California Public
Utilities Commission

Consolidated Stakeholder Responses to Post-Workshop Questions on CPUC's SB-884 Guidelines

SAFETY POLICY DIVISION

April 11 2025

Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines

April 11, 2025

Instructions:

- If any question in this document calls for a "yes" or "no" answer, please explain your answer rather than simply providing a one-word answer.
- The reference to Office of Energy Infrastructure Safety (Energy Safety) Guidelines are available at https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=58006&shareable=true.
- The Commission SB-884 Guidelines refers to Resolution SPD-15, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M526/K984/526984185.pdf

Definitions:

- **Cost Benefit Ratio (CBR)**: calculated by dividing the dollar value of Mitigation Benefit by the Mitigation cost estimate.[1]
- **Circuit Segment**: refers to a specific portion of an electrical circuit that can be separated or disconnected from the rest of the system without affecting the operation of other parts of the network. This isolation is typically achieved using switches, circuit breakers, or other control mechanisms.[2]
- **Electric Undergrounding Program (EUP):** an expedited utility distribution infrastructure undergrounding program established by the CPUC pursuant to section 8388.5(a).[3]
- **Investor Owned Utility (IOU)**: Utility regulated by the Commission that seeks SB 884 cost recovery or submits an SB 884 Application or seeks Energy Safety approval for an SB 884 Plan.
- **Key Decision-Making Metric (KDMM):** Energy Safety's 10-Year Electrical Undergrounding Plan Guidelines describe Key Decision-Making Metrics as a collection of top-level metrics that the Large Electrical Corporation is allowed to use to evaluate the efficacy of an Undergrounding Project. They do not reflect financial considerations. The utility must report on seven mandatory KDMMs, and may include 5 additional KDMMs of its choice. The mandatory KDMMs include Ignition Risk and Outage Program Risk.[4]
- **Memorandum Account (MA):** In the context of Senate Bill (SB) 884 Program: CPUC Guidelines, the Memorandum Account refers an account where a large electrical corporation may record implementation costs that do not meet the Phase 2 Conditions. In Phase 3, the large electrical corporation may file an application and request rate recovery for these costs.
- **Office of Energy Infrastructure Safety (Energy Safety) Guidelines**: explained in "Instructions," above.
- **Phase 2 Conditions (Conditions):** The Phase 2 Conditions will include, but are not limited to, a total annual cost cap, two-year rolling average recorded unit cost cap, two-year rolling average recorded CBR threshold, and applying third-party funding to reduce the cost cap.[5]

[1] D.24-05-064, Appendix A at A-3. A higher CBR means more risk reduction is achieved for the same amount of cost, indicating greater cost-efficiency. For example, if Project A has a CBR of 2.0 and Project B has a CBR of 1.0, Project A delivers twice the risk reduction benefit per dollar spent compared to Project B.

[2] This concept refers to the same concept found within the Energy Safety Guidelines Appendix A.

[3] Energy Safety 10-Year Electrical Undergrounding Plan Guidelines, A-1.

[4] For details see Energy Safety 10-Year Electrical Undergrounding Plan Guidelines, Section 2.7.3 at 31-32.

[5] For details see SPD-15, SB-884 Program: CPUC Guidelines at 10-11.

- **Protective Equipment and Device Settings (PEDS)**: advanced safety settings implemented by electric IOUs on electric utility powerlines to reduce wildfire risk.[6]
- **SB 884 Project List Data Requirements**: the list of data fields that the utility must complete for each project the utility includes in its EUP cost recovery Application. This data set must be submitted with the initial cost recovery Application and updated in the six-month progress reports. The detailed requirements are listed in Appendix 1 of SPD-15 or any future update to Appendix 1.
- **Screen 2 (Project Information and Alternative Mitigation Comparison)**: confirms there is sufficient information available on a Circuit Segment and requires comparison of undergrounding to alternative mitigations in order to determine which Eligible Circuit Segments can be treated as Undergrounding Projects.[7]
- **Screen 3 (Project Risk Analysis)**: the procedure for evaluating an individual Undergrounding Project in the context of the Portfolio of Undergrounding Projects and includes information obtained through the project development process resulting in a list of Confirmed Projects.[8]
- **Screen 4 (Project Prioritization and Finalization):** the procedure for prioritizing Confirmed Projects using the means of prioritization approved by Energy Safety in the Electrical Undergrounding Plan (EUP).[9]
- **Undergrounding Project**: an Eligible Circuit Segment that has completed Screen 2 including the SB 884 Project List Data Requirements from Appendix 1 of SPD-15 or any future update to Appendix 1.

