."
[113] *Id*.
[114] SCE WMP, p. 212.

approval of SCE's covered conductor proposal to the covered conductor budget approved in the forthcoming GRC Decision. Additionally, the WSD/Commission should require that covered conductor deployment be prioritized to address the riskiest segments first.

B. A More Limited Investment in Covered Conductor Provides Risk Mitigation Benefits at a More Affordable Price Tag

SCE's failure to size the program based on the concentration of risk leaves the utility unable to justify the scope of its covered conductor program. SCE's 2021 GRC requested approval of approximately $3.4 billion for the installation of 6,200 miles of covered conductor between 2019 and 2023.[115] TURN proposed an alternative covered conductor budget sufficient to fund the installation of approximately 2,581 miles of covered conductor over 2021-2023.[116] Not only is the narrower scope proposed by TURN in the GRC sufficient to address the highest risk circuits, the TURN program would address over 90 percent of risk under both the GRC and WMP risk models.[117]

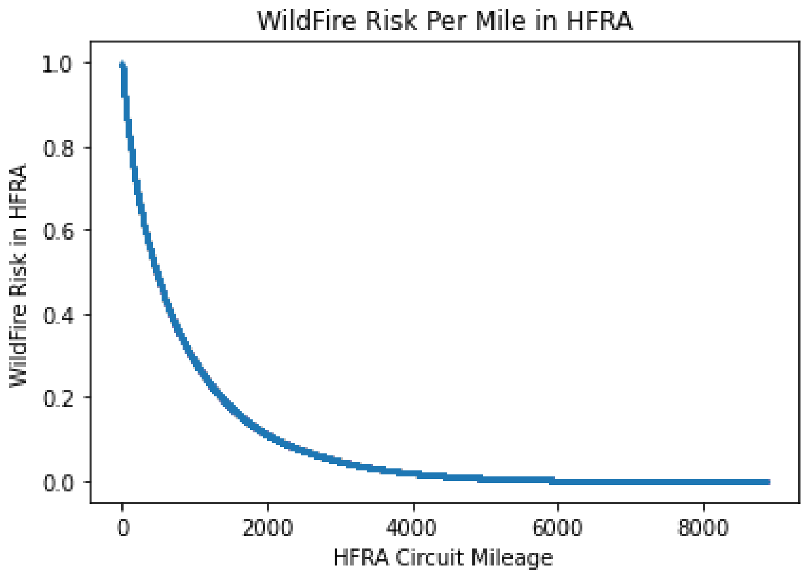
"In late 2020, SCE transitioned from using the Reax ignition consequence model to Technosylva, which resulted in some reprioritization of the circuit segments."[118] Despite the reprioritization it remains the case that risk is relatively concentrated in a limited number of miles. As stated by SCE, "[r]isk is not uniform and … some segments show significantly more wildfire risk than others."[119] For example, when discussing its inspections program, SCE points out: "[i]n 2021, nearly 60% of distribution and approximately 50% of transmission structures in

[115] TURN Opening Brief, p. 84.
[116] TURN Opening Brief, p. 85.
[117] TURN Opening Brief, p. 93; see Table 8 below.
[118] SCE 2021 WMP, p. 212.
[119] Data Request Set TURN-SCE-007, Response to Q 001(c).

HFRA will be inspected. The assets included in these inspections account for 99% of the wildfire risk in HFRA."[120]

The figure below is the "risk curve" "generated by ranking all conductor segments from highest to lowest risk."[121]

Figure 3: SCE Risk Curve[122]



The horizontal axis of the curve shows cumulative HFRA circuit miles and the vertical axis "represents the sum of all the wildfire risk in terms of both probability of ignition and consequence for circuit segments in the HFRA."[123] The risk curve is steeper from 0-2,000 HFRA circuit miles, when it begins to flatten out, meaning that risk is more concentrated in the first 2,000 HFRA circuit miles. As shown by the arrow in the figure above, SCE's proposed scope of covered conductor during the WMP term would address risk after the risk curve begins

[120] SCE 2021 WMP, p. 8.
[121] SCE 2021 WMP, p. 65.
[122] Data Request Set TURN-SCE-007, Response to Q 001(a).
[123] *Id.*

to flatten out. Analysis by TURN of risk information provided by SCE confirms that the risk remains concentrated in a limited number of miles, with 95% of risk concentrated in 2,925 miles:

Table 8: SCE Concentration of Risk[124]

Percentage of Risk Addressed	Cumulative Circuit Miles
10%	40
20%	110
30%	196
40%	311
50%	465
60%	667
70%	945
80%	1,361
90%	2,110
95%	2,925
100%	8,800

Circuit segments identified for covered conductor installation in SCE's WMP include "segments with risk scores between 22.5 and 15,720…using the Technosylva model."[125] Assuming a common circuit mile cost of covered conductor installation, the Risk Spend Efficiency (RSE), or risk reduction per dollar spent, will be much greater for circuit segments with risk scores at the high end of this range, 15,720, than for those with scores closer to 22.5. In other words, the utility is able to "buy" much more wildfire risk per dollar on riskier segments, but the risk addressed by each additional circuit mile of covered conductor installed diminishes.

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124 Calculated from workpapers provided to TURN. TURN-SCE-007, Response to Question 001(a). Determined from TURN-07, Question 1, by sorting circuit segments from highest to lowest according to the calculated risk score, then calculating cumulative risk (0-100%) and cumulative miles (0-8,800) represented at each circuit segment, as summarized in the Table.
125 Data Request Set WSD-SCE-004, Response to Q-008(a).

However, these diminishing returns did not inform the scope of covered conductor proposed by SCE.

Rather than identifying the optimal or most cost-efficient deployment of covered conductor based on the risk scores of individual circuit miles, "SCE utilized its enterprise level RAMP risk model to evaluate the scale of deployment of covered conductor."[126] SCE testified in the GRC, deployment is sized based on the "maximum amount of covered-conductor miles due to resource constraints that [SCE] could execute."[127] It appears that the target for covered conductor miles in the WMP is similarly constrained only by the ability to do the work. The 4,000 mile target "accounts for the operational realities of deploying covered conductor, which include planning and execution lead time, construction methods, work management efficiencies and compliance requirements…. as well as resource constraints."[128] Notably absent from SCE's response is the concentration of risk in the HFRA and the cost impact on SCE customers.

As TURN proposed in the 2021 SCE GRC, the risk scores of the individual circuit miles should be used not only to prioritize the installation of conductor but also to size the program consistent with affordability constraints. Regardless of the risk model used, TURN's proposed scope of 2,581 miles in the GRC would address over 90% of risk as identified.[129] The SCE WMP should be rejected pending the utility resubmitting a more narrowly scoped program targeting deployment of covered conductor program based on risk scores of individual segments.

[126] SCE 2021 WMP, p. 211.
[127] TURN Opening Brief, p.83, Note 256, citing 8 TR 930:6-9 (SCE/Roy).
[128] TURN-SCE-006, Response to Q1.
[129] Table 8.

C. Avoiding Wildfire and PSPS Risk Requires More than Covered Conductor Installation

A more limited installation of covered conductor does not mean that SCE's customers and the general public will not be protected against wildfire where covered conductor is not installed. The installation of covered conductor also does not mean that those segments with covered conductor are immune to wildfire risk. Successful wildfire mitigation requires the utility to pursue a suite of mitigations. TURN does not oppose deployment of other wildfire mitigation on lower risk circuits, it only opposes the idea that a high cost mitigation like covered conductor is the most cost-effective mitigation on those circuits. In SCE's GRC TURN explained:

> The discussion of covered conductor, one of the highest cost mitigations, must be in the context of the multiple other investments ongoing at SCE, many of which TURN does not oppose – Vegetation Management compliance-related programs, Enhanced Overhead Inspections and Remediations, Fire Science and Advanced Modeling, Sectionalizing Devices, Public Safety Power Shutoff (PSPS) Execution and Undergrounding.[130]

Different parts of a circuit mile may face different risks. A "circuit [that] traverses various tiers and is exposed to different probabilities of ignition by contact from objects or varying topography and vegetation can influence fire propagation and consequence."[131] Since covered conductor may not address all of these risks a number of different wildfire mitigations may be in place for any single circuit mile. Appropriately, SCE intends to continue deploying multiple mitigation on a circuit, "whether or not covered conductor is installed."[132] The WSD/Commission should direct the utility to continue to study the impact of multiple mitigations in one location. To the extent that the investment in one more expensive mitigation can adjust the frequency or scope of another, such adjustments should be made.

[130] TURN Opening Brief, p. 96.
[131] TURN-SCE-007, Response to Q 1 (c).
[132] TURN-SCE-006, Response to Q2.

Relatedly, if SCE intends to continue its aggressive installation of covered conductor it should specifically address how covered conductor will impact the likelihood of a PSPS event. SCE suggests that the installation of covered conductor would avoid future PSPS events:

> Nevertheless, by incorporating the PSPS risk into the overall wildfire risk to calculate a total MARS, we have the means to target mitigations to areas that have the highest combined risk in addition to targeting wildfire and PSPS impacts separately. For example, because covered conductor remains a major program component for system hardening, we could prioritize the frequently impacted circuits and reduce the frequency of PSPS on these circuits.[133]

In a data response to WSD, however, SCE clarified it is not yet using the "MARS PSPS Risk Score" to "determine where to deploy mitigation options" but "anticipates it will begin to use this methodology for mitigations deployed in 2023."[134] It is not clear that the installation of covered conductor will necessarily lead to a reduction in PSPS events. Even spans with covered conductor installed experienced PSPS events in 2020,[135] and in its GRC SCE was unwilling to commit to not calling PSPS on circuits with covered conductor.[136] The WSD/Commission should direct that before SCE uses a MARS PSPS Risk Score to justify or deploy covered conductor, it must quantify the impact on potential PSPS events or commit to a reducing reliance on PSPS as a mitigation.

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[133] SCE 2021 WMP, p. 62.
[134] WSD-SCE-004, Response to Q6.
[135] TURN-SCE-004, Response to Q1(a).
[136] TURN Opening Brief, p. 102, quoting Ex. SCE-47 (Roy), p. 7.

Date: March 29, 2021

Respectfully submitted,

By: __________/s/______________
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COMMENTS OF THE UTILITY REFORM NETWORK ON 2021 WILDFIRE MITIGATION PLAN UPDATES

ATTACHMENTS

ATTACHMENT INDEX

Attachment 1

PG&E 2020 GRC - PG&E Response to DR TURN 3-31

PACIFIC GAS AND ELECTRIC COMPANY
2020 General Rate Case Phase I
Application 18-12-009
Data Response

PG&E Data Request No.:	TURN_003-Q31		
PG&E File Name:	GRC-2020-PhI_DR_TURN_003-Q31		
Request Date:	March 15, 2019	Requester DR No.:	003
Date Sent:	April 5, 2019	Requesting Party:	The Utility Reform Network
PG&E Witness:	Steven Calvert	Requester:	Marcel Hawiger

SUBJECT: PG&E-04 (ELEC D)

QUESTION 31

Regarding Workpaper Table 9-12:

a. Please explain and provide all supporting workpapers in Excel for the number of units per mile for each activity.

b. Please explain and provide all supporting workpapers in Excel for the unit cost per mile for each activity.

c. Please explain and provide all supporting workpapers in Excel for the total cost per mile for each activity.

d. Does PG&E propose replacing all non-wood poles and non-exempt transformers on a targeted circuit mile? Please explain.

e. Please explain and quantify whether the non-wood pole replacement is separate from pole replacement required to install covered conductor.

f. Please explain and quantify why replacing all wooden poles on a circuit reduces a) the probability of ignition and b) the consequence of ignition, separately.

