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 WILDFIRE MITIGATION PLANS

TURN
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SUMMARY OF RECOMMENDATIONS

In these comments, TURN makes the following recommendations:[1]

Section 1 – Meaning of Plan Approval

- Approval of a WMP should mean that the WMP has sufficiently addressed each of the specified elements in Section 8386(c),[2] and can serve to guide and coordinate regulatory and investment policy toward minimizing the risk of utility-caused catastrophic wildfires.

- The Commission should make clear that approval does not constitute a finding that any program in the WMP or its associated costs meet the just and reasonable requirement of Section 451.

- The Commission should reject, as contrary to SB 901 and Sections 451 and 451.1, the large utilities' proposal to deem "substantial compliance" with the levels of work activities proposed in their WMPs as compliance with the prudence standard with respect to wildfire liability costs.

- Because the WMPs do no demonstrate compliance with all applicable rules, regulations and standards (Section 8386(d), the Commission should make clear that approval of a WMP does not constitute a finding of compliance with all applicable rules, regulations and standards.

Section 2 – Overall Objectives and Strategies

- The Commission's review of these first wildfire mitigation plans should focus primarily on near term measures that are likely to be successfully implemented to reduce wildfire risk in 2019. Despite TURN's concerns about using de-energization as a long-term strategy, in the near term it would be appropriate to rely more extensively on de-energization, enhanced situational awareness and enhanced operational practices (including protection measures and recloser disabling) to avoid ignitions in dangerous weather conditions.

Section 3 – Risk Analysis and Risk Drivers

- The Commission should find that these first WMPs define the risk broadly in terms of ignitions, most of which do not pose a risk of catastrophic wildfire, and are not sufficiently focused on preventing catastrophic wildfires. The Commission should

[1] Because of the time limitations in this case, TURN's analysis, and hence these recommendations, are necessarily limited to the large utilities -- PG&E, SCE. And SDG&E.

[2] In these comments, all statutory references are to the California Public Utilities Code, unless otherwise indicated.

further conclude that this shortcoming should be addressed in the next WMPs. One way to address this shortcoming is to include a risk and mitigation analysis that defines the risk event as an ignition in a high fire risk area *that takes place during high fire risk weather conditions*.

- The Commission should find that the WMPs do not contain sufficient information to demonstrate that the proposed WMP programs are supported by the necessary quantitative risk analysis to satisfy the just and reasonable standard and that such showing will need to be made in an appropriate rate case.

- The Commission should find that the WMPs do not provide sufficient analysis of the effectiveness of past investments and operational practices in reducing faults and ignitions during high hazard conditions and in preventing catastrophic wildfires and that this shortcoming should be addressed in the next WMPs.

Section 4 – Wildfire Prevention Strategies and Programs

- The Commission should order the following direction regarding the scope of work being planned for 2019 so as to minimize the risk of catastrophic wildfires:

  - The utilities should prioritize the installation of protection schemes and the use of operational practices, such as recloser disabling, in 2019.

  - The utilities should also prioritize the installation of equipment and staff to increase situational awareness and to ensure rapid response to any ignitions, especially during high fire risk weather conditions.

  - The utilities should focus on community outreach and protection of vulnerable customers to provide greater understanding of and support for the interim use of power shutoffs to eliminate ignition risk in 2019.

  - To the extent utilities start installing covered conductor, they should focus on areas in Tier 3 which have the highest risk scores (likelihood times consequence), including in the consequence calculation factors such as population density and egress limitations.

  - The utilities should similarly prioritize to the highest risk locations the trimming of trees to the proposed 12-foot clearance, but should minimize healthy tree removal until its need and cost-effectiveness, particularly where covered conductor is installed, is established.

- The Commission should find that utility spending on additional detailed inspections will need to be closely examined in any future review of memorandum account balances to ensure ratepayers are not paying for utility mismanagement.

- The Commission should find that the utilities have not explained their circuit prioritization methods for installation of covered conductor and that the issue of whether the utilities have proposed the appropriate mileage and/or circuit locations for 2019 will need to be addressed in appropriate application proceedings.

- The Commission should find that SDG&E has not justified its proposed 25-foot vegetation clearance requirement.

- The Commission should find that PG&E has not justified the amount of enhanced vegetation management it intends to accomplish in Tier 2 areas in 2019 as a cost-effective use of limited resources.

- The Commission should find that wildfire mitigation spending recorded in memorandum accounts, especially for SDG&E, will need to be closely examined in future application proceedings to ensure that utilities are not recording costs for activities authorized in part or in whole in a rate case decision, and then recording higher costs in the memorandum accounts as a way to evade the utilities' normal exposure to GRC forecasting risk.

Section 6 – Performance Metrics and Monitoring

- The Commission should direct that the following direct, outcome-based metrics be included in any metrics used to assess progress in achieving the goal of preventing catastrophic wildfires:

    - Number of catastrophic wildfires[3] started by utility facilities
    - Number of deaths resulting from utility-caused wildfires
    - Number of injuries resulting from utility-caused wildfires
    - Number of acres burned by utility-caused wildfires

- The Commission should consider as additional useful metrics the following indirect metrics: counts of wires down events, ignitions and outages in high fire threat areas caused by vegetation or utility equipment, when the fire potential index (FPI) is rated as very-high or higher.

- The Commission should reject the utilities' proposals to use the utilities' self-determined targets of amount of work to be performed as compliance requirements. Nor should such targets be considered useful metrics to assess progress in achieving the goal of preventing catastrophic wildfires based on the limited record in this case in which the reasonableness of those targets has not been established.

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[3] To create a clear and well-defined metric, TURN suggests that the CPUC consult with CAL FIRE to develop an appropriate, non-subjective definition of catastrophic wildfire (e.g., any wildfire resulting in a death or serious injury or destruction of a certain number of structures or burning of a certain number of acres) for this purpose.

- The Commission should require that monitoring of the quality of the utilities' wildfire mitigation work be performed by an independent entity, overseen be and answerable to the CPUC, such as the independent evaluator required by Section 8386(h)(2)(B).

Section 7 – Recommendations for Future Wildfire Mitigation Plans

- The Commission set a second phase, after its decision on the 2019 WMPs, to take concurrent opening and reply comments from the parties regarding recommendations for future WMPs.

- The WMPs should be more focused on preventing *catastrophic* wildfires, not simply ignitions, most of which do not pose a risk of catastrophic wildfire.

- The WMPs should provide more analysis concerning the effectiveness of past and current investments and operational strategies in preventing catastrophic wildfires.

- To the extent that WMPs propose programs that go beyond existing requirements or measures, the WMPs should quantify the incremental risk reduction benefit that the new programs will provide with respect to the risk of catastrophic wildfire.

- The WMPs should include a discussion to enable the Commission to verify whether the WMPs comply with all applicable rules, regulations, and standards (Section 8386(d). The Commission should also require the utilities to explain if and how they measure compliance with existing regulations concerning vegetation management and asset conditions, and what is the level of compliance with those regulations.

- The WMPs should provide more analysis on how the utilities will cost-effectively target investments and avoid duplicating reduction of the same risk with different technologies/investments.

1. MEANING OF PLAN APPROVAL

In this first-in-time implementation of Senate Bill (SB) 901, the Commission faces an important threshold question – what is the significance of approval of a Wildfire Mitigation Plan (WMP). The utilities seek to attach major ratemaking consequences to Commission approval, which as discussed below are contrary to the plain words of Section 8386(g) and otherwise poor policy. In this proceeding, intervenors (i.e., non-utility parties) will be afforded only five weeks for review, analysis and comment on seven WMPs -- without adequate opportunity to probe in any detail the scope, pace and cost-effectiveness of the many new programs they propose and without any opportunity to test the veracity of utility statements through cross examination and evidentiary hearings.[4] In order to enable the Commission to render a timely decision on the WMPs within the aggressive statutory time frame, each intervenor is limited to one pleading of no more than 30 pages to discuss the array of issues raised in the WMPs. Given these severe time and process constraints, the significance of Commission approval of these first-ever WMPs must be limited and modest, as discussed in this section.

1.1. Commission Approval of These Initial WMPs Should Be Limited To A Determination That the WMP Adequately Addresses Each Of The Elements Set Forth In Section 8386(c), and Can Serve to Guide and Coordinate Regulatory and Investment Policy Toward Minimizing the Risk of Utility-Caused Catastrophic Wildfires

SB 901provides direction regarding the meaning that should be ascribed to Commission approval of a WMP. The utilities are required to submit WMPs for the CPUC's "review and approval," which process shall include consultation with CAL FIRE. (Section 8386(b)). Prior to approval, the Commission may order modifications to the WMPs. (*Id.*) The CPUC is required to approve each plan within three months of submission, unless the CPUC finds and explains in writing why it cannot meet that deadline. (Section 8386(e)). The objective of this endeavor is for utilities to construct, maintain and operate their electrical facilities to minimize the risk of catastrophic wildfire. (Section 8386(a)). The Commission is also required to "verify that the plan complies with all applicable rules, regulations, and standards, as appropriate." (Section 8386(d)).

Based on these SB 901 provisions and the conditions under which these first WMPs are being reviewed, Commission approval should focus on whether each WMP has adequately addressed each of

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[4] Because of the severe time constraints, TURN has not had time to review and analyze the WMPs of the small utilities and transmission owners.

the twenty elements specified in Section 8386(c) and, in that way, assess whether the approved WMP appears consistent with minimizing the risk of a catastrophic wildfire caused by the utility's electric system. If, in the limited opportunity for review, the CPUC or CAL FIRE is aware of near-term feasible efforts that are not included in the WMP that would increase the potential for minimizing the risk of a catastrophic wildfire, the CPUC may order that the WMP be so modified, as provided for in Section 8386(b).

In this effort, the Commission should rely on its prior experience with Smart Grid Development Plans (SGDPs). There, as here, the directive to develop such plans came from the Legislature.[5] And the Commission sought to make clear the import that was appropriately assigned to its approval of the initial plans submitted by the utilities. In its initial decision setting forth the elements that would need to be addressed in the SGDP, the Commission addressed the question of how it should use these plans, and determined

> the best use of the deployment plans is to set a baseline indicating the current development of Smart Grid technologies and as a document for guiding future Smart Grid investments.[6]

Once presented with the major electric utilities' SGDPs for review and approval, the Commission maintained this approach. After reiterating the guidance from D.10-06-047 regarding the use of the plans to set a baseline and to guide future Smart Grid investment, the decision states:

> As a consequence, the SGDPs need not contain the level of detail that the Commission would require to determine the reasonableness of a specific investment; the plans need only provide information at a level necessary to guide and coordinate regulatory and investment policy in ways that promote the smart grid as envisioned by SB 17.[7]

The decision's review of the utility-submitted plans went element-by-element through the eight elements identified in D.10-06-047. For each element, it described the utility's plan, and concluded that the utility had fulfilled the requirements by addressing the element. The decision ended with a confirmation that the approval of the plan was limited in nature:

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[5] With the SGDPs, the statutory basis was SB 17, a 2009 bill which enacted Sections 8360 *et seq* of the PU Code.

[6] D.10-06-047, p. 21.

[7] D.13-07-024, pp. 10-11.

> The SGDPs are guidance documents, and approval of the SGDP does not constitute a determination of the reasonableness of any specific project.[8]

Treating "approval" in such a manner here is also consistent with the Commission's earlier discussion of the scope and scale of its undertaking in this case. The OIR (p. 3) makes clear that expectations for what can be accomplished in this case should reflect the combination of a short time frame and the scale of the plans under review: "The Commission does not expect to achieve perfection in the short time that will be available for the initial review and implementation of the first wildfire mitigation plans, but will work with the parties to make the best use of that time to develop useful wildfire mitigation plans. The Commission will also use this proceeding to further refine its approach to the review and implementation of subsequent utility wildfire mitigation plans." Thus, given the time constraints, plan approval cannot represent a CPUC determination that the approved plans are perfect or ideal in all respects. Implicit in this quote is the CPUC's recognition that, as these are the first WMPs that will be approved, they will offer a sense of direction and guidance to be further developed in future WMPs, rather than setting rigid requirements. Consistent with this earlier recognition, the Commission should designate "approval" for purposes of Section 8386(b) as being its determination that the WMP has sufficiently addressed each of the specified elements, and can serve to guide and coordinate regulatory and investment policy toward minimizing the risk of utility-caused catastrophic wildfires.

1.2. As Required by Section 8386(g), Approval Must Not Mean a Finding that New Programs or Incremental Spending Are Reasonable for Purposes of Cost Recovery

SB 901 includes language and adopts a process that together make clear that the limited time for approval of WMPs is not intended to allow a Commission determination that the programs outlined in the plans and their associated costs are just and reasonable. Instead, this issue is expressly reserved for rate cases.

Section 8386(g) states:

> (g) The commission shall consider whether the cost of implementing each electrical corporation's plan is just and reasonable in its general rate case application. Nothing in this section shall be interpreted as a restriction or limitation on Article 1 (commencing with Section 451) of Chapter 3 of Part 1 of Division 1.

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[8] *Id.*, p. 124, Finding of Fact 166.

The first sentence of Section 8386(g) explicitly requires that the issue of whether the costs associated with a utility's WMP are just and reasonable "shall" be reserved for the utility's general rate case. The second sentence strongly reinforces this point, by specifying that nothing in Section 8386 may be interpreted in a way that would restrict or limit any provision in the specified article of the Public Utilities Code, which includes Section 451. That section provides in relevant part:

> All charges demanded or received by any public utility . . . for any product or commodity furnished or to be furnished or any service rendered or to be rendered shall be just and reasonable. *Every unjust or unreasonable charge demanded or received for such product or commodity or service is unlawful*. (Emphasis added).

Thus, nothing in the provisions of Section 8386 is intended to abridge the fundamental principle that only costs that have been found to be just and reasonable may be included in rates, as well as the powerful corollary principle that the inclusion in rates of costs that are not just and reasonable is unlawful. As discussed in the next section, key to the reasonableness of costs under Section 451 is the issue of whether the program that drives the costs is necessary, reasonable in scope and pace, and cost-effective.

Consistent with Section 8386(g), the OIR makes clear that the scope of this case excludes the just and reasonable determination that is necessary before costs may be recovered in rates:

> The Commission's approval of wildfire mitigation plans in this proceeding is not a substitute – implicit or explicit – for the Commission's review in a general rate case whether the associated costs are just and reasonable [citing Section 8386(g)]. The Commission will not consider or approve explicit expenditures in wildfire mitigation plans in this proceeding; however, in evaluating the proposed plans the Commission may weigh the potential cost implications of measures proposed in the plans.[9]

Thus, the Commission has already made clear that approval of a WMP should not be viewed – even implicitly – as a finding that costs associated with a plan satisfy Section 451's just and reasonable requirement.[10]

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[9] OIR at 4 (emphasis added).

[10] The Commission's interest in gaining a broad understanding of the potential cost implications of measures proposed in the plans – as evidenced by the second above-quoted sentence -- is entirely appropriate and consistent with the limited scope stated in the first of the quoted sentences. The cost information that utilities were directed to include in the 1/17/19 ALJ Ruling on WMP Template was designed to help the Commission and the parties understand which programs are new and which are already included in rates and to gain an early indication of the extent of cost recovery that utilities may seek in the future. As the OIR makes clear, provision of such information in no way transforms this

1.3. The Utilities' Efforts to Ascribe Ratemaking Significance to Approval of a WMP Should Be Rejected

PG&E and SCE contend that approval of a utility WMP should be, in effect, a determination that the program is just and reasonable for ratemaking purposes.[11] This effort to ascribe such weighty import to approval of a WMP squarely conflicts with Section 8386(g), the scope of this case set forth in the OIR and Scoping Memo, and fundamental notions of fairness and due process.