A. Should the Commission Consider Supplementing the Phase 2 Application Requirements?

Background:

SPD-15 included a list of 20 requirements that must be included in any Application submitted to the Commission seeking conditional approval of Plan costs. Would it be appropriate for the Commission to consider adding the following requirements?:

1. Include the data associated with the list of all projects (SB 884 Project List Data Requirements) as required by Screen 2 of the Energy Safety Guidelines
    a. Require the utility to provide us with a forecasted scope of all projects for the ten-year plan, with the expectation that projects far in the future would change.
    b. This requirement would make it explicit that the Underground Project List, which is an output from Screen 2 in the Energy Safety Guidelines, must be ready for the Commission to review before an Application can be submitted.
2. Require the utilities to provide a detailed explanation for any spans that extend beyond the HFTD for any project included in the Underground Project List from Screen 2 of the Energy Safety Guidelines.[10]
    a. The Energy Safety Guidelines allow for undergrounding circuit segments with assets inside the HFTD, then each span that crosses the Tier 2 or 3 HFTD boundary and up to two adjacent spans outside of a Tier 2 or 3 HFTD may also be included in a project.
    b. This requirement would ask the utilities to provide a detailed explanation regarding why they must include any spans that extend beyond the HFTD.

[6] For details see https://www.cpuc.ca.gov/industries-and-topics/wildfires/protective-equipment-device-settings
[7] For details see Energy Safety 10-Year Electrical Undergrounding Plan Guidelines, Section 2.4.4 at 18-19
[8] For details see Energy Safety 10-Year Electrical Undergrounding Plan Guidelines, Section 2.4.5 at 19-20
[9] For details see Energy Safety 10-Year Electrical Undergrounding Plan Guidelines, Section 2.4.6 at 20
[10] For details see PUC 8388.5(c)(2) and Energy Safety 10-Year Electrical Undergrounding Plan Guidelines, Section 2.4.3.1 at 16.

3. Require utility to submit a depreciation study with updated information of the type of assets that are impacted by an SB-884 Application
    a. Depreciation studies are typically updated when a utility files its GRC.
    b. Because undergrounding projects have large capital expenditures, there is a potential that depreciation and salvage costs may be contested in an EUP cost recovery Application.
    c. This would require a depreciation study be included in the record, but it should be a depreciation study with updated information since an EUP cost recovery Application will not necessarily be submitted in the same time frame as a GRC.
4. Require both nominal and present value lifetime calculations for the capital expenditures for each project included in the Undergrounding Project List from Screen 2 of the Energy Safety Guidelines [11]
    a. PUC 739.15 specifically calls out the need for greater clarity on the lifetime cost and benefit of a capital expenditure project such as those submitted in an EUP cost recovery Application.
    b. This would require both nominal and present value lifetime calculations for the capital expenditure of each undergrounding project.
5. Require data retention policy for lifetime of EUP for tabular and geodatabase data. This should be required for both the initial application and any of the data updated through the six-month progress reports.
    a. Since there are no additional requirements for data retention related to an EUP, this will require the utility to retain all tabular and geodatabase information submitted as part of the EUP and any data included in six-month progress reports.
    b. Staff intend to hold data template working groups later in the spring.
6. Require utilities to submit the same Key Decision-Making Metrics (KDMM) data for Commission review as provided for in the submission to Energy Safety.

B. What, if Any, Additional Phase 2 Conditions Should the Commission Consider?

Background:

SPD-15 listed five Phase 2 Conditions that must be met for the costs of any project to be booked to a one-way balancing account. The parameters or threshold values of the Conditions will be established in the Phase 2 Decision based on the forecasted numbers presented in the cost recovery Application. As explained in the Instructions above, the five Conditions listed in SPD-15 include a total annual cost cap, a two-year rolling average recorded unit cost cap, a two-year rolling average recorded CBR threshold, a requirement to apply third-party funding to reduce the cost cap, and any further reasonable Conditions supported by the record of the proceeding and adopted by the Commission in the Phase 2 Decision.[12]

