February 6, 2025 **Via Electronic Filing**

Caroline Thomas Jacobs, Director
Office of Energy Infrastructure Safety
California Natural Resources Agency
Sacramento, CA 95814
ElectricalUndergroundingPlans@energysafety.ca.gov

Subject: **Public Advocates Office's Reply Comments on the Second Revised Draft of Guidelines for the 10-Year Electrical Undergrounding Plans (Revised EUP)**

Docket: **2023-UPs**

Dear Director Thomas Jacobs,

The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) respectfully submits the following reply comments on the Office of Energy Infrastructure Safety's *Second Revised Draft 10-Year Electrical Undergrounding Plan Guidelines*. Please contact Nat Skinner (Nathaniel.Skinner@cpuc.ca.gov) or Henry Burton (Henry.Burton@cpuc.ca.gov) with any questions relating to these comments.

We respectfully urge the Office of Energy Infrastructure Safety to adopt the recommendations discussed herein.

Sincerely,

/s/ ***Angela Wuerth***

Angela Wuerth
Attorney
Public Advocates Office
California Public Utilities Commission

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I. INTRODUCTION

The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) submits these reply comments on the Office of Energy Infrastructure Safety's (Energy Safety) *Second Revised Draft 10-Year Electrical Undergrounding Plan Guidelines* (Second Revised Draft), issued January 6, 2025.[1] The Second Revised Draft provides guidelines for electric utilities to submit electrical undergrounding plans (EUPs) pursuant to Senate Bill (SB) 884.[2] SB 884 authorizes large electric utilities[3] (utilities) to submit ten-year plans to underground distribution lines[4] and tasks Energy Safety and the California Public Utilities Commission to determine whether to approve, conditionally approve, or deny a utility's plan.[5]

II. ISSUES

A. Energy Safety should be aware of potential issues involving PG&E's non-linear risk scaling methodology.

In comments on the Risk Attitude Function and Risk Scaling/Weighting, PG&E seeks to apply non-linear risk scaling to Key Decision-Making Metrics (KDMMs).[6] PG&E contends that the KDMMs should incorporate risk attitude and risk scaling or weighting so as to align with the methodology that PG&E uses in the Risk Assessment Mitigation Phase and the General Rate Case. However, the non-linear risk scaling seen in the most recent Risk Assessment Mitigation Phase application has several problems.

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[1] Energy Safety, *Second Revised Draft 10-Year Electrical Undergrounding Plan Guidelines* (Second Revised Draft), January 6, 2025, docket 2023-UPs.

[2] McGuire, Stats. 2022, Chap. 819. SB 884 is codified at Public Utilities Code Section 8388.5.

[3] Per statute, a large electrical corporation refers to an electrical corporation with at least 250,000 customer accounts within the state. (Pub. Utilities Code §§ 3280, 8385.) Public Utilities Code Section 8388.5(b) limits participation in the electric utility distribution undergrounding program to these entities. These comments use the term "utilities" to refer to large electrical corporations.

[4] Pub. Utilities Code § 8388.5(c).

[5] Pub. Utilities Code §§ 8388.5(d), (e) and (f).

[6] PG&E, *Pacific Gas and Electric Company's Comments on the Second Revised Draft 10- Year Electrical Undergrounding Plan Guidelines* (PG&E Comments on Second Revised Draft) at 3-4, January 27, 2025, docket 2023-UPs.

PG&E states that non-linear risk scaling will allow it to select locations for undergrounding that will reduce the greatest amount of wildfire risk.[7] However, as Cal Advocates has previously noted, PG&E's non-linear risk scaling values are predominately affected by reliability rather than safety risk.[8] In addition, The Utility Reform Network (TURN) provided a thorough critique of PG&E's non-linear risk scaling during the Risk Assessment Mitigation Phase proceeding. The following passage describes the key problems:

> PG&E's scaling function implies preferences that most people are unlikely to share, namely that not every dollar and not every life is valued equally. For example, PG&E's function values a reduction of 11 fatalities to ten fatalities at least ten times more than a reduction of one fatality to zero. While everyone wants to avoid catastrophic events, PG&E has not made the case for why ratepayers should be expected to pay ten times as much to avoid one fatality if that fatality is part of an 11-fatality event, as opposed to a single fatality event.[9]

In summary, PG&E's non-linear scaling methodology is flawed. Energy Safety should consider previous comments that explain its problems (included in Attachments 1 and 2 here) before deciding whether non-linear risk scaling is appropriate for KDMMs.

B. PG&E's opening comments do not comply with Energy Safety's requirements.

Energy Safety directs stakeholders to comment only on redlined revisions to the EUP Guidelines.[10] Pacific Gas and Electric Company (PG&E) includes in comments topics that do not pertain to redlined revisions. PG&E provides no evidence that its comments are relevant to revised aspects of the Second Revised Draft. Therefore, Energy Safety should disregard PG&E's comments on the following topics:

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[7] PG&E Comments on Second Revised Draft at 3.

[8] *The Public Advocates Office Corrected Informal Comments on The Application of Pacific Gas and Electric Company to Submit its 2024 Risk Assessment and Mitigation Phase (RAMP) Report* at 8-9, October 15, 2024, docket A.24-05-008

[9] TURN, *Informal comments of TURN on PG&E's RAMP Report* at 9, October 9, 2024, docket A.24-05-008

[10] Energy Safety, *Second Revised Draft EUP Guidelines Cover Letter* at 1, January 6, 2025: "Stakeholders are invited to provide written comments only on the redlined revisions in Energy Safety's Second Revised Draft EUP Guidelines and the sample data submission templates."

1) **Risk Targets and Metrics**: PG&E states that it will be extremely difficult to manage the multitude of metrics, objectives, targets, thresholds, and standards.[11]

2) **Lack of Compliance Requirements**: PG&E states that Energy Safety's timeline, which entails releasing compliance guidelines after the guidelines for EUP submissions are finalized, will make it challenging for utilities to submit an EUP.[12]

3) **Mapping Secondary Lines and Service**: PG&E reiterates that it would have trouble submitting secondary lines and service Geographic Information System information before EUP submission.[13] PG&E's comment does not address the tabular, JavaScript Object Notation, or Geographic Information System data templates but the actual EUP data requirements, which is contrary to Energy Safety's instructions in the cover letter.

4) **Project Level Threshold Changes**: PG&E does not support making the project-level thresholds static for the duration of the EUP.[14]

If Energy Safety considers PG&E's extraneous comments, it would bias the comment process against stakeholders who followed the instructions. Cal Advocates followed the instructions and limited its opening comments to topics related to the redlined revisions. If Cal Advocates and other stakeholders had ignored the instructions, as PG&E has done, they could have commented on a variety of additional issues in their opening comments.

C. PG&E should submit its EUP after Energy Safety finalizes compliance guidelines.

PG&E asserts that it will be challenging to "submit an EUP without a clear understanding of the implications of the objectives, thresholds, standards, and key-decision making metrics outlined in the plan."[15] To resolve this concern, PG&E can simply wait to submit its EUP until Energy Safety has developed and finalized compliance guidelines. When Energy Safety releases

[11] PG&E Comments on Second Revised Draft at 4.

[12] PG&E Comments on Second Revised Draft at 4.

[13] PG&E Comments on Second Revised Draft at 6.

[14] PG&E Comments on Second Revised Draft at 6.

[15] PG&E Comments on Second Revised Draft at 4.

draft compliance requirements, Energy Safety should also host at least one workshop for stakeholders to provide input and seek clarification.

III. CONCLUSION

Cal Advocates respectfully requests that Energy Safety adopt the recommendations described herein.

Respectfully submitted,

/s/ ***Angela Wuerth***

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February 6, 2025

ATTACHMENT 1

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U 39 M) to Submit Its 2024 Risk Assessment and Mitigation Phase Report	Application 24-05-008

THE PUBLIC ADVOCATES OFFICE CORRECTED INFORMAL COMMENTS ON THE APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY (U39M) TO SUBMIT ITS 2024 RISK ASSESSMENT AND MITIGATION PHASE (RAMP) REPORT

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October 15, 2024

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THE PUBLIC ADVOCATES OFFICE CORRECTED INFORMAL COMMENTS ON THE APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY (U39M) TO SUBMIT ITS 2024 RISK ASSESSMENT AND MITIGATION PHASE (RAMP) REPORT

I. INTRODUCTION

The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) hereby submits these informal comments on Pacific Gas and Electric Company's (PG&E) Application (A.) 24-05-008 regarding its 2024 Risk Assessment and Mitigation Phase (RAMP) Report ("PG&E's RAMP Report").[1]

Cal Advocates identifies significant concerns and shortcomings with PG&E's RAMP Report that are detailed in Section II of these comments. Cal Advocates recommends that SPD require PG&E to supplement its RAMP Report and that SPD consider Cal Advocates' concerns in its report on PG&E's RAMP Report, as described in Section II.

[1] A.24-05-008, *Application of Pacific Gas and Electric Company to Submit its 2024 Risk Assessment and Mitigation Phase Report*, May 15, 2024.

II. COMMENTS

A. PG&E failed to provide a meaningful comparison of covered conductor against undergrounding as an alternative wildfire mitigation in its RAMP.

Two primary industry methods to mitigate wildfire risk are to (1) replace overhead distribution lines with insulated covered conductors or (2) replace overhead distribution lines with underground conductors.

PG&E plans 608 miles of work units for 2024-2026 in its "System Hardening [Overhead]" (covered conductor) program and 950 miles of work units for 2024-2026 in its "System Hardening [Undergrounding]" program.[2]

PG&E's proposed undergrounding program ("M022")[3] would convert overhead distribution lines and equipment to underground lines. Instead of proposing an alternative to the M022 undergrounding program that compares the costs and benefits of covered conductor to undergrounding, PG&E compared M022 undergrounding to these two primary alternatives:

1. A second alternative undergrounding mitigation proposal that only undergrounds primary conductors, and not secondary conductors and service lines ("A001").[4, 5] PG&E has stated service lines are not included in its undergrounding program.[6]
2. An alternative mitigation proposal that substitutes Grid Monitoring for undergrounding ("A002").[7, 8]

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[2] PG&E's RAMP Report at PG&E-4 1-71.

[3] DOVHD-M022, PCEEE-M003, WLDFR-M022 (System Hardening [Underground]).

[4] DOVHD-A001, WLDFR-A001, PCEEE-A003 (System Hardening [Underground] (Alternative Workplan)).

[5] PG&E's RAMP Report at PG&E-4 1-98 and 4-45.

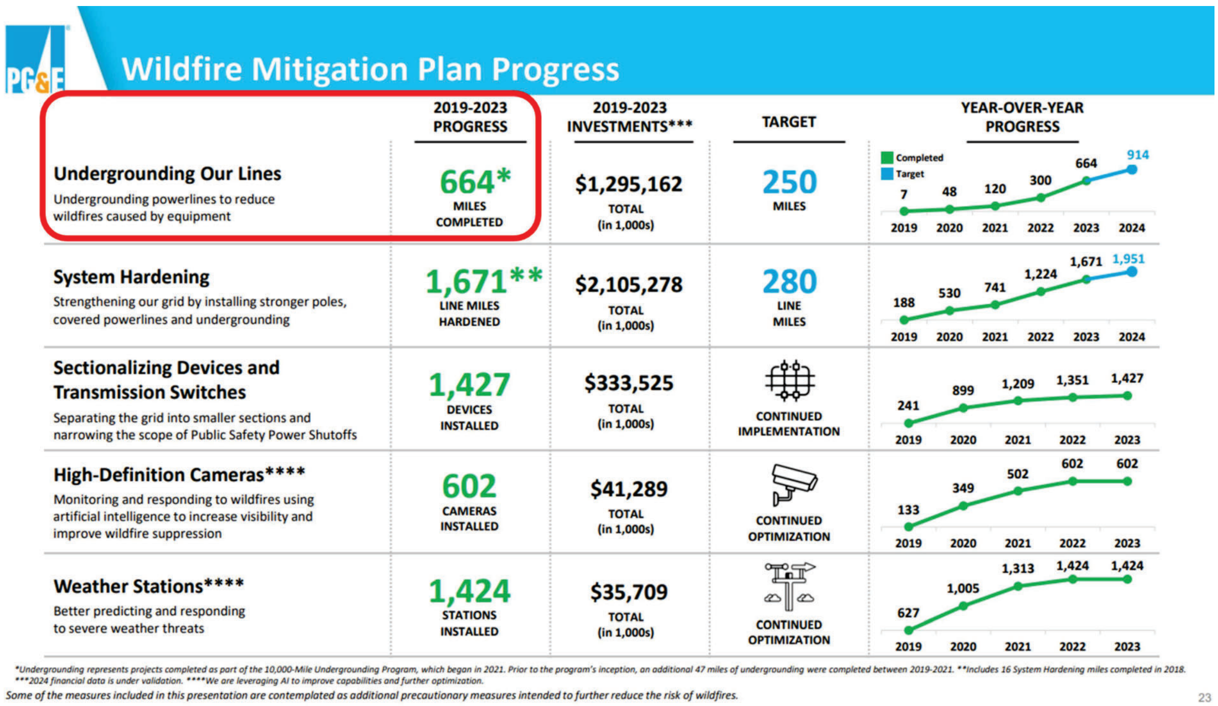
[6] PG&E "Undergrounding Fact Sheet", available at https://www.pge.com/assets/pge/docs/outages-and-safety/safety/undergrounding-fact-sheet.pdf

[7] DOVHD-A002, WLDFR-A002 (Grid Monitoring).

[8] PG&E's RAMP Report at PG&E-4 1-100 and 4-48.