To understand the problem with the utilities' interpretation, it is necessary to recognize what Section 451 requires. The Commission's longstanding rate case practice makes it clear that the determination of whether the costs of a utility program are just and reasonable is a two-step process, which can be broadly summarized as: (1) whether the program itself is necessary, reasonable in scope and pace, and otherwise cost-effective; and (2) if so, whether the costs to perform the scope of work that is found to be reasonable are themselves reasonable. The first step is often the most important and, under the utilities' interpretation, would somehow be resolved by this case, despite the strikingly inadequate record that this case affords for making such a determination.

The Commission has repeatedly emphasized the importance of the first step in the Section 451 reasonableness analysis, even when the achievement of critical goals such as safety and reliability are at issue:

> . . . our overarching policy is that PG&E must provide reliable electric service to its customers. However, that alone is insufficient reason for approving Cornerstone. *We also have the obligation to ensure that rates are reasonable. Whether characterized as a policy or a basic ratemaking principle, for a capital program or project such as Cornerstone, there must be a compelling demonstration of need. A broad policy such as the desirability of maintaining or improving electric distribution reliability can only be implemented at the program or project level if there is demonstrated need for the particular programs or projects*. PG&E has the burden to demonstrate such need for Cornerstone.[12]

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abbreviated case into a forum for determining – even implicitly – whether any costs associated with an approved WMP are just and reasonable.

[11] In their 2/25/19 response to TURN's conditional motion for evidentiary hearings (p. 3), PG&E and SCE contend that in a rate case, review of programs that were included in WMPs approved by the Commission should be limited to "confirm[ing] that actual costs were incurred for the Commission-approved programs and were consistent with the cost estimates offered by the utilities as measured by a reasonableness band." They go on to argue (p. 5) that WMP approval "constitutes finding that implementing the WMPs is reasonable, subject only to a reasonableness review of the costs." The utilities' repeated these positions at the 2/26/19 morning workshop session.

[12] D.10-06-048, p. 16 (emphasis added).

In the above-quoted "Cornerstone" case, the Commission found that, instead of the $2 billion program proposed by PG&E, only a $400 million reliability improvement was needed because the evidence showed that "a significantly less costly program" could still achieve substantial reliability benefits.[13] This decision shows just how important the first step of the just and reasonableness showing can be, reducing by $1.6 billion the proposed spending that PG&E claimed was necessary to remedy the reliability crisis that it was facing in the mid-2000s.

As another example, PG&E's 2014 GRC decision contains an excellent discussion of the required analysis to satisfy the just and reasonable requirement, an analysis that the utilities seek to preempt in this case:

> *The burden is on PG&E to establish that its proposed work activities are necessary, and that it has prudently examined alternatives before receiving ratepayer funding*. PG&E's policy witnesses agreed in principle that, for all proposed programs, even those justified on the basis of safety, *PG&E's GRC showing must demonstrate both (1) the need for and reasonableness of PG&E's proposed programs, supported in most cases by a well explained cost-benefit analysis; and (2) that the proposed approach is the most cost-effective method available to the utility*. . . . We have carefully evaluated PG&E's justifications of costs both in terms of quantified cost savings and qualitative benefits that PG&E did not or could not quantify. We have also considered the basis for objections to approval of cost increases as raised by various opposing parties. In weighing the qualitative benefits in relation to costs, however, it is not enough merely for PG&E to make assertions that benefit will result. In addressing PG&E's proposals, as discussed throughout this decision, given the limitations in PG&E's cost/benefit showing, we have used our best judgment to weigh both the quantitative and qualitative benefits in relation to the costs involved for each program or project. In many cases, based on our weighing of overall benefits versus costs, we approve funding for the new or expanded programs proposed by PG&E. *In other cases, we approve program funding, but reduce the level of funding below what PG&E requested or based on a more extended time schedule. In other cases, we decline to approve any funding for certain programs where we find that the claimed benefits do not justify the costs to ratepayers*.[14]

This passage is typical of the nature of the showing that is required and the scrutiny that is applied to requests to fund safety work.[15] To make the findings of this nature -- such as whether the utility considered all reasonable alternatives, proposed the most cost-effective approach, and

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[13] *Id.*, p. 17.

[14] D.14-08-032, pp. 28-29.

[15] *See also* D.12-11-051 (SCE's 2012 GRC decision), pp. 9-10, explaining that "[r]atepayers are entitled to the Commission's sharp eye and consideration of other options before committing their hard-earned cash."

demonstrated that the benefits exceed the costs – requires a well-developed record and a level of scrutiny that the timetable for this case simply does not allow.[16]

Moreover, the utilities' expansive view of the meaning of Commission approval would unduly restrict, if not preempt altogether meaningful scrutiny in pending and future rate cases of the same programs proposed in WMPs. The utilities' WMPs, particularly PG&E's and to a lesser extent SCE's, propose significant new programs that are extremely costly.[17] As summarized at the February 13, 2019 workshop, PG&E is proposing up to $2.3 billion of additional spending above what is previously included in rates, just for 2019.[18] This figure includes up to $1.4 billion ($1 billion capital and $400 million expense) for additional inspections of facilities, $325 million (all capital) for system hardening, and $430 million (all expense) for vegetation management. SCE is proposing up to $680 million ($345 million capital and $335 million expense) of programs for 2019,[19] including new programs consisting of $245 million ($100 million capital and $145 million expense) for enhanced overhead inspections, $180 million (almost all capital) for covered conductors, and $90 million (all expense) for enhanced vegetation management.[20]

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[16] On February 20, 2019, TURN filed a Conditional Motion for Evidentiary Hearings, in which it requested evidentiary hearings in the event that the Commission is inclined to conclude that approval of a utility WMP constitutes a finding that the programs proposed in the WMP are just and reasonable for cost recovery purposes under Section 451. At the February 26th prehearing conference, the ALJs denied TURN's motion in part because the schedule did not allow for an interim determination of the legal issue raised by TURN's motion regarding the significance of plan approval. (Tr., p. 77). The upshot is that the Commission has rejected TURN's effort to develop the necessary record in this case to make any determinations regarding the reasonableness for cost recovery purposes of the programs described in the WMPs.

[17] SDG&E's WMP also involves substantial proposed incremental costs, mostly associated with activities the utility characterizes as accelerated when compared to the pace underlying the forecast in its pending test year 2019 GRC. SDG&E WMP, Appendix B. However, as discussed in Section 4.2, below, SDG&E appears to measure incremental costs based on amounts authorized in its test year 2016 GRC, which makes it difficult to assess the proposed spending above levels requested or likely to be approved for 2019 in the pending GRC.

[18] See Slide 11 of PG&E's 2/13/19 Workshop presentation. Attachment E to PG&E's WMP indicates that PG&E views only a very small amount of the $2.3 billion total as currently included in rates. See the 7th column from the left in the table on pages AtchE-1 to AtchE-2. Here, TURN is only reporting, not endorsing, PG&E's position, as another issue is the extent to which PG&E's estimated costs relate to activities, such as inspection, that should already be covered by current rates.

[19] See slide 17 of SCE's 2/13/19 Workshop presentation.

[20] SCE's WMP, pp. 98-99.

The reasonableness of these new programs has yet to be addressed by the Commission, but will be a key focus of SCE's pending Grid Safety and Reliability Plan (GSRP) rate case (A.18-09-002) and PG&E's 2020 General Rate Case (A.18-12-009). Those rate cases provide a meaningful opportunity, consistent with established due process requirements, to address through testimony, discovery, evidentiary hearings and briefs, whether the programs are needed, reasonable in scope and pace, and otherwise cost-effective. The finding that the utilities request here -- that any program included in an approved WMP is just and reasonable – would pre-empt the scrutiny that Section 451 requires, contrary to the mandate of Section 8386(g), which reserves such determinations to rate cases.[21]

Based on questions and comments at the 2/26/19 workshop, TURN expects the utilities to argue that they would be exposed to excessive financial risk if they implement new WMP programs without assurance that the Commission will find those programs just and reasonable in this case.[22] As discussed, this contention conflicts with the clear requirements of Section 8386(g), which were well known to the utilities when they prepared their WMPs. Moreover, Section 8386(e) fully preserves the opportunity of the utilities to recover their WMP implementation costs in a future rate case by allowing them to book those costs in a memorandum account. Thus, the only risk the utilities face is if they are not able to demonstrate that their new programs meet the just and reasonable standard -- which the utilities knew, when they prepared their WMPs, they would have the burden of satisfying in a future rate case. This is a risk that utilities routinely face in rate case reasonableness reviews and therefore not a reason to adopt the utilities' interpretation that, in any event, conflicts with Section 8386(g).

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[21] PG&E and SCE's reliance on D.14-02-015 as support for their position (p. 4 of PG&E/SCE's 2/25/19 response to TURN's conditional motion for evidentiary hearings) is completely misplaced. There, unlike here, the Commission adopted new, specific regulations to modify GO 95 based on an extensive record. Moreover, the Commission stated that it expected the adopted regulations to have "negligible financial impact." (D.14-02-015, p. 85). In sharp contrast, the WMPs do not contain any new regulations and instead describe major new utility-designed programs that have the potential to impose billions of dollars of additional costs on ratepayers, in 2019 alone.

[22] This argument has a significant problem on its face because the utilities are already doing the work described in their WMPs and will have completed much of the work before the Commission can render a decision. For example, PG&E states that it will complete the additional distribution and transmission inspections it describes (the most costly element of its WMP programs) by May 31, 2019 and the identified corrective actions by June 30, 2019. (PG&E WMP, pp. 40-41).

1.4. The Commission Should Reject the Utilities' Proposal to Treat Their Self-Determined "Targets" for Work Under New Programs as Compliance Requirements

In another proposal that would expand the import of Commission approval beyond the clear limitations of Section 8386(g), the large utilities' WMPs suggest that the Commission adopt as compliance requirements the utilities' self-determined "targets" of planned activities under their new programs.[23] In doing so, the utilities are effectively asking the Commission to make an implicit determination that those new programs, in the scope, pace and volume of work specified by the utilities, are reasonable. That is, if the Commission were to determine that the proposed work <u>must</u> be done as a matter of compliance, and subject to penalties for "non-compliance," the question of the reasonableness of the required activities and programs would implicitly already have been decided.

The Commission should reject these utility proposals because they would circumvent Section 8386(g)'s requirement to reserve for rate cases the issue of whether programs and associated costs are just and reasonable under Section 451, as is more fully described in the preceding sections. This request by the utilities is exactly the type of "implicit" determination of whether the utilities' WMP costs are just and reasonable that the OIR stated was outside the scope of this case.

The effect of the utilities' proposals would be to confer on their self-determined targets a status equivalent to CPUC General Orders. Such targets should not be given safety compliance requirement status unless the Commission has developed a sufficient record to conclude that the activities in question are clearly defined and essential for safety. As previously discussed, the limited record here does not allow a determination that all of the work included within the targets is so necessary for safe operation of the system as to warrant compliance requirement status. Moreover, the utility targets do not define with sufficient specificity the work that will be done, in which locations, and to what degree of quality. Simply performing a certain volume of work (which is all that the targets require) does not necessarily promote safety if the work is not properly targeted and not performed properly. While the utilities' results in performing the work described in the WMPs should be monitored and reviewed, the utility-

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[23] PG&E WMP, p. 132; SCE WMP, p. 90 (using the term "performance metrics" -- akin to PG&E's "targets" -- to describe SCE's proposed compliance requirements); SDG&E WMP p. 75 *et seq* (listing proposed compliance requirements, most (but not all) of which are based on a certain amount of work to be performed.) For example, PG&E's proposed WMP compliance requirements include performing enhanced vegetation management on 2,450 circuit miles and 150 miles of conductor and pole rebuild/replacement. (PG&E WMP, pp. 134-135).

specified targets should not be treated as compliance requirements triggering the potential for violations and penalties.

1.5. The Commission Should Reject the Utilities' Effort to Re-Write SB 901 to Weaken the Prudence Standard

SCE, SDG&E and PG&E each propose a strikingly extreme significance to be ascribed to Commission approval of WMPs – that "substantial compliance" with the utility's self-proposed "metrics" (i.e., the targets discussed in the previous section) should satisfy the prudence standard.[24] The Commission should soundly reject this proposal as an inappropriate effort to re-write SB 901.

In 2018, the utilities made a concerted effort in the legislature, through SB 1088, to change the prudence standard exactly as they propose here, in an attempt to reduce the chance they would not be able to recover wildfire liability costs in authorized rates. The Legislature did not make that change and instead chose another way of addressing the prudence standard. Specifically, SB 901 adds Section 451.1, which enumerates 12 factors the Commission *may* consider in applying the prudence standard to requests to recover wildfire liability costs for catastrophic wildfires occurring after January 1, 2019. Thus, the utilities' effort to re-write the prudence standard conflicts with the extremely specific language in SB 901 and should be rejected by this Commission.

Moreover, the utilities' proposal would effectively gut the prudence standard, with extremely bad consequences for wildfire safety and public policy in general. The utilities would have the Commission find that the prudence standard is satisfied merely by "substantial compliance" with their own targets for performing a certain volume of work.[25] However, prudence is not and should not be determined in this

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[24] "Substantial compliance with the objective metrics set forth in the WMP (when approved by the Commission) will demonstrate that SCE prudent operated its system, and met the Commission's 'prudent manager' standard regarding wildfire risk mitigation." SCE WMP, p. 7. Nearly identical language appears in SDG&E's WMP at page 75. PG&E also included remarkably similar language in its WMP, although it referred to the "reasonable manager" standard rather than the "prudent manager" standard. PG&E WMP, p. 132.

[25] For example, SCE's WMP metrics are based on items such as number of trees removed, circuit miles re-conductored, and overhead lines inspected. (SCE WMP, p. 91, Table 6-6). Similarly, PG&E's WMP lists a series of targets, such as number of inspections completed, miles of system hardening work completed, and miles of enhanced vegetation management work completed. (PG&E WMP, pp. 39-45, Table 9). SDG&E's WMP takes a similar approach. (SDG&E WMP, pp. 75-80). And each of the utilities includes an "out" clause that would lower the bar for "substantial compliance" should they encounter "events out of [the utility's] control, such as qualified personnel constraints, supply chain

way. Prudence requires not just *completing* a certain amount of work, but *doing it right*. In addition, prudence means making sound managerial decisions under the circumstances presented, including selecting the right work to perform. The utilities' proposed standard completely ignores these key elements of prudent operations.

In R.19-01-006 (the "Stress Test" OIR), SCE has argued that its proposal follows from the AB 57 construct used for power procurement.[26] If anything, AB 57 shows what SB 901 would have said if the Legislature had intended to radically change the prudence requirement. Section 454.5(d) states that one objective of the AB 57 procurement plans is to "eliminate the need for after-the-fact reasonableness reviews" and replace it with a process to verify that contracts are administered in accord with the terms of the contract. In stark contrast with that language, Section 8386(g) reaffirms the role of rate cases and the just and reasonable requirement under Sections 451 and 451.1.

Furthermore, procuring power is a very different undertaking from safely and prudently operating inherently dangerous facilities. The Commission's longstanding interpretation of the prudence requirement appropriately imposes a higher standard of care when inherently dangerous facilities are involved. Utility managers are expected to exercise "proportionately greater care" in decisions involving large amounts of money, greater levels of uncertainty, or high degrees of risk.[27] Where tasks undertaken are "of such enormity as to greatly expose the utilities and potentially their ratepayers to substantial financial risks, utilities must exercise even greater care and managerial acumen than would be called for in ordinary circumstances."[28] The utilities want the Commission to ignore this longstanding law and weaken the standard of care they must meet.

