BEFORE THE OFFICE OF ENERGY INFRASTRUCTURE SAFETY

OF THE STATE OF CALIFORNIA

OPENING COMMENTS OF THE UTILITY REFORM NETWORK ON PACIFIC GAS AND ELECTRIC COMPANY'S 2023-2025 WILDFIRE MITIGATION PLAN

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SUMMARY OF RECOMMENDATIONS

1. Energy Safety should avoid undermining the CPUC's pending General Rate Case (GRC) decision by including clear guidance regarding the intent and effect of the WMP decision. Specifically, the decision on this WMP should state the following:

    a. In instances when the GRC has determined or will determine the authorized scope of a wildfire mitigation activity that may be recovered in rates, the WMP decision does not authorize a utility to perform additional work beyond what is authorized in the GRC;

    b. If a utility nevertheless chooses to perform work beyond what the CPUC approves in the GRC, it should be aware that the WMP decision will not be allowed to serve as justification for rate recovery for the additional work.

2. Energy Safety should require PG&E to make the following changes to its WMP in order to gain approval:

    a. Because risk is highly concentrated in relatively few overhead circuit miles, PG&E must show that 80% of the proposed underground miles in its revised plan will address the top 20% of the risk in PG&E's HFTD (not the top 20% of circuit segments).

    b. In choosing among system hardening alternatives – which should include undergrounding, covered conductor and covered conductor coupled with other ignition limiting technologies -- PG&E must make a location-specific determination of the best alternative for that location, based on the specific risk factors present in the location.

    c. The location-specific selection among system hardening alternatives must expressly consider the extent to which the execution and schedule risks for undergrounding described in PG&E's 2021 WMP are present in the location and recognize the benefits of deploying an alternative that will achieve risk reduction sooner than other alternatives.

    d. The location-specific selection among alternatives must include a comparison of the location-specific cost-effectiveness of each alternative, based on the Risk Spend Efficiency (RSE) measure. If the utility wishes to select an alternative that does not have the highest RSE, it must show special and compelling circumstances that justify deployment of a lower RSE alternative in that location.

e. The RSE calculations must use a location-specific conversion factor for the number of underground miles necessary to replace one mile of overhead conductor, not an assumed generalized conversion factor, such as PG&E's current 1.25 figure that is not based on actual results or location-specific information.

f. PG&E must present a revised system hardening plan for 2023-2025 that it has developed using a process that complies with the preceding requirements. The revised plan should include workpapers showing how PG&E determined its target mileage consistent with the above requirements for each of the system hardening alternatives it proposes in its revised plan.

3. The following deficiencies should be corrected in PG&E's next WMP submission:

   a. PG&E should re-calculate its risk reduction figures to recognize the significant risk reduction that will result from avoiding compliance failures of the type that caused the major wildfires ignited by PG&E facilities in 2015-2020. (See Section VII.)

   b. In order to develop realistic data-based underground to overhead conversion factors, PG&E should be required to maintain a database of actual results from PG&E's undergrounding projects that identifies, for each project, the underground miles deployed and the miles of overhead conductor replaced. In addition, as applicable, the database should describe the reasons that undergrounding needed to deviate from the direct overhead path. (See Section VI.A.)

   c. To have data to compare the reliability of undergrounded facilities to overhead hardened facilities, PG&E should be required to keep separate reliability measures (e.g., SAIFI and MAIFI) for overhead circuit segments with covered conductor. (See Section VI.C.)

   d. PG&E should describe its policy for undergrounding of secondary conductor and services and discuss its expectations for whether poles will be removed in underground locations. The discussion should address the effect that remaining overhead wires and poles in locations with undergrounding have on the estimated risk reduction from undergrounding generally, and specifically the risk associated with ingress and egress in locations where fire is present, whether or not ignited by utility facilities. (See Section VI.B).

OPENING COMMENTS OF THE UTILITY REFORM NETWORK ON PACIFIC GAS AND ELECTRIC COMPANY'S 2023-2025 WILDFIRE MITIGATION PLAN

The Utility Reform Network ("TURN") submits these comments on the 2023-2025 Wildfire Mitigation Plan (WMP) submitted by Pacific Gas and Electric Company ("PG&E").

I. INTRODUCTION AND SUMMARY

PG&E's WMP presents a costly, multi-billion-dollar system hardening plan that relies heavily on undergrounding of power lines in high fire risk areas. This plan is a product of the default-to-undergrounding policy that PG&E adopted in late 2021. Under this policy, PG&E automatically rejects other system hardening alternatives unless undergrounding ultimately proves to be infeasible. As a result, PG&E fails to make sufficient use of covered conductor, which can reduce risk more quickly and more cost-effectively in most high-risk locations.

In its decision on PG&E's 2022 WMP, Energy Safety informed PG&E that this policy was unacceptable and directed PG&E to choose among system hardening alternatives based on a location-specific analysis of which type of mitigation is best for each project. Energy Safety required PG&E's analysis to consider the multitude of risk-based factors that influence which is the best choice, including an up-front comparison for each project of cost-effectiveness measures (known as Risk Spend Efficiency or RSE) for the competing alternatives.

However, as explained in Section III of these comments, PG&E did not heed Energy Safety's direction. Instead, PG&E has doubled down on the default-to-undergrounding approach that the company was instructed to abandon and fails to make a project-specific comparison of the RSEs of the alternatives before selecting the best option. The result is an undergrounding-heavy plan that serves PG&E's corporate interest in fattening its bottom line, while defeating the public interest. PG&E's plan would: delay the necessary risk reduction in high risk areas, which can be achieved much faster with covered conductor; make highly inefficient use of the limited resources available to reduce wildfire risk; and accelerate the unsustainable, above-inflation rate increases that all PG&E customers, including low-income families, are already experiencing.

Section IV of these comments explains another serious problem with PG&E's undergrounding plan. Contrary to the company's claims, PG&E's plan does not target the top 20% highest risk locations in its HFTD. Instead, PG&E's expansive definition allows it to count as high risk any circuit segment in the *top 80%* of wildfire risk. Because risk is concentrated in relatively few circuit segments, PG&E's slow-to-implement undergrounding-focused plan will take far too long to address too many risky parts of PG&E system. TURN shows that *deploying 450 miles per year of covered conductor, from the highest to lowest risk circuits,* ***will reduce more risk than PG&E's undergrounding plan, at $2.3 billion less cost.***

Section VI explains that PG&E's WMP downplays important limitations of undergrounding: (1) PG&E does not properly account for the circuitous routing that undergrounding often requires compared to overhead hardening, which means that PG&E overestimates the risk reduction from undergrounding and understates its cost compared to covered conductor; (2) PG&E fails to acknowledge that its undergrounding program would still leave many poles and wires above ground, which limits the claimed ingress/egress risk reduction benefit, since falling poles and lines could still impede escape routes during a fire; and (3) outages on undergrounded circuits typically take longer to repair than on overhead lines, which means that lines with covered conductor have the potential to be equal to or better than undergrounding for overall reliability, measured by frequency and duration of outages.

Section VII demonstrates, as TURN also showed in PG&E's pending CPUC General Rate Case (GRC) that PG&E's risk modeling fails to acknowledge the significant risk reduction that will be achieved simply by improving PG&E's compliance with regulations, particularly for vegetation management and equipment maintenance. As a result, PG&E overlooks the most potent and cost-effective wildfire risk reduction strategy.

Finally, these comments begin with a reminder that virtually the same wildfire mitigation proposals presented in PG&E's WMP are currently under consideration in PG&E's pending CPUC GRC proceeding. In that proceeding, TURN and several other parties have vehemently opposed PG&E's undergrounding plan, for reasons that are germane to Energy Safety's review and discussed in these comments, and also for other reasons, such as affordability and impact on the State's greenhouse gas reduction goals, that are beyond Energy Safety's purview. The CPUC has the challenging obligation to balance the competing objectives of ensuring just, reasonable and affordable rates while achieving safe and reliable service. TURN recommends language for the decision on this WMP to ensure that the CPUC's efforts to strike that balance are respected and not undermined.

II. ENERGY SAFETY MUST ENSURE THAT ITS RESOLUTION OF THIS WMP IS CONSISTENT WITH THE CPUC'S RESOLUTION OF PG&E'S PENDING GENERAL RATE CASE

A. Much of PG&E's WMP Proposal Is Currently Under Scrutiny in PG&E's General Rate Case, Where TURN and Numerous Other Parties Raised Serious and Well-Supported Challenges to the Same System Hardening Plan Presented Here

Much of the same wildfire mitigation work presented in PG&E's WMP is also being reviewed and analyzed by the CPUC in PG&E's pending General Rate Case (GRC), Application (A.) 21-06-021. This includes PG&E's most expensive proposed wildfire mitigation, undergrounding. In this WMP, PG&E proposes to perform 1,350 miles of undergrounding in

2023-2025, the same amount it proposed for that period in its GRC.[1] Because the GRC covers the four-year period, 2023-2026, PG&E's GRC request includes its proposal to carry out an additional 750 miles of undergrounding in 2026. The total proposed GRC cost for PG&E's 2023-2026 undergrounding request is $5.9 billion, making it by far the most costly program proposal in PG&E's GRC.

The CPUC's GRC decision will review each of PG&E's proposed programs, including undergrounding and PG&E's other wildfire mitigation proposals, and determine the appropriate scope of those programs that should be funded in rates. The CPUC will base its decision on an extensive record of testimony, data request responses, cross examination of witnesses sponsoring testimony, and three rounds of briefing.[2] Parties are now awaiting the issuance of a proposed decision in PG&E's GRC, which is expected some time in the next few months.

TURN's GRC testimony and briefs recommended a very different and much less costly wildfire mitigation strategy than PG&E proposed. TURN showed that PG&E will achieve significant risk reduction simply by improving PG&E's unfortunate past record of non-compliance with wildfire safety requirements with respect to vegetation management and repair of worn equipment. PG&E's risk analysis failed to recognize this important source of risk reduction. We discuss this point in Section VII of these comments and note that PG&E's WMP also suffers from this serious shortcoming. In addition to improved compliance, TURN recommended in the GRC that PG&E focus its system hardening efforts on covered conductor, which is much more cost-effective, has many fewer risks and impediments, and is faster to

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[1] PG&E response to TURN Data Request (DR) 12, question 2, pp. 12-13. All PG&E data request responses cited in these comments are available at: https://www.pge.com/en_US/safety/emergency-preparedness/natural-disaster/wildfires/wildfire-mitigation-plan-discovery-data-requests.page

[2] Ordinarily, GRCs have two rounds of post-evidentiary hearing briefs, opening and reply rounds, but, in PG&E's pending GRC, the Commission allowed parties a sur-reply round to address PG&E's revised undergrounding proposal, which it revealed for the first time in its reply brief.

deploy than undergrounding, points that we address in the following sections of these WMP comments. TURN recommended much more covered conductor than PG&E -- 1,800 miles compared to PG&E's 320 miles for the 2023-2026 period. And instead of PG&E's 2,100 miles of undergrounding for that period, TURN recommended 200 miles. TURN attaches to these comments a slide briefing package that summarizes TURN's positions and recommendations in PG&E's GRC and places TURN's wildfire recommendation in the context of the serious issues concerning the affordability and cost-effectiveness of PG&E's proposal.[3] Other parties were also severely critical of PG&E's undergrounding proposal and presented their own recommendations. Those parties included Cal Advocates, Mussey Grade Road Alliance (MGRA), AARP, the California Farm Bureau Federation, Comcast, and AT&T.