PG&E's August 28, 2024 presentation to Commissioners included the following slide, which depicts PG&E's progress in undergrounding 664 miles of line since 2019.[9]

Figure 1: PG&E Wildfire Mitigation Plan Progress[10]



For comparison, Southern California Edison Company (SCE), presented slides in its August 29, 2024 presentation,[11] which depict SCE's greater progress in using covered conductor to harden 5,600 miles of conductor since 2018. SCE asserted that is has

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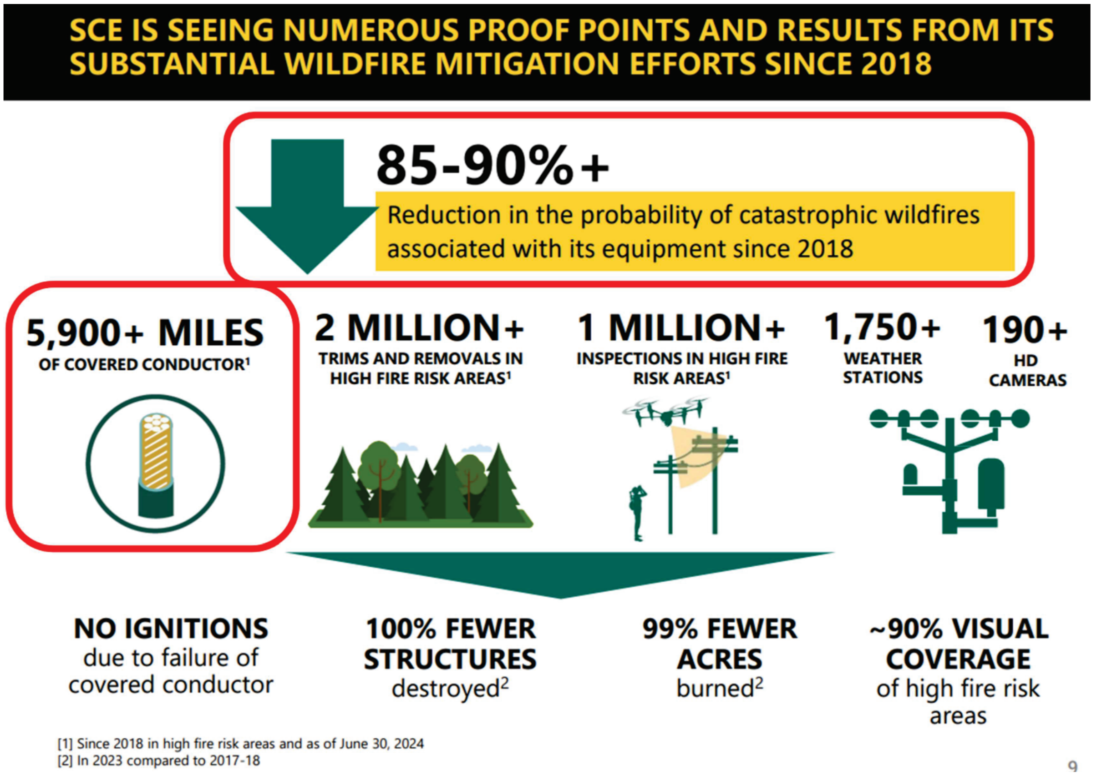
[9] PG&E Annual Public Safety Briefing, August 28, 2024, slide 23. Access at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/meeting-documents/pge_cpuc-safety-briefing_082824.pdf

[10] PG&E Annual Public Safety Briefing, August 28, 2024, slide 23. [Red circle highlight added] Access at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/meeting-documents/pge_cpuc-safety-briefing_082824.pdf

[11] SCE CPUC/Energy Safety Public Meeting on Safety, August 29, 2024, slide 9. Access at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/meeting-documents/sce-cpuc-oeis-bod-safety-public-meeting_082924.pdf

reduced the probability of catastrophic wildfires from its equipment by 85-90%+ since 2018.[12]

Figure 2: SCE Wildfire Mitigation Efforts Since 2018[13]



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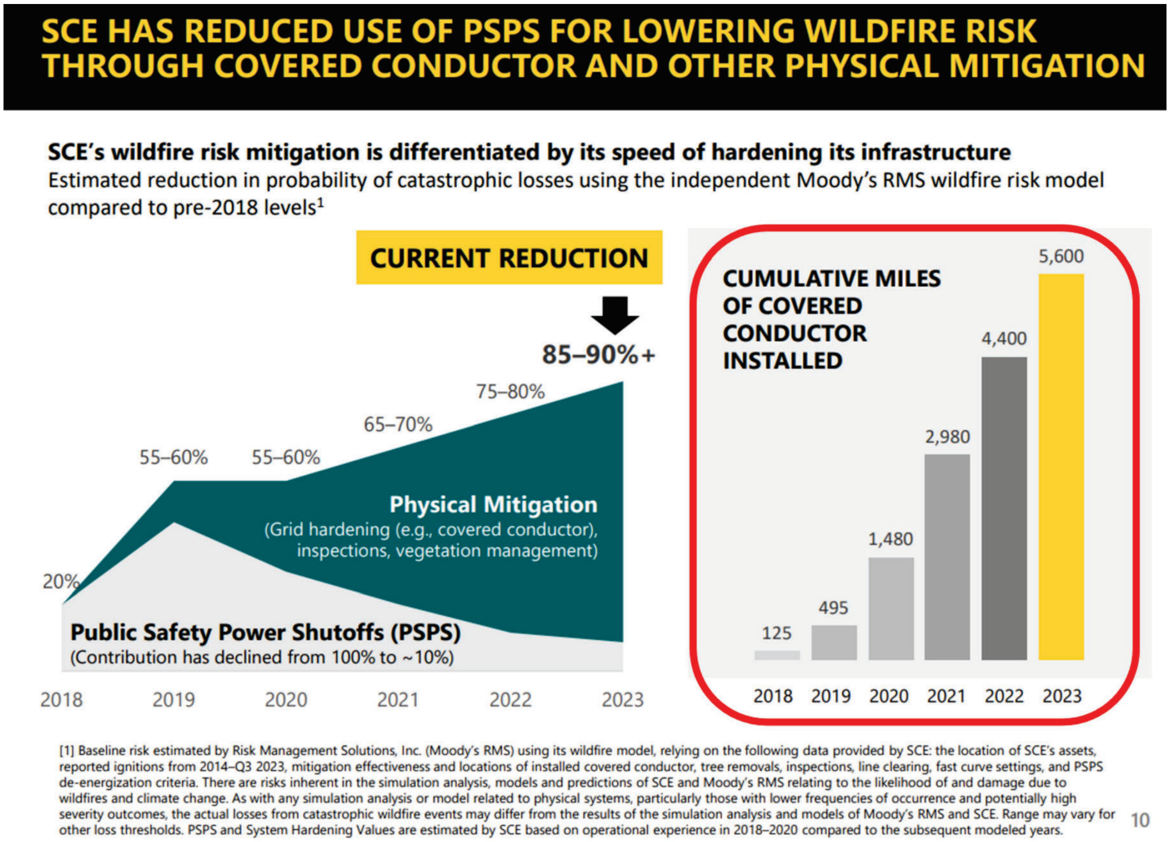
[12] SCE CPUC/Energy Safety Public Meeting on Safety, August 29, 2024, slide 9. Access at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/meeting-documents/sce-cpuc-oeis-bod-safety-public-meeting_082924.pdf

[13] SCE CPUC/Energy Safety Public Meeting on Safety, August 29, 2024, slide 9. [Red circle highlights added] Access at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/meeting-documents/sce-cpuc-oeis-bod-safety-public-meeting_082924.pdf

Figure 3: SCE Reduction in PSPS Through Covered Conductor[14]



Decision (D.)14-12-025 directs utilities to provide two alternative risk mitigations for each RAMP risk proposal.[15] PG&E, in choosing the alternatives it presented to the Commission for its undergrounding program, failed to provide a detailed analysis of the

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[14] SCE CPUC/Energy Safety Public Meeting on Safety, August 29, 2024, slide 10. [Red circle highlight added] Access at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/meeting-documents/sce-cpuc-oeis-bod-safety-public-meeting_082924.pdf

[15] D.14-12-025, *Decision Incorporating a Risk-Based Decision-Making Framework into the Rate Case Plan and Modifying Appendix A of Decision 07-07-004*, December 9, 2014, at 32 and 37-38. ("The Refined Straw Proposal recommends that the utility's RAMP report contain at least the following…For comparison purposes, at least two other alternative mitigation plans the utility considered and an explanation of why the utility views these plans as inferior to the proposal plan… We adopt the following RAMP process...The utility's RAMP submission shall contain the information that the Refined Straw Proposal has described, as summarized above.")

costs and benefits of covered conductor as one of its two alternatives to its M022 undergrounding program proposal.

PG&E stated that general factors that may result in undergrounding as the preferred mitigation include tree strike potential, proximity to a major ingress or egress route, localized fuel types, and past fire history.[16] PG&E also stated that undergrounding of secondary and service lines provides additional benefits that are not as easily quantified, such as improvements to Public Safety Power Shutoffs (PSPS), end of line reliability, and customer satisfaction.[17]

SCE, however, has also seen a significant reduction in the use of PSPS from its covered conductor program, as depicted in Figure 3 above.

Furthermore, SCE states:

> SCE's wildfire risk mitigation is differentiated by its speed of hardening its infrastructure.[18]

Cal Advocates recommends that SPD and the Commission require PG&E to supplement its RAMP submission, and all future RAMPs and General Rate Case (GRC) applications, with a detailed comparison of the costs and benefits of covered conductor as an alternative to all undergrounding proposals.

B. PG&E failed to provide an adequate justification for its decision to select a $6.5 billion undergrounding wildfire mitigation program over a $1.7 billion covered conductor alternative.

In response to a data request from Cal Advocates, PG&E disclosed that a covered conductor program alternative to its M022 undergrounding would cost close to $5 billion less than its undergrounding proposal.[19] PG&E also disclosed that the cost-benefits of a covered conductor program alternative are more than twice that of its undergrounding

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[16] PG&E's RAMP Report at PG&E-4 1-58.

[17] PG&E's RAMP Report at PG&E-4 1-98 and 4-46.

[18] SCE CPUC/Energy Safety Public Meeting on Safety, August 29, 2024, slide 10. Access at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/meeting-documents/sce-cpuc-oeis-bod-safety-public-meeting_082924.pdf

[19] PG&E's Data Request Response *RAMP-2024_DR_CalAdvocates_004-Q002Atch01*.

proposal.[20] In other words, a cost-benefits analysis overwhelmingly favored covered conductor as a wildfire mitigation over costly and slow undergrounding.

When asked to justify its decision to select undergrounding over covered conductor, PG&E responded that:

> PG&E chose undergrounding as our preferred mitigation because it provides the most wildfire risk reduction, significantly improves customer reliability, especially surrounding [Enhanced Powerline Safety Settings (EPSS)] and PSPS outages, and provides an electric distribution system which is more resilient to the adverse impacts of climate change with deep uncertainty. Undergrounding also substantially addresses factors such as ingress/egress and tree fall-in risk, which are not mitigated by an overhead alternative. Additional considerations influencing the decision to pursue the most risk reducing mitigation include Risk Tolerance, modeling limitations, and other uncertainties affecting the analysis.
>
> For more information on PG&E's undergrounding mitigation please see PG&E's 2023-2025 WMP: 2023-2025 Wildfire Mitigation Plan R6 (pge.com), sections 8.1.2.1 and 8.1.2.2.[21]

PG&E's justification lacks evidentiary support and does not address why PG&E selected undergrounding as opposed to covered conductor, which is a less costly and has a better cost-benefit ratio (CBR). PG&E's RAMP is the first RAMP to incorporate the Commission's new Cost-Benefit Approach (CBA) for selection of risk mitigation programs. While a utility is not required to select a mitigation based solely on a cost benefits analysis,[22] PG&E's unsupported narrative is not sufficient.

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[20] See PG&E's Data Request Response *RAMP-2024_DR_CalAdvocates_004-Q002Atch01*.

[21] See PG&E's Data Request Response *RAMP-2024_DR_CalAdvocates_004-Q001*.

[22] D.22-12-027, Appendix A at Row 26: "In the RAMP and GRC, the utility will clearly and transparently explain its rationale for selecting Mitigations for each risk and for its selection of its overall portfolio of Mitigations. The utility is not bound to select its Mitigation strategy based solely on the Cost-Benefit Ratios produced by the Cost-Benefit Approach. Mitigation selection can be influenced by other factors including, but not limited to, funding, labor resources, technology, planning and construction lead time, compliance requirements, Risk Tolerance thresholds, operational and execution considerations, and modeling limitations and/or uncertainties affecting the analysis. In the GRC, the utility will explain whether and how any such factors affected the utility's Mitigation selections."

C. PG&E failed to evaluate the risk from delayed mitigation of wildfire risk due to the necessary extended time needed to implement undergrounding as an urgent wildfire mitigation.

PG&E needs to consider the unmitigated and ongoing wildfire risk that continues during the lengthy time needed to implement undergrounding. A typical overhead hardening project can advance from concept to execution, documentation, and close out in 13-16 months, whereas a typical underground project can often take 18-45 months depending on the various risks presented.[23] Undergrounding can take 2-29 months longer to implement compared to an overhead hardening project, which means wildfire will still pose as a risk to the public while the undergrounding project is underway. PG&E needs to evaluate the risk from the extended time needed to implement undergrounding compared to overhead hardening before selecting undergrounding as a primary mitigation measure.

D. PG&E should calculate the cost-benefit ratios of its undergrounding program as both a safety mitigation and a reliability mitigation.

PG&E assigns a risk value of $22.0 billion to "wildfire risk with PSPS and EPSS" in 2023.[24] Operational mitigations such as PSPS and EPSS are likely to reduce that risk by approximately $19.4,[25] but create their own reliability risks, totaling approximately $6.0 billion.[26]

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[23] A.21-06-021, *PG&E's 2023 GRC, Exhibit (PG&E-4), Workpapers Supporting Chapters 2-13*, *Volume 1 of 2*, February 25, 2022, at WP 4-90.

[24] PG&E 2024 RAMP Workshop #3, June 18, 2024, slide 33.

[25] Per PG&E 2024 RAMP Workshop #3, June 18, 2024, slide 33, PSPS and EPSS provide a $17.3 billion risk reduction in 2027, down from an expected total wildfire risk of $19.6 billion. This is approximately an 88 percent reduction. Applying this value to the 2023 wildfire risk of $22 billion results in a risk reduction of $19.4 billion, or a residual wildfire risk of $2.6 billion.

[26] Per PG&E 2024 RAMP Workshop #3, June 18, 2024, slide 33, PSPS and EPSS create new reliability risk totaling $5.3 billion, compared to a $17.3 billion risk reduction in 2027 due to the same mitigations. This is about a 30 percent risk add. Applying this value to the predicted $19.6 billion risk reduction in 2023 suggests that, in 2023, PSPS and EPSS will introduce approximately $6 billion of reliability risk in 2023.

These numbers suggest that PG&E's *current* risk for "wildfire risk with PSPS and EPSS" is closer to $8.6 billion, rather than the $22 billion shown.[27] Further, more than two thirds of this $8.6 billion is due to *reliability*, rather than safety risk.

Grid resiliency measures such as undergrounding will further mitigate safety risk. However, given that the majority of present-day risk is actually related to reliability, grid resilience will primarily mitigate reliability risk by hardening miles and removing them from the scope of PSPS and EPSS.