In sum, the utilities' proposed radical change to the prudence standard is directly contrary to SB 901 and would insulate the utilities from necessary and appropriate consequences for unsafe and imprudent operations. The utilities' proposal would provide exactly the wrong incentives for stopping catastrophic wildfires caused by utility facilities.

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disruptions, or permitting and construction delays." PG&E WMP, pp. 132-133; SCE's and SDG&E's WMPs each has nearly identical language. (SCE WMP, p. 7; SDG&E WMP, p. 75.

[26] R.19-01-006, SCE Opening Comments, pp. 12-13.

[27] *Re San Diego Gas & Electric Co.,* D.89-02-074, 31 CPUC 2d 236, 246.

[28] *Re Pacific Gas & Electric Co.* (Helms Pumped Storage Project), D.85-08-102, 18 CPUC 2d 700, 710-711 (rejecting view that "marginal" or "average" performance was required and holding PG&E to a "good performance" standard).

1.6. The WMPs Do Not Provide Sufficient Information for the Commission to Find Their Plans in Compliance with Applicable Standards

Section 8386(d) directs the Commission to verify that each WMP complies with "all applicable rules, regulations, and standards, as appropriate." However, none of the large utilities' WMPs directly address this requirement. The utilities repeatedly mention the various regulations which govern grid inspection, repair, and vegetation management programs, but fail to demonstrate that they are in compliance with these regulations, as evidenced by their answers to a data request question regarding whether their WMPs provided information concerning compliance with existing regulations.[29] TURN submits that the WMPs do not provide the information the Commission needs to provide the verification contemplated by Section 8386(d), and the Commission should make clear that its approval of a WMP does not mean that the plan complies with all applicable legal requirements.

The failure to demonstrate full compliance with each currently applicable rule, regulation and standard is an important shortcoming in the utilities' WMPs. A lack of utility compliance has been at least a contributing factor in past utility-caused wildfires, as evidenced by CAL FIRE's determination that eleven of the eighteen Northern California 2017 wildfires were caused by PG&E's failure to comply with applicable vegetation management standards.[30] Furthermore, a lack of compliance with existing standards could contribute to the need for and scale of some of the mitigation programs proposed by the utilities, and raises the possibility that some of the work could be reduced if the utilities simply complied with already existing regulations and standards.

A demonstration of compliance with the inspection and repair requirements of General Order 165 would be particularly important to the assessment of proposed programs in the WMPs. GO 165 requires that the utilities perform detailed overhead inspections of distribution assets *at a minimum* every five years, or more frequently "as necessary, to ensure reliable, high-quality and safe operation."[31] The

[29] SCE Response to TURN DR 3-1 (the undifferentiated "entirety" of the SCE plan contains the required information); SDG&E Response to TURN DR 3-1 (SDG&E's "entire" WMP should facilitate the Commission's review and approval); PG&E Response to TURN DR 4-1 (not identifying any specific part that would facilitate the Commission's discharge of its responsibilities and instead contending that TURN and others should use their comments to point out any noncompliance and then utilities can respond in reply comments.) (See Attachments).

[30] See, CAL FIRE news releases concerning the McCourtney, Lobo, Honey, Sulphur, Blue, Norrom, Partrick, Pythian, Adobe, Pocket, and Atlas Fires. (See Attachments).

[31] GO 165, Section III.B and Table 1.

utilities must fix all identified "corrective actions" so that all structures and equipment function "properly and safely."[32] Thus, establishing where each utility stands in terms of its ongoing compliance with GO 165 is an essential element for assessing the "enhanced inspection programs" included in PG&E's and SCE's WMPs. If the utilities have not been in compliance with GO 165 in recent years, the Commission would have reason to question whether the utilities' acceleration of the pace of the next round of regular overhead detailed inspections is not an "enhancement," but rather a remedy for such non-compliance.

Because of the importance of the issue of compliance with existing regulations and the utilities' failure to address that issue in these first WMPs, the Commission should expressly require that the next round of WMPs specifically address this Section 8386(d) requirement of demonstrating utility compliance with all applicable rules, regulations and standards.

2. OVERALL OBJECTIVES AND STRATEGIES

2.1. The Commission's Review Of These First Wildfire Mitigation Plans Should Focus Primarily On Near Term Measures That Are Likely To Be Successfully Implemented to Reduce Wildfire Risk in 2019

These 2019 Wildfire Mitigation Plans are the first proposals in what is intended to be an annual review cycle. For its initial review of such plans, the Commission should focus on measures that are most likely to meaningfully reduce wildfire risk in the near term, including this coming summer. Of course, the utilities should start other necessary and cost-effective programs that are likely to require a longer time frame to fully implement. But the initial review should seek to ensure that appropriate resources are focused on measures that can be implemented in the near-term without taxing the utility's available resources.

The WMPs of the three large utilities propose to try to achieve short-term implementation of programs that would be subject to a longer time frame but for the wildfire mitigation context here. For example, PG&E has proposed large programs 1) to inspect and repair 685,000 distribution poles and 50,000 transmission structures, 2) to replace poles and conductors on 150 circuit miles, and 3) to perform enhanced vegetation on about 2,450 circuit miles. As noted above in Section 1.3, PG&E estimated additional costs of up to $2.3 billion for these programs. This proceeding is not an appropriate vehicle for assessing whether it makes sense to do the work at the scale and pace proposed by PG&E,

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[32] GO 165, Section III.A.

given the limited record-development opportunities and extreme time constraints. The new programs are included in PG&E's test year 2020 GRC, and will be reviewed more comprehensively in that proceeding. Furthermore, PG&E acknowledges that its ability to meet its ambitious goals with these major spending programs could well be compromised due to a lack of sufficient resources.[33] To minimize wildfire risk in 2019, PG&E should focus its efforts and resources on measures that are more likely to be implementable in the near term, including operational practices such as recloser blocking and protective equipment settings, improved situational awareness, and the public safety power shutoff program.

Indeed, SCE appears to prioritize such near-term measures in its WMP, explaining that it will focus on installing certain protective equipment and using operational settings on existing reclosers and relays to reduce the risk of faults during high fire risk conditions, while at the same time commencing system hardening activities and other longer-term programs.[34]

TURN has significant concerns about the use of the PSPS as a long-term risk mitigation strategy, and TURN will advocate in Rulemaking 18-12-005 for proper procedures to ensure that power shut-off is used as a tactic of last resort. However, TURN supports use of the PSPS in the near-term – with improved notification and communication and enhanced safeguards for affected customers[35] -- as a stopgap measure until the Commission has reviewed and authorized, and the utilities have more substantially implemented, other more permanent wildfire risk mitigation measures in HFTD areas. Relying more extensively on de-energization, and enhancing operational measures to avoid ignitions in dangerous weather conditions, as well as to respond more quickly to any ignitions that might occur, is likely to be the more effective strategy for mitigating catastrophic wildfires in 2019.

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[33] PG&E discusses at length the challenge of finding sufficient numbers of qualified personnel to conduct the enhanced vegetation management on its aggressive schedule. PG&E WMP, Section 4.4.5 at pp. 80-85. While the utility is silent about such challenges with regard to the other major inspection and asset repair and replacement programs, the Commission may safely assume that similar concerns are likely to arise there as well.

[34] SCE WMP Section 2.3.1, p. 15.

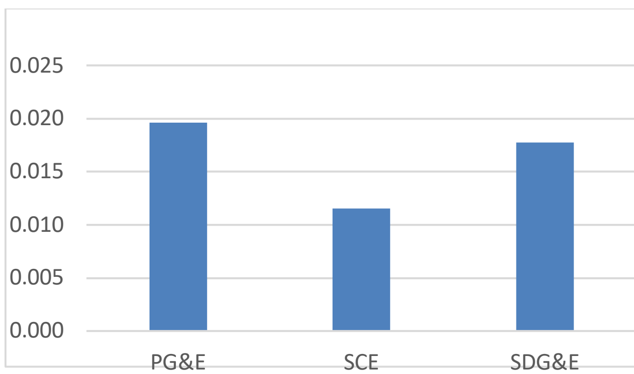
[35] These issues will be addressed in Phase 1 of R.18-12-005, in which a decision is expected before the 2019 wildfire season.

3. RISK ANALYSIS AND RISK DRIVERS

3.1. The Large Utilities' WMPs Should Be More Focused on Preventing Catastrophic Wildfires, Not Ignitions in High Fire Threat Areas

The Risk discussions[36] in the large utilities' WMPs do not focus sufficiently on the specific risk that WMPs are supposed to address – the risk of catastrophic wildfires.[37] Instead of defining the risk event in this way, they define it more broadly, as the risk of utility-caused CPUC reportable ignitions in high fire threat areas (PG&E and SCE) or even broader yet, as just utility-caused wildfires without narrowing the geographic location (SDG&E).[38] There is significant evidence that reportable ignitions are not the right focus. As TURN noted at the February 13th workshop, from 2015-2017, PG&E and SDG&E had almost the same number of CPUC reportable ignitions per mile on distribution facilities in high fire threat districts, as shown in the figure below.

Figure 1: Frequency of Ignition Incidents (2014-2017) per Mile of Distribution Overhead Conductor In High Fire Districts Is Similar for PG&E and SDG&E



SDG&E is held up as an example of a company that is effectively managing the wildfire risk, but the main difference in the experience of PG&E and SDG&E in recent years is that SDG&E has not had a catastrophic wildfire, while PG&E's facilities have caused many catastrophic wildfires.

[36] In these comments, Risk discussions refers to the Section 3 in the utilities' WMPs.

[37] Section 8386(a) (stating goal as minimizing risk of "catastrophic" wildfire posed by electrical lines and equipment).

[38] PG&E WMP, p. 21, Fig. 2; SCE WMP, p. 21, Fig. 3-2; SDG&E, p. 17, Fig. 2.

The utilities' overbroad definitions of the risk event have repercussions for their risk analysis.[39] PG&E and SCE focus most of their Risk discussions on an analysis of drivers of CPUC reportable ignitions in high fire threat areas.[40] However, because most ignitions do not result in catastrophic wildfires, the utilities' overbroad analysis may lead to a selection of mitigations that are not sufficiently targeted at preventing *catastrophic* wildfires.

Further contributing to the problem is the scant attention that the utilities' WMPs devote to the *consequences* of a wildfire risk event. Risk is calculated by multiplying the likelihood of a risk event times the consequence of that event.[41] Even if one uses the utilities' broad definitions of risk event in their WMPs, a catastrophic wildfire is distinguished from an inconsequential wildfire by extreme consequences in terms of death, injury, property damage or acreage burned. The large utilities' Risk discussions do not show whether or how their risk analysis and selection of mitigations was influenced by reducing the consequences of catastrophic wildfires. They could have done this by providing risk scores (which, as noted, are based on likelihood times consequence) and showing how their various selected mitigations reduced those scores, but they did not include such a showing.[42] Instead, their discussions are focused on drivers, which only relate to the likelihood side of the risk equation. Again, the result of this deficiency may be that mitigations that would be more effective at reducing the consequences of catastrophic wildfires are not given sufficient emphasis in the utilities' WMPs.

TURN offers the following recommendation for supplementing and improving the utilities' WMP risk analysis. Because catastrophic wildfires most often happen during red flag weather events and other dangerous weather conditions, the utilities should provide an analysis that defines the risk event as ignitions in high fire risk areas *that take place during high fire risk weather conditions.* In this

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[39] The exact nature of those repercussions is unclear because of the high-level and incomplete Risk discussion provided in the utilities' WMPs, as discussed in Section 3.2 below. Lacking more detail, TURN's discussion in this section is necessarily limited to identifying potential problems.

[40] PG&E WMP, p. 27, Fig. 5 and SCE WMP, pp. 21-22, Fig. 3-2 and Table 3-1,in which both utilities quantify the drivers for CPUC reportable ignitions in high fire threat areas, without further limiting the risk event to dangerous weather conditions. SDG&E, p. 17, Fig. 2, provides only a high-level list of all drivers of utility-caused wildfires, without limiting the risk event either geographically or based on weather conditions, and does not provide a quantification of the drivers.

[41] D.18-12-014, Settlement Agreement, Row 13.

[42] Alone among the large utilities, SCE's risk analysis recognizes the importance of weather conditions by acknowledging different "outcomes" of a risk event based on weather conditions (SCE WMP, p. 23). But, like the other utilities, SCE does not how it calculated pre- and post-mitigation risk scores, which prevents any analysis of how SCE's quantitative analysis reflects extreme weather events.

way, the identified drivers and consequences would relate to the events that are of the greatest concern. Assuming the remainder of the risk analysis is properly performed,[43] the results should identify the most effective mitigations for reducing the combined likelihood and consequences of ignitions under the most dangerous conditions. Put another way, this approach should yield the most effective strategies for preventing catastrophic wildfires, which is the fundamental goal of these WMPs.

3.2. The WMPs Do Not Provide a Sufficient Risk Analysis to Satisfy the Section 451 Just and Reasonable Standard

Whether or not the utilities' Risk discussions comply with the statutory requirements for WMPs, the Commission should recognize that those discussions fall far short of the comprehensive risk and mitigation analysis that is necessary to determine whether each of the utilities' proposed mitigation programs is necessary, reasonable in scope and pace, and otherwise cost-effective, as required by the Section 451 just and reasonable standard.[44] Instead, the utilities' Risk discussions are generally high-level and incomplete, in that they do not address many of the important elements and details of a well-designed quantitative risk assessment framework.

For example, the large utilities' WMPs do not discuss how they constructed any Multi-Attribute Value Function (MAVF) they may have used in their analysis. An MAVF is a key tool for combining all possible consequences of a risk event in a single measure[45] and is thus a critical foundational element for a reasonable quantitative risk analysis. With a well-constructed MAVF, a utility can capture in one measure all of the trade-offs with a mitigation measure, such as de-energization, which can prevent the consequences of a catastrophic wildfire but has its own adverse consequences including harm to health and safety from extended blackouts, the financial harm to businesses and individuals experiencing lengthy outages, and environmental harm from use of back-up power such as diesel generators. In the

[43] This is a critical assumption, which as discussed in Section 3.2, cannot be verified based on the utilities' WMPs.

[44] TURN speaks to this issue with considerable expertise, as TURN and its experts have taken the lead in the S-MAP case (A.15-05-002 et al) in pushing the utilities to significantly improve their risk analysis and mitigation assessment. TURN's work is evidenced in: (1) D.16-08-018, in which the Commission adopted on an interim basis the "Joint Intervenor" approach advocated by TURN in lieu of the competing utility approaches; and (2) D.18-12-014, where the Commission adopted a settlement, in which TURN was the leading non-utility party, that provides detailed minimum requirements for a quantitative risk-based decision-making framework to be applied by the large utilities in RAMPs and GRCs.

[45] D.18-12-014, Settlement, p. A-3.

S-MAP settlement, the utilities have agreed to principles for properly constructing an MAVF;[46] only in a RAMP/rate case is there sufficient opportunity to determine whether a utility has satisfied these principles, which is an important element of determining whether a utility's proposed programs are supported by a reasonable quantitative risk assessment.

As another example, the large utilities' Risk discussions do not include details regarding most aspects of the mitigation analysis that is necessary to meaningfully calculate and compare the risk reduction benefits and risk spend efficiencies (RSE) of various mitigation alternatives. As the S-MAP settlement shows,[47] mitigation analysis is a several step process that requires proper calculation of pre- and post-mitigation risk scores, which in turn rely on reasonable estimates of pre- and post- mitigation likelihoods and consequences of a correctly specified risk event. Again, most of these steps are not addressed in the utilities' Risk discussions. As a result, the WMPs do not provide the key details of a quantitative analysis showing why the utilities believe the portfolio of mitigations they have selected are optimal.