Based on the extensive record, the CPUC will render a decision determining which wildfire mitigation programs, in what size, should be funded by ratepayers. Pursuant to Public Utilities Code Section 451, the CPUC must find that PG&E has met its burden of demonstrating that its requested costs are "just and reasonable" before those costs can be approved for recovery in rates.[4] While it is of course difficult for any outside party to predict how the CPUC will decide, it should not be surprising if the CPUC rejects significant portions of PG&E's wildfire mitigation proposals and adopts a different and less costly, but still effective, suite of wildfire mitigation measures, in light of the following:

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[3] Appendix A to these Comments. Slides 11 through 14 address TURN's wildfire mitigation recommendations, and slides 1-10 address the affordability and cost-effectiveness context for TURN's recommendations. More detail about TURN's wildfire mitigation recommendations, and the analysis on which they are based, can be found in Sections 4.2 and 4.3 of TURN's Opening Brief, Reply Brief, and in its Sur-Reply Brief.

[4] The applicability of the CPUC's just and reasonable standard to wildfire mitigation plan costs is reinforced in Public Utilities Code Section 8386.4(b)(1), which provides that "[t]he commission shall consider whether the cost of implementing each electric corporation's [wildfire mitigation] plan is just and reasonable in its general rate case application."

- PG&E's wildfire mitigation proposals carry a huge price tag that would significantly drive up the cost of electric service for generations. A conservative estimate of the cost of PG&E's 10-year undergrounding program is $30 billion, which balloons to $100 billion when PG&E profits, taxes and other charges over the life of the assets are added. As such, PG&E's 10-year plan would be the most expensive utility program in California history;

- Even without the wildfire proposals in the pending GRC, PG&E's rates have already been escalating far faster than inflation since 2018 and would accelerate more steeply if PG&E's wildfire proposals are approved, which will make it even harder for many Californians, particularly struggling families, to afford essential energy service;

- The steep rate increases that would result from PG&E's proposal would imperil California's greenhouse gas reduction strategy, which depends on convincing consumers to switch from fossil fuel-powered vehicles and appliances to electric-powered alternatives;

- As noted, PG&E's wildfire proposals faced strong opposition from a diverse range of intervenors; and

- Most importantly, as discussed in these comments, undergrounding is plagued by many risks and challenges that, in most locations, render it less cost-effective, riskier to accomplish, and longer to deploy than overhead hardening. This means PG&E's proposals subject the state to *more* wildfire risk from powerlines than a less underground-focused approach.

B. The Decision on PG&E's WMP Must Respect the Careful Balance that the CPUC Must Strike in Its GRC Decision

The Commission's GRC decision will require it to strike a careful and thoughtful balance among a variety of competing considerations, in determining the activities and costs that warrant ratepayer funding. The important factors that need to be balanced include: safety and reliability; the plethora of other activities that require ratepayer funding that are not at issue in this WMP;[5] preventing PG&E's energy services from becoming unaffordable and therefore unusable for more households; and achievement of California's greenhouse gas reduction goals. Unless

[5] To gain a sense of many of the other demands on limited ratepayer dollars that PG&E has presented in its GRC, see TURN's slide briefing package regarding the GRC, Appendix A, slides 15-21.

affirmative care is taken to ensure consistency between the two decisions, the resolution of this WMP risks undermining the careful balance that the CPUC will need to strike in its GRC decision.

The need for consistency is evident when one considers the possibility of a WMP decision that approves a WMP with programs that are larger in scope than what the CPUC approves in the GRC. Using undergrounding as an example, if the approved WMP has mileage targets that are greater than the undergrounding mileage the CPUC ultimately approves in the GRC, PG&E can be expected to record the costs of additional mileage beyond the GRC authorized level in the WMP memorandum account created pursuant to Public Utilities Code Section 8386.4(a). At some point in the future, PG&E can then be expected to use the approved WMP to seek rate recovery through a CPUC application for this additional amount of undergrounding, unless its regulators make clear that such an effort would be futile. From the perspective of ratepayers, a highly troubling outcome would be that the CPUC feels compelled to approve the additional funding because PG&E was never informed that its WMP approval would not be allowed to justify rate recovery for undergrounding beyond what was authorized in the GRC. Even the best possible outcome of such a scenario would be undesirable from ratepayers' perspective -- the unnecessary expenditure of limited agency and stakeholder resources to obtain a decision denying such a request. Put simply, WMPs should not be used to circumvent the CPUC's statutory obligation to constrain utility spending plans to keep rates just, reasonable and affordable.

The decision on this WMP can avoid these undesirable scenarios by making clear that the WMP process does not permit a utility to circumvent a CPUC GRC decision that determines the authorized scope of a wildfire mitigation activity. To allow the WMP process to provide utilities another bite at the ratepayer funding apple would be extremely poor policy and a waste of limited agency and stakeholder resources. It would also be illegal, as only the CPUC has authority to determine what can be put into utility rates. The CPUC's GRC decisions that carefully weigh and resolve a variety of competing considerations, including affordability, should not be undermined by a WMP decision that is not designed or intended to address any factors other than wildfire safety.

Energy Safety can avoid undermining the CPUC's GRC decision by including clear guidance regarding the intent and effect of the WMP decision. Specifically, the decision on this WMP should state the following:

- In instances when the GRC has determined or will determine the authorized scope of a wildfire mitigation activity that may be recovered in rates, the WMP decision does not authorize a utility to perform additional work beyond what is authorized in the GRC;

- If a utility nevertheless chooses to perform work beyond what the CPUC approves in the GRC, it should be aware that the WMP decision will not be allowed to serve as justification for rate recovery for the additional work.

In this way, while a utility is not prohibited from doing work beyond GRC authorized levels, it is put on notice that it will not be allowed to use the WMP decision as a reason to override the funding limitations prescribed in a GRC decision.

Balancing the competing objectives in achieving just, reasonable and affordable utility rates while achieving safe and reliable service is challenging. To achieve an optimal balance of those competing goals, Energy Safety and the CPUC must make clear that they will ensure consistency in their decisions.

III. PG&E'S DEFAULT-TO-UNDERGROUNDING APPROACH FAILS TO CHOOSE THE BEST SYSTEM HARDENING ALTERNATIVE BASED ON LOCAL CONDITIONS, INCLUDING COST-EFFECTIVENESS

At this point in the ever-changing evolution of mitigation strategy for reducing wildfire risk, a key choice is presented – whether to rely on undergrounding, the most costly mitigation, or to use other less expensive alternatives, such as covered conductor. As Southern California Edison (SCE) reports in its WMP, SCE has had great success with covered conductor in reducing risk and preventing ignitions.[6] Until late 2021, PG&E too made considerable use of covered conductor and only reserved undergrounding as a wildfire mitigation for specialized situations. However, PG&E abruptly changed its policy in late 2021 so that, by its 2022 WMP, PG&E had adopted, what Energy Safety described as "a decision-making process that heavily favors undergrounding."[7]

As discussed below, in its decision on PG&E's 2022 WMP, Energy Safety sharply criticized PG&E's new approach for failing to adequately evaluate alternatives based on key considerations such as local conditions and cost-effectiveness. Despite this directive, PG&E has not changed its decision-making process and instead continues to "default to undergrounding."[8] As discussed at the end of this section, PG&E's failure to comply with Energy Safety's directive is a serious failure that has caused PG&E to propose significantly more undergrounding than would be warranted if PG&E adopted the decision-making process Energy Safety told PG&E to use. Energy Safety should accordingly reject PG&E's WMP until such time as PG&E complies with the clear requirements of Energy Safety's 2022 decision.

[6] Southern California Edison Company (SCE) 2023-2025 WMP, pp. 2-3.
[7] OEIS Final Decision re PG&E 2022 WMP, p. 144.
[8] *Id.*

A. Energy Safety's 2022 WMP Decision Directed PG&E to Revise Its Decision-Making Process to Abandon the Default to Undergrounding Approach

Both Sections 4.6.3 (Grid Design and System Hardening) and 4.6.8 (Resource Allocation Methodology) of Energy Safety's 2022 Decision criticized PG&E's new process for selecting among system hardening alternatives.

Section 4.6.3 stated:

> PG&E ***must weigh a multitude of factors for its evaluation of system hardening alternatives*** and ***demonstrate that it has not primarily defaulted to undergrounding. In PG&E's 2023 WMP, it must provide*** further analysis of its decision-making process, ***demonstrating a full evaluation of system hardening alternatives*** including considering combinations of system hardening initiatives. This is discussed further in Section 4.6.8.[9]

Section 4.6.8 elaborated on Energy Safety's concerns:

> Upon review, Energy Safety found that ***PG&E's system hardening decision-making flowchart does not give sufficient weight to quantitative factors such as costs, risk reduction values, and RSE estimates***. For example, the flowchart hierarchy prioritization is influenced more by construction limitations than by RSE estimates. This may lead PG&E to fast-track more expedient locations ***rather than considering the option with the highest RSE estimate*.** In addition, ***it is notable that PG&E's decision-making process heavily favors undergrounding. PG&E did not provide a thorough analysis of other mitigation options to demonstrate how alternatives factor into its decision-making process***. Currently, ***PG&E's decision-making process is particularly driven by whether undergrounding is feasible***; if undergrounding is not feasible, another mitigation strategy is chosen. ***Energy Safety asserts that mitigation strategies must be chosen <u>for a given area</u> based on risk model output, prioritized by the risks present at that location. PG&E's goal must be to conduct a rigorous, quantitative analysis of alternative strategies that prioritizes a mitigation strategy according to highest risk, <u>addresses risk by location</u> and uses limited resources effectively. Quantitative measures must have higher placement in the decision tree hierarchy than is currently shown.***[10]

[9] *Id.*, pp. 79-80 (emphasis added).

[10] *Id.*, p. 144 (emphasis added).

As these quotations show, Energy Safety was clearly displeased with PG&E's new process for selecting system hardening mitigations that heavily favors undergrounding. The problems identified included:

- PG&E did not show that it considers the "multitude of factors" that is needed in order to avoid an inappropriate default-to-undergrounding approach;
- PG&E did not show that it engages in a full, ***location-specific*** analysis of mitigation alternatives, including combinations of mitigations;
- PG&E's decision-making flowchart does not give sufficient consideration to quantitative factors such as costs, risk reduction values and Risk Spend Efficiency (RSE), *i.e.*. cost-effectiveness, measures;
- PG&E's mitigation selection process places too much emphasis on whether undergrounding is feasible, and does not consider the many other relevant factors;
- PG&E does not conduct a rigorous, quantitative analysis of mitigation alternatives based on location-specific risks;
- PG&E does not demonstrate through quantitative analysis that it is using limited resources effectively, *i.e.*, choosing cost-effective alternatives.

Energy Safety required PG&E to address these problems in this WMP, as reflected in the quotations above and in Area of Continuing Improvement (ACI) 22-34:

> **PG&E-22-34. Revise Process of Prioritizing Wildfire Mitigations**.
>
> o Description: PG&E's current process of prioritizing wildfire mitigations assigns a high priority to undergrounding and ***does not demonstrate adequate weight to risk model outputs or RSE estimates***.
>
> o Required Progress: In its 2023 WMP, ***PG&E must conduct*** a quantitative analysis of alternative mitigation techniques. ***This must***:
>
> - Support an overall mitigation strategy that prioritizes mitigation techniques and projects according to highest wildfire risk, ***addresses wildfire risk by location, and effectively uses resources***.

- ***Evaluate all alternatives to undergrounding, both as individual mitigations as well as combinations, focusing on addressing <u>location specific</u> risks***.

- ***Incorporate RSE estimates and risk model outputs at a project level early in the decision-making process***, ***adjusting both the scope and pace of PG&E's undergrounding program as necessary based on the analyses performed.*** Describe and justify the threshold at which projects move forward even as risk prioritization evolves.