PG&E should assess the cost-benefit ratios of grid resiliency efforts such as undergrounding as primarily being a *reliability* mitigation. This will likely result in lower expected benefits because the present reliability risk is substantially lower than the present wildfire risk before PSPS and EPSS. Due to PG&E's non-linear risk scaling function, this methodology would likely produce substantially lower CBRs for grid resilience measures.

The Commission should require utilities to evaluate undergrounding both by its perceived safety benefits (permanent wildfire risk reduction) as well as by the practical effects under PG&E's modern operations framework (permanent reliability benefits).

E. PG&E should include an analysis and forecast of ratepayer bill impacts when comparing alternative risk mitigation programs.

PG&E should consider ratepayer bill impacts when evaluating alternative risk program mitigations and when justifying selection of a particular mitigation. However, its RAMP Report provides no such analysis.[28, 29] Ratepayer impact is critical information for the Commission to consider to ensure that rates are just and reasonable.[30] Cal Advocates recommends that SPD require PG&E to supplement its RAMP Report with an analysis and forecast of ratepayer impacts when comparing and selective alternative

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[27] $22 billion - $19.4 billion + $6.0 billion = $8.6 billion.

[28] See PG&E's RAMP Report.

[29] See PG&E's Data Request Response *RAMP-2024_DR_CalAdvocates_002-Q003*.

[30] Public Utilities Code section 451.

mitigation programs. For example, PG&E should estimate the costs of hardening the other approximately 15,000 miles of its overhead distribution system in the high threat fire district, since PG&E's focus on undergrounding only addresses approximately 8,000 miles of overhead conductor hardening.

F. PG&E should evaluate the risks from incomplete safety, reliability, and maintenance work.

PG&E's risk modeling does not explicitly connect inspections completed (or not completed) and the downstream effects on enabled risk-reducing work. Consequently, PG&E's 2024 RAMP risk modelling does not directly estimate changes in safety risk attributable to the number of inspections completed.[31]

Investigations of utility infrastructure events have identified incomplete safety and reliability work as a root cause of costly catastrophic events, such as the Zogg Fire, the Camp Fire, and the Sulphur Fire.[32, 33, 34] PG&E continues to fall behind in completing critical safety and reliability work as identified in PG&E's 2023 Risk Spending and Accountability Report (RSAR).[35]

For example, in the 2020-22 GRC cycle PG&E did not complete 15% of authorized work for its Intrusive Pole Inspections (MAT Code GAA).[36] In 2023 (the start of the 2023-26 GRC cycle), PG&E's percentage of incomplete authorized Intrusive Pole

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[31] PG&E's Supplemental Data Request Response in *RAMP-2024_DR_CalAdvocates_002-Q007* and *RAMP-2024_DR_CalAdvocates_002-Q009*.

[32] Kasler, Dale. *PG&E equipment caused deadly Zogg Fire in Shasta County. Cal Fire says tree hit power line,* March 22, 2021. The Sacramento Bee. Access at: https://www.sacbee.com/news/california/fires/article250134899.html

[33] I.19-06-015, *Motion of the Safety and Enforcement Division to Expand the Proceeding Scope to Include the 2018 Camp Fire, Appendix A, SED Incident Investigation Report for 2018 Camp Fire with Attachments,* November 26, 2019, at 16. Access at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M320/K909/320909806.PDF

[34] Van Derbeken, Jaxon. *PG&E Admits it Broke 2020 Promise to Fully Inspect 50K Poles in High Fire Risk Zones,* May 14, 2021. NBC Bay Area. Access at: https://www.nbcbayarea.com/investigations/pge-admits-itbroke-2020-promise-to-fully-inspect-58000-poles-in-high-fire-risk-zones/2545708/

[35] See *Comments of the Public Advocates Office on Pacific Gas and Electric Company's 2023 Risk Spending Accountability Report* (RSAR Comments), August 21, 2024.

[36] RSAR Comments at 6.

Inspections rose to 55%.[37] Pole failure is a contributor to PG&E's CPUC-reportable ignitions, with 28 such ignitions stemming from pole failure in the last four years.[38]

The deficits in PG&E's 2023 RSAR highlights the need for PG&E to evaluate the risks of incomplete safety, reliability, and maintenance performance to mitigate risks to the public. Completing critical safety and reliability work timely can prevent or reduce future catastrophic events.

G. PG&E should not exclude its water conveyance system as a top RAMP risk.

PG&E's RAMP Application includes some risks and excludes others that PG&E deems as less significant. Cal Advocates is concerned that significant vulnerabilities have therefore been excluded and not addressed. For example, PG&E did not explain why it excluded PG&E's water conveyance system as a component RAMP Risk.[39] News articles have reported fatalities associated with water conveyance facilities.[40] In November 2010, an 18-month-old fell to his death while walking near a PG&E canal with his stepmother. The Gold Country Media article written about the incident stated that the PG&E canal "is running swift and cold at this time of year, with little chance to get out for victims who fall in." The same article states that the 18-month-old is "the sixth [death] in an Auburn-area canal since January 2009. The bodies of the five canal victims- all adult men- were found in the Wise Canal or Wise Forebay."

Cal Advocates recommends that SPD require PG&E to supplement its RAMP Report to justify why its water conveyance system is not a significant risk to employees and the public.

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[37] RSAR Comments at 6.

[38] RSAR Comments at 13-14.

[39] PG&E's RAMP Report, Table 1-1 at Page 1-6 lists water conveyance facilities as an "Out of Scope" risk.

[40] See, e.g., Gold Country Media, *Toddler dies after falling into Placer County Canal*, November 24, 2010, access at: https://goldcountrymedia.com/news/37206/toddler-dies-after-falling-into-placer-county-canal/

III. CONCLUSION

For the reasons stated herein, Cal Advocates recommends that SPD require PG&E to supplement its RAMP Report and that SPD consider Cal Advocates' concerns in its report on PG&E's RAMP Report, as described herein.

Respectfully submitted,

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October 15, 2024

APPENDIX A- DATA REQUESTS

#	Description
1	PGE Ramp-2024_DR_CalAdvocates_002-Q003
2	PGE Ramp-2024_DR_CalAdvocates_002-Q007
3	PGE Ramp-2024_DR_CalAdvocates_002-Q009
4	PGE Ramp-2024_DR_CalAdvocates_004-Q001
5	PGE Ramp-2024_DR_CalAdvocates_004-Q002Atch01

1. PGE RAMP-2024_DR_CalAdvocates_002-Q003

PACIFIC GAS AND ELECTRIC COMPANY
RAMP 2024
Application 24-05-008
Data Response

PG&E Data Request No.:	CalAdvocates_002-Q003		
PG&E File Name:	RAMP-2024_DR_CalAdvocates_002-Q003		
Request Date:	August 23, 2024	Requester DR No.:	002
Date Sent:	September 9, 2024	Requesting Party:	Public Advocates Office
PG&E Witness:	N/A	Requester:	Anna Yang

QUESTION 003

Please provide PG&E's analysis for how it quantifies the impacts of costly investments on customer rates.

ANSWER 003

PG&E did not conduct an analysis of this issue in its RAMP Report. The RAMP is not a funding request and does not evaluate the impact of investments on customer rates.

2. PGE RAMP-2024_DR_CalAdvocates_002-Q007

PACIFIC GAS AND ELECTRIC COMPANY
RAMP 2024
Application 24-05-008
Data Response

PG&E Data Request No.:	CalAdvocates_002-Q007		
PG&E File Name:	RAMP-2024_DR_CalAdvocates_002-Q007		
Request Date:	August 23, 2024	Requester DR No.:	002
Date Sent:	September 10, 2024	Requesting Party:	Public Advocates Office
PG&E Witness:	N/A	Requester:	Anna Yang

QUESTION 007

PG&E's 2023 RSAR shows that PG&E did not complete 55% of its authorized work for Intrusive Pole Inspection (MAT Code GAA) in 2023.[5] Please provide PG&E's analysis for how it quantifies the safety risks of not completing these inspections.

ANSWER 007

PG&E objects to use of the term "authorized work." The correct term is "imputed adopted work".

PG&E's risk modeling does not explicitly connect inspections completed (or not completed) and the downstream effects on enabled risk-reducing work, as this type of work is generally foundational in nature. As such, PG&E's 2024 RAMP risk modelling does not directly reflect changes in risk attributable to completing 45% of imputed/adopted inspection work in 2023.

5 A.24-05-008, PG&E's 2023 RSAR, Table 3-3, Line 76.

3. PGE RAMP-2024_DR_CalAdvocates_002-Q009

PACIFIC GAS AND ELECTRIC COMPANY
RAMP 2024
Application 24-05-008
Data Response

PG&E Data Request No.:	CalAdvocates_002-Q009		
PG&E File Name:	RAMP-2024_DR_CalAdvocates_002-Q009		
Request Date:	August 23, 2024	Requester DR No.:	002
Date Sent:	September 10, 2024	Requesting Party:	Public Advocates Office
PG&E Witness:	N/A	Requester:	Anna Yang

QUESTION 009

PG&E's 2023 RSAR shows that PG&E did not complete any authorized work for its Underground Manhole Inspections (MAT Code BFF) in 2023.[7] Please provide PG&E's analysis for how it quantifies the safety risks of not completing these inspections.

ANSWER 009

PG&E objects to use of the term "authorized work." The correct term is "imputed adopted work".

Underground Manhole Inspection is a foundational program. PG&E's risk modeling does not explicitly connect inspections completed (or not completed) and the downstream effects on enabled risk-reducing work. As such, PG&E's 2024 RAMP risk modelling does not directly estimate changes in safety risk attributable to the number of inspections completed in 2023.

7 A.24-05-008, PG&E's 2023 RSAR, Table 3-3, line 58 at 3-5.

4. PGE RAMP-2024_DR_CalAdvocates_004-Q001

PACIFIC GAS AND ELECTRIC COMPANY
RAMP 2024
Application 24-05-008
Data Response

PG&E Data Request No.:	CalAdvocates_004-Q001
PG&E File Name:	RAMP-2024_DR_CalAdvocates_004-Q001
Request Date:	October 2, 2024
Requester DR No.:	004
Requesting Party:	Public Advocates Office
Requester:	Anna Yang
Date Sent:	October 4, 2024
PG&E Witness(es):	N/A

QUESTION 001

In PG&E's RAMP Application, PG&E included two undergrounding proposals: M022 and A001. Please provide a justification for why PG&E selected undergrounding for each of these two mitigation proposals instead of covered conductor. In the justification, please include an explanation of all factors that PG&E considered for each proposal and how PG&E used such factors to arrive at its decision to select undergrounding instead of covered conductor.

ANSWER 001

PG&E chose undergrounding as our preferred mitigation because it provides the most wildfire risk reduction, significantly improves customer reliability, especially surrounding EPSS and PSPS outages, and provides an electric distribution system which is more resilient to the adverse impacts of climate change with deep uncertainty. Undergrounding also substantially addresses factors such as ingress/egress and tree fall-in risk, which are not mitigated by an overhead alternative. Additional considerations influencing the decision to pursue the most risk reducing mitigation include Risk Tolerance, modeling limitations, and other uncertainties affecting the analysis.

For more information on PG&E's undergrounding mitigation please see PG&E's 2023-2025 WMP: 2023-2025 Wildfire Mitigation Plan R6 (pge.com), sections 8.1.2.1 and 8.1.2.2.

5. PGE Ramp-2024_DR_CalAdvocates_004_Q002Atch01

FA	Risk ID	Program Type	Program ID	Program ID (Multiple)	Program Name	MWC or MAT	Program 2027-2030 $M (NPV) [A] Total Program Cost	[B] Foundational Activity Cost	[C] Risk Reduction	[C]/([A]+[B]) CBR	Program-Risk 2027-2030 $M (NPV) [A] Total Program Cost	[B] Foundational Activity Cost	[C] Risk Reduction	[C]/([A]+[B]) CBR	Unit of Work 2027	2028	2029	2030	Capital ($000) 2027	2028	2029	2030
EO	WLDFR	Mitigation	WLDFR-M002 (M022 Alternative)	DOVHD-M002, PCEEE-M002, WLDFR-M002 (M022 Alternative)	System Hardening [Overhead] (M022 Alternative)	08W	$ 1,695	$ -	$ 30,356	17.9	$1,695	$0	$29,570	17.4	263	316	368	421	$ 327,702	$ 405,197	$ 486,912	$ 573,165
EO	DOVHD	Mitigation	DOVHD-M002 (M022 Alternative)	DOVHD-M002, PCEEE-M002, WLDFR-M002 (M022 Alternative)	System Hardening [Overhead] (M022 Alternative)	08W	$ 1,695	$ -	$ 30,356	17.9	$1,695	$0	$786	0.5	263	316	368	421	$ 327,702	$ 405,197	$ 486,912	$ 573,165
EO	PCEEE	Mitigation	PCEEE-M002 (M022 Alternative)	DOVHD-M002, PCEEE-M002, WLDFR-M002 (M022 Alternative)	System Hardening [Overhead] (M022 Alternative)	08W	$ 1,695	$ -	$ 30,356	17.9	$1,695	$0	$0	0.0	263	316	368	421	$ 327,702	$ 405,197	$ 486,912	$ 573,165
EO	WLDFR	Mitigation	WLDFR-M002 (A001 Alternative)	DOVHD-M002, PCEEE-M002, WLDFR-M002 (A001 Alternative)	System Hardening [Overhead] (A001 Alternative)	08W	$ 2,286	$ -	$ 40,138	17.6	$2,286	$0	$39,185	17.1	400	440	480	520	$ 497,684	$ 564,574	$ 634,376	$ 707,858
EO	DOVHD	Mitigation	DOVHD-M002 (A001 Alternative)	DOVHD-M002, PCEEE-M002, WLDFR-M002 (A001 Alternative)	System Hardening [Overhead] (A001 Alternative)	08W	$ 2,286	$ -	$ 40,138	17.6	$2,286	$0	$953	0.4	400	440	480	520	$ 497,684	$ 564,574	$ 634,376	$ 707,858
EO	PCEEE	Mitigation	PCEEE-M002 (A001 Alternative)	DOVHD-M002, PCEEE-M002, WLDFR-M002 (A001 Alternative)	System Hardening [Overhead] (A001 Alternative)	08W	$ 2,286	$ -	$ 40,138	17.6	$2,286	$0	$0	0.0	400	440	480	520	$ 497,684	$ 564,574	$ 634,376	$ 707,858
PG&E's Original Proposals in the RAMP Application Below																						
EO	WLDFR	Mitigation	WLDFR-M022 (M022)	DOVHD-M022, PCEEE-M003, WLDFR-M022	System Hardening [Underground]	08W	$6,483	$ -	$ 51,321	7.9	$6,483	$ -	$50,295	7.8	400	480	560	640	$ 1,320,501	$ 1,575,164	$ 1,852,955	$ 2,139,167
EO	DOVHD	Mitigation	DOVHD-M022 (M022)	DOVHD-M022, PCEEE-M003, WLDFR-M022	System Hardening [Underground]	08W	$6,483	$ -	$ 51,321	7.9	$6,483	$ -	$1,020	0.2	263	316	368	421	$ 1,320,501	$ 1,575,164	$ 1,852,955	$ 2,139,167
EO	PCEEE	Mitigation	PCEEE-M003 (M022)	DOVHD-M022, PCEEE-M003, WLDFR-M022	System Hardening [Underground]	08W	$6,483	$ -	$ 51,321	7.9	$6,483	$ -	$6	0.0	263	316	368	421	$ 1,320,501	$ 1,575,164	$ 1,852,955	$ 2,139,167
EO	WLDFR	Mitigation	WLDFR-A001 (A001)	DOVHD-A001, PCEEE-A003, WLDFR-A001	System Hardening [Underground] (Alternative Workplan)	08W	$6,261	$ -	$ 60,724	9.7	$6,261	$ -	$59,476	9.5	400	440	480	520	$ 1,459,940	$ 1,571,705	$ 1,714,569	$ 1,861,676
EO	DOVHD	Mitigation	DOVHD-A001 (A001)	DOVHD-A001, PCEEE-A003, WLDFR-A001	System Hardening [Underground] (Alternative Workplan)	08W	$6,261	$ -	$ 60,724	9.7	$6,261	$ -	$1,240	0.2	400	440	480	520	$ 1,459,940	$ 1,571,705	$ 1,714,569	$ 1,861,676
EO	PCEEE	Mitigation	PCEEE-A003 (A001)	DOVHD-A001, PCEEE-A003, WLDFR-A001	System Hardening [Underground] (Alternative Workplan)	08W	$6,261	$ -	$ 60,724	9.7	$6,261	$ -	$8	0.0	400	440	480	520	$ 1,459,940	$ 1,571,705	$ 1,714,569	$ 1,861,676