1. Should the Commission consider imposing Conditions on the Memorandum Account (MA)? If so, what Conditions should be considered?
    a. Option 1: Establish a maximum total cap for the MA, limiting it to no more than 25% of the total sum of the ten-year annual caps established for the balancing account.
    b. Others?
2. Should the Commission consider assessing the variance between the forecast data submitted according to the SB 884 Project List Data Requirements in the initial cost-recovery Application to

[11] See also PUC 739.15
[12] For details see SPD-15, SB-884 Program: CPUC Guidelines at 10-11.

the Commission and the updated data submitted according to the SB 884 Project List Data Requirements in a six-month progress report and if so how?

   a. Option 1: If the variance between the forecasted CBRs and unit cost of a project presented in an Application compared to the updated CBRs and unit cost of a project presented in a six month Progress Report (after a project passes Energy Safety's Screen 4) exceeds a certain threshold, then all costs for that project must be recorded in the MA.
   b. Others?

3. Should the Commission consider adopting a CBR Threshold, and if so, what should the criteria be?
   a. Option 1: Require all projects to have a CBR greater than a specified value.
   b. Option 2: If a project's recorded CBR is less than a specified value, the utility must provide a detailed justification for this project.
   c. Option 3: After Screen 2, any project ranked below a certain CBR percentile threshold is ineligible for cost recovery via the BA.
   d. Others?
4. Should the Commission consider requiring a comparative CBR analysis of project alternatives? If so, how should this analysis be conducted?
   a. Option 1: If an Undergrounding Project has a CBR above a specified CBR Threshold but the Alternative(s) has a CBR that is a specified amount greater than the Undergrounding Project's CBR, then the undergrounding project should not move forward.
   b. Others?
5. Should the Commission consider applying some of Energy Safety's KDMMs to the Commission's consideration of whether to grant cost recovery for projects and if so, how?
   a. Option 1: After Screen 3, if the reduction in Ignition Risk and/or Outage Program Risk does not meet the required Project Level Standard set in the approved Plan, the project will not be eligible for cost recovery via the one-way balancing account.
   b. Others?

C. What methods could the Commission use to address the Audits and/or Review Procedure?

Background:

The Commission's SB-884 Guidelines require that costs submitted in an SB-884 Application meet certain Conditions (Phase 2 Conditions) before they can be authorized for recovery via a one-way balancing account.[13] That one-way balancing account is subject to audit. If the audit finds that costs were incorrectly recorded or failed to meet the Phase 2 Conditions, the Commission may order a refund. SPD-15 stated that the details of this audit would be determined in a later decision or order. The questions below explore two potential structures for determining whether costs were appropriately recorded to the balancing account:

Questions:

1. Should the Commission consider adopting the following review structure to ensure a rigorous review of the costs associated with an EUP?
   a. Annual post-implementation review process with intervenor participation.
   b. Objectives of the review should include verifying project completion, cost overheads, CBR methodology and an incrementality showing.

[13] The Phase 2 Conditions will include, but are not limited to, a total annual cost cap, two-year rolling average recorded unit cost cap, two-year rolling average recorded CBR threshold, and applying third-party funding to reduce the cost cap. For details see SPD-15, SB-884 Program: CPUC Guidelines at 10-11.

   c. Once deemed "used and useful" in a progress report, a project's costs may be included in rate base via an Advice Letter that must be disposed via Commission Resolution.
   d. Commission Resolution will determine whether recorded costs met the Phase 2 Conditions and other objectives of the review.
   e. Approved costs would enter rates via Annual True-up.
2. Should the Commission instead consider adopting the following review structure to audit the costs associated with an EUP?
   a. Annual audit by independent auditor with CPUC oversight.
   b. Objective of the audit should include verifying project completion, cost overheads, and an incrementality showing.
   c. Once deemed "used and useful" in a progress report, a project's costs may be included in rates via annual True-up and become subject to audit.
   d. If the audit finds that project costs were incorrectly recorded to the Balancing Account, then the utility must issue a refund to ratepayers.
3. Supporting Questions:
   a. How should the timing of the Independent Monitor's (IM) review and the utility's right to correct a deficiency found by the IM within 180 days (PUC 8838.5 (g)(2)) interact with the annual review of the costs of a project?
   b. How should projects that fail to meet key criteria be treated vis-a-vis cost recovery? What key criteria should be considered?
   c. Should intervenors participate in Options 1 and 2 above? If so, how and where?
   d. Should the Commission consider using a different option than 1 or 2 above? If so, explain each step in the proposed process. How and where would intervenor participation be accounted for in the proposed option?