The utilities appear to recognize that important elements and details of their risk and mitigation assessment cannot be found in their WMPs. For example, in response to an ALJ Ruling requesting RSEs for all its proposed WMP mitigations, PG&E points to the "detailed and extensive workpapers" in its 2020 GRC (A.18-12-009) regarding its RSE scores.[48] PG&E also acknowledges that it did not prepare an RSE analysis for WMP mitigations that are not in its 2020 GRC.[49] In addition, in response to a TURN data request for the workpapers and model that PG&E's WMP says it used to prioritize circuits, PG&E declined to provide the requested information, based on the "sensitive and proprietary nature of

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[46] D.18-12-014, Settlement, Rows 1-7.

[47] D.18-12-014, Settlement, Rows 13-25.

[48] PG&E 2/26/19 Response to ALJ Ruling, p. 7. In that response, PG&E attaches as Attachment C an excerpt from its 2020 GRC workpapers that includes a summary table of RSE values. TURN urges the Commission not to rely on these numbers as RSE values are, as noted above in the text, the result of a several step process (*see* D.18-12-014, Settlement, Rows 13-25) that needs to be performed properly in order to yield useful numbers. PG&E's excerpt does not provide information showing how it carried out the requisite steps and, in any event, the aggressive schedule for this case does not afford sufficient time to adequately review, analyze and comment upon any such information even if PG&E had shared it.

[49] *Id.*, p. 8.

the risk model."[50] Similarly, SCE states that, for a detailed discussion of how its risk-informed decision-making process is applied to the wildfire risk, one must consult its GSRP (A.18-09-002) filing.[51]

TURN presents its point in this section, not because SB 901 necessarily requires all the information TURN identifies as lacking in the WMPs, but because the utilities want Commission approval of a WMP to mean that the Commission has found the utilities' mitigation measures just and reasonable under Section 451. As this section shows, the utilities' WMPs fall far short of presenting the information necessary to meet their burden of demonstrating through a reasonable quantitative risk analysis that their programs are necessary, reasonable in scope and pace, and otherwise cost-effective. Precisely because this proceeding does not allow a sufficient record on this issue, Section 8386(g) reserves the Section 451 just and reasonable determination for rate cases.

3.3. The Utilities Failed to Evaluate the Effectiveness of Past Mitigation Practices

The three major utilities have all implemented a variety of past programs and practices designed to minimize the risk of ignitions. However, while SCE and PG&E provided limited data regarding the drivers of ignition events in 2015-2017,[52] neither of the utilities provided analyses correlating the locations of these ignitions (e.g. by circuit) with the presence or absence of their mitigation measures to-date (e.g. recloser blocking) on those circuits. Even more broadly, the utilities fail to provide analyses of the efficacy of mitigation measures they have been implementing for many years, if not decades. In some cases, it is a matter of the utilities being unable to provide what they do not have; when directed to "describe and quantify the effectiveness of the mitigation measures included in its Fire Prevention Plan" submitted under General Order 166, PG&E explained that it does not have "a prepared detailed quantification of the effectiveness." [53]

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[50] PG&E Response to TURN DR 5-6 (see Attachments). PG&E's response stated that production of the details TURN sought would need to be discussed in a follow-up meeting. The tight schedule for this case has not allowed time for such a meeting.

[51] SCE, p. 17, fn. 25.

[52] PG&E WMP, Figure 6. SCE WMP, Table 3-1. SDG&E does not provide such data.

[53] PG&E Response to ALJ Ruling, February 26, 2019, p. 1-2. PG&E did offer to prepare information on this topic if given two weeks to do so.

In response to ALJ questions, both PG&E and SCE promise that they will do exactly these types of analyses in the future, to test the effectiveness of their proposed new programs.[54] They claim they must wait for data to perform these analyses with regard to the new programs. But the utilities should already have done exactly these types of analyses, at a minimum using 2014-18 ignition data, to evaluate the efficacy of existing programs and asset investments.

For example, PG&E initiated a recloser disabling program as part of its Fire Risk Management Initiative in 2011,[55] though PG&E now states that it first implemented the Wildfire Reclosing Disable program for the 2018 wildfire season.[56] SCE states that it has used recloser restrictions in its HFRA since the 1950's.[57] However, neither PG&E nor SCE provide analyses demonstrating the effectiveness of these long-standing operational practices in limiting ignitions.[58] It could be useful to know whether any of the ignitions in 2014-2018 occurred on circuits when reclosers were disabled under one of the existing programs. If recloser disabling, perhaps combined with other system protection strategies, can eliminate the risk of ignitions, those strategies could reduce the need for circuit reconductoring or power shutoffs.

The Commission should order the utilities, as part of their next WMP filing, to provide analyses evaluating the efficacy of past operational practices and investments in limiting ignitions, especially in HFTD and during high risk weather conditions.

4. WILDFIRE PREVENTION STRATEGIES AND PROGRAMS

The WMPs filed on February 6, 2019 overlap extensively with the utility proposals made in separate pending applications, two of which are in their earliest stages, and one of which is submitted

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[54] See, PG&E Response to ALJ Second Ruling, March 8, 2019, p. 1-2; SCE Response to ALJ, March 8, 2019, p. 2. PG&E, for example, describes these types of analyses as "correlation between targets and indicators." PG&E stated that such correlations are presently not known.

[55] A.09-12-020 (PG&E test year 2011 GRC), PG&E-03, pp. 11-1, 11-4, 11-13 to 11-15 (See Attachments).

[56] PG&E WMP, p. 47. PG&E explains that 2100 of its 2800 reclosers in HFTD are already equipped with SCADA. PG&E WMP, Sec. 4.3.4, p. 47-48.

[57] SCE WMP, Sections 2.3.1 (p. 15), 3.3.1.1.1 (p. 26), 4.3.2 (p. 47). SCE intends to continue installing remote-controlled automatic reclosers, as well as circuit breakers with fast curve settings and fusing strategy. SCE WMP Sec. 4.3.3.5, p. 54-55.

[58] SCE objected that analyzing the faults associated with fires to determine whether reclosers were disabled (or set at different sensitivity) would be unduly burdensome. SCE Response to TURN DR 005-01(c) and (d) (See Attachments).

and awaiting a proposed decision.[59] Consistent with the greater review opportunities in those other proceedings and the very aggressive schedule of this rulemaking, TURN has here conducted a necessarily very limited review of the plans submitted by PG&E, SCE and SDG&E.[60]

Based on that limited review, TURN discusses below a few concerns we have tentatively identified, which we will explore more deeply through expert testimony and analyses in the relevant application proceedings. At this stage, TURN expects that some amount of grid hardening (primarily covered conductor) and enhanced vegetation management will be part of a long-term solution to reduce the risk of ignition due to utility equipment in high-risk areas in dangerous weather conditions. However, the exact scope and scale are quite unclear, not least due to the following overarching questions:

- What is the synergy between different mitigation strategies, and what is the optimal mix of different strategies (operational, grid hardening, and vegetation management) on different circuit segments?
- How can activities be cost-effectively targeted to mitigate risk and ensure affordability for all customers?
- How much can the risk of catastrophic wildfires be reduced by a combination of enhanced situational awareness measures and operational practices, combined with judicious use of public safety shutoffs?

TURN fully appreciates that these are difficult questions that may not have definitive answers, and that utilities must make at least initial efforts to reduce wildfire risk before we know all the answers. However, it is important to target resources wisely by taking advantage of available information and expertise. To that end, TURN recommends that, over the course of 2019, the Commission organize workshops and/or webinar events with subject matter experts from Australia. That nation implemented a similar regulatory regime after its catastrophic bushfires of 2009, which killed over 170 people.[61] The relevant Australian utilities have implemented similar grid hardening and vegetation management

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[59] SCE's GS&RP application (A.18-09-002) and PG&E's test year 2020 GRC application (A.18-12-009, and SDG&E's test year 2019 GRC application (A.17-10-007). The only significant WMP "program" not proposed in those applications is the "enhanced inspection program" that has the hallmarks of the utilities attempting to backfill for past deficiencies in their efforts, thus warranting particularly close evaluation when the costs and activities are reviewed in the future.

[60] While TURN sent several data requests to the utilities, just over one month is an entirely inadequate period to meaningfully review the reasonableness and efficacy of the utility proposals.

[61] See, 2009 Victorian Bushfires Royal Commission, Final Report, July 2010; Progress Report, 1 August 2016 (available at http://royalcommission.vic.gov.au/finaldocuments/summary/PF/VBRC_Summary_PF.pdf).

programs, and are likewise testing alternative technologies.[62] While the California utilities have apparently benchmarked some of their proposals with Australian utilities,[63] a more general and public discussion of lessons learned and mistakes made could help California achieve more effective solutions more quickly.

4.1. Concerns With the Programs Proposed by the Large Utilities

4.1.1. Spending on Additional Detailed Inspections Will Need to be Closely Examined in Any Future Review of Memorandum Account Balances to Ensure Ratepayers Are Not Paying for Utility Mismanagement

PG&E intends to perform "Wildfire Safety Inspections" on 685,000 poles in HFTD, and complete high priority corrective actions identified during the inspections, at a forecast cost of $194,000,000 - $371,000,000 in expenses and $504,000,000 – $1,250,000,000 in capital.[64] Similarly, SCE intends to perform "Enhanced Overhead Inspections" of about 380,000 distribution structures in HFRA before summer 2019, at a forecast cost of $145,000,000 (expense) and $103,000,000 (capital).[65] SDG&E, on the other hand, describes its system inspection efforts as a continuation of its existing programs.[66]

GO 165 already requires Overhead Detail Inspections (ODI) every five years and requires that the utilities fix all identified "corrective actions" so that all structures and equipment function "properly and safely," as discussed previously in Section 1.6. The scope of the proposed "enhanced" inspections and repairs appears to be very nearly identical to the scope required for ODI compliance.[67]

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[62] See, for example, AusNet Services, "Bushfire Mitigation Plan," 23 March 2018 (available at https://www.aer.gov.au/system/files/Attachment%2021%20-%20BFM%2010-01%20BFM%20Plan%20Distribution%20v25.pdf).

[63] For example, PG&E WMP, pp. 2, 23, 111.

[64] PG&E WMP, Table 9 and Attachment E.

[65] SCE WMP, Sections 4.2.3, 4.2.4, and 7.1.1. SCE states that the forecast funding is or will be addressed in the 2018 and/or 2021 GRC. Thus, it is unclear what is the incremental funding above existing DIMP funding.

[66] SDG&E WMP, Appendix A, pp. A-10 and A-11.

[67] See, SCE WMP Sections 4.2.2.1 and 4.2.2.1.1 for a concise description of the Overhead Detail Inspection Program. See, TURN DR PG&E-003-16(d) (See Attachments).

Of the 685,000 poles in HFTD that PG&E plans to inspect, only 185,000 are due under the existing schedule for a GO 165 inspection.[68] Given the GO 165 requirement to conduct detailed inspections at least every five years, this means the remaining 500,000 poles were inspected at some point within the previous five years; and if performed on a ratable basis, a large percentage of them would have been inspected in the previous two years. The Commission should be extremely concerned that PG&E and SCE may well be redoing their ODI in HFTD areas because of the potential inadequacy of their past inspection practices. The Commission will need to closely evaluate this issue if and when the utilities seek recovery of these costs in memorandum accounts.

4.1.2. The Utilities Have Not Fully Justified the Pace and Scope of Enhanced Vegetation Management

The enhanced vegetation management programs of PG&E and SCE involve two primary components in HFTD areas: 1) trimming all trees to a 12-foot radius and trimming all branches hanging above power lines, and 2) removing healthy trees that are identified as having the potential to hit power lines if they fall down. SDG&E additionally proposes increasing its tree trim scope to 25-feet post-trim clearance, a level the utility recognizes is a "significant increase" and that may run into "some barriers."[69] SDG&E has not justified its expanded clearance requirement, and there is insufficient evidence to justify the healthy tree removal, especially in areas where covered conductor is being installed.

4.1.2.1. The Utilities Should Collect Data on the Efficacy of the CPUC's New Clearance Requirements In Order to Assess the Need for Even Stricter Measures

The Commission adopted new tree trimming clearances in D.17-12-024, changing the minimum clearance requirement from eighteen inches to four feet in all areas, and adopting a "recommended time of trim" clearance of twelve feet in HFTD areas. The utilities are additionally proposing to trim all overhangs above overhead wire, creating a four-foot "corridor from conductor to sky." Trees must be trimmed with the goal that that they do not grow closer than the minimum four-foot clearance requirement prior to the next trimming cycle.

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[68] TURN DR PG&E-003-17(b) (See Attachments).

[69] SDG&E WMP, pp. 43-44.

The proposal to comply with the recommended 12-foot clearance and to trim all overhangs appears useful, though we do not have sufficient data or information to evaluate the efficacy of either the changes adopted in 2017 or the proposed "conductor to sky" overhang corridor. Similar to the previous discussion in Section 3.3 concerning the efficacy of recloser disabling, the Commission should order the utilities to analyze available data to determine the degree to which the new minimum clearance requirement and recommended clearance at time of trim in HFTD have contributed to a reduced incidence of ignitions, especially during critical weather conditions. However, there is no evidence presented to justify SDG&E's proposed 25-foot clearance.[70]

4.1.2.2. The Effectiveness of the Removal of Healthy "Hazard Trees" Is Unknown, Especially in Areas with Covered Conductor

The efficacy of removing healthy "hazard trees" has not been adequately justified, and the Commission has not been presented sufficient evidence to evaluate utility claims that healthy trees may topple utility overhead power lines during dry conditions. Removing healthy trees that are potentially more than 100 feet from power lines is likely to be costly and extremely unpopular with property owners. There has also been minimal consideration regarding whether this activity is necessary where the utility installs covered conductor on the same circuit lengths. There is evidence that covered conductor significantly reduces ignition risk from vegetation contact.[71] Therefore, it appears that the removal of healthy trees is intended to eliminate the low probability of wire down events under very extreme wind conditions during dry weather, where wind could actually knock down healthy trees.[72] But covered conductor also reduces both the risk of wire down events,[73] and also the risk of ignition even if

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[70] The Commission should be skeptical of such a wide clearance standard or goal absent a convincing showing that the incremental risk reduction is sufficient to warrant the additional costs and likely public outcry.

[71] See, especially, SCE Covered Conductor Compendium, October 8, 2018, p. 23-33 (See Attachments). The entire lengthy document was provided as SCE Response to DR 005-06 in A.18-09-002 and should be available on the SCE discovery website.

[72] See, for example, A.18-09-002, SCE Response to TURN DR 006-29d (See Attachments). At the February workshops, utility experts agreed that many trees are at risk of falling during extreme rain storm conditions, when the ground is wet and soft. The experts claimed that the utilities have identified trees more at risk of falling during dry and windy conditions. TURN has not evaluated this claim.

[73] A.18-12-009, SCE Response to TURN DR 006-032 (See Attachments).

the conductor is downed, since only a small portion of the conductor would be exposed and capable of releasing energy.[74]

The IOUs claim that the two programs are "complementary." PG&E used past ignition data to conclude that covered conductor would eliminate 56% of historical ignitions and that adding enhanced vegetation management would eliminate an additional 23% of ignitions.[75] TURN intends to evaluate the need to remove healthy trees on circuits that are or will be reconductored with covered wire in the appropriate application proceedings.