APPENDIX B- NEWS ARTICLES

#	Description
1	Gold Country Media News Article

1. Gold Country Media News Article

Toddler dies after falling into Placer County canal

Gus Thomson, Journal Staff Writer Nov 24, 2010 11:11 AM

An 18-month-old boy died today after falling into a canal near Colfax while walking with his stepmother.

The boy - identified by the Placer County Sheriff's Office as Zachary Mather of Weimar - was found two hours after falling in at 9:30 a.m.

Zachary was discovered at a debris grate along the Hidden Valley Canal, off Peaceful Valley Road in Weimar.

Zachary's stepmother, who was not identified, told deputies that she and her stepson were walking alongside the canal in an area that was slippery and icy when both fell in. The stepmother was able to get out of the canal and neighbors who heard her yelling soon joined in the search.

"It looks to be a tragic accident," sheriff's spokeswoman Dena Erwin said.

Speaking outside Sutter Auburn Faith Hospital, where the boy had been taken after a sheriff's dive team member pulled him out of the water at about 11:45 a.m., Erwin said Zachary had been pronounced dead shortly after arriving at the North Auburn medical facility.

While early signs point to the death being accidental, an investigation had already started to determine the circumstances surrounding how the boy ended up in the water, Erwin said.

Lt. Ron Ashford of the sheriff's office said the Pacific
cold at this time of year, with little chance to get out
feet deep and about 10-12 feet wide, he said.

The water depth in the canal had been lowered by about three feet by PG&E by the time the boy was taken out of the water at the grate, about a half-mile from where he went in, Ashford said.

First aid was attempted after the boy was removed from the water. Ashford said that he didn't know if Zachary was showing signs of still being alive at that point.

The rural, residential area is located off Placer Hills Road near the Weimar Crossroads exit from Interstate 80.

Family members rushed to the hospital on a day before a holiday that normally would have been filled with celebration and thankfulness. The family was contacted through a third party and declined to talk with gathered media who had been kept from entering the building by facility security.

The death is the sixth in an Auburn-area canal since January 2009. The bodies of the other five canal victims – all adult men – were found in the Wise Canal or Wise Forebay. After the fifth death in the Auburn area, PG&E put up fencing to prevent people from slipping in along that section of canal.

ATTACHMENT 2

Informal Comments of The Utility Reform Network (TURN)

on PG&E's RAMP Report

A.24-05-008

October 9, 2024

TABLE OF CONTENTS

Informal Comments of The Utility Reform Network (TURN) on PG&E's RAMP Report

TURN appreciates the opportunity to present these informal comments on PG&E's RAMP Report. The comments first discuss issues that are generally applicable to PG&E's risk modeling. TURN then addresses issues specific to PG&E's modeling in relation to the Wildfire risk. A recurring theme in these comments is concern regarding PG&E's implementation of the Cost Benefit Approach (CBA) ordered in D.22-12-027. While these comments speak to many problems that TURN has identified, TURN did not have the time and resources to comprehensively review all aspects of PG&E's risk modeling. Accordingly, TURN's silence on any aspect of PG&E's RAMP submission should not be viewed as TURN agreement with PG&E's methodology or conclusions.

A summary of TURN's recommendations appears in the Appendix to these comments.

1. PG&E's One-Size-Fits-All Electric Reliability Calculation Ignores Geographical Variability in Interruption Cost Estimation

The Lawrence Berkeley National Laboratory (LBNL) Interruption Cost Estimate (ICE) Calculator is a tool designed to estimate the economic costs of electric service interruptions across different customer categories (residential, commercial, industrial).[1] The model considers various explanatory or independent variables such as duration of the outage, time of day, specific industry impacts, among others to predict cost per (outage) event.[2]

The ICE Calculator is primarily equipped to handle outages lasting 24 hours or less, making it less effective for modeling the economic impacts of longer or consecutive outages. The underlying data for the model is partly outdated, relying on surveys that are over 15 years old, which may not accurately reflect current economic conditions and customer behaviors. The Commission's decision acknowledged these limitations and directed IOUs to use the most current version of the ICE Calculator for standard dollar valuation of electric reliability risks or justify the use of an alternative model.[3] [4]

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[1] https://emp.lbl.gov/projects/economic-value-reliability-consumers#:~:text=The%20Interruption%20Cost%20Estimation%20(ICE)%20Calculator%20%2C%20a%20Berkeley%20Lab,economic%20costs%20of%20power%20interruptions.

[2] The regression models underlying the ICE Calculator's calculations may use as many as 23 variables for Medium and Large Commercial & Industrial (C&I) customers, and 22 variables for both Small C&I and Residential customers (See tab "Model" in PG&E Workpaper, RM-RMCBR-6).

[3] D.22-12-027, pp. 31, 32.

[4] Literature on electric reliability highlights biases in contingent valuation survey-based cost estimates that the ICE calculator is based on. PG&E's \$3.17/CMI translates to a cost per unserved kWh of \$4.50 for residential customers in California, which is significantly higher—about 1,223%—than the upper

The ICE calculator calculates the costs per event and unserved kWh for medium and large C&I, small C&I, and residential sectors by first applying the appropriate coefficients from the probit and generalized linear model (GLM) outputs. This is where the use of regression model outputs ends. The calculator then divides these costs per event by the "SAIDI value", to derive the cost per Customer Minutes Interrupted (CMI) for each customer class.[5] Finally, a weighted average of the aforementioned outputs is obtained by using the "number of customers" by sector. Through this method, PG&E's use of ICE calculator arrives at a combined cost of $3.17 per CMI (2023) for all customers, which it subsequently uses to quantify electric reliability costs across its electric risks.

PG&E argues that updating the ICE Calculator is premature due to the outdated data and assumptions of the current model and notes the challenges in determining the appropriate explanatory variables and their granularity.[6] PG&E further states that while it may be straightforward to input the number of customers at an appropriate granularity (for example, by fire-risk based geographic tiers), it is unclear what to assume for other explanatory variables and their granularity.[7]

TURN recognizes that, while the ICE 2.0 update, expected by the latter half of 2024,[8] is likely to yield more refined reliability metrics based on updated data and assumptions, immediate incremental improvements should not be delayed for the sake of a perfect solution. A key enhancement would be recalculating electric reliability using more detailed customer location data, reflecting the highly locational nature of electric reliability metrics such as service interruptions (See **Table 1** below). TURN also highlights that the variables used in the ICE Calculator's regression models, referred to as explanatory or independent variables, differ from

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market-based estimate from a well-cited 2021 study in "Energy Economics" suggesting costs range from $0.12 to $0.34 per kWh unserved across the US (California-specific: $0.23/kWh unserved). Reference: https://www.sciencedirect.com/science/article/pii/S0140988321001754?casa_token=7SYDpDibb9YAAAAA:FbWiwVBj1biwg4tvJyECQ-_A8rNvO5pwV6EmWN4PxUhqhCBpUy1iXG_t-mSh1KKhTpI01gPKuhtp

[5] PG&E RAMP Report, p. 2-15, Table 2-6 - PG&E uses territory-wide SAIDI value of 120 (2013-2022)

[6] PG&E RAMP Report , p. 2-57, lines 12-22.

[7] PG&E RAMP Report, p. 2-57, lines 31, 32. Although PG&E emphasizes household income as a "significant contributor" (p. 2-58) in the ICE Calculator's reliability value, the impact of income is relatively moderate (compared to, say, the outputs' sensitivity to SAIDI values). For instance, using PG&E's median California income of $56,862 results in a CMI of $3.170, whereas 2022 incomes at the 10th percentile ($29,000) and 90th percentile ($305,000) yield CMI values of $3.167 and $3.197, respectively (https://www.ppic.org/publication/income-inequality-in-california/).

[8] PG&E RAMP Report, p. 2-57, lines 23-25.

"global variables" like the number of customers and/or SAIDI values. These global variables are applied after model outputs are generated and can be adjusted to the specific granularity of geo-tier, tranche, or circuit segment without impacting the regression results.[9]

SPD requested that PG&E recalibrate its risk scores by geographic tiers, specifically the High Fire-Threat District (HFTD) Tier 3-Extreme, Tier 2-Elevated, NONHFTD-EPSS, and NONHFTD-NONEPSS, due to the differentiated Customer Minutes Interrupted (CMI) values reflective of the specific risks and service reliability in each area.[10] Additionally, PG&E was asked to implement the 4 new monetized values of electric reliability consequences to the Reliability Attribute for specific risks including Electric Transmission System-wide Blackout, Failure of Electric Distribution Overhead Assets, Failure of Electric Distribution Underground Assets, and Wildfire with PSPS and EPSS, which PG&E suggested would be tentatively available by end of September.[11] TURN notes that we have not evaluated the latter part of SPD's request, and any subsequent responses from PG&E.

As part of TURN's discovery, we received data on SAIDI distribution and observed significant variations in SAIDI values across the four geographic tiers and among different customer types.[12]

Table 1. Tier-specific SAIDI values (2016-2022 Average)

Customer Category	HFTD Tier 2 Elevated	HFTD Tier 3-Extreme	NONHFTD-EPSS	NONHFTD-NONEPSS
Small Commercial & Industrial (C&I)	454	613	179	103
Medium and Large Commercial & Industrial (C&I)	376	535	152	94
Residential	356	517	139	80

The first part of SPD's request involved the inclusion of the number of customers by the four geographic tiers and resulted in differentiated $/CMI values that reflect the specific risk and service reliability in each area. TURN recommends that the geographic-tier-based $/CMI values,

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[9] See tab "Model" and respective variables used in PG&E Workpaper, RM-RMCBR-6.

[10] Response to SPD-002-Q001(a-d)

[11] Response to SPD-002-Q003

[12] Response to TURN-03-Q002b (PG&E noted in its response that the outage to customer mapping dataset only includes outages from May 2015 onwards. Consequently, the historical average of SAIDI is computed for the years 2016 to 2022, rather than the initially requested span from 2013 to 2022)

computed using the varying number of customers per tier, be further refined by incorporating the differentiated average SAIDI values (as opposed to a uniform SAIDI of 120), as shown in Table 2 below.

Table 2. Adjusted $/CMI(2023) by geo-tier based on number of customers and average regional SAIDI values (TURN)[13]

	Number of Customers			$/CMI (2023)	
Geographic Tier	**Residential**	**Small C&I**	**Medium and Large C&I**	**$/CMI (2023) * (SPD)**	**$/CMI (2023) w. regional SAIDI** (TURN)**
PG&E - HFTD Tier 3-Extreme	315,786	29,975	5,168	1.46	1.65
PG&E - HFTD Tier 2-Elevated	152,264	11,237	1,567	2.04	0.62
PG&E - NONHFTD-EPSS	1,143,635	115,614	33,122	2.92	1.27
PG&E - NONHFTD-NONEPSS	3,349,740	312,761	124,103	3.40	3.78
			Weighted Average	**2.46**	**1.83**

*Based on DR SPD-PGE-2024-RAMP-002 and **Based on Response to TURN-03-Q-2. b (avg. SAIDI 2016-2022)[14]

As shown in Table 2, incorporating SAIDI values by geographic tier enhances the accuracy of $/CMI results and reduces the weighted average from 2.46 $/CMI to 1.83 $/CMI by reflecting unique interruption profiles based on historical, tier-specific SAIDI data (2016-2022) provided by PG&E.

TURN's Recommendation

TURN suggests a more nuanced application of the ICE Calculator by incorporating customer location data, at a minimum by geographic tiering, and potentially at more granular levels such

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[13] See TURN Workpapers: Module_1-Estimate_Interruption_Costs_v2.0_HFTD Tier 3-Extreme_avg SAIDI; Module_1-Estimate_Interruption_Costs_v2.0_PG&E - HFTD Tier 2-Elevated_avg SAIDI; Module_1-Estimate_Interruption_Costs_v2.0_PG&E - PG&E - NONHFTD-EPSS_avg SAIDI; Module_1-Estimate_Interruption_Costs_v2.0_PG&E - PG&E - NONHFTD-NONEPSS_avg SAIDI. These TURN workpapers can be accessed at: https://theutilityreform-my.sharepoint.com/:f:/g/personal/ryanagiba_turn_org/EvoolwteS9lHmda2w1ssLDkBPFQ0AU6b_skFeEe3mUq-7w.

[14] PG&E Response to DR TURN-03-Q002b provides SAIDI values for the year 2022 and average SAIDI (2016-2022) by geo-tier. The latter values (i.e. 2016-2022 avg SAIDI) were used in Table 2.

as tranche and circuit segment levels, where feasible. For electric risks where the tranches are not broken at the level of geographical tiers, the use of proxies, such as historical reliability impact by spatial classification, may be appropriate.[15] TURN recognizes the potential challenge in assessing electric risks for tranches that do not directly correspond to geographic tiers.[16] In such cases, we recommend a transparent and consistent framework to ensure that electric reliability assessments accurately reflect the unique risks and service reliability across different regions within PG&E's territory.