ANSWER 31

PG&E objects to these requests as vague, ambiguous, overbroad and unduly burdensome. Subject to and notwithstanding these objections, and without waiving the right to object to the introduction of its response into evidence, PG&E responds as follows:

a. The units provided under “typical reconstruction per circuit mile” on workpaper table 9-12 were developed from estimates based on historical experience of constructing similar projects and engineering judgement. See PG&E’s response to TURN_003 Q01, which provides the Excel workpapers for Exhibit (PG&E-4), Chapter 9.

b. The unit costs provided under “typical reconstruction per circuit mile” on workpaper table 9-12 were developed from historical experience of constructing similar projects and engineering judgement. The unit costs also include anticipated savings / efficiencies from jointly performing multiple types of work at once on de-energized lines.

c. The costs provide under “typical reconstruction per circuit mile” on workpaper table 9-12 were developed by multiplying the units and unit costs shown, summing the line items, and reducing the total by 10% to capture economies of scale.

d. In responding to this question, PG&E interprets Non-exempt Transformer replacement to refer to two distinct types of work; non-exempt equipment replacements and transformer replacements.

   Yes. As part of the upgrade process as forecast, PG&E proposes to replace all wood poles with non-wood poles, replace all non-exempt equipment with exempt equipment, and replace all overhead transformers that are more than five years old on the circuits miles targeted by the program. These lines will typically be de-energized during the rebuilding process when the upgrades will be performed.

e. Pole replacements (with non-wood) are necessary to support the installation and added weight of covered conductors.

f. The replacement of wood poles with non-wood poles increases the fire resiliency of the distribution line structure and provides additional strength to support the heavier covered conductor. The likelihood of ignitions is decreased by the covered conductor supported by the non-wood poles, not the non-wood poles themselves. The probability of a pole failing due to fire is reduced by using non-wood poles as they have been proven through testing to withstand conditions posed by wildfires. One additional benefit of non-wood poles is that they are more likely to survive wildfire events and therefore facilitate more rapid power restoration.

Attachment 2

PG&E 2020 GRC - PG&E Response to DR TURN 36-1

PACIFIC GAS AND ELECTRIC COMPANY
2020 General Rate Case Phase I
Application 18-12-009
Data Response

PG&E Data Request No.:	TURN_036-Q01		
PG&E File Name:	GRC-2020-PhI_DR_TURN_036-Q01		
Request Date:	June 7, 2019	Requester DR No.:	036
Date Sent:	June 25, 2019	Requesting Party:	The Utility Reform Network
PG&E Witness:	Steve Calvert	Requester:	Marcel Hawiger

SUBJECT: EXHIBIT (PG&E-4), CH. 9 (GH)

QUESTION 01

WP Table 9-12 (p. WP 9-15) and Follow-up to Response to TURN DR 03-031:

a. Does the $528,000 per circuit mile for "covered overhead conductor" include any costs for pole replacements necessary to support covered conductor?
   i. If yes, please quantify the number of pole replacements assumed and explain how this has been incorporated.
   ii. In no, please explain where those costs are forecast.
b. Please explain in detail the nature of the "non-wood poles" item forecast at $600,000 per circuit mile, including at a minimum:
   i. Does PG&E intend to replace every pole along the circuit? Why or why not? If not, how many of the poles per circuit mile is PG&E forecasting will be replaced.
   ii. Re. DR 03-31(e) and (f) - Is it PG&E's position that every wood pole along a circuit that is being reconductored with covered conductor must be replaced solely to support the additional weight of covered conductor?
      1. If yes, please provide any supporting data or pole loading analysis.
      2. If no, please explain what number (and percentage) of poles would need to be replaced solely due to conductor weight, and what portion is due to the fire resiliency benefit of non-wood poles?
c. Re. DR 03-31(d) – When PG&E states that the Table 9-12 forecast includes replacing "all non-exempt equipment," does the cost forecast include the replacement of surge arresters on the poles? If yes, please quantify the number of surge arresters, and explain how PG&E prevents double counting with the non-exempt surge arrester replacement program.

ANSWER 01

a. No. The $528,000 per circuit mile for "covered overhead conductor" excludes the costs for pole replacements necessary to support covered conductor. The pole costs are shown on the line above on the same workpaper as “non-wood poles”, estimated at $600,000 per circuit mile.

b. PG&E responds as follows:

   i. As discussed in PG&E’s opening testimony, PG&E intends to replace every pole along the circuits being hardened, consistent with PG&E’s overhead system hardening design. See Ex. (PG&E-4), Ch. 9 testimony p. 9-34, lines 5-9. PG&E initially intended to replace all wood poles with non-wood poles, but its current design contemplates the use of wood poles in some circumstances. All poles will be appropriately sized to support the additional weight of covered conductor.

   ii. In addition to the increased pole strength necessary to support the additional weight of covered conductors, PG&E’s use of non-wood poles along circuits that are being reconductored with covered conductor is intended to provide improved fire resiliency.

c. PG&E’s Overhead System Hardening program forecast shown on Table 9-12 includes replacing “all non-exempt equipment,” which would include surge arresters. Note, however, that the cost of replacing non-exempt surge arresters was not specifically included in forecast. PG&E estimates that that there are 12,258 locations in HFTD Tier 3 areas with non-exempt surge arresters that require replacement and grounding correction.[1]

   As forecast, PG&E’s Overhead System Hardening program intends to rebuild 7,100 miles of circuits, primarily in HFTD Tier 3 areas, over the course of 10 years. In addition, as discussed in PG&E’s opening testimony at Exhibit (PG&E-4) pp. 2A-38 to 2A-40 and 2A-46 to 2A-49, the program is subject to considerable uncertainty. As a result, most non-exempt surge arrester locations in Tier 3 HFTD areas would not be replaced in the Overhead System Hardening program for a number of years. By contrast, PG&E’s Non-Exempt Surge Arrester Replacement program is forecast to be complete by December 2022 (and is planning to give priority to Tier 3 HFTD locations).

   In order to reduce fire risk related to surge arresters on a more timely basis, PG&E plans to replace non-exempt surge arresters as part of the Non-Exempt Surge Arrester Replacement program. If and when circuits are subsequently rebuilt as part of the Overhead System Hardening program, PG&E will re-use previously installed exempt surge arresters and grounding rods to the extent possible. Labor costs related to any incremental surge arrester work needed as part of the Overhead System Hardening program are expected to be low since electric lines will be de-energized and are undergoing a complete rebuild, including pole replacements and attachments.

[1] This estimate was prepared as part of a prior data response to the Office of Public Advocates concerning PG&E’s Non-Exempt Surge Arrester Program (which is described in PG&E’s opening testimony at Exhibit (PG&E-4) pp. 6-43 to 6-46). *See* GRC-2020-PhI_DR_PubAdv_199-Q16, attached here as GRC-2020-PhI_DR_TURN_36-Q01Atch01.

Attachment 3

WMCE - PG&E Response to DR TURN 3-5

PACIFIC GAS AND ELECTRIC COMPANY
Wildfire Mitigation and Catastrophic Events
Application 20-09-019
Data Response

PG&E Data Request No.:	TURN_003-Q05		
PG&E File Name:	2020WMCE_DR_TURN_003-Q05		
Request Date:	December 2, 2020	Requester DR No.:	PGE-003
Date Sent:	December 16, 2020	Requesting Party:	The Utility Reform Network
PG&E Witness:	Sandra Cullings	Requester:	Marcel Hawiger

QUESTION 05

PG&E states on p. 2-18, lines 23-24, that it "completed hardening for 171 distribution line miles in HFTD areas." However, PG&E states on p. 2-44, line 22, that it completed 125.3 circuit miles.

a. Please explain and reconcile the two figures, including the number of miles for which PG&E seeks cost recovery.

b. In Excel, please provide the cost of system hardening work by activity – e.g., covered conductor, pole replacement, undergrounding, etc – and in total. Please provide all supporting workpapers.

c. Please provide the total unit cost per mile for this work by individual activity.

d. Please provide the "circuit protection zones" this work was completed for that match prioritization list based on highest to lowest risk circuits/areas of PG&E's grid used to prioritize system hardening work. TURN understands this can be found in a PG&E GRC data request – – "GRC-2020-PhI_DR_TURN_003-Q07Atch02" - tab "DX-SH." If not, please provide the prioritization list used with the data requested in Excel and an explanation of how prioritization was conducted.

e. Please add a column to the spreadsheet GRC data response (referenced in part (d)) that indicates the type of work performed and number of corresponding miles (e.g., undergrounding, covered conductor, etc.). For pole replacements, please indicate the number of poles replaced due to the weight of covered conductor versus some other reason (and state the reason).

ANSWER 05

a. 171 miles is the total number of distribution line miles PG&E hardened in 2019. As stated on page 2-44, lines 22-23, of these 171 completed miles, PG&E in this filing only seeks cost recovery for 125.3 miles. Please refer to page 2-46, lines 20-27 for a further breakdown of the 125.3 completed miles being sought for recovery.

b. PG&E tracks System Hardening costs at the project level and did not track cost information at the activity level for 2019. For each job, PG&E tracks the miles completed, but does not track individual activity costs within each order. Please reference Workpaper Table 2.B.2-2 for information on the 2019 System Hardening miles completed.

c. Please refer to the answer provided to question 5.b in this set.

d. See attachment 2020WMCE_DR_TURN_003-Q05Atch01 for the list of each Circuit Protection Zone (CPZ) and corresponding risk rankings completed for the 113.2 miles of 2019 System Hardening work recorded to MAT 08W. The circuit protection zone rankings included in the attached spreadsheet are derived from the prioritization model that was used at the beginning of 2019 to develop the 2019 System Hardening workplan. For the 12.1 miles of Idle Facilities removal recorded to MAT 2AF, no risk rankings were created as these facilities are not energized and are not necessary for the operations of the system.

e. Please refer to the answer provided to question 5.b.

Attachment 4

WMCE - PG&E Response to DR TURN 3-7

PACIFIC GAS AND ELECTRIC COMPANY
Wildfire Mitigation and Catastrophic Events
Application 20-09-019
Data Response

PG&E Data Request No.:	TURN_003-Q07		
PG&E File Name:	2020WMCE_DR_TURN_003-Q07		
Request Date:	December 2, 2020	Requester DR No.:	PGE-003
Date Sent:	December 16, 2020	Requesting Party:	The Utility Reform Network
PG&E Witness:	Sandra Cullings	Requester:	Marcel Hawiger

QUESTION 07

Please provide the amount of wildfire risk mitigated due to each activity of system hardening, separately. Please provide in Excel with all supporting workpapers.