4.1.2.3. The Scope of PG&E's EVM Work in 2019 May be Overbroad

PG&E plans to perform EVM on 2,450 circuit miles in 2019, of which approximately 55% is in Tier 3 and 45% is in Tier 2.[76] Given the utility-acknowledged problem with workforce availability, TURN intends to probe in an appropriate application proceeding why performing so much EVM in Tier 2 areas in 2019 is an optimal and cost-effective use of limited resources.

4.1.3. Grid Hardening

4.1.3.1. PG&E and SCE Have Yet to Justify the Amount of Planned Covered Conductor Deployment

PG&E and SCE intend to replace 150 and 96 circuit miles, respectively, with covered conductor in HFTD areas in 2019.[77] SDG&E would limit use of covered conductor to certain applications where it would be beneficial and is in the process of developing criteria and standards for the program, with no costs forecasted for 2019.[78]

If covered conductor is deployed in HFTD areas, TURN agrees that the utilities should prioritize deployment on circuits based on a risk analysis that considers both likelihood of ignition (e.g. risk of vegetation contact, risk of high winds, etc.) and consequence of ignition (e.g. amount of fuel, population density, egress, etc.). The utilities did not include in their WMPs or data responses the showing

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[74] A.18-12-009, SCE Response to TURN DR 006-031 (See Attachments).

[75] PG&E Response to TURN DR 003-13 (See Attachments). As noted above in Section 3.1, these data include non-consequential ignitions and therefore provide information of limited benefit in attempting to prevent catastrophic wildfires that occur in extreme weather conditions.

[76] PG&E Response to TURN DR PG&E-003-09(c) (See Attachments).

[77] PG&E WMP, Table 9, p. 41; SCE WMP, Table 6-6, p. 91.

[78] SDG&E WMP, pp. 37-38 and Appendix A, p. A-27.

necessary to evaluate their prioritization models in this review,[79] and the issue of whether the utilities have proposed the appropriate mileage and/or circuit locations for 2019 will have to be addressed in appropriate application proceedings, where the utilities will need to provide a more robust showing.

4.1.3.2. The Utilities Have Not Justified Transformer Replacement

In their WMPs, PG&E and SCE each propose to replace mineral oil-insulated transformers with new ester fluid insulated transformers.[80] This is an example of a project that may not warrant inclusion in the WMP at all, as there is no indication that any ignitions have been caused by transformers.[81] The utilities will need to justify the need for this program in appropriate application proceedings.

4.1.4. Public Safety Power Shutoff (PSPS) – PG&E and SCE Should Focus on Outreach, Education and Protection of Vulnerable Customers

As discussed by SDG&E at the February 27th workshop, the success of the PSPS strategy was significantly improved by deliberate outreach and communication to affected communities. Thus, over the next few months, PG&E and SCE should focus on outreach and education to communities in HFRA to explain the need for, and operational procedures of, the PSPS.[82] PG&E should also ensure that there are sufficient public facilities with back-up generation available to persons who require electricity or cool locations for health and safety.

4.2. Cost Recovery Review Concerns Arising From SDG&E's WMP

The "Cost Information" contained in SDG&E's WMP highlights the challenging task the Commission faces with the almost forensic nature of the ratemaking review that will be required to ensure the utilities do not double recover program costs, and are not able to use wildfire-specific ratemaking mechanisms to evade forecast risk that appropriately falls on the utility in a GRC. SDG&E explains that, because its test year 2019 GRC is still pending, it does not know its authorized level of 2019 funding for the proposals it included in its GRC request, which represent many of the programs

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[79] PG&E did not provide its prioritization model. PG&E Response to TURN DR 005-06b (See Attachments). TURN will evaluate SCE's prioritization model in A.18-09-002.

[80] PG&E WMP p. 62; SCE WMP Section 3.3.1.3.2, p. 26.

[81] For example, SCE Response to DR TURN 004-02 (See Attachments).

[82] The Commission also intends to address this issue before the 2019 fire season in an upcoming decision in R.18-12-005.

and activities covered in the WMP. SDG&E therefore relies on the amounts it has inferred were authorized for 2018 from its test year 2016 GRC as the point of comparison to determine the amount of O&M costs that should be deemed incremental with regard to its proposals here.[83] For capital spending, SDG&E includes the entire cost, rather than attempt to determine the incremental amount. And for nearly all spending (capital and O&M), SDG&E proposes to record costs in the WRMMA, subject to a later reconciliation once a decision in A.17-10-007 is implemented.[84] The Commission will therefore later face the task of determining the amount authorized for each WMP program or activity that is covered in part or in whole by SDG&E's GRC, and assess whether any spending above the authorized amount is subject to GRC forecasting risk, such that recovery through the WRMMA may not be appropriate. It will also need to compare the basis for the GRC forecast with the contentions made in the WMP where a proposal appears to have grown substantially in cost but not scope between the GRC forecast and the proposal set forth here.[85] In short, the Commission must recognize that commitment to record costs to a particular memorandum account is no assurance of an easy or straightforward future review of cost eligibility for rate recovery.

4.3. Recommendations for Improvements to the Wildfire Management Plans for 2019

Based on the very limited high-level review of the WMPs able to be performed within the adopted schedule, TURN recommends that the Commission order the following prioritization of work being planned for 2019 so as to minimize the risk of catastrophic wildfires:

- The utilities should focus on community outreach and safeguards for vulnerable customers to provide greater understanding and support for the interim use of power shutoffs to eliminate ignition risk in 2019 and to minimize the adverse consequences of such shutoffs.
- The utilities should prioritize the installation of protection schemes and should use recloser disabling (either automatically or manually) liberally in 2019.

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[83] SDG&E WMP, pp. 82-83.

[84] See the "costs" discussion for nearly every program included in Appendix A of the SDG&E WMP.

[85] For example, SDG&E's LTE Communication Network proposal as presented in the GRC entailed forecasted costs of $22 million in 2018 and $50 million in 2019, with the expectation that it would be put into service by the end of 2019 and would achieve "expanded communications coverage for historically high fire risk areas." A.17-10-007, SDG&E-24-R, p. 24, and associated workpapers, p. 266. In SDG&E's WMP, the LTE program includes forecasted costs of $8.8-$13.2 million in 2019, and $36-$52 million in 2020, without any clear indication of any scope or scale difference between the program as proposed in the GRC and the program as described in the WMP. SDG&E WMP, pp. 39 and A-29.

- The utilities should also prioritize the installation of equipment and staff to increase situational awareness and to ensure rapid response to any ignitions, especially during high hazard weather conditions.
- To the extent utilities start installing covered conductor, they should focus on areas in Tier 3 which have the highest risk scores (likelihood times consequence), including in the consequence calculation factors such as population density and egress limitations.
- The utilities should similarly prioritize to the highest risk locations the trimming of trees to the proposed 12-foot clearance, but should minimize healthy tree removal until its need and cost-effectiveness, particularly where covered conductor is installed, is established.

5. EMERGENCY PREPAREDNESS, OUTREACH AND RESPONSE

6. PERFORMANCE METRICS AND MONITORING

6.1. The Large Utilities' Proposed Metrics Fail to Track the Ultimate Desired Outcomes

The most noticeable feature of the metrics proposed in the large utilities' WMPs is that none of them directly track the outcomes that the WMPs are supposed to achieve. TURN recommends that the Commission should adopt the following as the most important metrics to assess utility performance:

- Number of catastrophic wildfires[86] started by utility facilities
- Number of deaths resulting from utility-caused wildfires
- Number of injuries resulting from utility-caused wildfires
- Number of acres burned by utility-caused wildfires

There can be no dispute that reducing each of these measures to zero should be the ultimate goal of the WMPs.[87]

6.2. The Utilities' Proposed 'Targets' Should Not Be Used to Assess Compliance and Are Poor Metrics; However, Some Utility Proposed 'Indicators' Could Be Useful Metrics

As noted in Section 1.4 above, PG&E and SCE, and SDG&E to a lesser extent, propose that the key metrics the CPUC should adopt are what PG&E calls "targets," which are essentially utility-specified goals for performing a certain amount of work. They propose that these targets be used to assess whether the utilities have complied with their plans. TURN has already explained in Section 1.4

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[86] To create a clear and well-defined metric, TURN suggests that the CPUC consult with CAL FIRE to develop an appropriate, non-subjective definition of catastrophic wildfire (e.g, any wildfire resulting in a death or serious injury or destruction of a certain number of structures or burning of a certain number of acres) for this purpose.

[87] TURN does not propose these as metrics against which utility compliance should be measured.

why the Commission should not treat these utility-designed work goals as compliance requirements.[88] As explained, such requirements should be based on Commission findings that the requirements are clearly defined and essential for safety -- findings the WMPs do not support. Instead, at this initial stage in the implementation of SB 901, the utilities' compliance with respect to wildfire mitigation should be measured by their compliance with existing rules, regulations, and standards that are designed to prevent catastrophic wildfires.

In addition, the utilities' proposed targets make poor metrics for assessing utility progress in preventing catastrophic wildfires. As noted in Section 1.4, merely performing a certain amount of work does not necessarily improve safety if the right work is not selected or the work is not done properly. Viewing these utility work goals as metrics, particularly before the Commission has found the goals and the underlying programs reasonable, could create an unduly inflated sense of progress in reducing the risk of catastrophic wildfires.

In contrast, some of the "indicators" identified by the utilities may be worthy of treating as metrics.[89] Even though they do not directly track progress toward the desired outcome, indicators can be useful, albeit indirect, metrics if their improvement is likely to be correlated with reduction in the risk of catastrophic wildfires. Effective metrics should also be: (1) objective, so that trend analysis over time is not influenced by a utility's subjective judgment, and (2) capable of being easily audited, to ensure that utilities are presenting accurate data. Examples of potentially worthwhile indirect metrics include counts of wires down events, ignitions, and outages cause by vegetation or equipment failure in high fire threat areas when the fire potential index (FPI) is rated as very-high or higher.[90]

6.3. The Commission Should Require That Monitoring of the Quality of the Utilities' Work Be Performed by An Independent Entity, Overseen By and Answerable To The Agency

The WMPs of the major utilities describe monitoring of the quality of their wildfire mitigation work activities as a function that, to the extent it occurs, will be undertaken either

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[88] In addition, Section 1.5 explains why the Commission should soundly reject the large utility proposals to deem "substantial compliance" with utility-designed targets as sufficient to meet the prudence standard under Sections 451 and 451.1.

[89] PG&E and SCE describe indicators as useful to track longer-term trends. PG&E WMP, p. 132; SCE WMP, p. 93.

[90] These examples are proposals, or variants thereof, made in PG&E's WMP at pp. 134, 136.

internally or through third parties answerable to the utilities.[91] The utilities do not explain how their approaches will achieve improved monitoring as compared to historical efforts, which similarly relied upon such internal and third party review – and, at least in the case of PG&E, have produced calamitous results. TURN recommends that the Commission require the utilities to fund independent safety evaluators who would be managed by and answerable to the agency. Such evaluators would be charged with, among other things, performing spot checks of ongoing and completed projects under the WMP, in order to assess not just that the work is completed, but completed at an appropriate level of quality.[92]

7. RECOMMENDATIONS FOR FUTURE WILDFIRE MITIGATION PLANS

TURN recommends that the Commission set a second phase, after its decision on the 2019 WMPs, to take concurrent opening and reply comments from the parties regarding recommendations for future WMPs. As discussed in previous sections, TURN expects that its recommendations will include the following:

- The WMPs should be more focused on preventing *catastrophic* wildfires, not simply ignitions, most of which do not pose a risk of catastrophic wildfire.
- The WMPs should provide more analysis concerning the effectiveness of past and current investments and operational strategies in preventing catastrophic wildfires.
- To the extent that WMPs propose programs that go beyond existing requirements or measures, the WMPs should quantify the incremental risk reduction benefit that the new programs will provide with respect to the risk of catastrophic wildfire.
- The WMPs should include a discussion to enable the Commission to verify whether the WMPs comply with all applicable rules, regulations, and standards (Section 8386(d).

[91] PG&E WMP, pp. 137-140; SCE WMP, pp. 95-96; and SDG&E WMP, p. 81.

[92] These duties fit well within the scope of the duties outlined for the independent evaluator required by Section 8386(h)(2)(B).

Respectfully submitted,

Dated: March 13, 2019

By: __________/s/______________

Thomas J. Long

Thomas J. Long, Legal Director
Robert Finkelstein, General Counsel
Marcel Hawiger, Staff Attorney
THE UTILITY REFORM NETWORK

ATTACHMENTS

To TURN Comments on WMPs

CAL FIRE NEWS RELEASE

California Department of Forestry and Fire Protection

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RELEASE DATE: May 25, 2018

CAL FIRE Investigators Determine Cause of Four Wildfires in Butte and Nevada Counties

Sacramento – After extensive and thorough investigations, CAL FIRE investigators have determined that four Northern California wildfires in last year's October Fire Siege were caused by trees coming into contact with power lines. The four fires, located in Butte and Nevada counties, are the first fire investigations from last October to be completed.

CAL FIRE investigators were dispatched to the fires last year and immediately began working to determine their origin and cause. The Department continues to investigate the remaining 2017 fires, both in October and December, and will release additional reports as they are completed.

The October 2017 Fire Siege involved more than 170 fires and charred more than 245,000 acres in Northern California. More than 11,000 firefighters from 17 states helped battle the blazes.

Below is a summary of the four completed investigations:

- The La Porte Fire, in Butte County, started in the early morning hours of Oct. 9 and burned a total of 8,417 acres, destroying 74 structures. There were no injuries to civilians or firefighters. CAL FIRE has determined the fire was caused by tree branches falling onto PG&E power lines. CAL FIRE investigators determined there were no violations of state law related to the cause of this fire.

- The McCourtney Fire, in Nevada County, started the evening of Oct. 8 and burned a total of 76 acres, destroying 13 structures. There were no injuries to civilians or firefighters. CAL FIRE has determined the fire was caused by a tree falling onto PG&E power lines. The investigation found evidence that PG&E allegedly failed to remove a tree from the proximity of a power line, in violation of the state Public Resources Code section 4293.

- The Lobo Fire, in Nevada County, started the evening of Oct. 8 and burned a total of 821 acres, destroying 47 structures. There were no injuries to civilians or firefighters. CAL FIRE has determined the fire was caused by a tree contacting PG&E power lines. The investigation found evidence that Public Resources Code section 4293, which requires adequate clearance between trees and power lines, was allegedly violated.

- The Honey Fire, in Butte County, started in the early morning hours of Oct. 9 and burned a total of 76 acres. There were no injuries to civilians or firefighters and no structures were destroyed. CAL FIRE has determined the fire was caused by an Oak branch contacting PG&E power lines. The investigation found evidence that Public Resources Code 4293, which requires adequate clearance between trees and power lines, was allegedly violated.

The McCourtney, Lobo, Honey investigations have been referred to the appropriate county District Attorney's offices for review.

Californians are encouraged to remain vigilant and prepared for wildfire. For more information, visit www.readyforwildfire.org or www.fire.ca.gov

# # #

CAL FIRE NEWS RELEASE

California Department of Forestry and Fire Protection

CONTACT: Michael Mohler
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RELEASE DATE: June 8, 2018

CAL FIRE Investigators Determine Causes of 12 Wildfires in Mendocino, Humboldt, Butte, Sonoma, Lake, and Napa Counties

Sacramento – After extensive and thorough investigations, CAL FIRE investigators have determined that 12 Northern California wildfires in the October 2017 Fire Siege were caused by electric power and distribution lines, conductors and the failure of power poles.

The October 2017 Fire Siege involved more than 170 fires and burned at least 245,000 acres in Northern California. About 11,000 firefighters from 17 states and Australia helped battle the blazes.