- Discuss how undergrounding projects are prioritized based on wildfire risk and feasibility. The discussion must include how PG&E weighs wildfire risk and project feasibility.[11]

As had also been made clear in Sections 4.6.3 and 4.6.8, Energy Safety stated that these are changes that PG&E "must" make in this WMP.

B. PG&E's WMP Fails to Address Energy Safety's Requirements

1. PG&E's Response to ACI 22-34 Does Not Describe Any Changes to Avoid Defaulting to Undergrounding

PG&E's response to ACI 22-34 shows that the company has not corrected the above-described problems identified by Energy Safety. PG&E does not identify any changes to the undergrounding-favoring decision-making process that Energy Safety criticized in its 2022 decision. Instead, PG&E doubles down on continuing with the same process:

> In the 2022 WMP, PG&E discussed the decision tree used to inform mitigation selection at high wildfire risk location [sic]. This required the review of high-risk locations informed by the WDRM for line removals and remote grids first, before considering the viability of undergrounding and overhead hardening. While we still review system hardening projects for possible line removal first, ***we explained in our 2022 WMP how undergrounding is a more effective mitigation in terms of long-term risk reduction than overhead hardening when line removal is not possible. Therefore, we have shifted to using undergrounding as the preferred method of system hardening.***[12]

[11] *Id.*, pp. 184-185 (italic bold emphasis added).

[12] PG&E 2023-2025 WMP (R1), p. 967 (emphasis added, footnotes omitted).

Rather than changing its process to avoid the default to undergrounding approach to which Energy Safety objected, PG&E simply reiterates the change it announced in its 2022 WMP – "using undergrounding as the preferred method of system hardening." In particular, PG&E does not even attempt to claim that it performs a location-specific analysis of system hardening alternatives. Nor does it claim to do a project-level comparison of RSEs early in the process in order to ensure that it is using limited resources in a cost-effective manner.

PG&E then spends most of the rest of its response to ACI 22-34 describing measures -- Simplified Wildfire Risk Spend Efficiency (SWRSE) and Wildfire Feasibility Efficiency (WFE) – that it uses to decide which *undergrounding projects* to prioritize.[13] Those measures are only calculated for undergrounding projects and therefore *do not compare mitigation alternatives*. Thus, they are not a quantitative means of assessing whether undergrounding or a different mitigation technique is appropriate for a particular location.[14]

In short, PG&E's response to ACI 22-34 fails to show that it has changed its undergrounding-centered decision-making processes to address Energy Safety's concerns.

2. PG&E's Discovery Responses Confirm that Its Current Decision-Making Process Defaults to Undergrounding and Does Not Engage in the Location-Specific Comparison of Alternatives that Energy Safety Requires

TURN's discovery confirmed that PG&E has persisted with the default to undergrounding approach that Energy Safety warned PG&E not to use. In data request 5-1, TURN asked PG&E to provide any decision-tree schematic that shows, for a given location where PG&E believes that system hardening is necessary, how it decides which mitigation technique to use, including the criteria for making that selection. In response, PG&E stated that,

[13] *Id.*, pp. 968-969.

[14] PG&E response to TURN DR 12, question 1.

since late 2021, PG&E has completed most of its planned scoping of system hardening projects using a Targeted Undergrounding decision tree, which it provided as Attachment 1 to its response.[15]

As its name implies, that Undergrounding decision tree describes a process in which, after line removal is considered, undergrounding is the default alternative. Contrary to Energy Safety's directive, PG&E does not perform an up-front, location-specific comparison of system hardening alternatives. Instead, overhead hardening, i.e., covered conductor, only is considered if undergrounding is ultimately found to be infeasible. PG&E confirms this point in the text of its data request response, where it states that, "if undergrounding is ultimately determined to be infeasible, we typically proceed with covered conductor."[16] The discussion in PG&E's WMP regarding covered conductor echoes this point: PG&E only selected overhead hardening "where undergrounding was deemed infeasible . . .."[17] This is precisely the approach that Energy Safety criticized and directed PG&E to change – a "process [that] is particularly driven by whether undergrounding is feasible."[18]

In contrast, prior to PG&E's switch to its default-to-undergrounding approach in late 2021, PG&E used a "System Hardening Decision Tree," in which it made the choice between undergrounding and covered conductor (referred to as "OH" in this decision tree) based on an up-front analysis of location-specific factors for each project.[19] The choice between these alternatives turned on such considerations as:

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[15] PG&E response to TURN DR 5, question 1 and Attachment 1.

[16] PG&E response to TURN DR 5, question 1; PG&E response to TURN DR 6, question 3(b) (defining "infeasible").

[17] PG&E 2023-2025 WMP (R1), p. 340.

[18] OEIS Final Decision re PG&E 2022 WMP, p. 144.

[19] PG&E response to TURN DR 5, question 1 states that, before the "10K UG program, PG&E predominantly used" the System Hardening Decision Tree (and a Fire Rebuild Decision tree in rebuild

- The extent to which there are areas with tree strike potential within the circuit segment (if low, OH is preferred);
- The extent to which the location is affected by PSPS (if not so affected, OH is preferred); and
- The extent to which egress/ingress concerns are present in the location, and, if present, whether those concerns can be addressed by wrapped or composite poles.[20]

TURN presents this prior decision tree not to suggest that it perfectly captured all appropriate considerations and resolved them in an ideal manner. However, it does show that PG&E used a process that evaluated system hardening alternatives based on location-specific risk considerations, which is much more consistent with what Energy Safety was requiring in ACI 22-34.

3. PG&E Has Abandoned Its Own Sensible, Location-Specific Analysis of System Hardening Alternatives that It Described in Its 2021 WMP

Similarly, PG&E's ***2021*** WMP explained that, at that time, PG&E used a process that based the choice of system hardening alternatives on location-specific factors. PG&E explained in its 2021 submission that, when considering undergrounding as an alternative, "it is essential that all execution risks are considered to provide an accurate cost projection for the installation and lifetime of the asset."[21] PG&E then listed a host of location-specific issues that needed to be examined in assessing execution risks:

> Among the cost risks to installing underground assets are: accessibility, rights-of-way, public utility easements, private property crossings, the number of services,

situations). The System Hardening Decision Tree is Attachment 3 to that data request response. (Notwithstanding the "Confidential" label at the bottom of that document, PG&E did not designate it as confidential in its data request response.) PG&E's response to TURN DR 6, question 2, states that the System Hardening Decision Tree "is not and will not be used for newly scoped work."

[20] PG&E response to TURN DR 5, question 1, Attachment 3.

[21] PG&E's 2021 WMP (Revised 6/3/21) (hereafter "2021 WMP"), p. 600.

> space for necessary subsurface and pad mounted equipment, environmental restrictions such as naturally occurring asbestos or endangered species, Archeology and Historic Preservation, soil remediation and soil conditions to name a few.[22]

As a result of these many location-specific factors, PG&E stated that it "has found that there are many impediments to underground construction that limit its viability to be a cost-effective mitigation alternative when compared directly to overhead system hardening."[23]

PG&E's 2021 WMP also pointed out the importance of considering what it referred to as "schedule risks" when weighing system hardening alternatives:

> Another impediment to this [undergrounding] alternative is its schedule risks. ***A typical overhead hardening project can advance from idea to execution, documentation, and close out in 13-16 months. Whereas an underground project can often take 18-45 months depending on the various risks presented***. The most impactful driver in many cases is land rights. Most of our systems in the high-risk areas have existing overhead rights only and require the acquisition of new underground easements to complete the relocation. As PG&E is often unable to construct underground in the exact same path as the overhead, these easements are often required with customers and/or agencies without current agreements. ***This land rights acquisition process alone can take 6-18 months and requires the project to be at a fairly mature design stage prior to contacting property owners about the needed rights***.[24]

Thus, PG&E's 2021 WMP recognized that specific location-dependent factors, particularly land rights acquisition, can significantly delay an undergrounding project, such that certain undergrounding projects could take ***three times longer than deploying covered conductor***. To promote the goal of achieving as much risk reduction as quickly as possible, the location-specific execution and schedule risks must be thoroughly considered in choosing the best system hardening alternative for a given location.

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[22] *Id.*

[23] *Id.*, p. 601.

[24] PG&E's 2021 WMP, p. 601 (emphasis added).

In sum, despite cogently explaining in its 2021 WMP many of the multitude of factors that should influence the choice of system hardening mitigation for a given location, PG&E has spurned the Energy Safety directive to make an up-front assessment of the location-specific considerations before choosing undergrounding. In so doing, PG&E attempts to undermine Energy Safety's efforts to make the best use of limited resources for wildfire mitigation work.

C. Contrary to Energy Safety's Direction, PG&E Does Not Incorporate Project-Specific RSE Estimates of System Hardening Alternatives Early in the Process to Promote Effective Use of Resources

As previously noted, Energy Safety's 2022 decision on PG&E's WMP sharply criticized PG&E's failure to consider RSEs when deciding which system hardening measures to use in a particular high-risk location:

> *In PG&E's 2023 WMP, it must provide* further analysis of its decision-making process, *demonstrating a full evaluation of system hardening alternatives* including considering combinations of system hardening initiatives.[25]
>
> . . .
>
> Upon review, Energy Safety found that PG&E's system hardening decision-making flowchart *does not give sufficient weight to quantitative factors such as costs, risk reduction values, and RSE estimates*. For example, the flowchart hierarchy prioritization is influenced more by construction limitations than by RSE estimates. This may lead PG&E to fast-track more expedient locations *rather than considering the option with the highest RSE estimate*.[26]

ACI PG&E 22-34 directed PG&E to show in this GRC that it has remedied this problem, requiring PG&E to show that it incorporates RSE estimates of alternative measures "at a project level early in the decision-making process . . ..."[27]

[25] Energy Safety 2022 PG&E WMP Decision, pp. 79-80 (emphasis added).
[26] Energy Safety 2022 PG&E WMP Decision, p. 144 (emphasis added).
[27] *Id.*, p. 184.

PG&E's response to ACI 22-34 does not explain any modifications to its decision-making flowchart to compare the RSEs of alternative system hardening mitigations at any point, let alone early in the decision-making process. PG&E's response to a TURN data request confirms that PG&E did not make the required change. TURN asked PG&E to provide documents showing that PG&E was using RSE estimates when comparing mitigation alternatives. PG&E's response was that it has no such documents.[28]

Thus, contrary to Energy Safety's direction, PG&E does not compare RSEs of alternative options when deciding the best mitigation for a particular project location. The reason why PG&E has defied Energy Safety's requirements is evident. As discussed in Section V below, in most locations, covered conductor will have a higher RSE, *i.e.*, will be more cost-effective than undergrounding. Comparing RSEs would show that PG&E's default-to-undergrounding approach imposes undergrounding in numerous locations where overhead hardening would be a much more efficient use of limited resources.

PG&E's WMP and data request responses try to make it sound as if PG&E has complied with the RSE requirements in ACI 22-34 by calculating what PG&E calls Simplified Wildfire RSE (SWRSE) or Wildfire Feasibility Efficiency (WFE) in evaluating undergrounding projects.[29] However, as PG&E confirmed in a data request response, those measures *are only calculated for undergrounding projects* and *cannot* be used to compare the cost-effectiveness of undergrounding with any mitigation alternative.[30]

By not comparing RSEs of alternative mitigations when considering a system hardening project, PG&E is serving its own corporate interest in maximizing undergrounding, and defying

[28] PG&E response to TURN DR 1, question 1(b)(ii).
[29] *Id.*
[30] PG&E response to TURN DR 12 question 1.

the public interest in ensuring that the best and most cost-effective mitigation strategies are being deployed.