ANSWER 07

PG&E does not track System Hardening wildfire risk at the activity level. PG&E can provide system level forecast of risk reduction at the system level but cannot provide this information based on the actual miles performed in historical years.

Attachment 5

WMCE - PG&E Response to DR TURN 3-16

PACIFIC GAS AND ELECTRIC COMPANY
Wildfire Mitigation and Catastrophic Events
Application 20-09-019
Data Response

PG&E Data Request No.:	TURN_003-Q16		
PG&E File Name:	2020WMCE_DR_TURN_003-Q16		
Request Date:	December 2, 2020	Requester DR No.:	PGE-003
Date Sent:	December 16, 2020	Requesting Party:	The Utility Reform Network
PG&E Witness:	Sandra Cullings	Requester:	Marcel Hawiger

QUESTION 16

Re the 125.3 miles of system hardening described on pp. 2-46 to 2-47:

a. Please explain whether covered conductor was installed on all or a portion of these miles.

b. Please provide total and unit (mile or asset) individual activity for the activities described on p. 2-47, lines 1-4.

c. For each activity provided in part (b), please provide the average recorded cost for this activity from 2012-2018, in Excel with all supporting workpapers.

d. For the 2,805 poles retired and 3,766 new poles installed, please provide a list of all poles (separately for the retired and new poles) that includes the pole identification number and the pole size classification.

e. For a random selection of 100 poles that were removed, please provide the reason why the pole was removed, and explain whether documentation exists to verify the reason cited by PG&E. Please provide such documentation.

f. Please identify how many poles were removed due to "overloading," and how this was determined.

ANSWER 16

a. The breakdown of the 125.3 System Hardening miles completed in 2019 is as follows:
    - 13.9 miles of removal
    - 3.4 miles of undergrounding
    - 108.0 miles of overhead

Of the 108.0 miles of overhead work, covered conductor was installed on all 108.0 miles

b. Please refer to response 5.b in the set.

c. The System Hardening program did not exist prior to 2019, so no costs were incurred for the System Hardening program from 2012-2018.

d. While PG&E tracks each pole with a unique identifier for operational purposes, this information is currently not tracked in a manner that would allow PG&E to align the data with the specific cost information.

e. See response to question 16.d. above.

f. See response to question 16.d. above.

Attachment 6

WMCE - PG&E Response to DR TURN 9-5

PACIFIC GAS AND ELECTRIC COMPANY
Wildfire Mitigation and Catastrophic Events
Application 20-09-019
Data Response

PG&E Data Request No.:	TURN_009-Q05		
PG&E File Name:	2020WMCE_DR_TURN_009-Q05		
Request Date:	January 8, 2021	Requester DR No.:	009
Date Sent:	March 2, 2021	Requesting Party:	The Utility Reform Network
PG&E Witness:	Sandra Cullings	Requester:	Eric Borden

All page references refer to PG&E's opening testimony unless otherwise specified.

QUESTION 05

For all overhead projects listed in Excel workpaper WP 2B.2-2, please provide in aggregate the costs and, number of miles or assets (whichever is applicable) of the system overhead hardening program including but not limited to the following:

a. Covered conductor – number of miles and associated cost, including pole replacements.
b. Pole replacements not related to covered conductor installation;
c. Transformers;
d. Fuses;
e. Other equipment – please detail.

ANSWER 05

a. In 2019, PG&E installed 108 miles of covered conductor and completed 3,766 pole replacements as part of System Hardening at a total cost of approximately $217.8 million.

b. PG&E does not track data for pole replacements specifically not related to covered conductor. However, the majority of pole replacements were related to covered conductor and are thus included in our response to 5.a. above.

c. In 2019, 1,407 transformers were part of System Hardening. PG&E does not currently track cost information at the asset level.

d. In 2019, 3,533 fuses were part of System Hardening. PG&E does not currently track cost information at the asset level.

e. No 'other equipment' detail exists.

Attachment 7

WMCE - PG&E Response to DR TURN 9-7

PACIFIC GAS AND ELECTRIC COMPANY
Wildfire Mitigation and Catastrophic Events
Application 20-09-019
Data Response

PG&E Data Request No.:	TURN_009-Q07		
PG&E File Name:	2020WMCE_DR_TURN_009-Q07		
Request Date:	January 8, 2021	Requester DR No.:	009
Date Sent:	February 10, 2021	Requesting Party:	The Utility Reform Network
PG&E Witness:	Sandra Cullings	Requester:	Eric Borden

All page references refer to PG&E's opening testimony unless otherwise specified.

QUESTION 07

PG&E's testimony at p. 2-47, line 1 states PG&E accomplished "108 miles overhead equipment replacement" as part of system hardening:

a. Please provide a definition of "overhead equipment replacement" including what assets this refers to (e.g. transformers, surge arrestors, fuses, poles, etc.).

b. Please explain whether PG&E replaces all assets that are included as part of overhead equipment replacement.

c. Please provide the total number of poles installed on these 108 overhead miles before the system hardening program.

d. Please provide the number of each type of asset listed in part (a) before the system hardening program.

e. Please provide the number of each type of asset replaced due to system hardening listed in previous sub-parts.

f. Please provide the number of assets replaced because they were failing, deteriorated or in any condition that would violate compliance requirements, by asset type.

g. Please explain how and under what criteria PG&E decided to replace certain assets as part of this program.

ANSWER 07

a. Overhead equipment replacement refers to equipment replaced as part of overhead system hardening. The assets comprising overhead equipment for system hardening includes poles, crossarms, fuses, tree wire, insulators, angle washers, storm guys, aerial cable, transformers, tie wires, insulated jumpers, surge arrestors, switches, and reclosers. For additional detail, please refer to attachment 2020WMCE_DR_TURN_009_Q07Atch01 (PG&E standard TD-9001B-009) which outlines PG&E's system hardening requirements for overhead equipment replacement.

b.

Per PG&E standard TD-9001B-009 (attachment 2020WMCE_DR_TURN_009-Q07Atch01), PG&E replaces the majority of the assets. If certain assets are already hardened (such as service wire, covered secondary, exempt fuses, etc.), PG&E does not replace those assets.

c. PG&E does not maintain historical records at the level of detail sought in the question. PG&E only maintains current data for operational purposes, and thus does not have data available regarding the number of poles present before the system hardening projects were completed.

d. Please see PG&E's response to 7.c. above.

e. Please refer to PG&E's response to TURN-003, question 5.b.

f. The goal of PG&E's system hardening program was to harden assets as required by the system hardening standard (attachment 2020WMCE_DR_TURN_009-Q07Atch01) regardless of whether the assets were failing or deteriorating. Therefore, PG&E cannot provide the number of assets replaced because they may have been failing or deteriorating.

g. Please refer to attachment 2020WMCE_DR_TURN_009-Q07Atch01 (PG&E standard TD-9001B-009) which outlines PG&E's design guidance for System Hardening.

Attachment 8

WMCE - PG&E Response to DR TURN 9-7 Attachment

Fire Rebuild Design Guidance for System Hardening

SUMMARY

This document describes the standard Overhead design requirements for all **new construction and reconstruction work in Tier 2 and Tier 3 Fire Areas, and Zone 1 (tree mortality) areas**. In many cases, the requirements listed are current standard requirements or special application requirements used in new construction.

The requirements outlined in this bulletin are not intended or required for maintenance and emergency work (unless the emergency is in follow-up to a fire event, requiring system rebuild).

The information in this bulletin is available for use immediately but will be **effective on 1/15/20**. Take reasonable steps to implement requirements as soon as practical. These requirements do not apply retroactively to rebuild work completed to date. In addition, some requirements may change in the future as we gather more information and receive feedback.

This bulletin supersedes bulletin TD-9001B-009 Rev 1**.**

Level of Use: Informational Use

AFFECTED DOCUMENT

See Reference Documents in Overhead and Underground tables below.

TARGET AUDIENCE

The target audience is Service Planning, Estimating, Capacity & Reliability Planning Engineering, and Electric M&C personnel and contractors associated with the fire rebuild areas.

WHAT YOU NEED TO KNOW

1. Overhead Design and Construction Requirements:

Requirement	Reference Document(s)	Intent
1.1. The following are the PG&E standard conductor sizes allowed in Tier 2 and Tier 3 areas: • 1/0 ACSR Tree wire[1] • 397 All Al Tree wire[1]	059690 059626	Current standard for new construction, reduces risk of wires down due to mechanical

[1] Refer to bulletins TD-059626B-005 for information on this conductor, including material code, ampacity, sag curve, and construction requirements

Fire Rebuild Design Guidance for System Hardening

Requirement	Reference Document(s)	Intent
• 715 All Al Tree wire[1] For corrosion/coastal areas use: • #2 CU Tree wire • 397 All Al Tree wire • 715 All Al Tree wire	076251 TD-059626B-005	failure/deterioration of wire which reduces risk of wildfire ignition caused by wires down faults
1.2. The required setting depth shall be adjusted using the table listing set depths by pole length provided in Attachment 2.	015203	The “Rule of Thumb” for High Fire Threat Design (HFTD) T2-T3 Setting Depth is: • **10%+3 ft** for all poles up to and including 65 feet • **10%+2.5 ft** for all poles = 70 feet • **10%+2 ft** for all poles longer than 70 feet
1.3. A pole loading calculation (PLC) must be performed using either PLS CADD or O-Calc Pro® software tools on each pole prior to construction. This applies to all PLCs, including those submitted by third parties. New direction regarding safety factors will be released with an update to O-Calc.		