CAL FIRE investigators were dispatched to the fires last year and immediately began working to determine their origin and cause. CAL FIRE investigators continue to investigate the remaining 2017 fires, both in October and December, and will release additional reports as they are completed. The cause of four Northern California fires were released on May 25.

Below is a summary of the findings from the 12 completed investigations:

The **Redwood Fire**, in Mendocino County, started the evening of Oct. 8 and burned a total of 36,523 acres, destroying 543 structures. There were nine civilian fatalities and no injuries to firefighters. CAL FIRE has determined the fire started in two locations and was caused by tree or parts of trees falling onto PG&E power lines.

The **Sulphur Fire**, in Lake County, started the evening of Oct. 8 and burned a total of 2,207 acres, destroying 162 structures. There were no injuries. CAL FIRE investigators determined the fire was caused by the failure of a PG&E owned power pole, resulting in the power lines and equipment coming in contact with the ground.

The **Cherokee Fire**, in Butte County, started the evening of Oct. 8 and burned a total of 8,417 acres, destroying 6 structures. There were no injuries. CAL FIRE investigators have determined the cause of the fire was a result of tree limbs coming into contact with PG&E power lines.

The **37 Fire**, in Sonoma County, started the evening of Oct. 9 and burned a total of 1,660 acres, destroying 3 structures. There were no injuries. CAL FIRE investigators have determined the cause of the fire was electrical and was associated with the PG&E distribution lines in the area.

more

The **Blue Fire**, in Humboldt County, started the afternoon of Oct. 8 and burned a total of 20 acres. There were no injuries. CAL FIRE investigators have determined a PG&E power line conductor separated from a connector, causing the conductor to fall to the ground, starting the fire.

The Norrbom, Adobe, Partrick, Pythian and Nuns fires were part of a series of fires that merged in Sonoma and Napa counties. These fires started in the late-night hours of Oct. 8 and burned a combined total of 56,556 acres, destroying 1355 structures. There were three civilian fatalities.

> CAL FIRE investigators determined the **Norrbom Fire** was caused by a tree falling and coming in contact with PG&E power lines.
>
> CAL FIRE investigators determined the **Adobe Fire** was caused by a eucalyptus tree falling into a PG&E powerline.
>
> CAL FIRE investigators determined the **Partrick Fire** was caused by an oak tree falling into PG&E powerlines.
>
> CAL FIRE investigators determined the **Pythian Fire** was caused by a downed powerline after PG&E attempted to reenergize the line
>
> CAL FIRE investigators determined the **Nuns Fire** was caused by a broken top of a tree coming in contact with a power line.

The **Pocket Fire**, in Sonoma County, started the early morning hours of Oct. 9 and burned a total of 17,357 acres, destroying 6 structures. There were no injuries. CAL FIRE has determined the fire was caused by the top of an oak tree breaking and coming into contact with PG&E power lines.

The **Atlas Fire,** in Napa County, started the evening of Oct. 8 and burned a total of 51,624 acres, destroying 783 structures. There were six civilian fatalities. CAL FIRE investigators determined the fire started in two locations. At one location, it was determined a large limb broke from a tree and came into contact with a PG&E power line. At the second location, investigators determined a tree fell into the same line.

CAL FIRE's investigations have been referred to the appropriate county District Attorney's offices for review in eight of the 12 fires – Sulphur, Blue, Norrbom, Partrick, Pythian, Adobe, Pocket and Atlas – due to evidence of alleged violations of state law.

Californians are encouraged to remain vigilant and prepared for wildfire. For more information on how to be prepared, visit www.readyforwildfire.org or www.fire.ca.gov

# # #

Southern California Edison
R.18-10-007 – SB 901

DATA REQUEST SET T U R N - S C E - 0 0 3

To: TURN
Prepared by: Ryan Stevenson
Job Title: Senior Advisor
Received Date: 2/22/2019

Response Date: 3/1/2019

Question 01: Please identify by page number, each part of your company's WMP that will facilitate the Commission's discharge of its responsibility under Section 8386(e) to "verify that the plan complies with all applicable rules, regulations, and standards, as appropriate."

Response to Question 01:
SCE objects to this question on the basis that is vague and ambiguous, overly broad and burdensome, and seeks legal conclusions and interpretation. Notwithstanding this objection, SCE responds as follows. Section 8386(e) does not include the referenced phrase. The referenced phrase is included in 8386(d) and reads as follows: The commission shall accept comments on each plan from the public, other local and state agencies, and interested parties, and verify that the plan complies with all applicable rules, regulations, and standards, as appropriate. Moreover, the Commission has neither asked for assistance in fulfilling its responsibilities under Section 8386, nor has it interpreted this section of the statute as to which are appropriate. The entirety of SCE's 2019 Wildfire Mitigation Plan (WMP) contains the required information to facilitate the Commission's discharge of its responsibility under Section 8386(d). Additionally, SCE's WMP as initially filed may change as a result of Commission review. The Commission's verification will be of the final WMP in the event of any such changes.

Southern California Edison
R.18-10-007 – SB 901

DATA REQUEST SET T U R N - S C E - 0 0 4

To: TURN
Prepared by: Andrew Garcia
Job Title: Senior Manager
Received Date: 3/1/2019

Response Date: 3/6/2019

Question 02: Re. WMP p. 26, RAMP Control C2:

a. Does footnote 35 mean that SCE will replace existing transformers only if they are "failing"? If yes, please explain how SCE determines if a transformer is failing.
b. Have there been any ignitions associated with the operation of existing mineral oil transformers? If yes, please quantify. Please explain whether the ignition was related to the mineral oil or fluid.
c. Please quantify the number of existing mineral oil transformers disaggregated by Tier-1, Tier-2 and non-HFTD.
d. Please quantify the number of existing ester fluid transformers disaggregated by Tier-1, Tier-2 and non-HFTD.
e. How many transformers does SCE forecast will be replaced in 2019 and 2020?

Response to Question 02:

a. SCE replaces existing transformers under a number of conditions which includes when a transformer is demonstrating signs of degradation potentially leading to failure. SCE uses visual inspections of transformers to identify degraded parts that may lead to reduced service life and failure such as oil leaks, tank corrosion, overheated terminals, and damaged bushings. SCE has had success using smart meter voltage readings for transformers to identify failing transformers where internal winding shorts can be detected, and the transformer may be replaced prior to a faulted condition developing due to the transformer. Severely overloaded transformers cause degradation of the insulating oil, paper, and other components of transformers. SCE has established loading limits for transformer replacements where prolonged operation may lead to reduced service life and premature transformer failure. SCE may also replace installed transformers as maintenance opportunities to allow for bundling work activities to take advantage of work execution efficiencies, such a replacement of transformers during a pole replacement where limited additional work is needed for updating the installation.

b. There have been three transformer-related fires where the transformer contained mineral oil. However, SCE could not determine if they were associated with mineral oil or some other cause.

c. SCE's existing inventory of in-service mineral oil transformers is as follows:

	Tier 3	Tier 2	Non-HFRA
Mineral Oil Transformers	45,507	25,813	357,214

The above counts are based on a system query ran on 3/4/19. SCE expects these numbers to decrease by a few thousand over the next few months as 2018 work orders continue to be completed in the system reflecting replacements of some of the above units with ester oil units.

d. SCE's existing inventory of in-service ester oil transformers is as follows:

	Tier 3	Tier 2	Non-HFRA
Ester Oil Transformers	645	242	2,361

The above counts are based on a system query ran on 3/4/19. SCE expects these numbers to increase by a few thousand over the next few months as 2018 work orders continue to be completed in the system.

e. Prior to 2019, SCE has replaced roughly 5,000 overhead transformers annually in HFRA. Including the Wildfire Covered Conductor Program efforts, SCE expects to replace roughly 5,600 overhead transformers for circuits in HFRA. SCE HFRA locations include CPUC Tier 2, Tier 3, a small buffer, and non-CPUC HFRA as detailed in Section 3.4.1 of SCE's 2019 Wildfire Mitigation Plan. 2020 wildfire mitigation activities, including those associated with WCCP, will be considered in the 2020 WMP proceeding, and are not within the scope of this proceeding. For 2020, SCE has not yet decided upon a final scope of grid-hardening work including the overhead transformers; however, we anticipate replacing roughly 5,600 transformers.

TURN DATA REQUEST: TURN-SDG&E-03
R.18-10-007 – SB901 WILDFIRE MITIGATION PLAN OIR
SDG&E RESPONSE

Date Received: February 27, 2019
Date Submitted: March 4, 2019

QUESTION 1:

Please identify by page number, each part of your company's WMP that will facilitate the Commission's discharge of its responsibility under Section 8386(e) to "verify that the plan complies with all applicable rules, regulations, and standards, as appropriate."

RESPONSE 1:

SDG&E objects on the basis that this question is vague and ambiguous, overly broad and burdensome, and seeks legal conclusions and interpretation. Notwithstanding these or any other objections, and without waiving any objection SDG&E responds as follows: The Commission has neither asked for facilitation of its responsibilities under Public Utilities Code Section 8386 (d) (which contains the phrase cited in the question), nor has it interpreted this section of the Code as to which are appropriate. SDG&E's entire Wildfire Mitigation Plan should facilitate the Commission's review and eventual approval of the plan. SDG&E has not performed any analysis of which parts or page(s) of its Plan would facilitate such review. Furthermore, SDG&E's Plan as submitted may change in response to Commission review. The Commission's verification will be of the final Wildfire Mitigation Plan in the event of such changes.

QUESTION 2:

Please identify by page number, each part of your company's WMP that identifies the "applicable rules, regulations, and standards."

RESPONSE 2:

SDG&E objects on the basis that this question is vague and ambiguous, overly broad and burdensome, and seeks legal conclusions and interpretation. Notwithstanding these or any other objections, and without waiving any objection SDG&E responds as follows: SDG&E's Wildfire Mitigation Plan identifies a number of rules, regulations and standards as listed below. However, SDG&E's Plan did not attempt to identify every applicable rule, regulation, or standard, nor has the Commission yet ruled on which rules, regulations and standards are appropriately applied to such Plans.

The following rules, regulations, standards were mentioned in SDG&E's Plan:

Rule, Regulation, Standard	Section	Page number(s)
18 CFR 388.113	Section 4.2.4	29-30, n.55
49 CFR 192.615	Section 6.2.3.2	79-80
AL 3177-E	Section 5.3	68-69
AL 3333-E	Section 4	19-20, n.45
California Public Resources Code (PRC) § 4292	Section 4.2.3 Section 4.3.11 Section 4.4 Section 4.4.7 Section 4.4.8 Appendix A Appendix B	28 35-36, n.60 41, n.67 45-46 46 A-12, A-35 – A-40, A-42 B-1 – B-2
California Public Resources Code (PRC) § 4293	Section 4.2.3 Section 4.4 Section 4.4.8 Section 6.2.1.4 Appendix A Appendix B	28 41, n.67 46 77 A-12, A-34 – A-39, A-42 B-1 – B-2
D.10-04-047	Section 4.2.1.2	27, n.54
D.12-04-024	Section 4.7.1 Appendix A Appendix B	54 A-52 – A-55 B-3
D.14-01-002	Section 4.3.7	33, n.57
D.14-02-015	Section 6.3.1	80-81

Date Received: February 27, 2019
Date Submitted: March 4, 2019

Rule, Regulation, Standard	Section	Page number(s)
D.14-12-025	Section 3.1.8 Section 7.1	13, nn.29-31 82-83
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QUESTION 3:

Please identify by page number, each part of your company's WMP that is intended to show compliance with "applicable rules, regulations, and standards."

RESPONSE 3:

SDG&E objects on the basis that this question is vague and ambiguous, overly broad and burdensome, and seeks legal conclusions and interpretation. Notwithstanding these or any other objections, and without waiving any objection SDG&E responds as follows:
SDG&E's Wildfire Mitigation Plan is a forward-looking actionable plan as opposed to a document addressing an unspecified list of regulations and rules. It is also subject to change in response to Commission direction and guidance, as provided in SB 901.

PACIFIC GAS AND ELECTRIC COMPANY
Wildfire Mitigation Plans
Rulemaking 18-10-007
Data Response

PG&E Data Request No.:	TURN_003-Q09		
PG&E File Name:	WildfireMitigationPlans_DR_TURN_003-Q09		
Request Date:	February 20, 2019	Requester DR No.:	003
Date Sent:	February 25, 2019	Requesting Party:	The Utility Reform Network
PG&E Witness:	Matthew Pender	Requester:	Marcel Hawiger

QUESTION 09

PG&E states it will accomplish EVM "on approximately 2,450 circuit miles in HFTD."

a. How was this determined?

b. How will PG&E prioritize the circuits it targets? Please explain and provide all supporting workpapers.

c. What percentage of this work will be in Tier 3 vs. Tier 2 HFTDs? Please explain and provide all supporting workpapers.

ANSWER 09

a. PG&E's 2019 target of approximately 2,450 circuit miles of EVM work was based on an estimated resource allocation by month as outlined in the attached excel file, WildfireMitigationPlans_DR_TURN_003-Q09-Atch01. As shown in that spreadsheet, the total target is based on that estimated resource allocation multiplied by available workdays each month and estimated productivity per tree crew resource.

b. PG&E is prioritizing where to perform the 2019 EVM work based on two factors: first, PG&E is completing work at locations where inspection work was already performed in 2018. Second, PG&E will be completing the remaining miles of planned 2019 work on generally the highest risk circuits based on PG&E's risk model. The list of circuits where work is planned for 2019 is provided in WildfireMitigationPlans_DR_TURN_003-Q09-Atch02. Note that the sum of column E, planned miles, lists approximately 30% more miles than the 2019 target (shown in column F) based on an expectation that a portion of these initially planned miles will not be workable due to various constraints including environmental restrictions.

c. As identified in excel row 325 of the attachment, WildfireMitigationPlans_DR_TURN_003-Q09-Atch02, the estimated split of 2019 EVM work is ~1,340 miles (or 55%) in Tier 3 and ~1,110 (or 45%) in Tier 2.

PACIFIC GAS AND ELECTRIC COMPANY
Wildfire Mitigation Plans
Rulemaking 18-10-007
Data Response

PG&E Data Request No.:	TURN_003-Q13		
PG&E File Name:	WildfireMitigationPlans_DR_TURN_003-Q13		
Request Date:	February 20, 2019	Requester DR No.:	003
Date Sent:	February 25, 2019	Requesting Party:	The Utility Reform Network
PG&E Witness:		Requester:	Marcel Hawiger

QUESTION 13

Regarding covered conductor and EVM:

a. Please explain whether covered conductor will be installed in areas / circuit miles where EVM will occur. Please explain the incremental risk reduction benefit of installing covered conductor in the same area / circuit mile where EVM is occurring. Please provide all supporting workpapers and analyses that support this response.

b. Please explain whether EVM will be installed in areas / circuit miles where covered conductor will be installed. Please explain the incremental risk reduction benefit of installing covered conductor in the same area / circuit mile where EVM is occurring. Please provide all supporting workpapers and analyses that support this response.

ANSWER 13

a. Yes, ultimately covered conductor will be installed in the same areas and on the same circuits where Enhanced Vegetation Management (EVM) work occurs. One of the reasons for this is that, while these two wildfire risk mitigation activities address some of the same wildfire risks, they also address different threats to the powerline. EVM primarily addresses risks from vegetation contacting the overhead facilities, including large trees that would damage and/or bring down any powerline if the tree were to fail into the line, even if covered conductor has been installed. Likewise, installation of covered conductor primarily addresses equipment failure and third party risks that are not addressed by EVM. While there may be overlap in that both programs provide mitigation for the threat of smaller limbs and branches falling (or blowing) into powerlines, they are also complementary in addressing different risk factors.