TURN believes that a geo-tiered evaluation of $/CMI, using tier-specific average SAIDI values provides more accurate results by considering the varying risk profiles and SAIDI data across different geographic tiers. Using this approach, TURN recommends using the more representative average of 1.83 $/CMI (2023) based on data provided in Table 2.

2. PG&E's Arbitrary Application of California-Specific Adjustments Is Contrary to D.22-12-027 and Results in an Unreasonable Value of Statistical Life (VSL)

D.22-12-027 states that each Investor-Owned Utility (IOU) must calculate the Safety Attribute using one of two prescribed methods: 1) Apply the latest published Department of Transportation (DOT) Value of Statistical Life (VSL), adjusted to the base year of their respective Risk Assessment Mitigation Phase (RAMP) filing, or 2) Choose an alternative VSL from within a range provided by the United States Department of Health and Human Services (HHS), accompanied by a sensitivity analysis to evaluate the Cost-Benefit Ratio (CBR) impact in comparison to the standard DOT VSL.[17]

PG&E does not follow the clear instructions in D.22-12-027. Instead, PG&E opts for a hybrid approach that does not comply with either of the alternatives in D.22-12-027. Rather than simply updating the DOT value using DOT's prescribed data, it adds other California-specific inputs in a way that is at odds with the DOT's methodology. Specifically, PG&E applies California-specific income and wage multipliers to the nationwide DOT VSL calculation to increase the VSL from $13.2 million, the adjusted 2023 base year value under the DOT methodology, to $15.2 million.[18]

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[15] PG&E Response to SPD-03-Q003b, suggests the use of a proxy measure to estimate reliability impact from ignition spread, which is currently not evaluated by geo-tiers.

[16] PG&E Response to SPD-02-Q001 (Supp01).

[17] D.22-12-027, p. 63, ordering paragraph 1.

[18] PG&E RAMP Report, p. 2-10 to 2-11.

PG&E argues that the state's higher income and inflation rates justify this approach.[19] However, PG&E's method is wrong, as DOT guidance makes clear. To correctly apply a California-correction, you would need a meta-analyses of California-specific VSL estimates, and then update them for the base year as provided in the DOT guidance. That guidance emphasizes that "Prevention of an expected fatality is assigned a single, nationwide value in each year, regardless of the age, income, or other distinct characteristics of the affected population."[20] The guidance further notes and provides a methodology to "adjust the VSL to the base year used in the analysis". In fact, the DOT Guidance provides exact links to national inflation and real-income data in footnotes 10 and 11 of the guidance, presumably to avoid using incorrect base year adjustment.

The DOT approach respects the complexity of VSL determinations by incorporating diverse datasets that likely include California populations but are not limited to them. The DOT's $9.1 million VSL estimate for 2012 is based on the average VSL from 9 selected meta-analyses using the Bureau of Labor Statistics' (BLS) Census of Fatal Occupational Injuries (CFOI).[21] Typically, VSL estimates, based on population-level surveys or contingent valuation analyses, inherently factor in variables such as age, income, and wealth, making them representative of a nationwide valuation. Thus, aside from adjusting for inflation, there is no need for further escalation of the VSL as it encompasses a comprehensive national perspective.

Simplistic adjustments based on the use of state-level economic data like CPI and median wages leads to biased or inaccurate VSL estimations. Furthermore, the VSL study referenced by PG&E to justify its California-specific adjustment, emphasizes the need for using comprehensive and detailed demographic, occupational, and economic data—including industry-specific risks, socio-demographic variables like age and ethnicity, and job-related factors such as wages and work experience—to potentially enhance the accuracy and relevance of VSL adjustments within California.[22] Applying a constant ratio-based adjustment to the nationwide Value of Statistical

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[19] PG&E RAMP Report , p. 2-9, lines 24-26 and p. 2-10, lines 1,2.

[20] Departmental Guidance: Treatment of the Value of Preventing Fatalities and Injuries in Preparing Economic Analyses, March 2021, p. 4, found at: https://www.transportation.gov/sites/dot.gov/files/2021-03/DOT%20VSL%20Guidance%20-%202021%20Update.pdf

[21] Departmental Guidance: Treatment of the Value of Preventing Fatalities and Injuries in Preparing Economic Analyses, March 2021, p. 6, Table 1.

[22] "Updating Value per Statistical Life Estimates for Inflation and Changes in Real Income" (Apr. 2021), available at: https://aspe.hhs.gov/sites/default/files/2021-07/hhs-guidelines-appendix-d-vsl-update.pdf

Life (VSL) estimate, using only wages and Consumer Price Index (CPI), introduces biases from omitted variables and lacks mathematical and logical soundness.

TURN's Recommendation

TURN recommends the use of $13.23 million as the 2023 VSL, based on escalation of the DOT VSL from 2012 ($9.1 million).[23]

Alternatively, analysis conducted by the California Air Resources Board (CARB), suggests a mid-point California-specific VSL of $9.0 million (2013) which translates to $12.33 in 2023 dollars, after applying an adjustment factor (1.37) based on California-specific CPI-U.[24] [25]

3. Risk Averse vs. Risk Neutral Scaling Functions

3.1. PG&E Has Not Demonstrated the Reasonableness of Its Extreme Scaling Function

The risk scaling function PG&E proposes to use is categorized into three distinct regions based on financial levels and the degree of risk adjustment. Slope 1, ranging from $0 to $10 million monetized levels of attributes, represents the risk-neutral region where a linear, 45-degree progression indicates a consistent and proportional adjustment to risk across this range. Slope 2, from $10 million to $1 billion, is termed the "insurance-based" risk region, characterized by a steeper slope of 2.0. Slope 3, from $1 billion to $1.25 billion, termed as the "Capital-Markets" risk region, displays a very steep slope of 7.5, signifying an almost infinite willingness to pay (or a potential squared or cubic convex function) at higher monetized levels of an attribute.

PG&E's graphical depiction of its scaling function (the figure below on the left) is not drawn to scale and masks how drastically it increases consequence values compared to a risk neutral function, particularly in the third risk region, as shown in the to-scale figure on the right.

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[23] PG&E Workpaper, RM-RMCBR-6 (Rows 3-26)

[24] "Review of Mortality Risk Reduction Valuation Estimates for 2016 Socioeconomic Assessment", 2016, p. 17. https://ww2.arb.ca.gov/sites/default/files/2021-10/SCAQMD%20Mortality%20Risk%20Reduction%20Valuation.pdf

[25] Use of a California-specific CPI-U escalator is appropriate for a California-specific VSL.

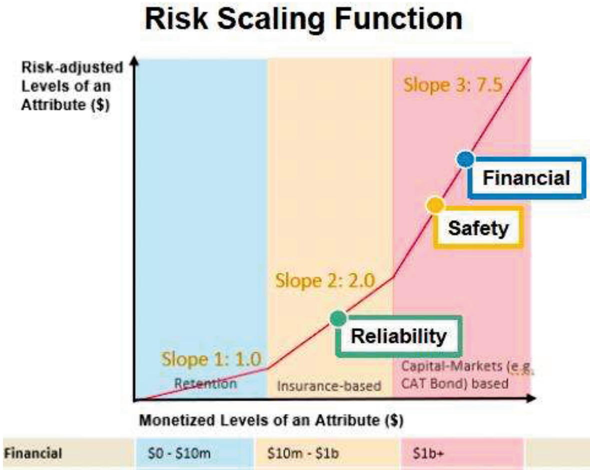

Figure 2. PG&E's Depiction of its Risk Scaling Function (Post-Filing Workshop, Slide 36)

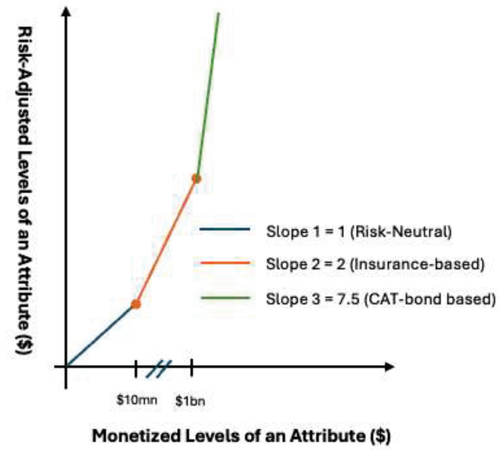

Figure 1.PG&E's Risk Scaling Function, drawn to scale.

PG&E has not justified its use of such an extremely convex scaling function compared to a risk-neutral function.

PG&E avoids the central question of whose risk preference is being expressed. PG&E is a regulated monopoly, and it is the interests of the ratepayers and the general public that are relevant. Because PG&E is spending ratepayer money, the scaling function should reflect the ratepayers' attitudes toward uncertainty. The Commission has made it clear that the utilities' risk models should not be based on shareholders' financial interests and should remove such considerations from their decision-making frameworks.[26]

There is no reason to believe that the people of California, or a single utility's ratepayers, can be characterized as having a single preference for risk or attitude toward uncertainty. The preference will be personal and variable. PG&E has not addressed the difficulty of determining the preferences of groups as large as the California public or the diverse body of PG&E ratepayers. Nor has PG&E shown that its scaling function betters reflects the attitudes of these groups to risk than a linear scaling function.

To the contrary, PG&E does little to disguise the fact that its "market-based" approach is based not on its customers' risk attitude but based on PG&E's "risk management objective,"[27] which,

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[26] D.16-08-018, p. 123.

[27] PG&E RAMP Report, p. 2-20.

as an investor-owned utility, is indisputably driven by the financial interests of the company's shareholders. PG&E's three-tiered "risk financing strategy" is based on the "management of losses *by firms*,"[28] and is not an approach to risk that many of its customers would recognize. Participants in the "cat bond" market are typically institutions, not individuals. While individuals and households often purchase insurance, the reasons for doing so vary as does the coverage chosen by each individual. The range of insurance products available reflect consumers with a broad range of preferences.

In addition, it is important not to confuse risk-aversion with aversion to bad outcomes. Most people would spend money to avoid a bad outcome. Under a risk neutral function, a utility's ratepayers would be expected to spend twice as much money to avoid twice as many deaths or twice as much financial loss. But PG&E's scaling function implies preferences that most people are unlikely to share, namely that not every dollar and not every life is valued equally. For example, PG&E's function values a reduction of 11 fatalities to ten fatalities at least ten times more than a reduction of one fatality to zero. While everyone wants to avoid catastrophic events, PG&E has not made the case for why ratepayers should be expected to pay ten times as much to avoid one fatality if that fatality is part of an 11-fatality event, as opposed to a single fatality event.

The impact of PG&E's scaling function is to make mitigation activities appear more valuable than they would otherwise be if they were evaluated using a linear scaling function. This serves the company's financial interest in justifying higher expenditures, including higher capital spending on which the utility's shareholders collect a profit.

In short, PG&E and its shareholders may be as risk averse as its scaling function implies, but PG&E has utterly failed to demonstrate that it is fair to ascribe the same level of risk aversion to its customers who are paying the bills.

3.2. Consistent with D.24-05-064, PG&E's GRC Showing Should At Least Supplement Its CBR Calculations with CBRs Based on a Linear Scaling Function

Notwithstanding TURN's concerns with PG&E's approach, PG&E is free to present the results of its risk analysis using its preferred scaling function. It is up to the Commission whether to view PG&E's results, including its CBRs, as reasonable and useful for decision-making purposes. The preceding section offers reasons why the Commission should be skeptical of relying on modeling results based solely on PG&E's preferred scaling function and why understanding how PG&E's approach compares to a risk-neutral alternative. However, without running the data through PG&E's models, it is often difficult to predict for a given mitigation

[28] *Id.*, p. 2-22 (emphasis added).

how much PG&E's preferred scaling function will affect the CBR calculation compared to a risk-neutral scaling function. The only reliable way to understand this impact is for the utility to present, for comparison purposes, CBRs using a linear scaling function.

In D.24-05-064, the Commission held that utilities basing their analysis on a convex scaling function as a means of addressing uncertainty must supplement their analysis by also presenting risk-adjusted attribute levels using a linear scaling function.[29] This requirement applies to PG&E because the utility readily admits that it uses a convex scaling function to address uncertainty concerning the frequency and consequences of catastrophic events.[30]

D.24-05-064 was effective on May 30, 2024, after the May 15, 2024 due date for PG&E's RAMP submission, and therefore does not apply to this RAMP proceeding. However, the revisions to the RDF indisputably went into effect on May 30, 2024 and thus apply to all events occurring after that effective date, including the GRC that PG&E will file in May 2025.

Nevertheless, in response to TURN discovery, PG&E asserts that it is not required to abide by the requirements of D.24-05-064 and provide CBRs based on a linear scaling function.[31] PG&E contends that risk modeling requirements that do not apply to a utility's GRC unless they also applied to the utility's RAMP.[32]

The Commission made no such statement in D.24-05-064, nor in any other decision. If this were the Commission's intent, it could have said so in D.24-05-064. But the Commission did not delay the effectiveness of any of the decision's provisions. This silence contrasts starkly with D.22-12-027, in which the Commission expressly delayed the implementation of the wholesale changes in the new RDF adopted in that decision – transitioning from the MAVF to the CBA approach -- specifying that the new approach would apply beginning with this PG&E RAMP.[33]

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[29] D.24-05-064, p. 97, and Appendix A, p. A-8, Row 7. The decision states on page 97: "We also agree with MGRA that use of the risk scaling function is not necessary to address uncertainty. The concern with uncertainty can be addressed through the topic of tail risk, as addressed in Rows 5 and 24 of the RDF and affirmed with this decision (see sections 7 and 8 above). *To ensure that IOUs will transparently demonstrate to decisionmakers that the risk scaling function is not being used to address uncertainty in the model*, but instead is focused on expressing the axiological preferences of the utility, we include additional language to Row 7 that draws from TURN's proposal." (Emphasis added.)

[30] PG&E RAMP Report, p. 2-2 to 2-3. *See also* pp. 59-60, where PG&E acknowledges that its scaling function addresses at least one type of uncertainty ("epistemic" uncertainty).

[31] Response to TURN DR 11, question 1.

[32] *Id.*

[33] D.22-12-027, p. 63.

PG&E has been aware of the modified Row 7 requirement since May 2024 and has had, and continues to have, ample time, to address it in its upcoming GRC. Unlike the transition to the CBA ordered in D.22-12-027, the requirement to supplement its CBR calculations with values based on a risk neutral function does not require development of an entirely new modeling framework. Notably, PG&E states that it has no objection to providing alternative *risk scores* based on a linear scaling function.