D. How could the Commission address changes to approved projects?

Background:

Changes to project costs and implementation status can impact cost recovery under the SB-884 framework. Except for 25 projects that Energy Safety's Guidelines will require to pass through all four Screens, cost and risk data (including CBR calculations) presented will be associated with projects having passed Screen 2 at the time of Application submittal. However, it isn't until after projects have passed Screen 4 that their full scope is determined and more accurate data associated with project cost and risk (including CBR calculations) are provided. These updated data are expected to be received throughout the life of the 10-year Plans and submitted via the six-month progress reports. Accordingly, how should the Commission handle new costs added to projects after the Phase 2 Decision is issued, based primarily on Screen 2 data? How should the Commission treat costs from abandoned or incomplete projects? The following questions explore potential approaches for managing these changes.

1. Should new costs added to approved projects after the Phase 2 Decision be booked to the Memo Account?
   a. If the updated rolling average CBR falls below the Phase 2 Condition threshold, should all new costs be deemed non-recoverable?
2. Should certain categories of cost overruns (e.g., inflation-driven, safety-driven) be treated differently from discretionary cost increases?

E. Should the Commission include an Appendix with guidance for calculating the CBR of an undergrounding project?

Background:

The calculation of the CBR for undergrounding and alternative projects is a critical factor in determining project eligibility for cost recovery. In addition, the selection of CBR Year Zero[14] plays a pivotal role in accounting for the time value aspect of CBR calculations. Notably, the Energy Safety Guidelines define Total Utility Risk as the sum of Ignition Risk and Outage Program Risk.[15] The following questions explore how utilities should apply existing methodologies and present their results.

1. What level of granularity[16] should the utility use when applying the Interruption Cost Estimator (ICE) Calculator to generate a Monetized Value of Electric Reliability? Should the analysis be based on:
    a. HFTD and PEDS-activated circuits
    b. Operational Region and HFTD[17]
    c. Others?
2. How should the utility calculations of CBR be presented when using the three discount rate scenarios (Weighted Average Cost of Capital, Social and Hybrid) required by D.24-05-064?[18]
3. Since the Energy Safety Guidelines allow the utility to consider an Ignition Tail Risk Threshold and High Frequency Outage Program Threshold,[19] if the utility applies a convex risk scaling function to the calculation of CBR, how should the utility also present calculations that do not apply a convex risk scaling function, as required by D.24-05-064?[20]
4. How should the Commission consider the combined CBR benefits of Ignition Risk reduction and Outage Program Risk reduction, given that a proposed mitigation may also reduce outage program risk?
    a. Option 1: Calculate the CBR benefit based on the Ignition Risk reduction only.
    b. Option 2: Calculate the CBR benefit based on a combination of Ignition Risk reduction and Outage Program Risk reduction?
        i. Should the CPUC assume mutual exclusivity between Ignition Risk and Outage Program Risk when aggregating the CBR benefits? If not, how should these risks be comibined?
5. What is the appropriate point in time for utilities to use as CBR Year Zero in CBR calculations?
    a. Option 1: The first year of application cycle.
    b. Option 2 : The year the project is expected to become used and useful.

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[14] The year that all Costs and Risk Reductions are discounted to for the purpose of CBR calculations.
[15] For details see Energy Safety 10-Year Electrical Undergrounding Plan Guidelines, Section 2.7.3 at 31.
[16] "Level of granularity," as used in this context, refers to the spatial scale at which it is expected the utility will organize data inputs for use with the ICE Calculator.
[17] For details see R.20-07-013, ALJ Ruling Entering Phase 4 Technical Working Group Materials and Related Staff Proposal into the Record and Setting Comment Schedule, Attachment 2: Proposed Data Template Guideline for RAMP and GRC Applications, February 7 at 5 and 18-19. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M556/K602/556602764.PDF
[18] See the requirement in D.24-05-064 at 102-105 and D.24-05-064, Appendix A, Row 25.
[19] For details see Energy Safety 10-Year Electrical Undergrounding Plan Guidelines, Section 2.7.9.1 at 42.
[20] See the requirement in D.24-05-064 at 97-98 and D.24-05-064, Appendix A, Row 7.