Fire Rebuild Design Guidance for System Hardening

Requirement	Reference Document(s)	Intent
1.4. The PLC must be evaluated with a special load case designed for HFTD Tiers 2 & 3; 1.4.1. GO 95 minimum requirements for wind, ice/snow, and temperature are covered 1.4.2. "HFTD T2-T3 Peak Wind" load case: • Wind Speed Load Case is pre-selected from EDGIS wind gust speed layer Ensure the appropriate load case is selected where Construction Grade (A vs. B) is changing or when switching between existing and new poles. **The extreme wind loading requirement is not intended or required for emergency work, work only involving a single location or temporary construction in the affected fire areas. Local personnel may make exceptions to this based on local conditions, knowledge and history for site specific scenarios. Use the Variance Process for these exception requests.**	TD-9001B-010 TD-2951P-01	The intent of this requirement is to ensure poles are strong enough to withstand higher wind speeds. Tailored load cases (HFTD T2-T3 Peak Wind) will be deployed along with this bulletin that incorporate known wind speeds from local studies and fire safe design criteria. HFTD T2-T3 uses recent wind study data that measured wind gusts at 10 meters above ground level; these are the wind speeds shown in the Environment window in EDGIS WebViewer. Refer to the O-Calc job aid for instructions on how to evaluate HFTD T2-T3 peak wind in O-Calc Pro®.
1.5. <u>Do not</u> increase pole class by 1 class per TD-015203B-002, "High Wind Area Criteria for Distribution Wood Poles".	TD-015203B-002	The requirement to increase class size is no longer required, as the appropriate sizing is now accounted for with the load cases in 1.4.
1.6. Consider the use of fire rated composite poles in Tier 2 and Tier 3 areas, areas with extreme wind conditions and areas with woodpecker issues. These poles can also be used to meet other construction needs, including maintenance	TD-066202-B001	

Fire Rebuild Design Guidance for System Hardening

Requirement	Reference Document(s)	Intent
1.7. Build to standard Triangular Crossarm construction (Using PG&E approved bonded Composite Crossarm). Pole-top extensions are not allowed if it requires the current framing to be changed from triangular to flat.	066196	Raptor construction is not necessary with tree wire.
1.8. All insulators, including post and pin types, that support span wires and slack spans (excluding jumper supports) must have angle washers installed at the top and bottom of the composite arm. This construction applies to tangent, angle and slack span construction for wind loading reinforcement purposes.	068180 will be revised to reflect this requirement.	Field personnel must ensure changes are executed in the field.
1.9. Trees are not to be used as a means of attaching primary, secondary, or services. Trees are also not an approved means for anchoring or guying of any poles.	TD-2999B-044	
1.10. In heavily wooded areas, never use trees for guy support. Consider the increased vegetation clearance planned in HFTD Tiers 2 & 3 and determine if the newly available lead length is enough to support the pole.		

Fire Rebuild Design Guidance for System Hardening

Requirement	Reference Document(s)	Intent
1.11. Due to the wind speed, new un-guyed (e.g. tangent) poles may require larger class sizes than historically designed. Storm guys may be used as an option to offset the need for a larger pole class. Consider changing the route, using shorter span lengths, or increase the pole class and set depth as needed until the pole loading model shows a passing safety factor. The use of storm guys will require consultation with the Land Department to determine and/or obtain land rights (easements).		
1.12. Ensure clearances are met with the greater sags of tree wire. Sags for tree wire can be much greater than bare wire and set depths are deeper leaving less room for clearances.		Example: Bare 2 ACSR in heavy loading has a 10’ sag on a 400’ span. 1/0 ACSR TW has a 15’ sag for the same span. For a 45’ pole set 7.5’ deep the clearance for the 1/0 ACSR TW is only 22.5’
1.13. The prior 200-foot span requirement is now a recommendation.		Try to limit span lengths to 200’ or less when possible due to increased sags.
1.14. No new in-line splices to be installed. (This requirement does not apply to repairs as part of repair, restoration and emergency activities. However, all splices must be covered.)	TD-022487B-003	Current standard for new construction, reduces risk of wires down due to splice failure which reduces risk of wildfire ignition caused by wires down faults
1.15. Replace all open-wire secondary with ACSR aerial cable or AWAC aerial cable.	059690	Current standard for new construction improves reliability and reduces risk of wires down due to tree contact. This reduces risk of wildfire ignition caused by wires down faults.
1.16. Only transformers with FR3 insulating fluid are allowed in Tier 2 and Tier 3 fire areas		FR3 fluid standards were implemented in 2014 and latest DOE high efficiency standards were implemented in 2016.

Fire Rebuild Design Guidance for System Hardening

Requirement	Reference Document(s)	Intent
1.17. Ensure that all transformer locations are fully bird/animal guarded and include insulated jumpers	061149	Reduces risk of wildfire ignition caused by bird/animal contact with equipment
1.18. Ensure that all risers and equipment locations are fully bird/animal guarded and include insulated jumpers	061149	Reduces risk of wildfire ignition caused by bird/animal contact with equipment
1.19. Ensure that any Regulator installations are Closed-Delta with SCADA.	TD-015239B-003	Current standard for new construction, improves reliability by reducing restoration time
1.20. Install Cal Fire Exempt surge arrestors per 031822 (Check with Planning Engineer).	031822	Current standard for high fire areas, reduces risk of wildfire ignition caused by equipment operation
1.21. Install Cal Fire Exempt equipment only – no new, non-exempt equipment shall be installed; install ELF or Fault Tamer fuses for transformer protection and E-power fuses for lateral and riser protection (see Fuse decision tree). Install E fuses when fusing is required in fire areas. If coordination is not possible, installing an ELF fuse[2] at the discretion of the responsible distribution engineer is acceptable.	015225	Current standard for high fire areas, reduces risk of wildfire ignition caused by equipment operation

Requirement	Reference Document(s)	Intent
1.22. Use PG&E approved Composite Tie Wires or Covered Tie Material Code 290299, use pressed connectors or Fired Wedge connectors. All skinned conductors (e.g. Dead ends, T Connections) must be covered with approved raptor covers or taped up (medium voltage fusion tape material code M390190). Do not make connections under conductor covers. Piercing hot line connectors are not allowed to be used.	015195 021349 028853	
Three-phase switching devices as required by the local planning engineer: 1.23. Use automated line equipment (i.e. switches, regulators, etc.).		
1.24. Add SCADA to the existing switching device or install new SCADA MSO switch for isolating from one tier to another (i.e. Tier 1 from Tier 2, Tier 2 from Tier 3, Tier 1 from Tier 3). If required for system protection, use a line recloser.		
1.25. Phase Balancing: stagger transformer and single-phase lateral tap line connections to balance phase loading. On 3-phase line sections DO NOT reconnect transformers solely to the two outside phases.		

[1] Refer to bulletin TD-059626B-005 for information on this conductor, including material code, ampacity, sag curve, and construction requirements

[2] A current limiting fuse may not coordinate with downstream protective devices.

2. How and When to Apply the New Requirements for Reconstruction:

2.1. All designs and estimates not started prior to 9/1/19 must comply with these requirements. This will include jobs which may require revisions taking place after the 9/1/19 date.

2.2. For reconstruction jobs involving 4 spans or more, all assets must be constructed to comply with the requirements in this bulletin.

2.3. When replacing a pole to the new standard where there is an existing transformer on the pole, also replace the transformer to the new standard. (Per note 1.16, only use transformers with FR3 insulating fluid.)

2.4. All services must be insulated, and service poles must be sized according to GO95 standards. (Per note 1.14, replace all open wire secondary when adjacent to a transformer.)

2.5. The requirements outlined in this bulletin are not intended or required for maintenance and emergency work. For emergency work, work within company policies to restore service safely, quickly.

2.6. The requirements outlined in this bulletin are not intended or required for Temporary construction, including interim construction work in Tier 2 and Tier 3 areas to support clean up and reconstruction of the fire affected areas where ultimately the permanent system will be rebuilt as underground system within the next 24 months.

2.7. If an existing slack span is being reconductored to the new covered tree wire, refer to TD-059626B-005 Table 8 for the maximum span length and stringing sag limits. When an existing span exceeds Table 8 and there is no room to guy for full tension or add poles to meet the Table 8 span length requirements, longer span lengths are permitted under reduced tension. If there are no clearance issues (i.e. tree, secondary and communication), a slightly larger sag may be permitted.

2.8. Reduced tension should only be called for when all other options have been exhausted. Reduced tension will require changing the required sag using the "sag to tension" feature in O-Calc. to calculate pole loading without guying. Basically, acting as a self-supported pole. For reduced tension the following is required: Frame with dead-ends instead of slack span preforms, specify the required reduced tension stringing sag derived from O-Calc on the construction drawing and document O-Calc as to why reduced tension is being used. If there are no clearance issues (i.e. tree, secondary and communication), a slightly larger sag may be permitted.

2.9. For calculating minimum requirements for customer cost, these are the new construction standards in the applicable areas and should be treated similar to any other application of our construction standards.

2.10. Coordinate with Joint Utilities team as needed.

Document Approver

[redacted], Director, Standards and Work Methods

DOCUMENT CONTACT

[redacted], Supervisor, Electric Distribution Standards

[redacted] Principal Electric Process Engineer, Engineering Center of Excellence

Fire Rebuild Design Guidance for System Hardening

[redacted] Manager, Engineering Center of Excellence

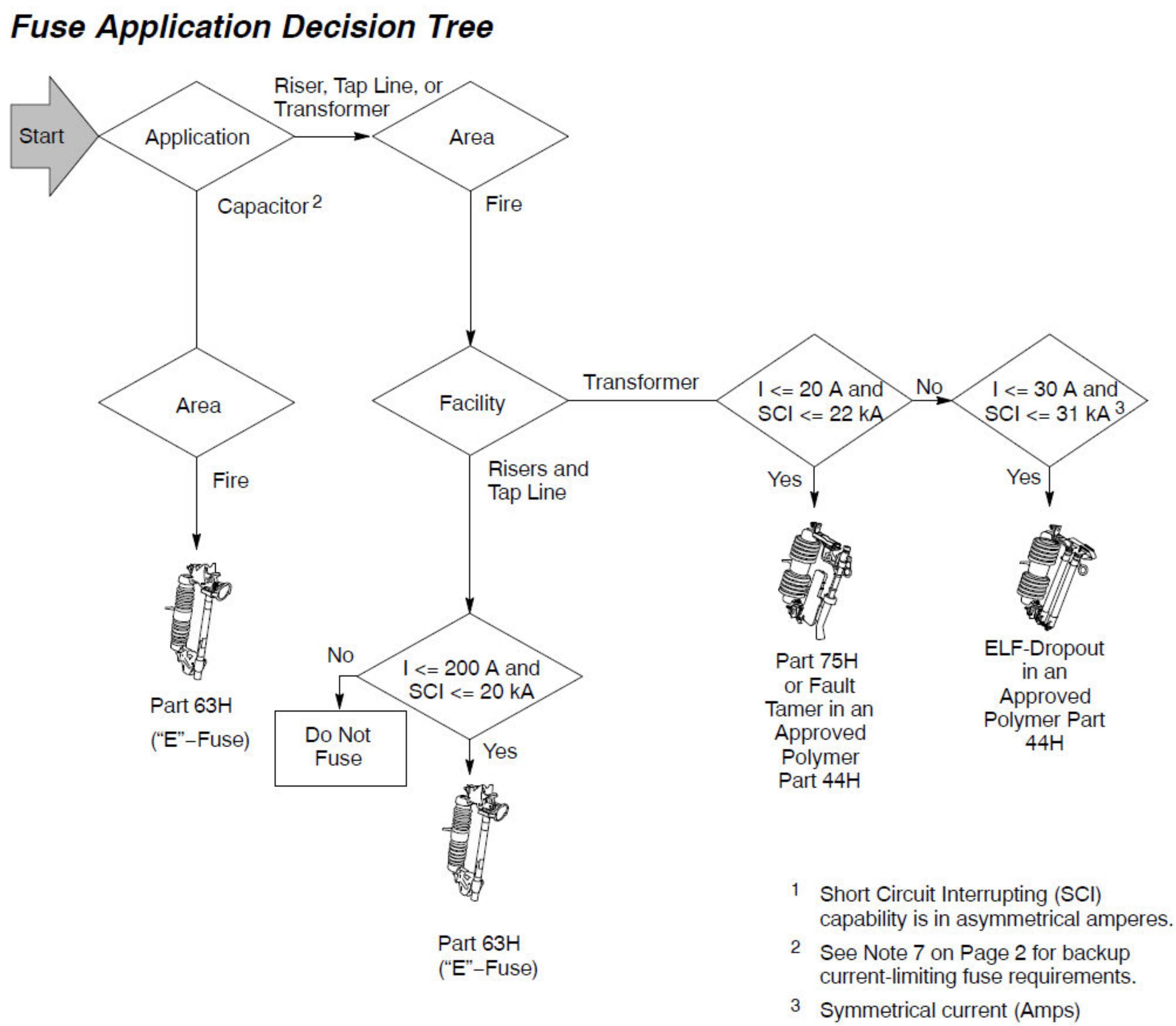
INCLUSION PLAN

Affected documents will be updated to include the design criteria in this bulletin.