As the Commission stated in D.24-05-064, this CBR information is necessary to "transparently demonstrate to decisionmakers that the risk scaling function is not being used to address uncertainty in the model . . ..."[34] This requirement does not require PG&E to endorse the CBR results based on a linear scaling function -- only to provide those alternative results as a matter of transparency and for comparative purposes.

TURN urges PG&E to re-visit its position and to announce that it will comply with the clear requirements of D.24-05-064 in its GRC submission.

4. PG&E's GRC Filing Should Allow the Commission and Intervenors to Compare the Cost-Effectiveness of Alternative Mitigations on an "Apples to Apples" Basis

The purpose of utility risk modeling is to allow the utilities, Commission, and intervenors to assess, explore, and understand utility risk to then propose mitigations that balance risk reduction with costs. As the Commission stated "the objective of the S-MAP is to fulfill the state's policy of ensuring that the Commission and the energy utilities place the safety of the public and utility employees as the top priority, and for the Commission to carry out this priority safety policy consistent with the principle of just and reasonable cost-based rates."[35] Under D.22-12-027, a key output of this risk modeling is a cost-benefit ratio (CBR), which provides cost-effectiveness values for multiple mitigations.

The presentation of CBRs to-date by all the utilities, including PG&E, is misleading when alternative mitigations are capable of serving a similar risk mitigation purpose. Rather than calculating the cost-effectiveness of mitigations on an "apples-to-apples basis" whereby each mitigation is assumed to be deployed to the same risk area, the utilities calculate CBRs based only on the utility-specific *proposal,* which usually entails deployment of its preferred mitigation to the highest-risk areas or tranches, while other mitigations are assumed and modeled as mitigating risk to other, lower-risk areas. These calculations do not lend themselves to direct comparisons of CBRs. CBRs calculated based on this methodology are thus only relevant to the

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[34] D.24-05-064, p. 97.

[35] D.18-12-014, p. 6.

utility's proposal, rather than alternatives which would deploy alternative mitigations to the same risk area or tranche as the utility's proposal.

Ideally, utilities would calculate CBRs based on deploying mitigations to the same tranche and same number of miles which would allow for an apples-to-apples comparison of cost-effectiveness. For example, such apples-to-apples comparisons would be appropriate for competing wildfire system hardening alternatives, such as covered conductor and undergrounding, and for replace versus repair alternatives for gas and electric infrastructure.

At minimum, PG&E should allow the Commission and intervenors to conduct these comparisons at their own accord, with the ability to examine multiple alternatives. For example, TURN appreciates that, several weeks after TURN requested it, PG&E created a spreadsheet tool that allowed us to compare the cost-effectiveness of system hardening initiatives when deployed to the same tranche or risk area, as well as modify inputs like the number of miles and unit costs.[36] In its GRC, whenever alternative mitigations can be deployed to reduce risk, PG&E should provide a similar tool with its workpapers for all top risk areas when it files its GRC. At a minimum, PG&E should be prepared to provide such a tool upon request to interested parties and the Commission within the customary 10 business-day data request cycle.

5. PG&E's Wildfire Risk Modeling

5.1. PG&E Inaccurately Estimates the Financial Consequences of Wildfire Risk

The financial consequence of wildfires is based primarily on the assumed number of structures destroyed multiplied by an assumption that each structure is worth $1 million.[37] This $1 million value per structure is based on the weighted average (by number of structures) from 2015-2017, which PG&E has maintained from its 2020 RAMP "given the high variability of average dollar damage per structure year to year."[38]

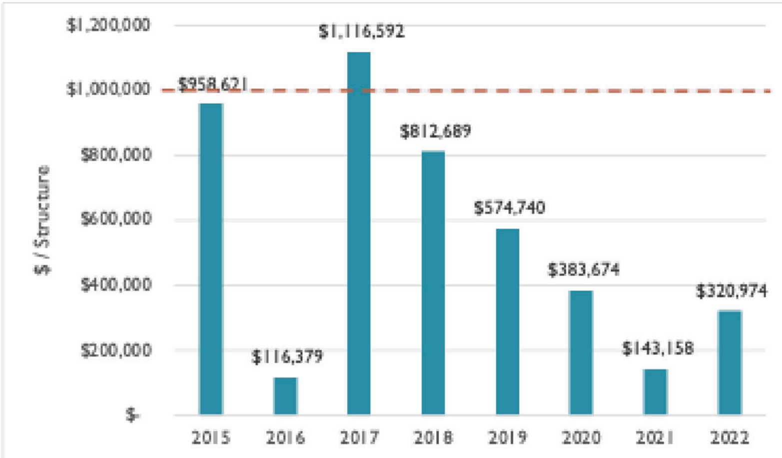
The $1 million per structure assumption is outdated and does not reflect a reasonable assumption. Indeed, 2017 was the only year in which this damage value reflected reality – in every other year from 2015-2022, the dollar damage per structure was less, in many years significantly less. From 2020-2022, the $1 million assumption overstated actual recorded data by an average of 324%.

[36] This Excel tool was sent via email to TURN and is called "WLDFR OH, UG comparison tool_Final_7-15-24.xlsx."

[37] EO-WLDFR-7_CalFire Large+ Fires 2015-2022, tab "Consequence_Destructive."

[38] Response to DR TURN-5, question 2(f).

Figure 3. Dollar Damage per Structure Destroyed (Recorded)



A more realistic assumption that incorporates significantly more data is for PG&E to use the weighted average (by number of structures) from 2015-2022 – approximately $723,000.[39] This is a more accurate and robust estimate than arbitrarily retaining the 2015-2017 weighted average from the 2020 RAMP.

Incorporating this recommendation has a significant impact on the baseline wildfire risk score. **By itself, this change lowers the wildfire risk score by 26% in each year from 2027-2030**.[40] Making this change would also generally reduce the CBRs for PG&E's wildfire mitigations as there would be less risk to mitigate for the same cost.

5.2. PG&E Should Base the Mitigation Effectiveness of Covered Conductor on Recorded Data

To calculate the mitigation effectiveness of overhead hardening, which primarily consists of installation of covered conductor to replace bare conductor, PG&E relies on internal subject matter experts (SMEs). SMEs use judgement to categorize the ability of covered conductor to prevent a historical outage. Each category is then mapped to a corresponding mitigation percentage value.[41]

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[39] Response to DR TURN-5, question, 2, attachment 1.

[40] Response to DR TURN-8, question 1, attachment 2.

[41] Response to DR TURN-5, question 4a.

Table 3. Covered Conductor Mitigation Effectiveness Values used by SMEs

Name	Value
NONE	0%
LOW	20%
MEDIUM	40%
MEDIUM-HIGH	60%
HIGH	70%
VERY-HIGH	90%
ALL	100%

This results in an average mitigation effectiveness of 66% based on the drivers of outages examined.[42]

Probabilities assigned by SMEs, based on what is essentially a "best guess," may be a reasonable approach when no other data is available. However, this is no longer the case. PG&E alone has deployed over 1,100 circuit miles of covered conductor since 2018, while Southern California Edison (SCE) has deployed 4,400 circuit miles through 2022.[43] The utilities have also conducted significant laboratory testing of CC for several primary drivers of ignitions.[44]

Based on the extensive data collection accomplished to-date, the use of qualitative judgement from SMEs should be substituted with data-driven analysis on the actual performance of covered conductor. When PG&E has done such an analysis of ignition mitigation effectiveness on hardened circuits, it found a mitigation effectiveness percentage of 79%.[45] However, the utility does not believe the statistic is accurate because covered conductor was installed recently and has not been subject to degradation, some has been deployed in areas as part of wildfire rebuild which has a different risk profile, the utility deploys undergrounding in high strike tree risk areas which could skew the data, and the utility cannot always locate the exact location of an outage to determine if the portion of the circuit that caused it was covered or not.[46]

There are always some challenges with data collection and PG&E should seek to overcome them. It is, at best, unfortunate that PG&E has spent more than $1 billion on a program to install

[42] PG&E Workpaper: EO-WLDFR-14_2015-2022_Estimated_CC&UG_Effectiveness_Workpaper, tab "Effectiveness Outputs."

[43] SCE 2023-2025 WMP, p. 880, Table CC-1, https://www.sce.com/sites/default/files/AEM/Wildfire%20Mitigation%20Plan/2023-2025/SCE%202023%20WMP%20R2-clean.pdf.

[44] SCE 2023-2025 WMP, p. 880.

[45] Response to DR TURN-6, question 4.

[46] Id.

covered conductor and yet does not appear able or willing to collect and make use of data on the performance of the program to more accurately estimate mitigation effectiveness.

Rather than the qualitative approach currently used, PG&E should base its mitigation effectiveness for covered conductor on the drivers of ignitions in its service territory combined with data from both PG&E's own system and SCE. At minimum, SCE has amassed a large amount of data on mitigation effectiveness by driver, which can be utilized to calculate more accurate mitigation effectiveness values relevant to PG&E's service territory.

5.3. PG&E Includes Inaccurate Assumptions that Overstate the Risk of PSPS

PG&E incorporates two inadequately supported assumptions regarding PSPS risk. Namely, PG&E overestimates the number of customer minutes of outage and understates the effectiveness of PSPS for mitigating wildfire risk. These flaws cause PG&E to understate the benefits of PSPS and overstate reliability impacts of PSPS. As a result, PG&E's baseline risk score for the Wildfire Risk – which incorporates risk reduction and consequences of PSPS and EPSS - is overstated.

PSPS Customer Minutes of Outage

In order to estimate the "risk" of PSPS outages on customers, PG&E uses a "lookback" approach. This approach applies the current PSPS criteria to weather conditions that PG&E's service territory has experienced in the past and identifies the locations where the PSPS criteria would be met."[47] PG&E states the "reliability consequence of a PSPS risk event is modeled with an exponential distribution whose mean is based on the average of customer minutes interrupted per PSPS lookback event."[48] This is then multiplied by a value of lost load (VOLL) to determine consequences in dollar terms.

Examination of historical data on the *actual* deployment of PSPS shows that PG&E's methodology significantly overestimates *modeled* PSPS impacts. For example, PG&E's model includes the year 2023, and estimates <u>722 million</u> customer minutes of outage due to PSPS. Yet the *actual* number of customer minutes of outage in 2023 was <u>only 5.3 million</u>.[49] This represents a difference of over 13,000%. This discrepancy means PG&E's estimate is simply not realistic or an accurate representation of PSPS outage minutes, as shown in the figure below.

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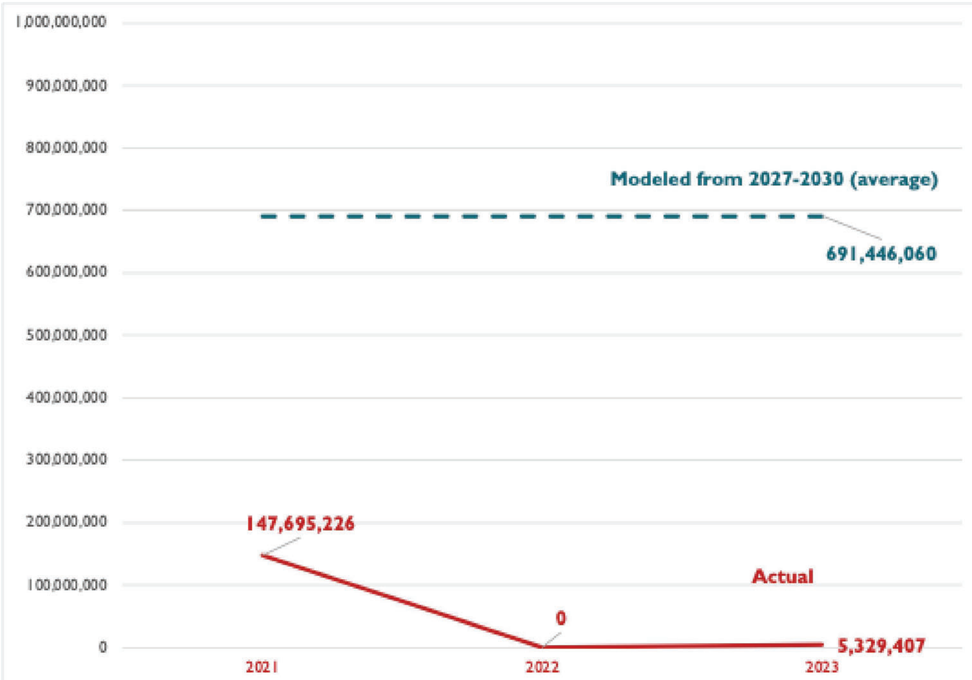
[47] PG&E RAMP Application, PG&E-4, p. 1-9.

[48] Response to DR TURN-2, question 4.

[49] Response to DR TURN-12, question 1.

Figure 4. Forecast Modeled Customer Minutes of Outage versus Actual Customer Minutes of PSPS Outage, 2021-2023



We note that in 2019 and 2020 (not shown in the figure) PSPS customer minutes were above the modeled average; however, we believe these years are not relevant to future forecasts of PSPS outages. First, these years used different PSPS protocols than the one currently in place (the latest was established in 2021).[50] Second, they do not reflect the operational improvements PG&E has made in implementing PSPS, particularly after 2019 when PG&E unnecessarily implemented PSPS to millions of customers in the midst of its bankruptcy using inadequate operational practices.[51]

This improvement is shown in the figure below, which shows the PSPS customer minutes of outage normalized for wildfire risk in each year. Normalization is accomplished by dividing annual PSPS outage minutes by the number of red flag warning circuit mile days, a measure of wildfire risk relevant to the implementation of PSPS.[52]

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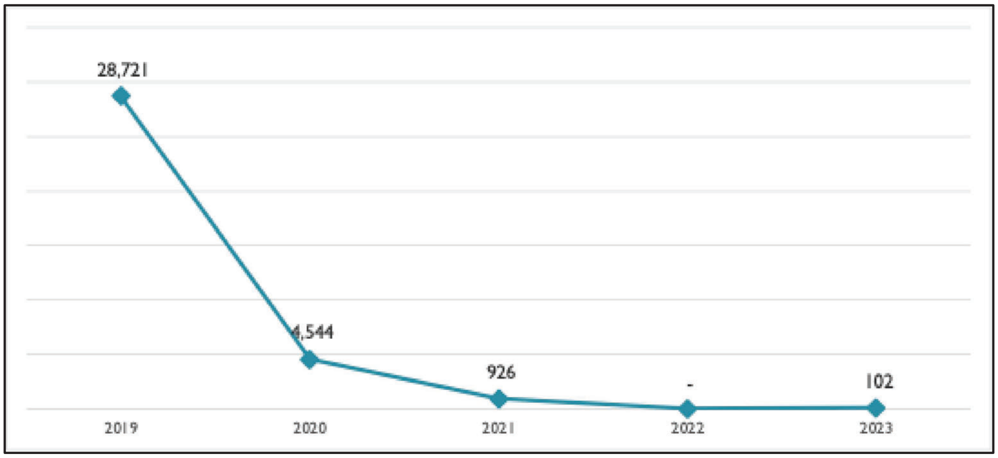
[50] Response to DR TURN-12, question 2.