April 25, 2025

Via Electronic Filing

Danjel Bout, Director
Safety Policy Division
California Public Utilities Commission
505 Van Ness Avenue
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SB884@cpuc.ca.gov

Subject: Public Advocates Office's Informal Comments on Planning Questions for Stakeholders Regarding the CPUC SB-884 Guidelines

Dear Director Bout,

The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) respectfully submits informal comments on the Questions for Stakeholders Regarding the CPUC SB-884 Guidelines.

Please contact Nat Skinner (Nathaniel.Skinner@cpuc.ca.gov) or Henry Burton (Henry.Burton@cpuc.ca.gov) with any questions relating to these informal comments.

We respectfully urge the Commission to adopt the recommendations discussed herein.

Sincerely,

/s/ ***Joshua Tey***
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cc: SB-884 Notification List

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I. INTRODUCTION

The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) provides these informal comments in response to Safety Policy Division's (SPD) planning questions for Senate Bill (SB) 884 Guidelines issued April 11, 2025 (Planning Questions). Each utility that submits an undergrounding plan under SB 884 should be held accountable for executing its plan in a timely and cost-effective manner. If a utility fails to do so, it risks failing to meet wildfire risk reduction targets, not meeting the California Public Utilities Commission's (Commission) affordability principle, and wasting ratepayer resources.

The Planning Questions go to the several requirements that utilities must meet in SB 884 applications. In these informal comments, Cal Advocates proposes several revisions to Resolution SPD-15 that will maximize the public benefit of these plans, tighten accountability measures, and ensure all undergrounding expenditures are just and reasonable.

A. Should the Commission Consider Supplementing the Phase 2 Application Requirements?

1. Utilities should be required to provide the Commission with a copy of the plan they submit to Energy Safety when it is submitted to Energy Safety.

Resolution SPD-15 requires utilities to provide a complete list of all projects that will be completed as part of an Electrical Undergrounding Plan (EUP) and application. This requirement should remain in place.[1, 2] This language is consistent with Public Utilities Code section 8355(c)(2) which requires utilities to identify "the undergrounding projects that will be completed."

Moreover, utilities must prepare the Underground Project List from Screen 2 of the Energy Safety Guidelines, which purports to satisfy the statutory requirements.[3] To

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[1] Resolution SPD-15, *Attachment 1 - Staff Proposal for SB 884 Program* at 4, Mar. 8, 2024.

[2] Planning Questions at 2.

[3] *Energy Safety 10-Year Electrical Undergrounding Plan Guidelines Section 2.4.4* at 18-19, Feb. 20,

enable SPD staff and intervenors to ensure that both the Commission and Energy Safety requirements are satisfied and minimize the risk of rework and inconsistencies, the utilities should submit the complete Electric Undergrounding Plan (EUP) to the Commission as a an application, including the Screen 2 lists when the EUP is submitted to Energy Safety.

2. The Commission should require utilities to pursue cost recovery for miles outside of the High Fire-Threat Districts (HFTD) through the General Rate Case (GRC).

Public Utilities Code section 8388.5(c)(2) prohibits the consideration and construction of projects outside of tier 2 and 3 HFTDs or rebuild areas. If a utility wishes to request recovery of costs for undergrounding in areas outside of tier 2 and 3 HFTDs, it should pursue funding through its GRC. Cal Advocates has previously commented on this issue to Energy Safety. For additional details, please refer to the Appendix.[4]

3. The Commission should require utilities to provide details on their Results of Operation (RO) models in the EUP.

Cal Advocates appreciates that SPD plans to require utilities to submit depreciation studies for the EUP.[5] This partially addresses the concerns we have raised about depreciation studies in the SB 884 RO model.[6] In addition, SPD should ensure that RO models used in an EUP are comparable with those used in the GRCs. If cost recovery applications in different proceedings use different RO models, it may be difficult to determine whether lines that were undergrounded as part of an SB 884 plan have been removed from the rate base in future GRCs.

For example, PG&E proposes to underground 1,711 miles of lines for the years 2027-2030 in its Risk Assessment Mitigation Phase (RAMP) report. However, Pacific

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2025.

[4] Appendix, Attachment 4, *Public Advocates Office's Reply Comments on the Updated Revised Draft Guidelines for the 10-Year Electrical Undergrounding Plan (EUP)* at 2-3, Oct. 14, 2024.

[5] Pursuant to SB 884.