Fire Rebuild Design Guidance for System Hardening

ATTACHMENT 1: Fuse Application Decision Tree

The following should be used in determining the appropriate fuse to be used in a Fire Area:



Note: Install Polymer Part 44H with ELF dropout door in the event coordinating with the appropriate E fuse is not possible

ATTACHMENT 2: Setting Depths

Note: For poles set in rock use GO 95 minimum set depths. For poles set in rock, use GO 95 values as a minimum since the overturn strength of the soil (rock) will be sufficient. (See below Table 6 – GO 95, Rule 49.1)

Pole Setting Depths - Pole Strength vs. Overturn		
Length	Rule of Thumb	
	10% + 2	10% + 3
25		5.5
30		6
35		6.5
40		7
45		7.5
50		8
55		8.5
60		9
65		9.5
70	9.5*	
75	9.5	
80	10	
85	10.5	
90	11	
95	11.5	
100	12	
105	12.5	
110	13	
115	13.5	
120	14	
125	14.5	

Table 6 – GO 95, Rule 49.1 Minimum Pole Setting Depths	
Total length of pole (feet)	Depth in Rock (feet)
20	3
25	3
30	3
35	3 ½
40	3 ½
45	4
50	4
55	4 ½
60	4 ½
65	5
70	5
75	5 ½
80	6

*Note: 70-foot pole “Rule of Thumb” value is 10%+2.5 to maintain consistency of the overall table

Attachment 9

Excerpts from Opening Brief of The Utility Reform Network
filed September 11, 2020

FILED
09/11/20
04:59 PM

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) for Authority to Increase its Authorized Revenues for Electric Service in 2021, among other things, and to Reflect that Increase in Rates.	Application 19-08-013 (Filed August 30, 2019)

OPENING BRIEF OF THE UTILITY REFORM NETWORK

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September 11, 2020

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demonstrates the asset poses any risk. SCE has not demonstrated that wholesale replacement is reasonable or necessary.[261] Finally, TURN recommends that the Commission reject proposed funding of Distribution Fault Analysis (DFA) pending the final results of the utility's ongoing DFA pilot.[262]

15.2 Covered Conductor Program: TURN's Proposed Covered Conductor Budget Addresses SCE's Highest Risk Circuits at a Reasonable Cost.

SCE proposes significant expenditures to address wildfire, its top public safety risk, requesting $733,024,000 for covered conductor in Test Year 2021 alone, and increasingly higher amounts in 2022 and 2023, for a total of $2.7 billion for 2021-2023.[263] Ultimately, SCE seeks approval of costs related to the installation of 6,200 circuit miles of covered conductor in the utility's High Fire Threat District (HFTD) between the years of 2019-2023 at a total price tag of $3.4 billion.[264] As explained by SCE Witness Roy, SCE sized its deployment based on the "maximum amount of covered-conductor miles due to resource constraints that [SCE] could execute over that five-year period" rather than considerations of cost-effectiveness or affordability.[265] However, the proposed maximum deployment of covered conductor comes at a steep price tag and corresponding impact on affordability; indeed, SCE's covered conductor proposal represents 90% of its wildfire capital request.[266]

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[261] Ex. TURN-02 (Borden), p. 1:16-17.

[262] Ex. TURN-02 (Borden), p. 1:13-15.

[263] Ex. SCE-54, p. 190.

[264] Ex. SCE-15, Vol. 5 (Roy), p. 14:20; Ex. SCE-54, p.190.

[265] 8 TR 930:6-9 (SCE/Roy).

[266] Ex. TURN-02, Figure 1, p. 5.

TURN agrees that covered conductor plays an important part in wildfire mitigation efforts and proposes a budget sufficient to fund the installation of over 2,500 circuit miles of covered conductor between 2021 and 2023.[267] The TURN budget better incorporates affordability concerns, targeting ratepayer dollars at the highest risk circuits while still providing for a significant expansion of covered conductor- likely the largest in the world.[268] Acknowledging that no single mitigation is sufficient to address wildfire risk, TURN recommends only limited changes to the remainder of SCE's budget for wildfire mitigation. Specifically, TURN does not oppose SCE's proposed 2021forecast for Enhanced Overhead Inspections and Remediations (aside from adjustments related to vertical switches), Fire Science and Advanced Modeling, Sectionalizing Devices, Public Safety Power Shutoff (PSPS) Execution and Undergrounding.[269]

In sum, the Commission should reject SCE's forecast for covered conductor in favor of TURN's forecast. TURN's proposal targets scarce ratepayer dollars at the highest risk circuits consistent with the principles of just and reasonable ratemaking. TURN takes no position at this time on the scope of installation of covered conductor beyond the rate case period; TURN recommends a narrower scope in this case, chiefly to adjust the pace of covered conductor installation to limit the deleterious impact on short-term and long-term customer rates.

TURN's recommendation is fully consistent with safety, and any utility arguments framing it as otherwise are disingenuous at best. SCE suggests that TURN's proposal to slow the pace of covered conductor installation and reduce the associated forecast leaves Californians

[267] Ex. TURN-02, p. 1:18-24.

[268] Ex. TURN-02, p. 6:23-24.

[269] Ex. SCE-15, Vol. 5 (Roy), Table I-3, p. 6.

susceptible to undue risk.[270] Consistent with precedent, the Commission should reject any such suggestion outright:

> DRA and TURN represent ratepayer interests which may well be at odds with employee or management or shareholder interests during a GRC. That does not mean that recommended cuts equate with a 'pathology of indifference' or blatant disregard of safe operations, or a failure to see linkage between maintenance and reliability, for example. It means that these parties view SCE's methods and activities through a different lens of reasonableness.[271]

It is in the best interest of both shareholders and ratepayers that SCE avoid catastrophic wildfires. TURN proposes that, in recognition of both safety and affordability concerns, SCE employ a suite of wildfire mitigations while adjusting the pace at which one of its highest cost mitigations is deployed. As stated above, TURN has not opposed multiple other mitigations proposed by the utility, and SCE has or will spend considerable sums from 2018-2020 to mitigate wildfire risk.

15.2.1 SCE Has Not Targeted Deployment of Covered Conductor Consistent with Just and Reasonable Rates

As stated by the Commission, "[v]irtually everything a utility does [has] some nexus to safety," thus "the emphasis should be on those initiatives that deliver the optimal safety."[272] Rather than scoping its program by identifying those circuits where the utility can achieve "optimal safety improvement in relation to the ratepayer dollars spent,"[273] SCE's proposed covered conductor program is constrained only by the limits of the utility's resources to install

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[270] Ex. SCE-12, Vol. 1 (Payne), p. 8:19-21.

[271] D.12-11-051, p. 32.

[272] D.14-08-032, p. 28.

[273] D.14-08-032, p.28.

covered conductor.[274] In its review of the SCE Wildfire Mitigation Plan (WMP), the Commission describes the SCE covered conductor proposal:

> Southern California Edison Company (SCE) takes an "all in" approach to the deployment of covered conductor at significant cost with minimal analysis of alternatives or analysis of why this tool warrants extensive use.[275]

SCE Witness Roy explained that SCE's program was sized based on "the maximum amount of covered-conductor miles due to resource constraints that we could execute over that five-year period."[276]

Even though a narrow subset of miles reflects SCE's highest risk circuits, the utility has not used this knowledge to set the pace of its deployment of a costly wildfire mitigation to first target the highest risk segments.[277] SCE has risk analysis capabilities that will allow it to prioritize deployment of covered conductor to the riskiest segments first. SCE states that it "continue[s] to refine our risk analysis to better target the spans that pose the highest risk, and that is where we are focusing our grid hardening efforts."[278] However, rather than use these risk analyses to target the scope and pace of covered conductor installation, SCE uses the detailed information it has on each circuit only to identify the order of circuits for hardening: "The prioritization is driven by risk which is the product of probability and consequence."[279] TURN's

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[274] 8 TR 930:6-9 (SCE/Roy).

[275] WSD-004 (R.18-10-007), p. 10.

[276] 8 TR 930:6-9 (SCE/Roy).

[277] Ex. TURN-02-Atch-01 (Borden), p. 177: "REAX data stratification for HFRA identifies 2161 circuit miles present approximately 93.87% of the risk-consequence for SCE."

[278] Ex. SCE-01, Vol. 1, p. 18:24-25.

[279] Ex. TURN-02-Atch-01 (Borden), p. 137.

criticism of SCE's failure to target ratepayer spending is consistent with the Commission's findings on SCE's WMP: "SCE does not show that it is targeting deployment of initiatives to the highest-risk areas."[280] The Commission further found that "SCE provides little analysis justifying where it targets grid hardening programs for the greatest risk reduction."[281]

SCE's failure to target its spending at the highest risk circuits leaves the SCE plan unaffordable for its customers. SCE's plan to install as much covered conductor as possible does not include a consideration of the program's impact on affordability. While the utility claims that affordability was a part of its considerations designing its proposed program,[282] SCE has not identified what it considers to be cost-prohibitive.[283] Without a threshold for understanding affordability, SCE cannot demonstrate that its proposal is consistent with just and reasonable rates. Especially given the economic uncertainty facing ratepayers in the face of the Covid-19 pandemic, SCE's additional $2 billion for covered conductor on relatively low risk circuits is not just and reasonable.

As described further below, TURN relied on the detailed risk information the utility has developed on its circuits to scope TURN's budget for covered conductor.[284] TURN used the risk profile of each circuit segment not just to identify the order of deployment but to size the

[280] WSD-004 (R.18-10-007) at 27.

[281] WSD-004 (R.18-10-007) at 10.

[282] 3 TR 334:11-17 (Payne): "A What I'm saying is that based on the safety risk that exists and the evaluation of the options that we have to mitigate that risk and all the other factors that I just described, we would arrive at our proposal, which would be what we think is overall the best approach for our customers."