D. Energy Safety Was Right to Insist that the Selection Among System Hardening Alternatives Be Based on an Up-Front, Location-Specific Analysis , Including RSE Comparisons

As shown, beginning in the end of 2021, PG&E shifted from a sensible approach of making a location-specific determination of the best system hardening alternative to its current default-to-undergrounding ethos in which, for lines that cannot be removed entirely, PG&E will proceed with undergrounding unless it eventually determines that undergrounding is infeasible. As Energy Safety recognized in last year's decision, this broad-brush approach will lead to a highly inefficient use of limited resources and a slower pace of risk reduction by imposing the expensive, risky and protracted undergrounding mitigation in numerous locations where overhead hardening, supplemented where appropriate by other ignition limiting technologies, will provide much more cost-effective risk reduction on a faster, risk-free timeline.

1. Tree-Strike Potential Is Location-Specific and Does Not Justify Defaulting to Undergrounding

PG&E relies heavily on the fact that there are more and taller trees in its service territory compared to the other large utilities, posing an elevated risk that trees will fall on overhead lines and cause ignitions, even those reinforced with covered conductor. However, this generalization does not support abandoning a location-specific analysis of where tree strike risk is sufficiently high to warrant undergrounding. Needless to say, tree density, height and proximity to power lines will vary hugely among circuit segments and therefore needs to be assessed on a project-by-project basis. PG&E recognized this in its 2021 WMP, treating tree density and strike potential as factors that need to be taken into account in deciding whether undergrounding is appropriate for a given location. And as noted in Section III.B.2 above, prior to late 2021 PG&E used a "System Hardening" (not just Undergrounding) decision tree that treated tree strike potential as one of many considerations affecting the choice of system hardening alternative. That decision tree included the question: "Are there areas identified with tree strike potential within the circuit segment?" and then called for such potential to be rated as "Low (0-5), Moderate (6-14), or High (15+)."[31] If tree strike potential was rated moderate or high, then undergrounding was preferred; otherwise, overhead hardening was preferred. PG&E would not have had a decision tree asking this question if tree strike potential was uniformly sufficiently high to justify undergrounding in all locations.[32]

Even in locations with significant tree strike potential, undergrounding may not be the best mitigation. Energy Safety appropriately directed PG&E's alternatives analysis to include combinations of mitigations. One example of a highly promising combination is to supplement covered conductor with technologies that limit or prevent the release of current when a conductor falls to the ground, such as REFCL or downed conductor detection. SCE is now estimating that the combination of covered conductor and REFCL has mitigation effectiveness percentages approaching those of undergrounding, such as 95% for conductor damage or failure and 85% for vegetation contact.[33] These or other combinations may provide much more cost-effective means of addressing even high tree-strike potential locations.

[31] PG&E response to TURN DR 5, question 1, Attachment 3.

[32] As noted in Section III.B.2, TURN does not view PG&E's former System Hardening decision tree as perfect. As discussed in the following paragraph, it did not take into account that, in locations with "moderate" or high tree strike potential, covered conductor could be supplemented with current/ignition limiting technologies to further reduce ignition risk in a tree strike scenario.

[33] SCE response to MGRA DR 3, question 2. SCE data request responses are available at: https://www.sce.com/safety/wild-fire-mitigation

2. PSPS Risk Is Location-Specific and Does Not Justify Defaulting to Undergrounding

PG&E also states that undergrounding is preferable to other system hardening alternatives for mitigating PSPS risk. However, PSPS risk is also location-specific and does not justify undergrounding in all locations. PG&E's prior System Hardening Decision Tree recognized this point. That decision tree included the question: "Is this an area that is impacted directly by PSPS (>8 Frequency or >8 Cust Impact) OR Are there any critical customers within zone necessary to protect?" If the answer was yes, undergrounding was favored; if not, overhead hardening was preferred.[34] Notwithstanding this prior practice, PG&E admitted in a data request response that it no longer uses "PSPS risk in our quantitative decision-making when deciding whether to undertake an undergrounding project or an alternative mitigation."[35] In other words, PG&E chooses to plunge ahead with undergrounding, regardless of whether a location has high PSPS risk.

Even if a location is susceptible to PSPS risk, PG&E should assess the extent to which covered conductor, with or without other supplemental current limiting technologies, mitigates that risk – an assessment PG&E has not undertaken to date.[36] SCE states that it has determined that "lines with covered conductor have a ***90% reduction*** in PSPS activations"[37] and has increased its PSPS thresholds, *i.e.*, decreased the likelihood of calling a PSPS event, on circuit segments with covered conductor.[38] Combining covered conductor with current limiting technologies (see Section III.D.2 above) should likely further increase PSPS thresholds.

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[34] PG&E response to TURN DR 5, question 1, Attachment 3.

[35] PG&E response to TURN DR 1, question1(c).

[36] PG&E response to TURN DR 8, question 6.

[37] SCE 2023-2025 WMP, p. 252.

[38] *Id.;* Joint IOU 2023 Covered Conductor Working Group Report, p. 38.

Furthermore, distributed generation to critical and/or medically vulnerable customers is likely much more cost-effective for PSPS risk mitigation than undergrounding. Thus, a location-specific analysis can be expected to show that, in many locations, undergrounding would provide little or no incremental benefit to justify its higher cost when compared to covered conductor.

3. As Energy Safety Has Recognized, A Multitude of Location-Specific Factors Need to Be Assessed Before Concluding that Undergrounding Is the Best Choice and Will Deliver Timely Risk Reduction for a Given Project

As noted, Energy Safety's 2022 decision on PG&E's WMP informed the utility that it must weigh a "multitude of factors" to evaluate system hardening alternatives on a location-specific basis.[39] Those factors are well known to PG&E, as identified in its 2021 WMP,[40] and include numerous factors that are more problematic for undergrounding than overhead hardening, such as:

- Accessibility of location to required equipment
- Access to necessary rights of way
- Presence of necessary public utility easements or other property rights
- Presence of private property or water crossings
- Adequacy of space for necessary subsurface and pad-mounted equipment
- Environmental sensitivity of the location and impact of mitigation alternatives on environmental concerns such as endangered species and soil/erosion impacts
- Presence of Native American and other historical, archaeological and cultural resources and impacts of mitigation alternatives on those resources
- Rocky, steep, or difficult to penetrate terrain
- Prevalence of flooding in the location

[39] Energy Safety 2022 PG&E WMP Decision, p. 79.

[40] PG&E 2021 WMP, pp. 600-601.

At the April 27, 2023 WMP Workshop, Nancy Macy, a community leader in the Santa Cruz mountains, provided a real-world example of the unexpected problems that can make undergrounding a poor choice. She explained that, while she initially supported undergrounding for her extremely fire-prone area, she has come to learn from the experience of her water company that, in her steep erosive region, undergrounding would not work out well because it would be subject to erosion and would destabilize the steep slopes. Ms. Macy pointed out that there will surely be other, different types of obstacles in many other parts of Northern California, such as areas with wetlands and where the terrain features granite and other hard rocks. She strongly supports overhead hardening as a more realistic and faster solution.[41]

The timing concern raised by Ms. Macy is a particularly important factor that weighs against undergrounding. As PG&E explained in its 2021 WMP, one of the most important "schedule risks" associated with undergrounding is that it often requires a lengthy land rights acquisition process to obtain the necessary easements for relocated underground facilities (underground facilities often cannot follow the "as the crow flies" path of overhead lines, such as when traversing canyons or waterways). PG&E stated that "[t]his land rights acquisition process alone can take 6-18 months and requires the project to be at a fairly mature design stage prior to contacting property owners about the needed rights."[42] Thus, PG&E could spend 18 months simply figuring out which property owners it needs to negotiate with, and only then, begin those negotiations. Once negotiations start, PG&E would obviously not be in complete control of how long those negotiations will take or whether PG&E will reach an agreement at all.

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[41] Recording of 4/27/23 Workshop, remarks of Nancy Macy, beginning at approximately 4:57:00.
[42] PG&E 2021 WMP, p. 601.

Obtaining the necessary permits from governmental entities, especially when CEQA review is required, creates another set of schedule risks that are not within the control of PG&E. CEQA typically requires an alternatives analysis to examine whether there is a less environmentally impactful alternative to achieve the project objectives. For the reasons discussed in these comments, a CEQA reviewing agency could conclude that overhead hardening achieves those objectives without any of the environmental harm of undergrounding and thus is a superior alternative.

In short, PG&E could devote years to a proposed undergrounding project, only to find out that it cannot move ahead because of inability to secure the necessary property rights and government approvals. Even if PG&E can successfully run the gauntlet of challenges and approvals, undergrounding will almost always take longer – often several years longer – to deploy than covered conductor. In its 2021 WMP, PG&E estimated the idea to completion time for overhead hardening as 13-16 months. By comparison, it stated that an undergrounding project could often take 18-45 months depending on the risks presented in a given location.[43] Of course, in reality, some undergrounding projects will never be completed because they prove to be infeasible owing to any of the bulleted factors listed above or the inability to obtain necessary property rights and permits.

In light of these significant execution and schedule risks, PG&E's policy of proceeding with undergrounding unless and until it is proven infeasible, is unwise, if not foolhardy. Under PG&E's approach, a location in great need of wildfire and PSPS risk reduction could be deprived of any mitigation for years while PG&E determines whether undergrounding is feasible. If undergrounding leads to a dead end, PG&E will need to go back to the drawing board to deploy

[43] *Id.*

overhead hardening. In the process, PG&E will have squandered years of significant risk reduction that could have been obtained if it had used the up-front comparison of alternatives that Energy Safety required in ACI 22-34. PG&E's default-to-undergrounding policy is antithetical to the goal of obtaining as much risk reduction as quickly as possible and must be soundly rejected.

IV. PG&E'S UNDERGROUNDING PLAN DOES NOT TARGET THE HIGHEST RISK LOCATIONS

PG&E claims that it seeks to prioritize the highest risk segments in its service territory, specifically that "**87 percent** of PG&E's undergrounding work is planned for the top 20 percent of risk-ranked circuit segments."[44] TURN wishes to highlight for Energy Safety that this assertion does not mean PG&E is targeting the top 20% of wildfire risk in its service territory. There are three primary flaws (each is an independent issue) to PG&E's approach that means its efforts will not be targeted to the highest risk areas:

1. PG&E's definition of "top 20%" <u>does not</u> refer to the top 20% of *wildfire risk.* It refers instead to the number of circuit segments modeled by PG&E.
2. PG&E uses an old risk model ("WDRM v2") to claim some certain segments are high risk. Many of these circuit segments likely fall outside high risk areas in its latest model (WDRM v3) due to significant changes in results.
3. The 13% of circuit segments that fall outside of PG&E's own, expansive definition of "high risk" miles represent a significant number of miles, costs, and resources.