   In a simple analysis of historical drivers of fire ignitions in High Fire Threat Districts application of “System Hardening” (installation of covered conductor plus pole replacement) was identified to mitigate 56% of the historical ignitions by itself, when EVM was also applied to the analysis this number increased to 79% of historical ignitions mitigated. Please see page 12 of Attachment for details of the outcome of this analysis.

b. Yes, for the same reasons described in response to answer TURN_003, Q13a, Enhanced Vegetation Management (EVM) work will be performed in the same areas and on the same circuits where covered conductor has been installed. In a simple analysis of historical drivers of fire ignitions in High Fire Threat Districts application of EVM was identified to mitigate 31% of the historical ignitions by itself, when “System Hardening” (installation of covered conductor plus pole replacement) was also applied to this analysis this number increased to 79% of historical ignitions mitigated. Please see page 12 of the attachment produced in response to TURN_003, Q13a for details.

PACIFIC GAS AND ELECTRIC COMPANY
Wildfire Mitigation Plans
Rulemaking 18-10-007
Data Response

PG&E Data Request No.:	TURN_003-Q14		
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Request Date:	February 20, 2019	Requester DR No.:	003
Date Sent:	February 25, 2019	Requesting Party:	The Utility Reform Network
PG&E Witness:		Requester:	Marcel Hawiger

QUESTION 14

Attachment E, page E-2, provides the cost of several system hardening activities in 2019, of around $237 million.

a. Please provide all supporting workpapers for this Figure in Excel.

b. Please confirm that this combines the cost of several activities, and list the activities.

c. Please provide the separate cost of each activity under “system hardening” that comprise the $236,900,000 cost. Please provide each category in total and on a per mile basis for 2019.

ANSWER 14

Please see Attachment WildfireMitigationPlans_DR_TURN_003-Q14Atch01

System Hardening 2019 Cost Scenarios

			Low	Mid	High	Assumptions / Cost Drivers:
			Low	**Mid**	**Mid**	**Assumptions / Cost Drivers:**
Overhead	Cost by Category	Non-wood poles	$82,800,000	$81,000,000	$79,200,000	
		Covered OH Conductor -Tree wire	$72,864,000	$71,280,000	$69,696,000	
		Covered Secondary Conductor -	$2,760,000	$2,700,000	$2,640,000	
		Non- Exempt Equip / Transformer Replacement	$13,800,000	$13,500,000	$13,200,000	
		Increased Line Protection	$4,140,000	$4,050,000	$3,960,000	
		Economies of Scale	($17,636,400)	($17,253,000)	($16,869,600)	
		Total Cost	**$158,727,600**	**$155,277,000**	**$151,826,400**	
	Overhead Unit Cost	Non-wood poles	$600,000	$600,000	$600,000	
		Covered OH Conductor -Tree wire	$528,000	$528,000	$528,000	
		Covered Secondary Conductor -	$20,000	$20,000	$20,000	
		Non- Exempt Equip / Transformer Replacement	$100,000	$100,000	$100,000	
		Increased Line Protection	$30,000	$30,000	$30,000	
		Economies of Scale	($127,800)	($127,800)	($127,800)	**Economies of Scale:** 10% from GRC; Low/High Cost Driver?
		Total Unit Cost	**$1,150,200**	**$1,150,200**	**$1,150,200**	**OH Unit Cost:** OH UC $1.15M aligns with GRC and 2018 Act UC 120% Premium
30	Units of Work	Non-wood poles	4,140	4,050	3,960	
5280		Covered OH Conductor -Tree wire	728,640	712,800	696,960	
1000		Covered Secondary Conductor -	138,000	135,000	132,000	
10		Non- Exempt Equip / Transformer	1,380	1,350	1,320	
5		Increased Line Protection	690	675	660	
		Economies of Scale	0	0	0	
	Miles	**OH Miles**	**138**	**135**	**132**	**OH / UG Ratio** **Low**: 8% UG (12 miles), 92% OH (138 miles) **Mid**: 10% UG (15 miles), 90% OH (135 miles) **High:** 12% UG (18 miles), 88% OH (132 miles)
Underground	Total Cost	**Total Cost**	**$55,209,600**	**$69,012,000**	**$82,814,400**	
	Unit Cost	**Underground Unit Cost**	**$4,600,800**	**$4,600,800**	**$4,600,800**	**UG Unit Cost:** **Low, Mid, High:** 4:1 UG/OH unit cost based on historical Rule 20A
	Miles	**UG Miles**	**12**	**15**	**18**	
SH Total	SH Total	**System Hardening Total**	**$213,937,200**	**$224,289,000**	**$234,640,800**	
		Total Miles Target	**150**	**150**	**150**	

12.611 5%

Note: *WMP System Hardening forecast submitted $236.9M. Current forecast $225M is less than 5% change from 2020GRC submission (per WMP threshold of 15% to revise forecast).*

PACIFIC GAS AND ELECTRIC COMPANY
Wildfire Mitigation Plans
Rulemaking 18-10-007
Data Response

PG&E Data Request No.:	TURN_003-Q16		
PG&E File Name:	WildfireMitigationPlans_DR_TURN_003-Q16		
Request Date:	February 20, 2019	Requester DR No.:	003
Date Sent:	February 25, 2019	Requesting Party:	The Utility Reform Network
PG&E Witness:		Requester:	Marcel Hawiger

The following questions relate to the WSIP.

QUESTION 16

Re. WSIP Distribution (pp. 52-56 of the WMP):

Please explain in detail how the "wildfire-specific inspections" differ from GO 165 "detailed inspections"

a. Please provide the most relevant SOPs for PG&E's detailed overhead inspections pursuant to GO 165
b. Please provide any analyses or reports produced as part of the FMEA
c. For each "component" that was identified as having a point of failure that could lead to fire ignition, please explain all "relevant inspection methods" that were identified during the FMEA
d. Given the list of components in Paragraph 1 of p. 56, are there any components or assets connected to distribution poles or wires that would not be targeted as part of wildfire-specific inspections? If yes, please identify the components and explain why they are not included.
e. Please provide the forecast unit cost(s) of forecast 2019 expense based on the appropriate unit(s). Please provide all workpapers and explain any relevant assumptions.
f. Please provide the forecast unit cost(s) of forecast 2019 capital costs based on the appropriate unit(s). Please provide all workpapers and explain any relevant assumptions.

ANSWER 16

PG&E conducts "detailed inspections" as per GO 165 requirements, including a five year "detailed inspection" cycle of all distribution assets. The focus of GO 165 "detailed inspections" is identification, assessment, prioritization, and documentation of compelling abnormal conditions, regulatory conditions, and third party caused infractions that negatively impact safety or reliability. As part of PG&E's enhanced wildfire safety inspection efforts, PG&E is conducting accelerated and enhanced "wildfire-specific inspections" of distribution electric infrastructure in HFTD areas Tier 2 and 3. The “wildfire-specific inspections” are in addition to the routine GO 165 “detailed inspections”. “Wildfire-specific inspections” will cover 685,000 poles across 25,200 miles of the distribution network. The accelerated and enhanced inspection and repair process for the “wildfire-specific inspections”:

* Adopts a risk based approach using a Failure Mode and Effects Analysis (FMEA) associated with potential fire ignition

* Includes new electronic inspection forms and job aids for inspectors to capture findings

* Enhances the existing inspection review process with a team of individuals with experience in system maintenance to evaluate conditions for necessary repair

* Implements a process safety lens using multiple layers of control related to quality.

a. Please provide the most relevant SOPs for PG&E’s detailed overhead inspections pursuant to GO 165

   The most relevant SOP for PG&E detailed overhead inspections pursuant to GO 165 is the Electric Distribution Preventive Maintenance (EDPM) Manual.

b. Please provide any analyses or reports produced as part of the FMEA

   See attachment WildfireMitigationPlans_DR_TURN_003-Q16Atch01

c. For each “component” that was identified as having a point of failure that could lead to fire ignition, please explain all “relevant inspection methods” that were identified during the FMEA

   To clarify, the FMEA does not specifically use the word “component”. The FMEA for Distribution WSIP tracks 128 failure types associated with fire ignition risk.

   The Distribution WSIP visual inspection targeted for a May 31, 2019 completion date includes visual inspection of all 685,000 distribution poles in High Fire Threat District (HFTD) areas Two and Three for the 128 failure types. PG&E may leverage drones for difficult-to-access locations to assist in the inspection.

   In addition to visual inventory by inspectors, PG&E expanded thermal “infrared or IR” imaging analysis to scan an additional 6,564 miles of the network in Tier Three HFTDs in 2018. Where “hot spots” were identified through thermal infrared or IR, PG&E followed up with visual inspections. Additionally, PG&E is evaluating expanded aerial augmentation of Distribution WSIP inspections through helicopter and drone capabilities under an ongoing study.

d. Given the list of components in Paragraph 1 of p. 56, are there any components or assets connected to distribution poles or wires that would not be targeted as part of wildfire-specific inspections? If yes, please identify the components and explain why they are not included.

The Distribution WSIP visual inspections cover all inspection items associated with the failure types identified in the FMEA. It does not cover the following components:

- Components belonging to a third party on joint poles (e.g. telecommunications)
- Components belonging to underground facilities (e.g. transformer pads and pad mounted transformers)
- Components connected to distribution network that are covered by transmission or substation WSIP

e. Please provide the forecast unit cost(s) of forecast 2019 expense based on the appropriate unit(s). Please provide all workpapers and explain any relevant assumptions.

See attachment WildfireMitigationPlans_DR_TURN_003-Q16Atch02.

f. Please provide the forecast unit cost(s) of forecast 2019 capital costs based on the appropriate unit(s). Please provide all workpapers and explain any relevant assumptions.

See attachment WildfireMitigationPlans_DR_TURN_003-Q16Atch02.

PACIFIC GAS AND ELECTRIC COMPANY
Wildfire Mitigation Plans
Rulemaking 18-10-007
Data Response

PG&E Data Request No.:	TURN_003-Q17		
PG&E File Name:	WildfireMitigationPlans_DR_TURN_003-Q17		
Request Date:	February 20, 2019	Requester DR No.:	003
Date Sent:	February 27, 2019	Requesting Party:	The Utility Reform Network
PG&E Witness:		Requester:	Marcel Hawiger

The following questions relate to the WSIP.

QUESTION 17

Re. 2/13/19 Presentation, p. 9, Row labeled "Inspections-Distribution"

a. Please provide the number of poles slated for a "detailed overhead inspection" in 2019;
b. Are any of the forecast 685,000 poles scheduled for enhanced inspections already scheduled for a detailed overhead inspection? If yes, please quantify.
c. For 2013-2017 and 2018 (as available), please provide for each year:
   i. The number of corrective actions identified each year, segregated by equipment component
   ii. The number of corrective actions completed each year, segregated by equipment component
   iii. The number of months by which all corrective actions identified in the year were completed
   iv. The total cost, in capital and expense, for detailed overhead inspections and for corrective actions. Please identify the relevant MAT or WC (or other account) information where costs are recorded. Please provide a citation to the relevant testimony in the 2020 GRC providing the cost forecast for the accounts relevant to costs related to detailed overhead inspections and corrective action repairs.

ANSWER 17

a. 517,000 poles are scheduled in 2019 for "Detailed overhead inspection" under GO 165.

b. Of the 685,000 poles in high fire threat district (HFTD) areas, 185,000 are already planned for "detailed overhead inspection". In addition to routine detailed overhead inspection procedures, inspectors will apply the incremental inspection items consistent with the wildfire FMEA on all 185,000 poles.

c. PG&E will provide responses to subparts (c)(i) to (c)(iii) on Friday, March 1.

iv. The total cost, in capital and expense, for detailed overhead inspections and for corrective actions. Please identify the relevant MAT or WC (or other account) information where costs are recorded. Please provide a citation to the relevant testimony in the 2020 GRC providing the cost forecast for the accounts relevant to costs related to detailed overhead inspections and corrective action repairs. See attachment WildfireMitigationPlans_DR_TURN_003-Q17Atch04.

PACIFIC GAS AND ELECTRIC COMPANY
Wildfire Mitigation Plans
Rulemaking 18-10-007
Data Response

PG&E Data Request No.:	TURN_004-Q01		
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Request Date:	February 27, 2019	Requester DR No.:	004
Date Sent:	March 4, 2019	Requesting Party:	The Utility Reform Network
PG&E Response: Charles Middlekauff		Requester:	Tom Long

SUBJECT: FIRE INCIDENT DATA

QUESTION 01

Please identify by page number, each part of your company's WMP that will facilitate the Commission's discharge of its responsibility under Section 8386(e) to "verify that the plan complies with all applicable rules, regulations, and standards, as appropriate."

ANSWER 01

California Public Utilities Code section 8386(d) provides:

> The commission shall accept comments on each plan from the public, other local and state agencies, and interested parties, and verify that the plan complies with all applicable rules, regulations, and standards, as appropriate.

Preceding this provision, subsection (b) requires electrical corporations to prepare and submit wildfire mitigation plans, and subsection (c) describes in detail what the plans should include. On January 17, 2019, Administrative Law Judge (ALJ) Thomas issued a ruling that included a detailed template of what elements and information was to be included in each electrical corporation's plan.

Table 2 in PG&E's Wildfire Safety Plan (Plan) includes a detailed list of each statutory requirement in Section 8386(c), and where the information related to that requirement is included in the Plan. In addition, PG&E's Plan follows the template approved by ALJ Thomas. PG&E's Plan is replete with references to statutory requirements, such as California Public Resources Code section 4293, as well as General Orders (GO) issued by the Commission, such as GOs 95, 165, and 166. PG&E's Plan also includes citations to relevant Commission decisions and resolutions, such as Decision 12-04-024 and Resolution ERSB-8 both related to de-energization. A word search of the Plan will identify where statutes, rules, decisions, resolutions, and regulations have been cited.

Under Section 8386(d), the public, agencies, and interested parties, such as TURN, will have an opportunity to review and comment on PG&E's Plan. In this proceeding, TURN received PG&E's Plan on February 6, and has had an opportunity to review the Plan and seek necessary additional information through workshops, a technical conference, and discovery. Consistent with the statutory language, TURN will then have an opportunity to comment on PG&E's plan in its March 13, 2019 comments. In its comments, TURN, as well as other parties, can comment on whether PG&E's Plan, as well as the plans of the other electrical corporations, comply with applicable rules, regulations and standards, to the extent that TURN and/or other parties believe it is necessary and appropriate. The electrical corporations will then have an opportunity to file reply comments on March 22, 2019, including addressing any concerns from other parties that their respective plans do or do not comply with applicable rules, regulations, and standards.

Based on all of the submissions described above, as contemplated by the Legislature in Section 8386(d), the Commission will then be able to determine whether each electrical corporation's plan complies with applicable rules, regulations, and standards. Specifically, during its review, the Commission will determine whether each electrical corporation's plan complies with the requirements of Section 8386(c).

PACIFIC GAS AND ELECTRIC COMPANY
Wildfire Mitigation Plans
Rulemaking 18-10-007
Data Response

PG&E Data Request No.:	TURN_005-Q06		
PG&E File Name:	WildfireMitigationPlans_DR_TURN_005-Q06		
Request Date:	March 1, 2019	Requester DR No.:	005
Date Sent:	March 6, 2019	Requesting Party:	The Utility Reform Network
PG&E Witness:		Requester:	Marcel Hawiger

SUBJECT: FIRE INCIDENT DATA

QUESTION 06

Re WMP, Sec. 3.5:

a. Please provide the workpapers, with active Excel spreadsheet if available (with active cells showing formulae), for the "regression analysis" used to predict likelihood of asset failure. (p. 33)

b. Please provide the circuit prioritization model based on likelihood of asset failure, risk of wildfire spread, and egress risk, with active Excel spreadsheet if available (with active cells showing formulae). (p. 33-34)

ANSWER 06

a. Please see response to part b.

b. Please see the response to TURN_005, Q4 for the outputs of the circuit prioritization model. Due to the sensitive and proprietary nature of the risk model and concerns about publicly disclosing PG&E's risk analysis methodology, PG&E requests that a follow-up meeting be held to discuss production of details on the methodologies for the regression and circuit prioritization analyses.