[283] Ex. SCE-47, p.1: "SCE does not maintain a specific percentage increase term or threshold for what would be considered "cost-prohibitive" in this situation."

[284] Ex. TURN-02 (Borden), pp. 14:8-20:8.

program ensuring that each dollar of SCE's spending achieves "optimal safety improvement." As a result, TURN's proposal results in safety improvements at a more affordable cost to ratepayers.

15.2.2 TURN's Alternative Covered Conductor Proposal is Consistent with Just and Reasonable Rates and Should Be Adopted

While TURN offers an alternative scope, TURN supports SCE's reliance on covered conductor as a mitigation "given its potential to significantly reduce wildfire risk, particularly from vegetation contact."[285] TURN's proposal, in essence, addresses the concerns expressed in Resolution WSD-004 that SCE is not "targeting deployment of initiatives to the highest risk areas."[286] Recognizing the failure of SCE to propose a covered conductor program consistent with just and reasonable rates, TURN witness Borden recommends that the information SCE has on each of its circuits be used to develop the scope of the program in the rate case period. Based on this information, TURN proposes a budget sufficient to install 2,581 miles of covered conductor on SCE's highest risk segments.[287]

SCE's deployment prioritization model illustrates that risk is not consistent from circuit to circuit, and, indeed, SCE intends to address the highest risk segments first.[288] If each circuit has a different risk profile, but hardening costs are consistent from circuit to circuit, the cost efficiency of hardening each circuit will vary. Riskier circuits will be more cost-efficient to address, with cost-efficiency declining with each relatively less risky circuit. In Figure 5,

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[285] Ex.TURN-02 (Borden), p.11:17-18.

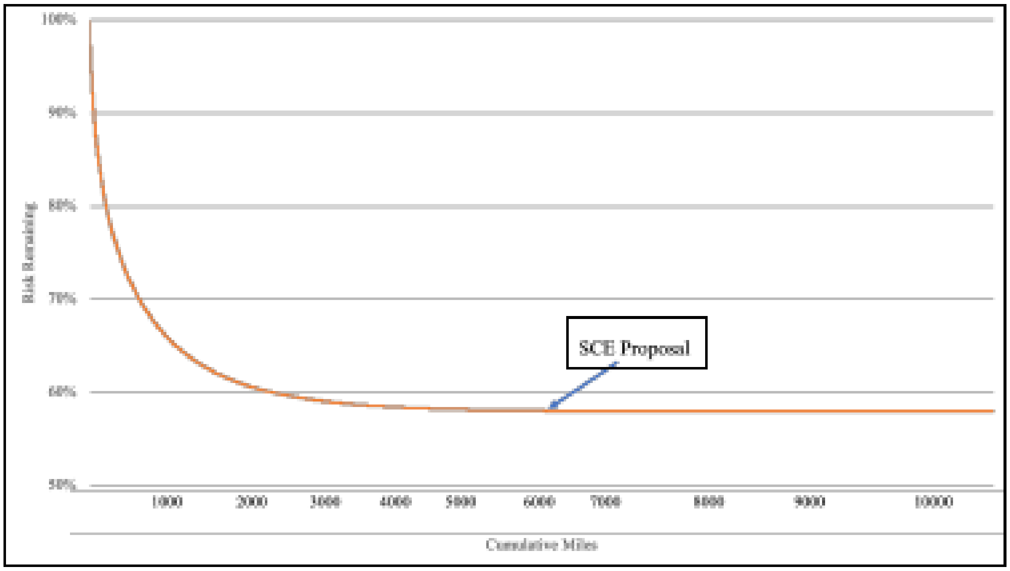
[286] WSD-004 (R.18-10-007), p. 27.

[287] Ex. TURN-02 (Borden), p. 22:21-24:2.

[288] Ex.SCE-001, Vol. 1 (Payne), p. 18:24-25.

reproduced below, TURN witness Borden's testimony illustrates the risk reduction potential of each additional mile of covered conductor installed:[289]

Ex. TURN-02 Figure 5 Wildfire Risk v Cumulative HFRA Miles; SCE GRC Risk Analysis[290]



The steep decline in Ex. TURN-02 Figure 5 demonstrates that SCE's highest risk segments are fairly concentrated. As the slope begins to flatten, each additional mile is less risky on a relative basis. TURN's proposed program focuses ratepayer spending on those circuits that present the most risk.

Based on SCE's prioritization model, TURN's budget is sufficient to address over 90% of SCE's wildfire risk at a fraction of the cost. The Commission has previously adjusted utility budgets accordingly when a utility proposes spending inconsistent with cost efficiency. Specifically, in D.10-06-048, the Cornerstone Decision, the Commission reduced spending on a PG&E reliability project noting that "up to 68% of the quantifiable reliability improvement

[289] Ex. TURN-02 (Borden), Fig. 5, p.20.

[290] Ex. TURN-02 (Borden), Fig. 5, p.20.

benefits identified in PG&E's Cornerstone Improvement Project proposal can be achieved for [] approximate[ly] 18% of the requested costs."[291] Costs that were rejected "[we]re done so without prejudice,"[292] and PG&E was directed that in the future it should demonstrate not just need but also that the chosen alternative is the "optimal solution."[293] Similarly, here, TURN's proposal does not seek to preclude additional future spending on covered conductor, only to limit the scope of covered conductor included in this rate case period.

15.2.3 That SCE's Covered Conductor Addresses More Absolute Risk than TURN's Covered Conductor Program Ignores Affordability

"SCE agrees that the installation of covered conductor in the first few years of the [covered conductor] program will likely capture greater per-mile risk reduction than the miles of conductor covered in the later years of the program."[294] Despite acknowledging declining cost efficiency, SCE argues that TURN's proposal should be rejected as "leav[ing] substantial risk on the system."[295]

As SCE explains, its prioritization curve measures relative risk, rather than absolute risk.[296] In other words, the circuits higher on the curve have a higher risk profile in comparison to circuits further down the curve. The risk curve is so steep because, as SCE acknowledges,

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[291] D.10-06-048, p.1.

[292] D.10-06-048, p.1.

[293] D.10-06-048, p. 2-3: "In developing future reliability improvement programs or projects PG&E must be able to demonstrate the need for such programs or projects, and if there is a need, whether the program or project represents the optimal solution when considering alternatives and cost-effectiveness in the identification and prioritization processes."

[294] Ex.SCE-15 (Roy), Vol.5, p. 21:1-3.

[295] Ex.SCE-15 (Roy), Vol.5, p. 21:3-5.

[296] Ex.SCE-15 (Roy), Vol.5, p. 21:6-14.

“certain circuit segments have extraordinarily high risk values.”[297] SCE argues that TURN’s proposal to target deployment of covered conductor during this rate case period at the riskiest circuits leaves a significant amount of absolute risk not addressed within the rate case. TURN agrees that SCE’s proposal will address more risk, but SCE’s proposal also costs ratepayers $2 billion more at a time where ratepayers are unable to bear such significant rate hikes.

In its Rebuttal Testimony, SCE uses tranches of 1,250 miles along the risk curve to demonstrate the absolute risk of the circuits that would remain unhardened in this rate case period under TURN’s program. SCE’s illustrations of absolute risk demonstrate, however, that TURN’s proposal to harden just over 2,500 miles will still address a significant amount of risk. Table II-7 of SCE’s Rebuttal Testimony, reproduced below, demonstrates that the first 2,500 miles on the risk curve represent not just a relatively higher risk profile or “Reax Score” but also the circuit miles with the greatest consequences per mile.[298]

[297] Ex.SCE-15, Vol. 5 (Roy), p. 21:13-14.

[298] Ex.SCE-15, Vol. 5 (Roy), Table II-7, p. 22.

Ex. SCE-15, Vol. 5 Table II-7: Average Wildfire Consequence Along the Relative Risk Buydown Curve[299]

Tranches of Cumulative Miles on Risk Curve	Average Reax Score for Tranche[50]	Average Wildfire Consequence per Mile for Tranche[51]
0-1,250	6,849	272 structures and 33,036 acres
1,251-2,500	1,291	107 structures and 16,830 acres
2,501-3,750	371	69 structures and 8,617 acres
3,751-5,000	104	42 structures and 4,102 acres
5,001-6,250	24	23 structures and 1,597 acres
6,251-7,500	3	9 structures and 334 acres
7,501+	0	1 structure and 23 acres

Using the average REAX scores shown in the Table shows that 94% of total risk is contained within the top 2,500 circuit miles. While every additional mile of covered conductor SCE would install under its program would address additional wildfire risk, that does not mean each additional mile represents "optimal safety" consistent with just and reasonable rates.

SCE also notes that TURN's proposal would leave unhardened circuits with critical customers and critical infrastructure facilities.[300] While these circuits may not be hardened under TURN's proposal, this does not mean that there will be no wildfire mitigation on these circuits. As discussed further in Section 15.2.5 below, these circuits will still be subject to other wildfire mitigations which TURN has left largely unopposed.

[299] Ex.SCE-15, Vol. 5 (Roy), Table. 11-7, p. 22.

[300] Ex.SCE-15, Vol. 5 (Roy), Fig. 11-2, p. 24.

15.2.4 TURN's Covered Conductor Recommendation Addresses Operational Requirements and SCE's Riskiest Circuits at a Just and Reasonable Cost

SCE argues that TURN does not account for SCE's operational considerations installing covered conductor, specifically the extra 20% covered conductor required for efficient installation.[301] As an initial matter, SCE did not highlight the need for this operational buffer until its rebuttal testimony. Regardless of SCE's initial failure to identify the need for a buffer, TURN's proposal for the installation of 2,581 miles of covered conductor is sufficient to include an operational buffer while still addressing significant risk.

Accounting for the operational buffer, TURN's budget would fund the installation of 2,150 miles and provide funding for 430 miles as an operational buffer. It is not clear whether the additional 430 miles is outside or within the top 2,600 riskiest circuit miles; SCE's rebuttal did not address this issue. However, even if the Commission assumes that the buffer miles would not address the highest risk circuits, the top 2,150 riskiest circuit miles represent would still address most of the identified wildfire risk because: "REAX data stratification for [High Fire Risk Areas] identifies 2,161 circuit miles [which] represent approximately 93.87% of the risk consequence for SCE."[302] Thus, a 20% operational buffer, even if this incorporates relatively low-risk areas, does not undermine the potential for TURN's proposal to address SCE's riskiest segments at a significant cost savings relative to SCE's proposal.

SCE's Rebuttal Testimony also argues that TURN's proposal is insufficient because it does not provide for the installation of additional covered conductor that would allow SCE to

[301] Ex.SCE-15, Vol. 5 (Roy), p. 28:1-3.