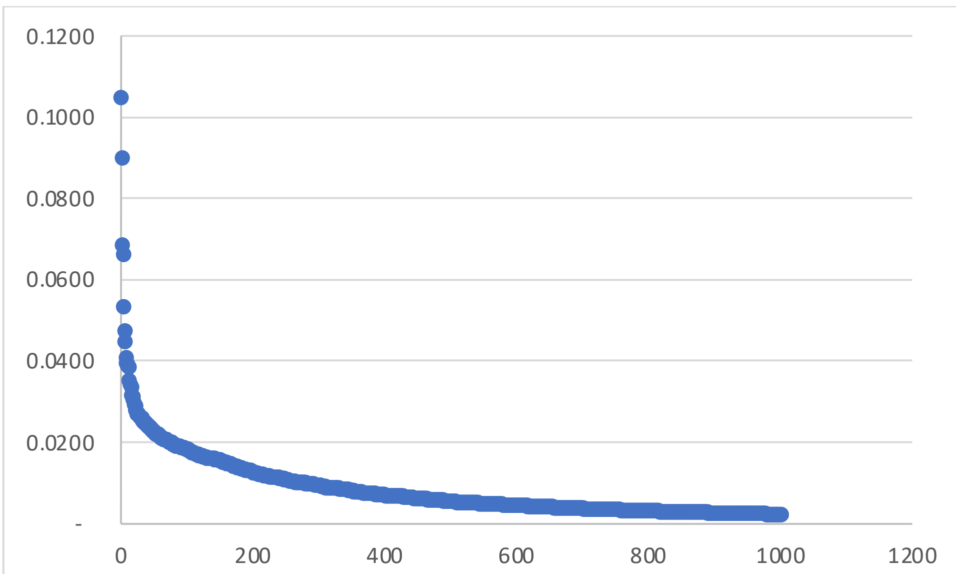
A. PG&E's Definition of "High Risk" Miles is Flawed and Allows for Prioritization of Miles that are Not Relatively High Risk

As stated above, a first blush reading of PG&E's WMP seems to indicate that its undergrounding plan is focused on the highest risk parts of its system. This is not the case.

[44] PG&E 2023-2025 WMP (R1), p. 4 (emphasis added).

PG&E's definition of "high risk" is based on a *count of circuit segments* modeled, in which the total number of circuit segments modeled in the utility's HFTD is multiplied by 20% to find the threshold of "top 20 percent."[45] This methodology would be equivalent to wildfire risk if each circuit segment had the same amount of risk. However, wildfire risk across circuit segments is highly heterogeneous. The figure below shows average risk per segment, which PG&E uses to rank and prioritize circuit segments.[46] The difference between relatively high and low risk circuits varies dramatically.

Figure 1. Average Wildfire Risk Score of Top 1,000 Circuit Segments[47]



1. Why Ranking by Circuit Segment Number is Different than Ranking by Risk

To further explain why PG&E's methodology does not result in a targeting of circuit segments in the top 20% of risk, we provide the following illustrative example. Let's say there are a total of 40 risk ranked circuit segments. Using PG&E's methodology, the "top 20%" of

[45] PG&E's response to DR TURN-13, question 1.

[46] PG&E 2023-2025 WMP (R1), p. 910.

[47] PG&E's response to DR TURN-11, question 1, attachment 2.

circuits is anything from the 8th ranked circuit and above (40 * .2 = 8). However, since the *risk* varies significantly across circuit segments, PG&E's threshold does not correspond to the top 20% of risk. This is shown using illustrative numbers below.

Table 1. Illustrative Circuit Segment Ranking by "Top 20%" – PG&E Methodology vs. Wildfire Risk

	Segment Rank	WF Risk	Cumulative WF Risk	Cumulative WF Risk %
	1	25,000	25,000	10%
Top 20% - WF Risk	2	24,000	49,000	20%
	3	15,000	64,000	27%
	4	14,900	78,900	33%
	5	14,800	93,700	39%
	6	14,700	108,400	45%
	7	14,600	123,000	51%
Top 20% - PG&E	8	14,500	137,500	57%
	9	14,400	151,900	63%
	10	14,300	166,200	69%
	11	14,200	180,400	75%
	12	14,100	194,500	81%
	13	14,000	208,500	87%
	14	13,900	222,400	93%
	15	16,800	239,200	100%
	16	1	239,201	100%
	17	1	239,202	100%
	18	1	239,203	100%
	19	1	239,204	100%
	20	1	239,205	100%
	21	1	239,206	100%
	22	1	239,207	100%
	23	1	239,208	100%
	24	1	239,209	100%
	25	1	239,210	100%
	26	1	239,211	100%
	27	1	239,212	100%
	28	1	239,213	100%
	29	1	239,214	100%
	30	1	239,215	100%
	31	1	239,216	100%
	32	1	239,217	100%
	33	1	239,218	100%
	34	1	239,219	100%
	35	1	239,220	100%
	36	1	239,221	100%
	37	1	239,222	100%
	38	1	239,223	100%
	39	1	239,224	100%
	40	1	239,225	100%

2. PG&E's "Count of Segments" Methodology Results in a Significant Mismatch Between Wildfire Risk and Planned Deployment of Undergrounding

The actual difference between wildfire risk and PG&E's methodology is much more significant than in the illustrative table above. A comparison of risk versus PG&E's "count of segments" methodology finds the following differences:[48]

- The **top 125 circuit segments** represent the highest 20% of wildfire risk in PG&E's service territory according to PG&E's modeling results rather than **the top 720** under PG&E's methodology.
- PG&E's methodology allows it to prioritize circuits for undergrounding anywhere in the top **80% of wildfire risk**, not the top 20%.
- PG&E has scoped just **437 of 1,802 total miles** in the top 20% of wildfire risk from 2023-2025. This means *at least* 76% of planned miles will not be accomplished in the top 20% of wildfire risk.

Regarding the latter, PG&E could deploy nearly its entire undergrounding program in relatively low-risk areas (below the top 20%) because PG&E includes "buffer" miles in its scoped versus forecast mileage amounts.[49] PG&E's plan that it has submitted to Energy Safety, if approved, would thus allow for a massive, resource-intensive effort that does not focus on the highest risk miles, according to PG&E's own risk modeling results.

B. PG&E Relies on an Old Risk Model to Justify Some Miles as "High Risk"

Independent from the issue discussed above, PG&E's high risk mileage count includes 451 miles from 2023-2025 based on "high risk" circuit segments according to PG&E's WDRM

[48] Findings presented here use the "Total wildfire risk score (MAVF Calibrated)" calculation provided in PG&E's response to DR TURN-11, question 1, attachment 2. This is calculated by summing cumulative wildfire risk with circuit segments ranked from highest to lowest average risk. These findings are very similar to what we calculate using the "Total Overall Risk (Wildfire + PSPS)" metric.

[49] PG&E response to TURN DR 11, question 2(h).

v2 model,[50] despite the fact that PG&E states it has improved this model and now utilizes a different version to prioritize deployment of its undergrounding program, WDRM ***v3***. This latest model's results significantly differ from previous iterations, as explained by PG&E in its WMP.[51] Due to this, many of the miles – 214 of the 451 - are no longer high risk according to WDRM v3 results (based on PG&E's definition of risk).[52] PG&E will thus spend around $716 million, and divert significant resources, to underground relatively low-risk miles, according to its own modeling and definition of high risk.[53]

C. PG&E's Proposes a Significant Number of Miles Outside of Its Definition of High Risk

Independent from the issues discussed above, PG&E proposes 13% of miles be deployed outside of its definition of the top 20% of risk ranked miles.[54] The 13% estimate refers to the 2023-2026 forecast: from 2023-2025, it is actually 19% of miles, shown below.

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[50] PG&E response to DR TURN-10, Question 2, Attachment 1 (CONF).

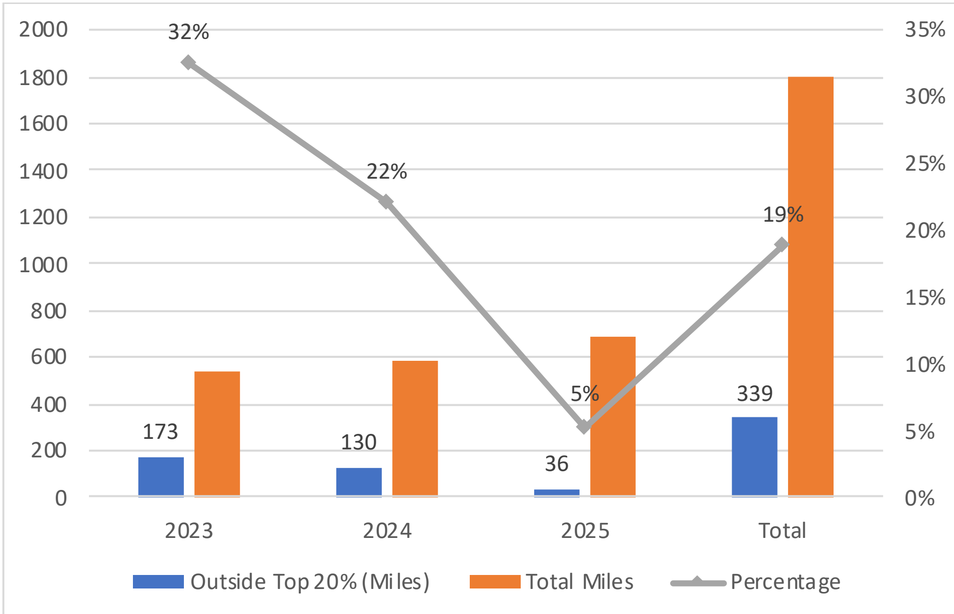
[51] PG&E 2023-2025 WMP (R1), p. 886.

[52] Calculated from PG&E's response to DR TURN-10, Question 2, Attachment 1 (CONF), which provides both v2 and v3 risk rankings. TURN examined the circuits justified as "high risk" based on the v2 model, and summed those miles which are no longer high risk in the v3 model (<=720).

[53] Cost estimate based on overall (SH and Butte) 2023-2025 unit costs (average of 2023-2025, $3.54 million) provided in response to DR TURN-11, question 2, attachment 3.

[54] PG&E 2023-2025 WMP (R1), p. 4.

Figure 2. Proposed Non High Risk Miles vs. Total 2023-2025[55]



To the extent that undergrounding is deployed, the tremendous costs and resources of this mitigation should be focused on the very highest risk areas. For example, the 339 miles shown above would cost ratepayers about $1.2 billion, despite mitigating very little risk. We understand that many (68%) of these non high-risk miles are for "fire rebuilds*,*" *i.e.*, infrastructure that must be rebuilt in the aftermath of a catastrophic wildfire.[56] Still, this highlights PG&E's approach to undergrounding as its default solution, rather than focusing on mitigating the most possible risk within reasonable resource and cost constraints.

D. TURN's Recommendations Reduce More Risk at Less Cost

Because PG&E does not focus its undergrounding program sufficiently on the riskiest circuits, likely due in large part to the complexity and difficulty of undergrounding (see Section

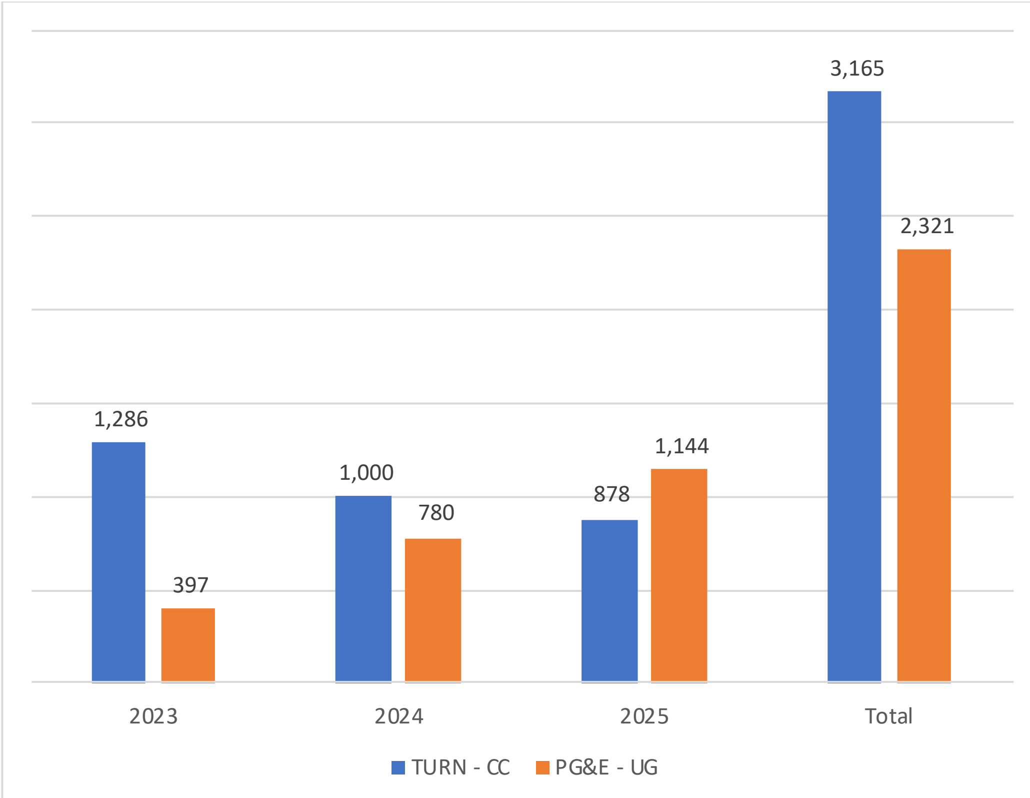
[55] TURN-10, Question 2, Attachment 1, CONF.
[56] PG&E WMP R1, p. 340.