[51] CPUC, https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-holds-pge-accountable-for-flawed-implementation-of-fall-2019-psps-events.

[52] "A "Red Flag Warning (RFW) Circuit Mile Day" is intended to capture the duration and scope of the fire weather that year. It is defined on page 5 of the 2020 WMP Guidelines to be calculated as the number of circuit miles that were under a RFW multiplied by the number of days those miles were under said RFW. For example, if 100 circuit miles were under a RFW for 1 day, and 10 of those miles

Figure 5. Actual PSPS Customer Outage Minutes Divided per Red Flag Warning Circuit Mile Days, 2019-2023



Normalized for wildfire risk, PSPS outage minutes have decreased by nearly 100% in 2023, compared with 2019.

PG&E's GRC filing should reflect a better estimate of customer minutes of outage for the general rate case period, incorporating the reality that PG&E has become significantly more targeted in its use of PSPS, and that PG&E's current modeling of customer outage minutes does not reflect a reasonable forecast of this risk.

TURN recognizes there are likely several ways to derive a more reasonable estimate. The table below utilizes the statistics discussed above – RFW circuit mile days and outage minutes per RFW circuit mile days – to calculate a reasonable range that PG&E's forecast should likely fall into, with the "maximum" amount representing an upper bound. This upper bound could be used to cap PG&E's statistical distribution curve, which is also a feature of PG&E's model that may need to be re-considered.[53]

As stated above, 2021-2023 are the most relevant years for a forecast of outage minutes per RFW circuit mile day, and we exclude 2022 because there were zero minutes of PSPS outages which may have been an anomalous year.

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were under RFW for an additional day, then the total RFW circuit mile days would be 110." Office of Energy Infrastructure Safety, https://energysafety.ca.gov/wp-content/uploads/docs/misc/docket/336483109.pdf.

[53] As stated above, PG&E uses an exponential distribution which may not be appropriate.

Table 4. Average and Maximum PSPS Customer Outage Minutes Based on Historical Data

	Maximum	Average
RFW Circuit Mile Days (2018-2023)	294,176	163,930
Outage Minutes per RFW Circuit Mile Day (2021, 2023)	926	514
PSPS Customer Outage Minutes	272,415,051	84,249,135

PSPS Mitigation Effectiveness

PSPS should have a very high effectiveness in mitigating wildfire risk, particularly for the most significant fires that happen due to risky wildfire weather likely to trigger a PSPS event. PG&E's estimate of PSPS effectiveness differs by type of fire – destructive, large, and small – shown below.[54]

[54] See PG&E RAMP, p. 1-36. "Destructive: Defined as a CPUC Reportable fire that burns 300 or more acres and destroys no less than 100 structures. Large: Defined as a CPUC-reportable fire that burns 300 or more acres, but destroys < 100 structures. Small: Defined as a CPUC-reportable fire that burns fewer than 300 acres."

Table 5. PG&E PSPS Effectiveness Assumptions and Derivation[55]

Outcome	PSPS Effectiveness	Notes
RFW - Destructive Fires	90.00%	This is based on the lookback analysis of applying the 2021 PSPS guidance to 2012-2020 historical fires with the detected size greater than 1000 acres. The 2021 guidance could have prevented 100% of historical destructive fires during RFW in 2015-2020. However, because the 2021 guidance is calibrated using historical fires, we assume that there could be 1 destructive fire over the same time period that won't be prevented, so the effectiveness is 9 / (9 + 1) = 90%
RFW - Large Fires	50.00%	Percentage of large fires occurred during RFW that are identified as catastrophic based on 2021 PSPS guidance. This is not perfect because the set of fires in Fire Data are only those with detected final size greater than 1000 acres, and there could be large fires that with detected size less than 1000 acres that are below guidance. However, since most of the wildfire risk is accounted for by destructive fires so the error should be small.
RFW- Small Fires	49.71%	This is based on 2020 hazards and damages data. There was 257 damages and hazards found during 2020 PSPS events, multiply that by ignition rate of 7.65% (estimated based on the veg and equipment ignition rate per outage) , and then the likelihood of ignition becoming small fires in HFTD during RFW at 85.48% (estimated based on CPUC reportable 2015-2020) to get the number of avoided small fires being .0765 * 257 * 85.48% = 16.8058. The observed small fires is 17 in 2020, so the effectiveness is 16.8/(16.8+17)=0.497

As PG&E states in the table, the 90% effectiveness for destructive fires is determined by arbitrarily assuming there would have been one fire missed by the PSPS protocol over the historical period examined, despite the fact that this is not the case. Given that there were 10 destructive fires over the period, this resulted in PG&E's 90% effectiveness statistic.

There are two problems with this methodology. First, it is sensitive to the number of fires caused in the historical period, which leads to some absurd conclusions. For example, if there had been 20 destructive fires over the period, adding one missed fire would result in a 95% mitigation effectiveness (19/20); if there had been just 2, it would be 50% (1/2). Second, the assumption that PSPS would miss one destructive fire is arbitrary and not based on data. PSPS criteria is specifically targeted to identify exactly the conditions in which a destructive or large fire is likely to occur.

Furthermore, from a common-sense understanding of PSPS as a wildfire mitigation, PSPS *should* have a near 100% mitigation effectiveness since it involves shutting off power during high-risk conditions that cause large and destructive fires. Given that PG&E's modeling assumption of including one "missed" destructive fire is arbitrary and unsupported, as well as a common-sense judgement regarding the effectiveness of shutting off power during high-risk

[55] PG&E Workpaper: EO-WLDFR-M021_EPSS and PSPS, tab "IN2_PSPS_Effectiveness."

conditions, the effectiveness of PSPS for mitigating destructive fires should be revised to at least 95%.

Regarding the 50% mitigation effectiveness of PSPS for large fires, the relatively low mitigation effectiveness value is driven by a very limited amount of data. Namely, in the utility's analysis of ignitions that occurred on its system from 2015-2020, the analysis finds there were 2 large fires that occurred in 2017 that PG&E claims would not have been mitigated by PSPS – this was divided by a total of four large fires over the period (three large fires occurred in 2016, one of which would have been mitigated by PSPS according to PG&E). However, the analysis ignores 2019 and 2020 when no large fires occurred and PSPS was in place; it could be that PSPS prevented large fires in those years, which therefore don't appear in the data set.

Table 6. PG&E Large Fire PSPS Analysis[56]

Year	Mitigation Effectiveness	Notes
2015	Not included	No large fires
2016	100%	1 large that would have been mitigated by PSPS
2017	33%	3 large, 1 that would have mitigated by PSPS
2018	Not included	No large fires
2019	Not included	No large fires
2020	Not included	No large fires

Similarly, there were no large fires in 2021 or 2023, and one large fire in 2022.[57] From both a conceptual standpoint regarding how PSPS is implemented, as well as data over the several years as PSPS has been in place, PSPS effectiveness for large fires should be significantly higher than 50%.

There is a dearth of data on PSPS effectiveness simply because it is in place and avoiding fires that would have otherwise occurred. Absent a more data-driven approach, given the clear success of PSPS in avoiding large fires PG&E should assume at least a 90% PSPS effectiveness in mitigating large fires. Again, these fires occur under precisely the conditions PSPS protocols are tailored to identify.

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[56] Analysis based on TURN-5, question 5, attachment 1.

[57] CPUC Ignition Database, https://www.cpuc.ca.gov/industries-and-topics/wildfires.

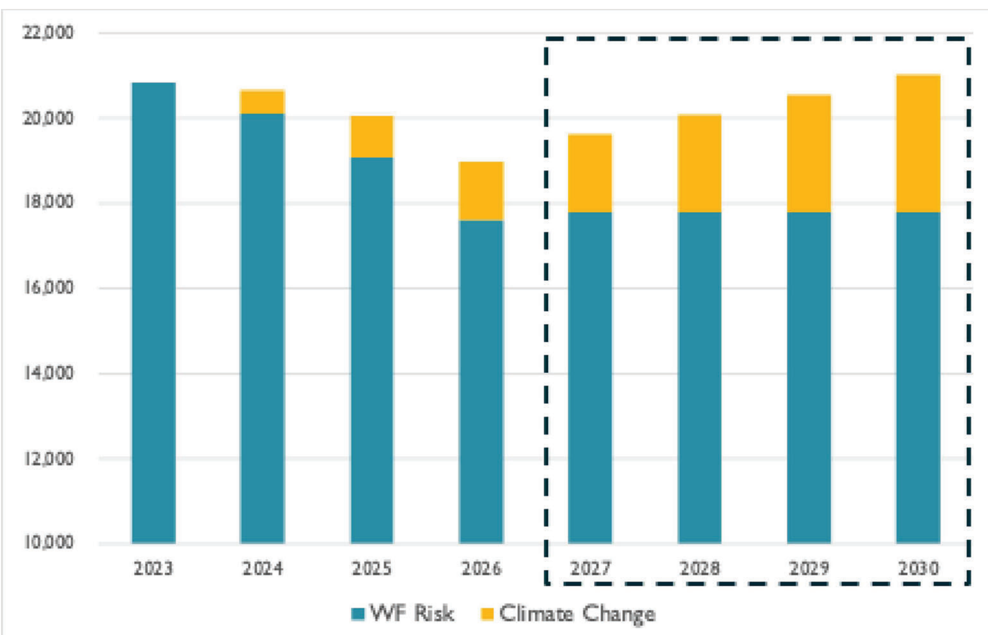
5.4. PG&E's Modeling of Climate Change Risk Is Not Reasonable

PG&E has attempted to incorporate the risk of climate change into its calculations of wildfire risk by increasing the number of ignitions expected to occur during RFW conditions as determined from climate change models, relative to a 2023 baseline:

> Climate impact is modeled as a % increase of ignitions occurring when a Red Flag Warning (RFW) is in place while keeping the total ignition frequency the same. The rate of increase is based on forecast of days above historical 95th percentile Fire Weather Index (FWI) [footnote omitted] provided by ICF climate center for 2030, 2050 and 2080 at Circuit Segment (CS) level for distribution in workpaper CC-CLIMT-14, and at Electric Transmission Line (ETL) level for transmission in workpaper CC-CLIMT-15.[58]

Incorporating climate change has a significant impact on total wildfire risk, comprising 9% of baseline wildfire risk in 2027 to 15% of baseline risk in 2030. Baseline wildfire risk increases by 18% due to climate change from 2023 to 2030.[59]

Figure 6. PG&E Modeling of Baseline Wildfire Risk and Impact of Climate Change



TURN has identified two issues with PG&E's climate change calculation.

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[58] Response to DR TURN-5, question 1.

[59] Response to DR TURN-5, question 1(c).

1. The use of climate change models to derive increases in RFW ignitions is not only extremely complex, PG&E's and ICF's modeling assumptions are highly opaque and virtually impossible, at least in the context of a single RAMP proceeding, to replicate, verify, or determine whether the inputs are reasonable.
2. The calculation appears designed to increase the impact of climate change exactly through the rate case cycle (2027-2030), after which climate change impacts would remain constant or *decrease.* At minimum, this is counterintuitive. This finding further highlights the inappropriateness of incorporating this significant driver of wildfire risk as presented, without further Commission understanding and review.

The lack of transparency stems in part from the complexity of the analysis. PG&E utilized an ICF analysis that combines results of eight different climate change models, deriving numerical values that were then compared to a 2023 baseline.[60] The relative merits of this approach and examination of inputs and outputs of ICF's analysis are not possible to determine with the materials provided by PG&E,[61] and, in any event, would require greater time, resources, and expertise than is available or possible in a single RAMP proceeding. There are bound to be numerous nuances and assumptions that drive the results here, and these need to be examined for reasonableness.

To provide just one (relatively simple) example, PG&E/ICF chose the 95th percentile results from the SSP3-7.0 climate change model and compared this to a 2023 baseline. PG&E has not explained why it believes this is the most reasonable scenario and produces the most accurate results. This kind of impactful analytic decision appears to be replicated numerous times in the modeling.

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[60] See PG&E workpaper: CC-CLIMT-14_WLDFR.

[61] Response to DR TURN-5, question 1(b).

Table 7. Shared Socioeconomic Pathway (SSP) Scenarios[62]

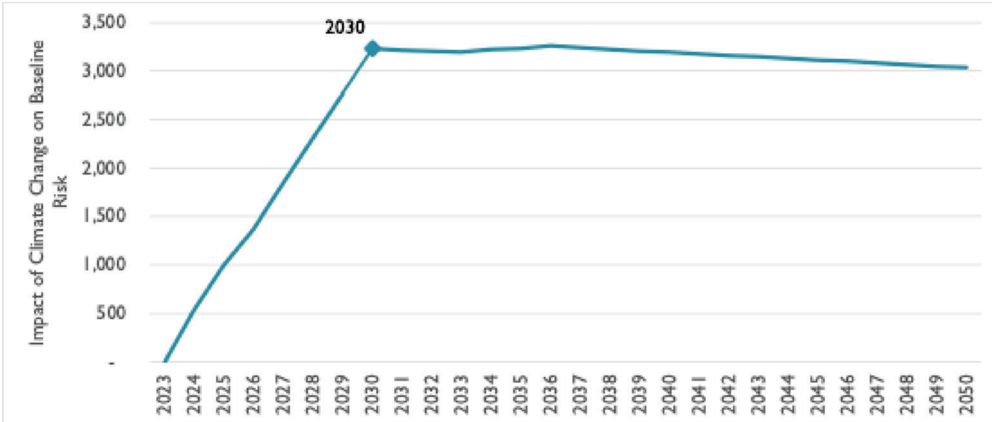
SSP Scenario	Summary Narrative	Temperature Change (2081–2100)	Sea Level Projections (2080-2100)
SSP1-1.9	Holds warming to approximately 1.5°C above pre-industrial levels with a slight overshoot, aiming for net zero CO2 emissions around mid-century.	1.0°C – 1.8°C (1.8°F – 3.2°F) Very Likely	For 1.5°C global warming
SSP1-2.6	Stays below 2.0°C warming relative to pre-industrial levels with net zero emissions targeted for the second half of the century.	1.3°C – 2.4°C (2.3°F – 4.3°F) Very Likely	For 2°C global warming
SSP2-4.5	Aligns with the upper end of current Nationally Determined Contributions (NDCs), predicting warming around 2.7°C by 2100.	2.1°C – 3.5°C (3.8°F – 6.3°F) Very Likely	For 3°C global warming
SSP3-7.0	No additional climate policies under a medium to high emission scenario, with particularly high non-CO2 emissions.	2.8°C – 4.6°C (5.0°F – 8.3°F) Very Likely	For 4°C global warming
SSP5-8.5	High emission scenario without additional climate policies, under a fossil-fuel-heavy development pathway.	3.3°C – 5.7°C (5.9°F – 10.3°F) Very Likely	For 5°C global warming

At this point, TURN simply cannot say whether this assumption is reasonable or what the implications of using other scenarios may be. The Commission and parties need significantly more time and exploration to determine how best to incorporate the climate change variable into risk calculations, particularly given its significant impact on the results.