[302] Ex. TURN-02-Atch-01 (Borden), p. 177.

further sectionalize circuits and potentially reduce PSPS events.[303] Rather than quantify the overage that this operational requirement necessitates, SCE notes that the additional deployment of miles required for sectionalizing "will be determined on a case-by-case basis during scoping & design based on the feasibility to operationalize this benefit."[304] It is inappropriate to reject or adjust the scope of TURN's proposal for the purposes of reducing PSPS because SCE cannot guarantee that additional covered conductor would result in fewer PSPS events. SCE specifically "cannot commit to not calling PSPS for circuits or circuit segments where covered conductor has been deployed because the decision of whether to conduct a PSPS de-energization is based on many factors."[305] To the extent that SCE will not commit to reduce PSPS, the unquantified increase in covered conductor costs required to avoid these events is unsupported and unjustified.

TURN notes that it does not propose the specific circuits that SCE should harden in this rate case period; instead it provides the utility with a substantial budget for its hardening work. To the extent that the utility further refines its model and identifies a different prioritization of high-risk circuits, the utility can make those changes during the rate case period.

15.2.5 Effective Wildfire Risk Management Relies on a Suite of Mitigations, Many of Which are Unopposed

Every circuit on SCE's system, especially those in the HFRA, is vulnerable to wildfire. While the Commission has tools to help understand the potential consequences of wildfire and

[303] Ex. SCE-15, Vol. 5 (Roy), p. 28:22-25.

[304] Ex. SCE-15, Vol. 5 (Roy), p. 29:1-2: SCE does not address how these additional miles interact with the 20% of operational buffer it also requests.

[305] Ex. SCE-47 (Roy), p.7.

the more likely locations for a catastrophic wildfire, no one can identify with any certainty where the next wildfire will occur. Ideally, every circuit would have the all mitigations in place to protect against ignitions, but as SCE notes, this is not cost effective or acceptable to customers.[306] Even with the most expensive, and effective, mitigations in place, it is not certain the utility could prevent every ignition. Given that "many potential ignitions – given the wrong conditions – could turn into the next catastrophic wildfire event," TURN agrees with SCE that it is advisable to deploy multiple mitigations across its HFRA to mitigate risk as efficiently and effectively as possible.[307] The discussion of covered conductor, one of the highest cost mitigations, must be in the context of the multiple other investments ongoing at SCE, many of which TURN does not oppose – Vegetation Management compliance-related programs, Enhanced Overhead Inspections and Remediations, Fire Science and Advanced Modeling, Sectionalizing Devices, Public Safety Power Shutoff (PSPS) Execution and Undergrounding.

While covered conductor provides significant benefits, it does not reduce all risk of a catastrophic wildfire. SCE acknowledges that "[c]overed conductor is not 100% effective in reducing all ignitions."[308] Even where covered conductor is installed, approximately 40% of wildfire risk remains.[309] It follows that an effective wildfire mitigation strategy relies on a variety of wildfire mitigations, not just one. As SCE states:

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[306] Ex. SCE-15, Vol. 5 (Roy), p. 29:20-23: "Undergrounding, as a program, does mitigate most risk drivers, however, it is financially prohibitive and practically infeasible from a widespread deployment perspective – SCE has over 9,600 circuit miles in its HFRA, and many of these miles are in areas with terrain prohibitive to undergrounding."

[307] Ex. SCE-12, Vol. 1 (Payne), p. 7:15-17.

[308] Ex. SCE-47 (Roy), p. 3.

[309] Ex.TURN-02-Atch 01 (Borden), p.1.

> To adequately address wildfire risk, it is often necessary to deploy multiple mitigation measures on a given circuit whether or not covered conductor is installed. For example, on circuits that either have covered conductor installed or not, SCE will continue to perform inspections, repair equipment as necessary, follow recommended and required vegetation management practices, etc.[310]

Provided that SCE will be pursuing its suite of mitigations across its system, the failure to deploy covered conductor in any one location does not mean that there are no mitigation measures in place for that circuit. SCE notes that "destructive wildfires recently have occurred in SCE's service territory on circuit miles located in areas on the risk buy-down curve that TURN would want to leave uncovered."[311] Uncovered is not the equivalent of unprotected.

As the Commission has observed, the potential for safety impact does not mean a program is an efficient use of ratepayer funding.[312] SCE relies on Figure II-3 (reproduced below) to demonstrate that fires have occurred further down SCE's risk buy down curve than where TURN's proposed conductor deployment would stop.[313]

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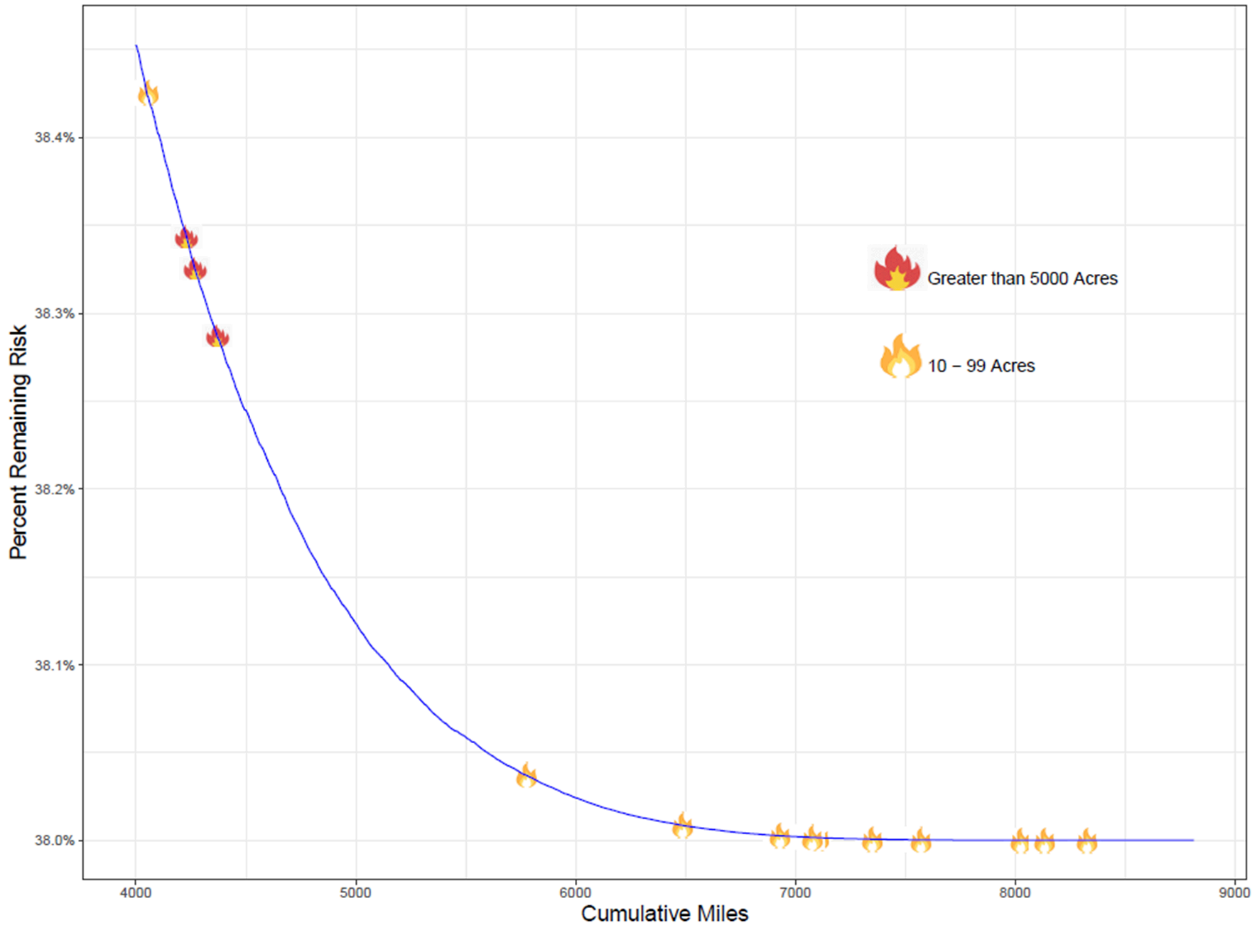
[310] Ex. SCE-47 (Roy), p. 2.

[311] Ex.SCE-12, Vol. 1 (Payne), p. 7:1-5.

[312] D.14-08-032, p. 28.

[313] Ex. SCE-15, Vol. 5 (Roy), Fig. II-3, p. 25.

Ex. SCE-15, Vol. 5: Figure II-3 Overlay of Historical Large Fire Events on SCE's Relative Risk Buydown Curve[314]



As an initial matter, and for purposes of clarification, each fire icon represented in the figure does not necessarily represent a separate fire, each icon instead represents an impacted circuit.[315] Figure II-3 reflects two fires greater than 5,000 acres and seven fires impacting between 10 and 99 acres.

TURN does not contest that nine fires have occurred from 2014-2018 on circuits that appear to be on miles between 4,000 and 9,000 on SCE's risk buydown curve, or that TURN's proposal would not deploy covered conductor on those miles. TURN does contest that it is an

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[314] Ex. SCE-15, Vol. 5E3 (Roy), p.25E.

[315] Ex. SCE-15, Vol. 5E3 (Roy), p. A331E.

efficient use of ratepayer dollars consistent with just and reasonable rates to deploy covered conductor to circuits at such relatively low points in the risk buydown curve. TURN fully expects other wildfire risk mitigations to be deployed here, as discussed above. As the y-axis of SCE's Figure II-3 demonstrates, the circuits shown represent between 38 and 38.5 percent of remaining wildfire risk. In other words, TURN does not believe it is just, reasonable, necessary, or efficient to spend $421,000 per circuit mile to potentially buy down less than 0.5% of remaining wildfire risk. SCE's Rebuttal demonstrates the utility has effectively ignored affordability constraints in lieu of arguments that ratepayer funds must be expended subject only to the limits of SCE's resources.

15.2.1 The Commission Should Direct SCE to Study the Interaction of Mitigations and Identify Efficiencies

TURN highlights that, despite the proposed extraordinary expansion of covered conductor, SCE has not identified any potential redundancies that would decrease SCE's spending on other mitigations in the locations where covered conductor is deployed.[316] For example, as stated by TURN witness Borden, "if covered conductor is as effective in mitigating ignitions when vegetation comes into contact with powerlines as SCE believes it will be, the utility should be able to relax more stringent tree trimming requirements."[317] Relaxed tree trimming requirements should result in reduced costs to be passed on to ratepayers, but a corresponding reduction is not evidenced in SCE's budget. While TURN believes that covered conductor should lead to lower costs elsewhere, it has made no adjustments to SCE's budget to

[316] Ex. TURN-02 (Borden), pp. 7:1-8:16.