III.B.3), its proposals are ineffective and inefficient. Rather than a default approach to undergrounding virtually anywhere in its HFTD, PG&E should focus undergrounding on the very riskiest circuit segments while deploying covered conductor on other high risk circuits.

As we discuss in Section III.D.3, covered conductor can be deployed more quickly and efficiently than undergrounding. The following figures show that a covered conductor-focused approach results in more risk reduction at less cost, when deploying covered conductor from highest to lowest risk circuits. We assume below TURN's GRC proposal of 450 miles per year of covered conductor, as well as PG&E's mitigation effectiveness assumptions, which the utility estimates at the circuit segment level.[57]

[57] Figures calculated from PG&E's risk reduction calculation in workpaper "2023-04-06_PGE_2023_WMP_R2_Section 6.4.2_Atch01."

Figure 3. Risk Reduction from Covered Conductor vs. Undergrounding TURN vs. PG&E, 63% Mitigation Effectiveness for CC



While PG&E's undergrounding proposal mitigates 10% of wildfire risk through undergrounding, TURN's corresponds to a 14% reduction.[58] And ratepayers would spend about $2.3 billion less on a covered conductor focused approach than undergrounding.[59]

We note, however, that PG&E's mitigation effectiveness assumptions of around 63% on average may be overly conservative; the joint IOU study indicates other utility estimates of up to 90%.[60] If covered conductor proves more effective than PG&E's assumptions, this would

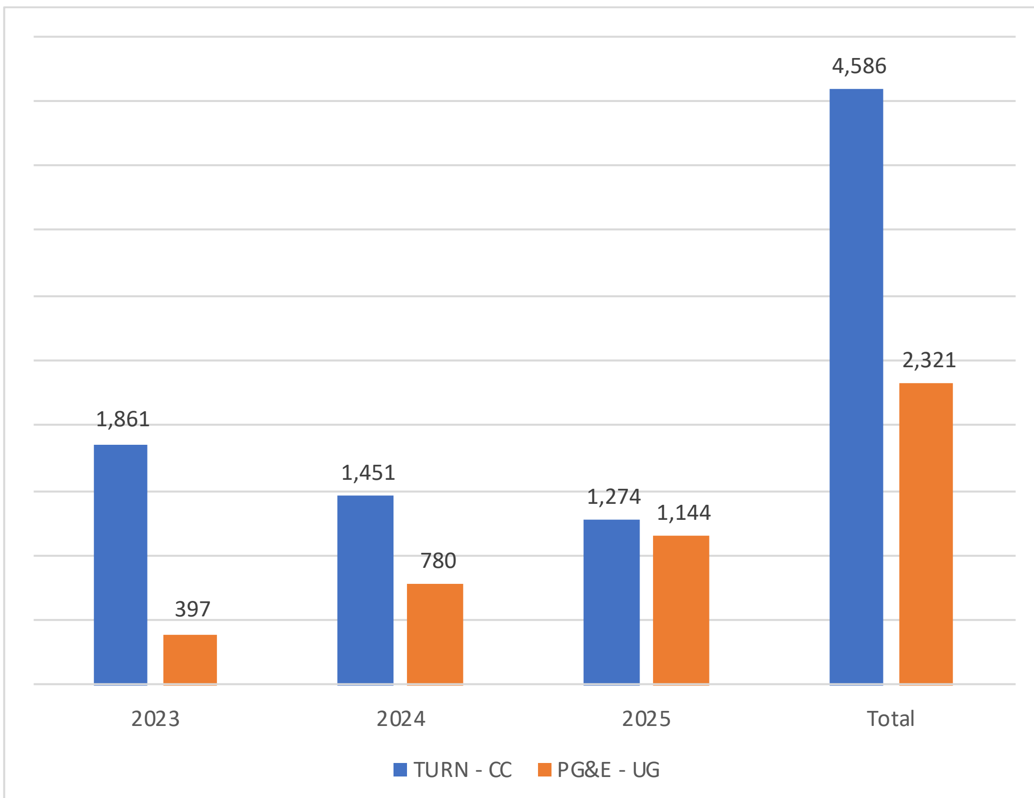
[58] Calculated from PG&E's risk reduction calculation in workpaper "2023-04-06_PGE_2023_WMP_R2_Section 6.4.2_Atch01."

[59] Assumes unit costs of $825,000 for covered conductor and $3.5 million per mile for undergrounding.

[60] 2023-2025 WMP, Joint IOU Covered Conductor Working Group Report, p. 1, states "the information compiled and assessments completed in 2022 continue to indicate CC effectiveness between approximately 60 to 90 percent in reducing the drivers of wildfire risk, consistent with benchmarking, testing and utility estimates." The 63% average for PG&E comes from workpaper" 2023-04-

significantly increase risk reduction through covered conductor deployment. The figure below shows that, at 90% effectiveness, covered conductor, if deployed from highest to lowest risk circuits, would achieve nearly double the risk reduction of PG&E's undergrounding program, in total mitigating 20% of wildfire risk.

Figure 4. Risk Reduction from Covered Conductor vs. Undergrounding TURN vs. PG&E, 90% Mitigation Effectiveness for CC



V. COVERED CONDUCTOR IS MUCH MORE COST-EFFECTIVE THAN UNDERGROUNDING IN MOST AREAS

Although PG&E's WMP does not share data that compares the RSE of covered conductor with undergrounding, TURN did a thorough analysis of the comparative RSEs in PG&E's currently pending GRC. As discussed in more detail below, the result of that analysis is

06_PGE_2023_WMP_R2_Section 6.4.2_Atch01" average of the circuit segment mitigation effectiveness provided in this workpaper.

that, on average, covered conductor has a significantly higher RSE than undergrounding. Covered conductor's RSE advantage also holds true at a more granular tranche level. This GRC data is the best available information comparing the cost-effectiveness of these alternatives because, as noted, PG&E does not calculate project-level RSEs to enable location-specific comparisons.

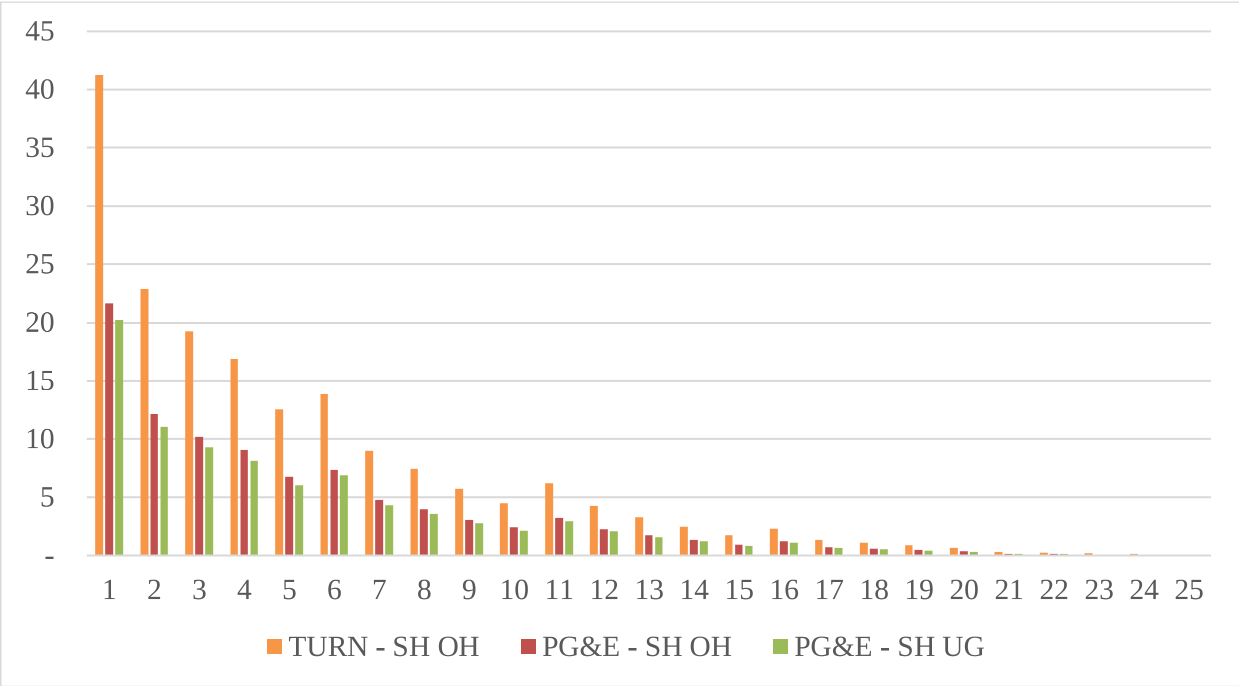
TURN presented its comparative RSE analysis in the GRC testimony of Eric Borden, TURN's wildfire risk expert, which is attached to these comments for ease of reference.[61] Using PG&E's data and adjusting the unit costs as discussed below, Mr. Borden calculated an average RSE for covered conductor of 11.0. By comparison, the average RSE for undergrounding was much lower, 5.3.[62] And, as shown in the figure below, when PG&E's HFTD distribution system was divided into 25 tranches based on risk profile, covered conductor had a higher RSE in each of the 25 tranches, with the advantage being particularly striking in the higher risk tranches, where a system hardening strategy is most needed.[63]

[61] Appendix B to these Comments. The voluminous attachments to this testimony are available upon request.

[62] Borden GRC Testimony for TURN, p. 26, Figure 8.

[63] *Id.*, p. 27, Figure 9. The tranches on the X axis of Figure 9 go from highest risk on the left to lowest risk on the right.

Figure 5. Risk Spend Efficiency of Overhead vs. Underground – Tranche Level



This RSE comparison – and the uniformity of the advantage for covered conductor across tranches -- shows that, if PG&E were to do the project-specific RSE comparison of system hardening alternatives, as directed in ACI 22-34, covered conductor can be expected to have a higher RSE for most projects.

As noted, to calculate the covered conductor RSE, Mr. Borden adjusted PG&E's cost figures by removing the costs to replace useful assets that do not pose significant ignition risk – which caused PG&E's claimed unit costs to be 150% higher than SCE's.[64] TURN's adjusted unit cost for covered conductor was $800,000 per mile - this is very close to the $826,000 per mile cost that PG&E reports in its WMP based on the most recent Joint IOU Covered Conductor

[64] *Id.*, pp. 21-23. PG&E's claimed unit cost for covered conductor was $1.6 million/mile, compared to $629,000 for SCE.