Lastly, ICF's modeling results are highly counterintuitive. The following figure shows the annual impact of climate change on baseline wildfire risk. Climate change increases baseline wildfire risk at a rising linear rate through 2030, the end of the rate case period, and then has virtually no impact or *decreases* thereafter.

[62] NASA, https://sealevel.nasa.gov/ipcc-ar6-sea-level-projection-tool?psmsl_id=1476&info=true&data_layer=scenario.

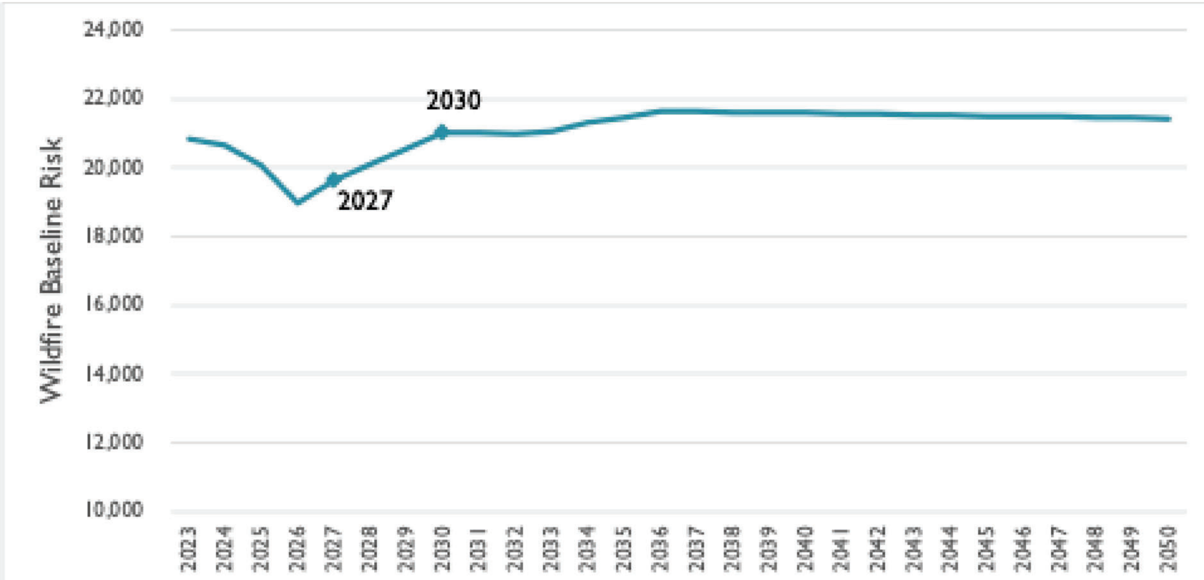
Figure 7. Annual Impact of Climate Change on Baseline Wildfire Risk Score (Risk Units) [63]



This impact is also seen in the wildfire baseline risk score below, which increases from 2027-2030 and then remains effectively flat thereafter. Note too that the impact of climate change completely erases all risk reduction achieved from 2023-2026 from undergrounding and other initiatives on which PG&E is spending billions and for which ratepayers, particularly those who are lower income, are incurring tremendous hardship.

[63] Response to DR TURN-8, question 1, attachment 2.

Figure 8. Wildfire Baseline Risk Score (Risk Units, 2023-2050) [64]



From a common-sense perspective about climate change, these results do not seem accurate, namely that higher temperatures result in a lower or flat increase in annual risk after 2030. PG&E sought to explain these results as follows:

> […]it is not unusual for FWI projections to decrease between two near-term time horizons, as precipitation, wind, and humidity are not increasing or decreasing linearly through time. FWI is a dynamic variable influenced by many different variables pulling it in different directions through time, but temperature will accelerate by late-century (2080) overwhelming any variability in the remaining variables.[65]

At minimum, this underscores that greater understanding and deliberation of these modeling results is required.

While aspects of PG&E's approach may be useful, it is not clear that PG&E's approach is accurate or robust enough to incorporate into the GRC to inform near-term investments. This issue affects all utilities and should be addressed more robustly in the S-MAP process.

In the meantime, while TURN does not oppose some climate change-based increase in risk being incorporated into PG&E's modeling between 2023 and 2030, PG&E's modeled increase cannot be verified, and it is frankly suspicious that climate change impacts should primarily affect the rate case cycle years (2027-2030) and erase all previous risk reduction gains, very likely leading

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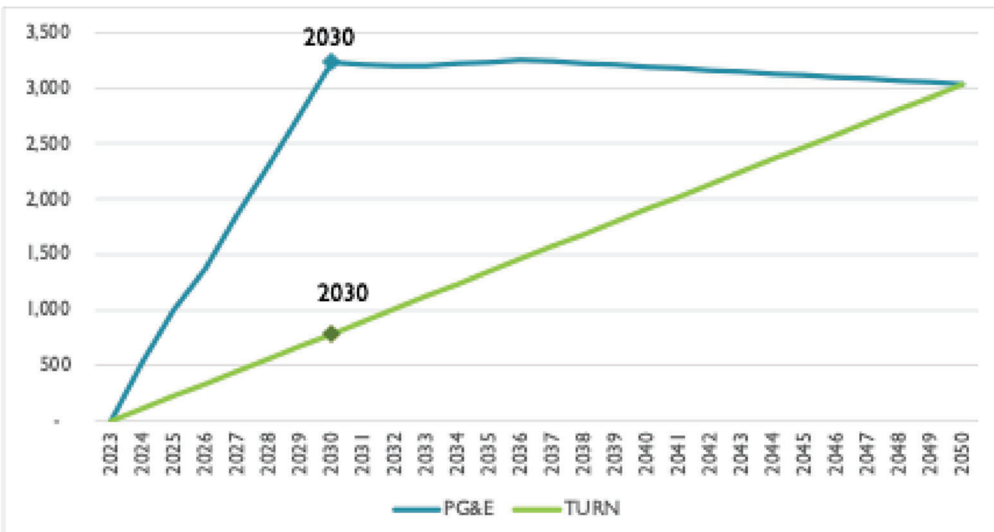
[64] Response to DR TURN-8, question 1, attachment 2.

[65] Response to DR TURN-5, question 1(d).

to dramatic and (until recently) unprecedented proposed spending levels to underground distribution infrastructure, in part based on this calculation.

TURN here offers an alternative approach based on the ICF data used by PG&E. Rather than utilizing results whereby all of climate change impacts' affect only the 2023-2030 time period, PG&E could incorporate a smoothed average estimate of climate change's annual impact based on ICF's results. To accomplish this, we calculate the average impact from 2023-2050 and then set this as the annual incremental amount by which climate change increases the baseline risk score. This approach would allow PG&E to incorporate a more gradual annual increase to the wildfire baseline risk score due to climate change while the Commission and parties explore the topic through a more robust process.

Figure 9. Alternative Estimate of Annual Impact of Climate Change on Baseline Wildfire Risk Score (Risk Units)[66]



5.5. PG&E Draws Incorrect Conclusions from Its Environmental and Social Justice Pilot Study

PG&E's RAMP presents an analysis that purports to show Disadvantage and Vulnerable Communities (DVCs) "receive a disproportionately large share of the benefit from wildfire

[66] Response to DR TURN-8, question 1, attachment 2.

safety work."[67] The analysis allocates risk to DVC customers in each tranche, assuming risk in each tranche is uniform:

> % DVC customers (CS-freq weighted or CS-risk weighted) represent the percentage of tranche-level frequency or risk allocated to the DVC customers, assuming the circuit segment frequency or risk is allocated equally to each customer served by the circuit segment. This number is equivalent to the weighted average of % of DVC customers in a circuit segment, with the circuit segment frequency (or risk) as a weight.[68]

As stated, PG&E's analysis purports to show that on a risk-weighted basis DVC customers benefit disproportionately from wildfire mitigation work. For example, PG&E notes that in one tranche, based on this methodology, "the DVC customers, which make up 23% of the total customer population, get 29% of the risk reduction value from SH."[69]

There are numerous flaws in PG&E's analysis.

First, even if taken at face value, the analysis is not very compelling and does not actually show that DVC customers "disproportionately benefit." In total, DVC customers (according to PG&E's analysis) represent 29% of the population but receive 31% of the risk reduction "value".[70] This can hardly be viewed as "disproportional."

Further, PG&E's conclusions are not necessarily reasonable when analyzed more holistically. For example, PG&E's risk modeling results and DVC population analysis show that, while 97% of wildfire risk is contained in the HFRA, just 5% of the total DVC population resides there,[71] as shown in the table below. Using PG&E's logic, this means that 95% of the DVC population does *not* benefit from programs like system hardening that occur in the HFRA. Further, since 16% of HFRA customers are DVC customers, 84% of the beneficiaries of wildfire risk reduction programs (again using PG&E's logic) are non-DVC, even though non-DVC customers represent just 71% of the population (as stated above, 29% of the population are DVC customers).[72] One

[67] PG&E 6/18/24 Workshop, slide 40.

[68] Response to DR TURN-10, question 3(b).

[69] PG&E 6/18/24 Workshop, slide 40.

[70] PG&E 6/18/24 Workshop, slide 40.

[71] PG&E Workpaper: EO-WLDFR-17_DVC analysis, tab "tranche and consequence."

[72] Id.

could therefore argue based on this data that ***non-***DVC customers disproportionately benefit from wildfire risk reduction in the HFRA.

Table 8. DVC Customers[73]

Total DVC Customers	1,608,416
DVC HFRA Customers	82,801
Total Percentage	*5%*

Total HFRA Customers	505,847
DVC HFRA Customers	82,801
Total Percentage	*16%*

Second, PG&E admits that its analysis allocates risk, and therefore implied risk reduction from wildfire risk reduction programs, uniformly across tranches, without regard to where projects will actually occur. HFRA tranches range from 477 primary and secondary miles to 14,231 miles, covering large geographic distances.[74] It therefore cannot be ascertained what "communities," much less specific customers, will actually benefit from these projects. Put another way, PG&E's methodology of allocating risk evenly across each tranche may have no relationship to how risk reduction accrues to DVCs or other types of communities, a fundamental flaw.[75]

Furthermore, contrary to PG&E's logic, TURN notes that locating an overhead hardening or undergrounding project to mitigate wildfire risk in a particular area does not necessarily benefit only the nearby community. Reducing the risk of wildfires, can provide at least some benefits to all of PG&E's customers, the state, and potentially out of state areas that would otherwise be subject to potentially toxic and harmful wildfire smoke.

Lastly, and perhaps most importantly, PG&E's analysis completely ignores affordability. Based on the lens by which PG&E presents its analysis, *any* amount of a regressive utility bill increase, as long as it reduces wildfire risk, would be "beneficial" to lower-income communities. This conclusion is contrary to any reasonable notion of fairness or equity. On this point alone,

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[73] *Id.*

[74] PG&E Workpaper: EO-WLDFR-17_DVC analysis, tab "tranche and consequence."

[75] Response to DR TURN-10, question 4(c).

PG&E's analysis is simply not useful for determining the extent to which DVCs benefit, or do not, from wildfire risk reduction programs.

TURN recognizes that PG&E's analysis was part of the Pilot Study ordered in D.22-12-027. However, recognizing that this type of analysis is new and in need of significant refinement, PG&E should refrain from stating dubious conclusions in its GRC, as it did at the June 18, 2024 workshop in this case, without a more solid analytic foundation.

This concludes TURN's informal comments.

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Appendix – Summary of Recommendations

- PG&E uses geography-agnostic data to calculate an interruption cost estimate of $3.17/CMI across its territory. This approach does not account for geographical differences in customer distribution and respective reliability impacts. TURN recommends a more nuanced four-tiered evaluation of $/CMI using tier-specific SAIDI values, resulting in an average electric reliability cost of $1.83/CMI.

- PG&E's hybrid approach for the Safety Attribute, applying California-specific adjustments to the DOT's nationwide Value of Statistical Life (VSL) to arrive at a VSL of $15.2 million, is contrary to DOT guidelines on the use of VSL and contrary to D.22-12-027. TURN recommends adhering to DOT guidelines by using the DOT's 2012 Value of Statistical Life (VSL) of $9.1 million, adjusted to $13.2 million for the year 2023.

- PG&E has not demonstrated that its extremely convex scaling function is reasonable. As required by D.24-05-064, PG&E's GRC submission should include alternative risk score and CBR results based on a risk neutral scaling function.

- PG&E's GRC filing should include workpapers that allow intervenors and the Commission to compare the CBRs of alternative mitigations assuming they are performed in the same risk areas. At minimum, upon request, PG&E should provide workpapers enabling such an apples-to-apples comparison within the customary 10 business-day data request cycle.

- PG&E should change its wildfire risk assumption of $1 million per structure destroyed to $723,000, the weighted average (by structures) from 2015-2022.

- The mitigation effectiveness of covered conductor should be based on recorded utility data. This may include data from Southern California Edison where applicable.

- PG&E's risk modeling should incorporate more realistic assumptions for PSPS customer minutes of outage, including an upper bound of around 272 million minutes per year.

- PG&E should assume PSPS mitigation effectiveness of 95% for destructive fires and 90% for large fires.

- In modeling climate change impacts, PG&E should incorporate less drastic annual increases for the rate case period in baseline wildfire risk based on its current modeling results while the Commission allows for more robust analysis of the issue in the S-MAP proceeding.

- PG&E conclusion that disadvantaged and vulnerable communities (DVCs) disproportionately benefit from wildfire risk reduction is poorly supported based on the current iteration of its DVC analysis. PG&E's conclusions about benefits to DVCs should be based on a more solid analytical foundation.