PACIFIC GAS AND ELECTRIC COMPANY
Wildfire Mitigation Plans
Rulemaking 18-10-007
Data Response

PG&E Data Request No.:	TURN_005-Q14		
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Date Sent:	March 6, 2019	Requesting Party:	The Utility Reform Network
PG&E Witness:		Requester:	Marcel Hawiger

SUBJECT: FIRE INCIDENT DATA

QUESTION 14

Re. WMP, Sec. 4.3.5 at p. 69 and the replacement of “non-exempt equipment/transformer.” Please compare the forecasts as shown in DR TURN-03-02Atch01 (Table 9-12) and DR 03-14Atch01 (System Hardening Scenario):

a. Please reconcile the 2018 unit cost of $10,000 (Table 9-12, cell E-24) with the unit cost of $100,000 in System Hardening Scenario (Cell I18). Is it simply the case that the units in System Hardening are circuit miles?

b. Please clarify whether the target 2019 “total system miles” is 150 or 200. “System Hardening Scenario” calculates the forecast based on 135 miles of OH and 15 miles of UG.

c. Please clarify the unit cost, scope and total cost forecast for the non-exempt equipment/transformer category.

d. In response to subpart (c), Please also disaggregate the forecast for just transformers, if possible. Please provide any relevant data supporting the forecast for transformer replacement.

ANSWER 14

a. The Overhead Unit Cost information provided in WildfireMitigationPans_DR_TURN_003-Q14Atch01 on the System Hardening tab is per circuit mile.

b. PG&E is proposing a target for 2019 of 150 circuit miles of System Hardening. *See* Wildfire Safety Plan, Section 6.2.3 at p. 134, Target #1. The Overhead Unit Cost information provided in WildfireMitigationPans_DR_TURN_003-Q14Atch01 on the System Hardening tab included a scenario of 135 circuit miles of overhead and 15 circuit miles of underground, which totals to 150 miles. Estimates were made with the assumption that the replacement costs vary depending on bundling of the line miles, whether or not the line is energized vs de-energized, and location of the line mile. Bundling refers to doing larger projects that scope out multiple miles instead of smaller projects that are scoping out fractions of a mile. Unit cost assumptions are the same in both exhibits for the overhead component of the system hardening program. 200 miles was assumed for 2019 at the time of the GRC filing, while underground costs was not assumed to be a component.

c. This cost component assumes 10 units at approximately $10k per unit for a total cost of approximately $100k for this cost component. Cost of transformers are not included in this unit cost assumption (held in a different MWC). Non-exempt equipment units (i.e., fuses, switches) are included in this unit cost. Cost for work to replace units is included in the unit cost.

d. Cost of transformers are not included in this unit cost assumption. Cost information was provided in PG&E's 2020 GRC in the workpapers for Exhibit PG&E-004, Chapter 16, specifically Workpaper Tables 16-36 and 16-34. These work papers have data on cost of transformers.

Southern California Edison
A.18-09-002 – GS&RP

DATA REQUEST SET T U R N - S C E - 0 0 6

To: TURN
Prepared by: Andrew Garcia
Job Title: Senior Manager
Received Date: 2/11/2019

Response Date: 2/26/2019

Question 29d: 29. Regarding investments and expenditures in covered conductor, remote reclosers, fuses, and enhanced vegetation management please provide the following:
d. If covered conductor is installed on a circuit, does this mitigate the need to accomplish enhanced vegetation management on all or any portion of the circuit? Please explain, provide an example of how the technologies work together or are complementary during a fault, and include whether and how SCE has accounted for this overlap in its proposal. Please provide all relevant workpapers/sources.

Response to Question 29d:
No, the presence of covered conductor does not eliminate the need for enhanced vegetation management, nor does the application of enhanced vegetation management eliminate the need to install covered conductor.

As noted in Section (IV)(B)(1)(c)(page 51) of SCE-01A (A. 18-09-002), Contact from Object (CFO) faults have a higher probability of being associated with a fire event, therefore, SCE is deploying covered conductor to reduce the number of CFO faults experienced therefore reducing ignition risk. However, covered conductor is being deployed in conjunction with enhanced vegetation management to more fully reduce the volume of potential contacts.

As noted in Section (III)(A)(3)(page 35) of SCE-01A (A. 18-09-002), SCE's enhanced vegetation management aims to reduce the likelihood that vegetation will contact overhead lines by increasing clearances and removing more trees than the standard program. However, SCE has limited ability to increase clearances in certain areas and recognizes that wind can blow debris into lines from significant distances despite appropriate clearances to nearby trees. For these reasons, SCE believes a more robust approach to mitigate CFO risks is to deploy its enhanced vegetation management program in conjunction with covered conductor, both of which are independently necessary, and together are complementary

If SCE were to simply to install covered conductor on a circuit in a heavily wooded area and not increase the vegetation clearance as would be done with the enhanced vegetation program, SCE would lessen the number of faults experienced in normal weather conditions because of the insulation properties of the covered conductor. However, in high wind conditions large over hanging branches may be shed into the lines or worse, a hazard tree that would have been removed by the enhanced vegetation management program may be uprooted and fall into the lines ripping them down, potentially causing an ignition. Conversely, if SCE were to exclusively deploy enhanced vegetation management and continue to rely exclusively on bare conductors it would similarly see a reduction in fault events in normal weather conditions. However, in high winds, SCE may still experience faults from palm fronds that shed from trees hundreds of feet away, or have wind-driven conductor-to-conductor contact potentially causing an ignition.

SCE believes covered conductor and enhanced vegetation management are complementary programs and are both necessary to achieve the greatest risk reduction.

Southern California Edison
A.18-09-002 – GS&RP

DATA REQUEST SET T U R N - S C E - 0 0 6

To: TURN
Prepared by: Noe Bargas
Job Title: Senior Manager, Engineering
Received Date: 2/11/2019

Response Date: 3/7/2019

Question 31: 31. If covered conductor is installed on a circuit but the wire falls to the ground and the power remains energized (wire down event), is there still a risk of ignition? Is the probability of ignition reduced by covered conductor in this instance or is it the same as bare wire? Please explain and quantify probabilities where possible.

Response to Question 31:
If a covered conductor energized wire-down event were to occur, a risk of ignition exists, but to a much lower degree than an equivalent bare-wire energized wire-down event. While difficult to quantify, the reasoning behind this conclusion is sound and primarily based on the length of exposed wire that can potentially create an arc and lead to a subsequent ignition. A bare-wire would be exposed for its entire length (ranging from fifty to over one-hundred feet) and could result in an arc anywhere along its length, while a covered conductor would only be susceptible to arcing at the exposed end (inches or possibly even less) where the conductor makes contact to ground.

Southern California Edison
A.18-09-002 – ***GS&RP***

DATA REQUEST SET T U R N - S C E - 0 0 6

To: TURN
Prepared by: Noe Bargas
Job Title: Senior Manager, Engineering
Received Date: 2/11/2019

Response Date: 3/7/2019

Question 32: 32. Does covered conductor reduce the likelihood of a wire down event? Please explain and provide probabilities (with covered conductor and without) where possible.

Response to Question 32:
Yes. Covered conductors will reduce the likelihood of wire down events from occurring by preventing contact related faults. Wire down events can occur when a fault initiating event generates a surge of current that surpasses the short circuit duty limit of a conductor. In HFRA, approximately 50% of faults that led to ignition in SCE's territory from 2015-2017 were caused by contact with objects. Because covered conductors are protected by insulating layers, they will prevent contact related faults from occurring. By decreasing the occurrence of faults, covered conductors will decrease the possibility of wire down events. Additionally, of 236 wire down events observed in HFRA from January 1, 2016 through January 31, 2019, 60 of them (25%) have been associated with metallic balloons, vegetation, or phase spacing. The majority of these specific causes of wire down events are expected to be mitigated by application of covered conductor.

Application: ____________________
(U 39 M)
Exhibit No.: (PG&E-3)
Date: December 21, 2009
Witness: Various

PACIFIC GAS AND ELECTRIC COMPANY

2011 GENERAL RATE CASE

PREPARED TESTIMONY

EXHIBIT (PG&E-3)
GAS AND ELECTRIC DISTRIBUTION

PACIFIC GAS AND ELECTRIC COMPANY
GAS AND ELECTRIC DISTRIBUTION

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GAS AND ELECTRIC DISTRIBUTION

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(CONTINUED)

40 SCADA line devices per year with an estimated cost of $2,000,000 annually between 2011 and 2013.

f. Replacement of Feeder SCADA

Some of the distribution line SCADA equipment is obsolete and/or unreliable. In some locations, the communication component of the SCADA equipment is obsolete and can no longer support the SCADA operations. Rather than continue to spend resources to maintain and service poor-performing legacy equipment, it is more cost effective to replace it with more modern equipment. The estimated unit cost is $50,000.

PG&E plans to replace 50 units per year with an annual forecast of $2,500,000 between 2011 and 2013. The driver for the increase forecast over 2008 recorded expenditure in this subprogram is to address the hundreds of obsolete SCADA feeder components requiring replacement. There are approximately 450 obsolete distribution line SCADA devices in PG&E's distribution system. The 50 units is an estimate based on a 9-year replacement schedule. Table 11-12 of the workpapers provides the listing of these devices. As reflected in Table 11-2, PG&E did not replace much of the obsolete SCADA line equipment in 2008 and 2009. A multi-year replacement schedule with 50 replacements per year is what PG&E believes to be reasonable and manageable.

g. Fire Risk Management

PG&E continuously identifies and assesses various risks to the public and employees due to Company facilities and operating practices. Because of recent drought conditions, fire fuel loads are at all-time highs in California. Consequently, an electric distribution facility igniting a wildland or urban fire is of particular concern to PG&E. To reduce this risk, PG&E is including a fire risk management initiative in the DAP program. This initiative will supplement the ongoing activities the Company routinely performs to prevent fires.

PG&E proposes to reduce the risk of electric distribution facilities igniting a fire by modifying or replacing certain pieces of electric distribution equipment so that operating personnel can remotely alter how the equipment responds during a fault. While PG&E is actively participating in the Commission's Fire Safety Rulemaking (R.08-11-005), none of the forecasts in this or any other chapter of the GRC are intended to seek cost recovery in anticipation of a ruling by the CPUC in that proceeding. The Company is including the capital expenditure forecasts for this fire risk management initiative because it believes implementing the initiative is appropriate under any outcome of the rulemaking. The following paragraphs describe how automation can mitigate potential fire hazards due to electric facilities.

Circuit breakers (CB) and Line Reclosers (LR) are protective devices designed to protect equipment from line faults and mitigate the effect of outages (i.e., reduce the number of customer interruptions). Sometimes faults are temporary (e.g., tree limb falling through line) and it is desirable for the CB or LR to momentarily open then close (i.e., a momentary outage) to avoid a sustained outage. To accomplish this, CBs and LRs have a reclose relay. A reclose relay tells the device how many times to operate when a fault occurs and how long to wait before each reclose operation. For example, PG&E typically sets a CB reclose relay to reclose twice.

The Company has not been manually changing the reclosing relay settings for the purpose of fire risk management. Consequently, there are no historical costs for manually adjusting the relays in the field for the purpose of fire risk management. PG&E has not performed a detailed cost comparison with remote versus manual adjustment of reclosing relays. However, the Company's preliminarily estimate indicates it would cost approximately $1.5 million to 2.0 million per year to adjust the relays manually on the number of high risk periods in a given year.

In any event, automating the recloser settings is preferable to manually doing so for significant reasons relating to safety and efficiency that cannot easily be quantified.

A manual program would require multiple trips by numerous employees year after year. At the beginning of every high-risk period, which usually lasts for days or weeks, many employees would be dispatched to adjust the relay setting to block the reclosing feature in all of the designated relays. At the end of each high-risk period, personnel would again be dispatched to reset the relays to their original settings in order to provide reclosing function for reliable service. This manual process could happen several times during windy, dry, high fire risk seasons. Leaving the reclosing relay to block reclosing for the entire high-risk season for months would unnecessarily compromise the reliability of the circuits due to their inability to reclose after a temporary fault without the presence of high fire risk during the season.

Performing the work manually is not effective from a timing and operational perspective. It is estimated, as described above, that there will be approximately 660 line reclosers and circuit breakers to manually adjust the reclosers. Because the risk of fire changes throughout the year, it would be beneficial to have the reclose relay enabled when the risk of fire is low (as it improves reliability) but disabled when the fire risk is high. Due to the large number of devices, it will take an extensive amount of time to change the settings and during this time creating a high risk of sustained outages increasing the customer outage minutes. This is not an efficient way to utilize field resources needed for maintenance and restoration work. For each of the multiple high-risk warnings anticipated in a given year, PG&E would have to mobilize personnel, taking them away from their scheduled work to manually set the relays. This break-in work is very disruptive to the work force and makes it more difficult to manage resources efficiently in getting the needed work done or require overtime to complete other work (a factor not included in the preliminary expense estimate described above).

PG&E is proposing to automate the operation of the reclose relay so that an operator at a distribution control center can remotely enable and disable the relay as appropriate, allowing the field crews to complete other work activities (e.g., customer service calls, responding to outages, maintenance work, etc.) and efficiently utilizing PG&E labor forces. Furthermore, the added visibility and addition information provided to the operators through automation will allow for optimal grid flexibility. Finally, an automated approach quickly and effectively addresses the risk, as opposed to the lag time associated with a manual approach, which requires mobilizing personnel, who must then travel to the designated areas and perform the necessary work on the relays.

PG&E plans to implement this new subprogram over 3-year period covered by this rate case. PG&E identified 680 reclosers and 200 feeder breakers in the high-risk area. PG&E estimates 75 percent of this equipment are not on SCADA. That leads to 510 reclosers and 150 feeder breakers that need to install SCADA in order to remotely change reclosing relay setting. The estimated average unit cost to modify a recloser is $45,000 and for a feeder breaker it is $150,000. The calculated cost to modify reclosers will be $7,650,000 and for feeder breakers it will be $7,550,000 annually (Workpapers, page WP 11-23, Table 11-14).

The master radio communication infrastructure will also be impacted. As each line recloser being installed, it needs to communicate to the SCADA master station via a master radio typically installed in high elevation on a mountain top. Based on the estimated number of line reclosers PG&E estimates 12 mountain-top master radios are needed to implement this initiative. The capital forecast for this element is not included in this chapter, but is explained in Exhibit (PG&E-7), Chapter 2, Information Technology Costs.

2. Distribution Automation and Protection Engineering Support – Expense MWC HX

This section describes expense expenditures for DAP program relating to substation and feeder circuit applications.[1] The expense program funds the engineering support of the automation and protection equipment to the maintenance and operation departments. The engineering support consists of two key components including: (1) Automation Engineering support; and (2) Protection Engineering support. Automation Engineering supports the

[1] PG&E's expense forecast for MWC HX – Distribution Automation and Protection in its 2007 GRC included expense expenditures for lease lines and maintaining existing master stations. These expenditures have been moved to another program and are covered in Exhibit (PG&E-7), Chapter 2, Information Technology Costs, MWC IO.