Working Group Report.[65] PG&E's updated cost number thus reinforces the appropriateness of Mr. Borden's covered conductor cost adjustments, and therefore the RSE calculations, which would not dramatically change with an additional $26,000 per mile for covered conductor deployment.

In fact, Mr. Borden's RSE comparison likely understates the advantage for covered conductor because the undergrounding RSE does not reflect the fact that, for a given project location, undergrounding could take two to three years longer to deploy than undergrounding, as discussed in Section III.D.3 above. If this delay in the realization of risk reduction benefits were recognized in the RSE calculations, the undergrounding RSE would be even lower.

These results help to explain, but do not justify, PG&E's non-compliance with Energy Safety's directive to compare RSEs for alternative mitigations at the outset of a system hardening project. Because covered conductor is generally more cost-effective than undergrounding, it is critically important that PG&E's WMP not be approved until PG&E has incorporated RSE comparisons into its decision-making and revised its undergrounding and covered conductor targets accordingly. Further, for any project in which covered conductor has a higher RSE yet PG&E still wishes to pursue undergrounding, PG&E should have the burden of showing special and compelling circumstances that justify undergrounding in that location. Severely limiting the instances in which the less cost-effective alternative is deployed is vital in order to ensure that ratepayers' limited resources are being used effectively.

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[65] PG&E 2023-2025 WMP (R1), p. 903. PG&E explains that this cost is based on components that make its program comparable to those of the other utilities.

VI. PG&E DOWNPLAYS IMPORTANT LIMITATIONS OF UNDERGROUNDING

A. PG&E Appears to Underestimate How Much Mileage and Cost Are Added by the Routing Limitations of Undergrounding and Thereby Overestimates the Risk Reduction and Cost-Effectiveness of Undergrounding

The path that an undergrounded circuit segment needs to take is often longer and more circuitous than the "as the crow files" path of the overhead segment it is replacing. SCE explained this point well at the April 27, 2023 workshop using the example of overhead wires spanning a canyon. To replace those overhead wires with undergrounded facilities requires running underground switchbacks down and then back up the canyon walls. This fact means that more than one underground mile is often necessary to replace one mile of overhead facilities. This is extremely important from a risk perspective, because the wildfire risk posed by utility lines is measured and assessed by overhead miles subject to risky wildfire conditions. PG&E's plans and forecast are measured in underground miles, which are not equivalent to overhead miles replaced. Unless an accurate underground to overhead conversion factor is used, a risk reduction comparison between system hardening alternatives will inaccurately estimate risk reduction and cost-effectiveness (RSE). This point also underscores the importance of a location-specific comparison of project alternatives, in which it is known how the routing of undergrounding would need to differ from the overhead route.

PG&E states that it assumes an overhead to underground conversion factor of 1.25, meaning that, on average, it will take 1.25 miles of UG to replace one mile of overhead facilities.[66] But a data request response shows that this figure is just an assumption and not based on actual data from its 2021 and 2022 undergrounding experience. TURN's data request asked

[66] PG&E 2023-2025 WMP (R1), p. 968. PG&E uses a higher 1.57 conversion factor for "community rebuild" undergrounding. PG&E response to TURN DR 10-1.

PG&E, regarding the 73 and 180 miles of undergrounding that PG&E performed in 2021 and 2022 respectively, to provide the corresponding number of overhead miles that were removed. PG&E's response was startling: "*We currently do not track the overhead miles removed and replaced through undergrounding*."[67] As a result, PG&E's data request response could only provide an estimate based on its *assumed* conversion factors. This as an unacceptable recordkeeping lapse. PG&E should be required to maintain a database of actual results from PG&E's undergrounding projects that identified underground miles deployed and overhead conductor miles replaced for each project, along with information describing the reasons that undergrounding was needed to deviate from the direct overhead path.

There is good reason to believe that PG&E's assumed 1.25 conversion factor is low, which would overestimate the risk reduction benefits of undergrounding. PG&E itself uses a 1.57 conversion factor for "community rebuild" projects such as in Butte County, but does not explain why a lower conversion factor makes sense for its general system hardening overhead work. Meanwhile, PG&E's WMP acknowledges that, "at times" its assumed 1.25 multiplier can be "2-3 times greater", *i.e.* 2.5 to 3.75, "especially in the highest risk locations because of existing OH circuitry traversing steep gradient and water crossings."[68] If even a few system hardening projects require a 2.5 to 3.75 conversion factor, it is hard to see how a 1.25, or even a 1.57 factor could be realistic. The key point is that PG&E does not provide sufficient data against which to assess the accuracy of its assumptions, and the data it has provided to date does not support this critical assumption.

[67] PG&E response to TURN DR 10, question 1 (emphasis added).
[68] PG&E 2023-2025 WMP (R1), p. 968.

If indeed PG&E is using excessively low conversion factors, PG&E's risk reduction estimates from its undergrounding plan would be significantly overstated. Estimates of risk reduction need to be based on the status quo overhead miles that are addressed, not the number of miles of undergrounding work performed. Overhead miles replaced, not underground mileage, is the key measure for determining risk reduction. PG&E estimates 1,175 miles of "system hardening" rebuild miles in 2023-2025 (and another 175 Butte County Rebuild miles).[69] Using PG&E's assumed 1.25 conversion factor, the 1,175 underground miles equate to replacement of 940 overhead miles. But, if a 1.57 conversion factor is used, the overhead miles replaced drops to 748 miles. And using the lower 2.5 conversion factor that PG&E admits will be necessary for the highest risk locations, only 470 overhead miles will be replaced. Replacing 470 overhead miles could provide a fraction of the risk reduction as PG&E estimates from its 1,175 mile undergrounding plan, depending on the allocation of risk across the particular circuits.

In addition, the risk reduction per dollar, *i.e.*, RSE, for undergrounding is significantly reduced when the overhead to underground conversion factor is higher, which makes undergrounding even less cost-effective. Thus, using a realistic conversion factor is a critical input, both for meaningful comparison with alternatives to undergrounding and for useful estimates of risk reduction achieved by undergrounding. Energy Safety should not take PG&E's risk reduction estimates for undergrounding at face value and, as discussed above, should require PG&E to track overhead miles replaced in its undergrounding projects.

[69] PG&E 2023-2025 WMP (R1), p. 347, Table 8.1.2-2.

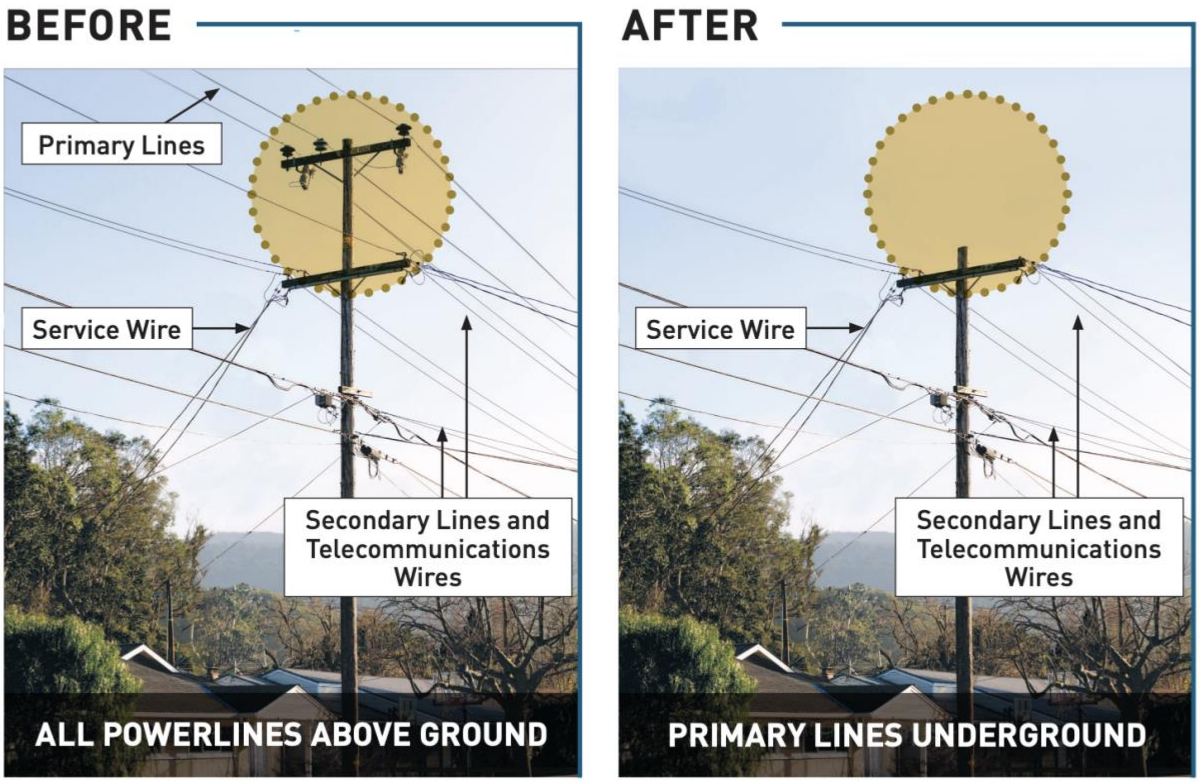
B. In Many, If Not Most, Undergrounding Locations, Most of the Distribution Poles and Wires Will Remain Above Ground

PG&E's WMP does not acknowledge that, in most locations where it performs undergrounding, it will only be replacing primary conductor, not secondary conductor and service drops.[70] Thus, even where undergrounding has occurred, it will be partial, because secondary conductor, service drops and most poles will remain above ground. In fact, even poles supporting primary conductor would remain above-ground (though may be topped off) if communications providers using those poles elect to keep their wires above ground.

Before and after undergrounding pictures from PG&E's website[71] show that undergrounding will not have the impact that many people may hope for and expect from an aesthetic perspective.

[70] PG&E response to TURN DR 5-4.

[71] https://www.pge.com/pge_global/common/pdfs/customer-service/other-services/electric-undergrounding-program/PGE-Undergrounding-Fact-Sheet.pdf



Residents who expect undergrounding to remove visually unappealing wires and poles will be sorely disappointed. In fact, for most people, it will be difficult to see any difference at all.

Apart from dashed hopes of residents and property owners in the affected areas, the even more important point is that the safety benefits of undergrounding will likely be less than expected. Because most poles and wires will remain, they are susceptible to falling and blocking ingress and egress routes during a fire. This is yet another factor that calls into question the claimed incremental risk reduction that undergrounding supposedly provides compared to covered conductor.

TURN raises this point not to criticize PG&E's policy. TURN recognizes that, if PG&E undergrounded secondary lines and services, undergrounding would be even less cost effective than it already is. However, it is important to understand the limitations of undergrounding in improving risks related to ingress and egress, a point that PG&E does not acknowledge in its WMP.

C. Outages on Underground Lines Trend Longer than for Overhead Lines

Another potential misconception about undergrounding is that, of the system hardening alternatives, it will provide the most reliability benefits.[72] In fact, overhead hardened lines may have better overall reliability than underground lines. At the April 27, 2023 workshop, PG&E's representative, in response to a question from Cal Advocates, stated that, in comparison to overhead unhardened facilities, underground lines typically have less frequent outages, *but the outages that do occur are longer*.[73] This is likely because underground outages take longer to find and repair. Meanwhile, the utility that has made the greatest use of covered conductor, SCE points out that covered conductor has "intrinsic reliability benefits," decreasing the number of faults caused by contact with foreign objects by 85%. Thus, covered conductor has the potential to provide the best of both worlds – less frequent outages than bare overhead wire and shorter duration outages than underground lines.