[317] Ex. TURN-02 (Borden), pp. 8:9-11.

address potential redundancies.[318] Related to the potential for redundancies and the potential for efficiencies, TURN recommends that the Commission direct SCE to study how costs can be reduced for ratepayers while maintaining a consistent level of safety.[319]

15.2.2 Wildfire Mitigation Practices in Australia Demonstrate the Importance of a Diverse Wildfire Mitigation Portfolio.

Other jurisdictions demonstrate the value of relying on a variety of wildfire mitigation practices, as proposed by TURN. SCE frequently points to the success of Australia in its use of covered conductor. According to SCE Witness Roy, "their fault information, which they call 'near misses' have gone down drastically based on all their wildfire mitigation, and covered conductor is a prominent piece of that."[320] Covered conductor, however, is only one among a number of wildfire mitigations utilized by AusNet, and has only been deployed over approximately 345 circuit miles, discussed below. An inexhaustible list of other "prominent programs in the Australian state of Victoria" that are also applicable to SCE include: 1) dampers and armour rods; 2) more frequent line inspections and pole tests; 3) LIDAR assessment of vegetation clearances; 4) conductor spacing survey and remediation; 5) Upgrading of [high voltage] fuses with [ACRs]; 6) Enhanced [ACR] settings; 7) Fuse-savers as [ACRs]; 8) insulated conductors on pole tops; 9) selective covered conductors; 10) selective undergrounding; 11) enhanced vegetation management clearances; 12) hazard tree management; 13) fire loss consequence maps; 14) aerial surveys and image evaluation; 15) earth fault ignition research and development; 16) vegetation fault ignition research; 17) vegetation fault signature research; 18)

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[318] Ex. TURN-02 (Borden), p.8:11-12.

[319] Ex. TURN-02 (Borden), p.8:11-16.

[320] 8 TR 938:22-939:6 (SCE/Roy).

installation of [REFCLs]; 19) development of fire risk models; and 20) the equivalent of Distribution Fault Anticipation (DFA).[321] SCE is proposing many of these programs in its 2021 GRC, or has already invested in such programs.[322] Given the multiple programs relied on by AusNet to reduce wildfire risk, its successes cannot be reduced to any one mitigation. Instead, AusNet is an example of the importance of maintaining a diverse wildfire mitigation portfolio, including but not limited to covered conductor.

Underscoring the success of Australia's suite of mitigations rather than just covered conductor, is that the utility has only installed and only is required to install a portion of the mileage of covered conductor that SCE proposes in this rate case. AusNet was directed by the Victoria Bushfire Royal Commission to replace electrical lines within identified high fire risk areas.[323] "Thirty-three codified areas have been identified by the Government as having the highest fire loss consequence[, and i]t is estimated that, on average, electrical lines in codified areas will be replaced within 25 years."[324] Approximately 1,000 miles of bare wire is within AusNet's territory identified as a "codified area."[325] As of December 2019, 555 km or approximately 345 miles, of AusNet's system was projected to be "replaced with covered conductor or underground lines."[326]

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[321] Ex. SCE-47 (Roy), p.12.

[322] Ex. SCE-47 (Roy), p.12: While TURN's position varies from program to program, it has only made reductions to some of the similar programs proposed by SCE. In the case of DFA, as discussed in Section 15.4 below, simply seeks additional information before customer's bear its costs.

[323] Ex. SCE-15, Vol. 5 (Roy), p. A110.

[324] Ex. SCE-47 (Roy), p. 11.

[325] Ex. SCE-15, Vol. 5 (Roy), p. A111.

[326] Ex. SCE-47 (Roy), p.11.

AusNet may have had success addressing wildfire risk, but AusNet's program does not justify SCE's proposal for an extraordinary expansion of covered conductor. It is not clear to TURN that the successes of AusNet's wildfire mitigation portfolio are solely due to its covered conductor installations to date. While TURN is hopeful that covered conductor is an extremely effective wildfire mitigation, even if covered conductor has been as successful as SCE argues it has in Australia, the scope and pace of its installation in Australia does not support SCE's proposal in this rate case.

15.2.3 Installation of Covered Conductor Will Not Necessarily Result in Reduced PSPS.

SCE highlights that over half of its ignitions over the last five years have been caused by Contact from Objects and Wire-to-Wire contact, and that only three mitigation programs address these drivers: "covered conductor, repeated and increasing use of PSPS, and widespread undergrounding."[327] SCE declines to implement large scale undergrounding because while undergrounding addresses the wildfire ignition drivers it is "financial prohibitive and practically infeasible from a widespread deployment perspective."[328] TURN, however, cautions the Commission from treating SCE's proposal as a choice between ongoing PSPS and covered conductor.

As noted above, SCE will not commit to any reduction in PSPS events for circuits covered conductor has been deployed.[329] Based on SCE's statements, it could in fact be the case that SCE would pursue its full 6,200 miles of covered conductor at a cost of $3.4 billion and still

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[327] Ex. SCE-15, Vol. 5 (Roy), p. 29:10-14.

[328] Ex. SCE-15, Vol. 5 (Roy), p. 29:15-16.

[329] Ex. SCE-47 (Roy), p. 7.

pursue PSPS at the same scope and scale resulting in additional harms to its customers already facing considerable affordability limitations.

In the WMP Resolutions, the Commission has found that "[PSPS] while potentially useful in the mitigation of wildfires, results in significant hardship and cost to utility customers."[330] As the Commission notes, when calculating Risk Spend Efficiency (RSE) for PSPS, "electrical corporations generally assume 100 percent wildfire risk mitigation and very low implementation costs because societal costs and impact are not included."[331] Because of this failure to include societal impacts, the Commission has directed utilities to "not rely on RSE calculations as a tool to justify the use of PSPS."[332] Similarly here, SCE should not be able to rely on PSPS as a reasonable alternative to and justification for covered conductor, especially since the utility cannot preclude that any given circuit won't both have covered conductor deployed and a PSPS event. Since SCE has not committed to reducing PSPS in any way due to deployment of covered conductor, this argument cannot be relied upon by the Commission to justify the scope and pace of SCE's covered conductor proposal.

15.2.4 TURN Recommends Reductions to the Pole Replacement and Tree Attachment Budget

SCE's original budget for pole replacement is based on the size of its covered conductor proposal and for a wholesale replacement of poles with fire resistant composite poles.[333] SCE however, adjusted its proposal for pole replacement in response to TURN's proposal that rather

[330] WSD-002 (R.18-10-007), pp. 2-3.

[331] WSD-002 (R.18-10-007), p. 20.

[332] WSD-002 (R.18-10-007), p. 20.

[333] Ex. SCE-04, Vol.5 (Roy), p. 28:8-12.

than full replacement using fire resistant composite poles, where feasible the utility should use wood poles and fire resistant wrap. For purposes of its proposed covered conductor program, TURN assumed that 75% of the time fire resistant wrap will be sufficient rather than the more expensive composite pole.[334]

SCE's rebuttal testimony acknowledged that TURN's position had merit but recommended that the covered conductor program budget assume a 60/40 split between pole wrap and full replacement.[335] SCE based its 60/40 split based on the development of a decision tree.[336] SCE's rebuttal testimony, however, does not explain how the decision tree logic better supports its proposed 60/40 split rather than the 75/25 split recommended by TURN. SCE has not run its population of poles through the decision tree yet, and until it does so, the appropriate ratio cannot be determined. SCE suggests that in some cases composite poles may be required given the impact of woodpecker damage: "at locations with…known woodpecker problem areas, SCE will continue to deploy composite polls."[337] The utility, however, admits that it has not reported any fire related to woodpecker damage between 2014 and 2019, and disputes that the Thomas Fire was related to a pole weakened by woodpecker damage.[338] As is the case with SCE's vertical switch program, discussed in Section 15.5.1 below, TURN agrees that damaged equipment should be replaced, but SCE's evidence does not suggest that the wildfire risk reduction is sufficient to justify the added expense of SCE's 60/40 proposal.

[334] Ex. TURN-02 (Borden), p. 24:7-20.
[335] Ex. SCE-15, Vol. 5 (Roy), p. 34:13-15.
[336] Ex. SCE-15, Vol. 5 (Roy), p. 259.
[337] Ex. SCE-15, Vol. 5 (Roy), p. 34:18-19.
[338] Ex. SCE-47 (Roy), p. 9.

In light of SCE's failure to demonstrate, with specificity, the number of poles that require replacement, TURN recommends that the Commission adopt its 75/25 forecast for pole replacement and direct the utility to track the actual split between pole wrap and fire resistant poles. Further, the Commission should direct the utility to default to pole wrap rather than installation of a fire resistant pole; if the utility demonstrates a different proportion, it can request those costs in the future.

Similarly, SCE's proposed budget for tree attachments is driven by the scope of its covered conductor proposal.[339] As described in its rebuttal testimony this proposal is driven by the operational efficiencies gained by replacing tree attachments at the time covered conductor is installed.[340] As discussed above, TURN's covered conductor proposal would deploy conductor, and replace tree attachments, on the circuits that represent the greatest risk. The circuits that TURN's proposal would address have the highest Reax scores, as "derived from the current…risk prioritization model,"[341] and would address the circuits with the largest average consequences per mile in terms of structures destroyed and acreage burned.[342] Presumably, and without any evidence suggesting otherwise, the other equipment like tree attachments in these high priority circuits would have similar risk scores, so the TURN proposal would address the highest risk tree attachments.

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[339] Ex. SCE-04, Vol. 5 (Roy), p. 21:15-27. SCE states it "plans to replace tree attachments together with covered conductor deployment."

[340] Ex. SCE-15 Vol. 5 (Roy), p. 33:11-12.

[341] Ex. SCE-15, Vol. 5 (Roy), p. 22, Note 50.

[342] Ex. SCE-15, Vol. 5 (Roy), Table II-7, p. 22.

SCE provides no risk information specific to tree attachments that demonstrates that tree attachments outside of the highest risk areas do not see a similar decline in risk score. To the extent that the efficiencies of addressing tree attachments at the same time as covered conductor justifies the cost of remediation, SCE has not demonstrated that, absent these efficiencies, the wholesale replacement and remediation of these tree attachments provides a safety benefit commensurate with its cost and consistent with just and reasonable rates. For areas where covered conductor is not deployed, TURN recommends that the utility replace tree attachments on an ad hoc basis when necessary based on inspection.

15.3 Community Resiliency Incentives

15.4 Distribution Fault Anticipation: Pending the Results of its DFA Pilot SCE has not Justified its Proposal for Full Deployment of DFA.

TURN recommends that the Commission reject SCE's forecast of capital and related O&M for a full deployment of the proposed Distribution Fault Anticipation (DFA) program. Rejection of the DFA program should be without prejudice and pending a subsequent application demonstrating the results of the DFA pilot. The Commission should not create the precedent of funding full roll out of programs before the results of a pilot have been presented.

In rebuttal testimony, SCE states that TURN has misunderstood the purpose of SCE's pilot and concluded that the technology is not promising.[343] On the contrary, TURN's testimony specifically states that the "technology sounds promising," but notes that parties and the Commission have not had a chance to review the results of the pilot.[344] SCE stated in response to discovery that it "is currently evaluating the DFA technology and will be complete with the

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343 Ex. SCE-15, Vol. 5 (Swisher), p. 40:13-21.

344 Ex. TURN-02 (Borden), p. 8: 21-23.