TURN's point here is again to point out that assumptions about the virtues of undergrounding may be exaggerated and not borne out by actual data. In a future where Californians will be more dependent than ever on electricity to combat climate change, covered conductor, not undergrounding, may be the better choice to provide the cost-effective reliability that customers will need and demand. If improving electric reliability is to be a significant

[72] Section III.D.2 above discusses the fact that SCE's experience shows that, in the areas where PSPS is an issue, undergrounding may provide little incremental benefit to covered conductor with respect to the need for PSPS activations.

[73] April 27, 2023 Workshop at approximately 3:36. Data from SCE that TURN obtained in discovery showed that, in the period 2018 -2022, underground lines typically had less frequent, but longer duration outages than overhead lines. SCE response to TURN DR 2, question 1.

consideration in choosing among system hardening alternatives, Energy Safety should require utilities to track the reliability of circuit segments with covered conductor (*i.e.*, separated out from reliability statistics for overhead lines without covered conductor) to compare with the reliability of underground segments.

VII. PG&E'S ANALYSIS DOES NOT ACKNOWLEDGE THE CONSIDERABLE RISK REDUCTION BENEFITS FROM IMPROVING COMPLIANCE WITH REGULATORY REQUIREMENTS

The risk reduction analysis that PG&E uses for its WMP suffers from the same serious problem that plagued its analysis in the CPUC GRC proceeding: PG&E does not acknowledge that it will achieve significant and highly cost-effective risk reduction simply by improving its compliance with regulations, particularly for vegetation management and equipment maintenance. The obvious reasons for this omission are twofold: (1) PG&E would prefer to avoid admitting how much its compliance failures have contributed to the catastrophic wildfires it has caused in the past several years; and (2) improvements that would prevent future compliance failures – such as better quality assurance/quality control and improved management -- are not financially lucrative to PG&E because they do not add to the investment base (aka rate base) on which PG&E's profits are collected.

PG&E's risk analysis in the WMP is based on the same risk driver analysis it used for the GRC, which is captured in the "bow tie" diagrams on page 136 of the WMP. Properly recognizing the drivers of PG&E's wildfire risk (left side of the bow tie) is obviously critical. Once we know what has caused PG&E's past catastrophic wildfires, we have a better understanding of the problems that need to be fixed and which mitigations will be most effective.

TURN's testimony and briefs in the GRC showed that PG&E's bow tie omits the most significant driver of its catastrophic wildfires during the 2015-2020 time period PG&E used for its driver analysis. All of the nine major wildfires PG&E that PG&E caused during that period -- including the deadly 2018 Camp Fire for which PG&E pled guilty to 84 counts of involuntary manslaughter for failing to replace a clearly worn C-hook -- were found by the investigating government agency to be the result of a violation of one or more regulatory requirements. Yet PG&E's analysis does not attribute any of these wildfires, including the Camp Fire, to compliance or operational failure.[74] This is so even though, under cross examination, PG&E's witness in the CPUC GRC proceeding, Andy Abranches (the same senior executive who led PG&E's presentation at the April 27, 2023 OEIS workshop) admitted that the Camp Fire should have been counted as resulting from operational failure.[75] In the GRC, TURN's wildfire risk expert, Mr. Borden, calculated that, when PG&E's modeling error is corrected, ***99.7%*** of PG&E's wildfire risk should be attributed to the compliance/operational failure driver.[76] As Mr. Borden explained, this result is due to the overwhelming impact that the most devasting wildfires have on overall wildfire risk, even though they are relatively infrequent.[77]

Once the important role that compliance/operational failure has played in shaping PG&E's wildfire risk is recognized, it becomes clear that improving PG&E's compliance with its operational requirements becomes the most potent and cost-effective wildfire risk reduction strategy, as Mr. Borden explained:

> Accurately recognizing the role of operational failure as the key driver of PG&E's wildfire risk has a significant effect on the risk modeling results and RSE of every wildfire mitigation proposed by PG&E, significantly decreasing the cost-effectiveness values for mitigations like overhead and underground system hardening. In turn, properly recognizing the outsize contribution of the operational failure driver to PG&E's wildfire risk means that any program to

[74] Appendix B, Borden GRC Testimony for TURN, pp. 13-14.

[75] TURN's Opening Brief in the GRC, p. 361.

[76] Appendix B, Borden GRC Testimony for TURN, p. 15.

[77] *Id.*

> improve compliance programs, such as enhanced Quality Assurance and Quality Control (QA/QC), would have significantly higher cost-effectiveness values than under PG&E's current modeling, particularly as these appear to be necessary for PG&E to implement its control [regulatory compliance] programs with a high degree of competence.[78]

In a related, but separate analysis in the GRC using data PG&E included in its RSE calculation workpapers, Mr. Borden further showed that ***98%*** of PG&E's projected risk reduction will come from regulatory compliance programs – vegetation management (routine and tree mortality), equipment maintenance and replacement, and pole replacement.[79] These compliance programs are mandated for the obvious reason that they are recognized to be the most important means of ensuring safe utility service. It only makes sense that the first line of defense against wildfires should be sound execution of this compliance work, particularly when compliance has been a demonstrated problem with PG&E for many years.

Energy Safety should not be misled by PG&E's WMP claim that the CPUC has found PG&E in compliance with its S-MAP Settlement Agreement requirements for quantitative risk and RSE analysis.[80] The decision cited by PG&E made clear that the CPUC had reached *no conclusions* about whether PG&E's analysis complied with those requirements:

> During the comment process, SPD and other parties identified several deficiencies in PG&E's RAMP Report as well as areas that can be improved. Two topics that were repeatedly pointed out are the need for increased granularity and improvements in the MAVF calculation. PG&E has an opportunity to incorporate party comments in its GRC filing and address any deficiencies and make further improvements to its RAMP showing. *However, the RAMP process does not afford the Commission the time to address these changes in this proceeding*.[81]

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[78] *Id.*

[79] *Id.*, pp. 10-13.

[80] PG&E 2023-2025 WMP (R1), p. 242, fn. 98.

[81] CPUC Decision 22-03-008, p. 10 (emphasis added).

Instead, the CPUC directed parties to raise issues regarding deficiencies in PG&E's risk analysis in its GRC proceeding,[82] which is exactly what TURN has done via the analysis described above.

In sum, the risk analysis PG&E used for both its GRC and this WMP is highly deficient in failing to recognize that significant risk reduction will be obtained if PG&E lives up to its promise to improve its compliance with basic regulatory requirements for wildfire safety. Either of both of the CPUC and Energy Safety should recognize this serious shortcoming and recognize that PG&E has overstated the benefit from other risk mitigation programs compared to sound execution of compliance work. Further, Energy Safety should direct PG&E to re-calculate its risk reduction figures to recognize the significant risk reduction that will come from avoiding compliance failures in the future.

VIII. TURN'S RECOMMENDATIONS

A. To Gain Approval, PG&E Should Be Required to Change Its System Hardening Decision-Making Process and Re-Scope Its System Hardening Programs

The foregoing has shown that, notwithstanding Energy Safety's warnings in its decision on PG&E's WMP last year, PG&E persists in maintaining a default to undergrounding decision-making process, in which undergrounding is the preferred system hardening alternative unless it is ultimately proven infeasible for a particular location. As discussed in Section III.D above, Energy Safety was well-informed in concluding that PG&E should consider the multitude of location-specific factors, as well as the RSEs of the competing system hardening alternatives, at the outset of its process to choose a system hardening mitigation.

This is a critical time in California's efforts to prevent utility-caused wildfires. We cannot afford to squander our limited resources on a plan that unduly favors undergrounding

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[82] *Id.*, p. 11.

even though in many, if not most, locations undergrounding is likely to be less cost-effective and slower to deploy than overhead hardening. As shown in Section IV.D, TURN's covered conductor proposal for 2023-2025 in the CPUC GRC will provide more risk reduction than PG&E's underground proposal for that period.

Thus, Energy Safety should direct PG&E to fix the serious problems in its WMP now, before it can be approved. PG&E was on notice that it needed to correct its undue emphasis on undergrounding and chose not to do so. Specifically, Energy Safety should require PG&E to make the following changes in order to gain approval:

- In choosing among system hardening alternatives – which should include undergrounding, covered conductor and covered conductor coupled with other ignition limiting technologies -- PG&E must make a location-specific determination of the best alternative for that location, based on the specific risk factors present in the location.
- The location-specific selection among system hardening alternatives must expressly consider the extent to which the execution and schedule risks for undergrounding described in PG&E's 2021 WMP are present in the location and recognize the benefits of deploying an alternative that will achieve risk reduction sooner than other alternatives.
- The location-specific selection among alternatives must include a comparison of the location-specific cost-effectiveness of each alternative, based on the Risk Spend Efficiency (RSE) measure. If the utility wishes to select an alternative that does not have the highest RSE, it must show special and compelling circumstances that justify deployment of a lower RSE alternative in that location.
- The RSE calculations must use a location-specific conversion factor for the number of underground miles necessary to replace one mile of overhead conductor, not an assumed generalized conversion factor, such as PG&E's current 1.25 figure that is not based on actual results or location-specific information.

- PG&E must present a revised system hardening plan for 2023-2025 that it has developed using a process that complies with the preceding requirements. The revised plan should include workpapers showing how PG&E determined its target mileage consistent with the above requirements for each of the system hardening alternatives it proposes in its revised plan.

In addition, the showing in Section IV above that PG&E's current system hardening plan does not address the areas of highest risk in PG&E's system is another serious problem with PG&E's WMP. Left to its current plan, some of the highest risk locations in PG&E's service territory may not be addressed for several years. To correct this problem, PG&E's revised plan for 2023-2025 should also do the following:

- Because risk is highly concentrated in relatively few overhead circuit miles, PG&E must show that 80% of the proposed underground miles in its revised plan will address the top 20% of the risk in PG&E's HFTD (not the top 20% of circuit segments).
- This showing must be based on PG&E's most current wildfire risk models.
- PG&E's revised WMP must include workpapers showing that it has complied with these requirements.

B. PG&E Should Be Directed to Remedy Additional Deficiencies in Its WMP

The following deficiencies do not necessarily warrant rejection of PG&E's current WMP, but should be corrected in PG&E's next WMP submission:

- PG&E should re-calculate its risk reduction figures to recognize the significant risk reduction that will result from avoiding compliance failures of the type that caused the major wildfires ignited by PG&E facilities in 2015-2020. (See Section VII.)

- In order to develop realistic data-based underground to overhead conversion factors, PG&E should be required to maintain a database of actual results from PG&E's undergrounding projects that identifies, for each project, the underground miles deployed and the miles of overhead conductor replaced. In addition, as applicable, the database should describe the reasons that undergrounding needed to deviate from the direct overhead path. (See Section VI.A.)
- To have data to compare the reliability of undergrounded facilities to overhead hardened facilities, PG&E should be required to keep separate reliability measures (e.g., SAIFI and MAIFI) for overhead circuit segments with covered conductor. (See Section VI.C.)
- PG&E should describe its policy for undergrounding of secondary conductor and services and discuss its expectations for whether poles will be removed in underground locations. The discussion should address the effect that remaining overhead wires and poles in locations with undergrounding have on the estimated risk reduction from undergrounding generally, and specifically the risk associated with ingress and egress in locations where fire is present, whether or not ignited by utility facilities. (See Section VI.B).

IX. CONCLUSION

For the reasons set forth above, TURN urges Energy Safety to adopt the recommendations in these Comments.

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Respectfully submitted,

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