[6] Public Advocates Office's Informal Comments on Questions for Stakeholders regarding the CPUC SB-884 Guidelines at 1-2, Nov. 12, 2024.

Gas & Electric (PG&E) states it will also pursue cost recovery for any undergrounding project that is operational on or after January 1, 2027 through the 10-year EUP.[7] PG&E's approach will not only artificially reduce its forecast expenditures in the GRC, but also may lead to problems with accounting for the costs of these 1,711 miles of undergrounding if different RO models are used. The inclusion of the EUP forecast costs with all other costs will give the Commission greater insight into the rate impacts of the EUP.

4. The Commission should ensure that unique project specific identifiers that are traceable between different proceedings are provided by the utilities

Currently, there is no consistent way to identify projects in EUPs, GRCs or other proceedings. As highlighted by The Utility Reform Network (TURN), the utilities could theoretically attempt to re-litigate prior Commission decisions on the scope and cost of undergrounding projects that have already been denied through SB 884.[8] To avoid this issue, the GRC and 10-year EUP RO models should utilize the same specific project identifiers for all projects, this will ensure full transparency.

5. The Commission should require both nominal and present value lifetime calculations.

Cal Advocates supports TURN's previous comments to SPD on nominal and present value lifetime calculations. TURN states:

> The Commission should make clear in a decision or ruling in advance of the submission of Phase 2 applications that those applications must include both nominal and present value (PV) lifetime calculations for the capital costs of their proposed plans. To account for the fact that different projects will start at different times over the duration of the proposed plan, the utility should include workpapers showing the lifetime costs for each proposed project.[9]

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[7] Appendix A-1 to A-2, PG&E's response to RAMP-2024_DR_CalAdvocates_005-Q001.

[8] Informal Comments of the Utility Reform Network (TURN) on The CPUC Staff Proposal for the SB 884 Program at 6-7, Sept. 27, 2023.

[9] *INFORMAL COMMENTS OF THE UTILITY REFORM NETWORK (TURN) IN RESPONSE TO OCTOBER 14, 2024 QUESTIONS FROM CPUC STAFF REGARDING SB 884 IMPLEMENTATION* at

Electrical undergrounding projects submitted to the Commission should include both nominal and present value lifetime calculations.

6. The Commission should require a data retention policy for the lifetime of the EUP.

Cal Advocates has submitted comments to Energy Safety and SPD that are relevant to inquiries about the EUP data retention policy. For additional details, please refer to Appendix A.[10, 11] The availability of historic spatial records for electrical systems is important for tracking the risk reduction utilities accrue to SB 884 projects. Knowing exactly which assets have been removed from service is the only way to accurately validate the risk reduction attributable to a specific project against the risk models used to make the decision to underground a particular section of the electrical system.

B. What, if Any, Additional Phase 2 Conditions Should the Commission Consider?

1. The Commission should impose a maximum total cap for the memorandum account, along with individual caps for projects.

Cost overruns are a risk that should be managed by the business. Ratepayers should not be responsible for a utility's inability to effectively forecast and manage its budget requirements. TURN has commented previously that, when utilities are allowed to seek cost recovery through memorandum accounts, the Commission loses its ability to control utility spending. TURN's previous comments detailed that:

> PG&E's 2020 GRC decision authorized forecast costs for wildfire mitigation in 2020-2022 of $4.7 billion. During that period, PG&E *actually* spent $14.3 billion.... This excess spending has already resulted in PG&E applications and advice letters seeking to recover

11, Nov. 12, 2024.

[10] Appendix, Attachment 3, *Corrected Comments of the Public Advocates Office on Pacific Gas and Electric Company's Topics for Discussion on Revised Draft EUP Guidelines* at 3-4, Aug. 9, 2024.

[11] Appendix, Attachment 5, *Public Advocates Office's Informal Comments on Questions for Stakeholders Regarding the CPUC SB-884 Guidelines* at 7, Nov. 12, 2024.

> an additional $5.2 billion in rates.[12]
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> Cal Advocates has previously submitted comments in the past to SPD regarding the need to track individual projects in the memorandum account.[13]
>
> In order to determine whether a utility is keeping within its cost forecasts, utilities should segregate memorandum accounts by project ID and track expenditures for each project. In other words, every entry in the memorandum account should be linked to a specific project ID. This would allow the Commission and parties to determine whether the utility's cost forecasts are generally low, high, or approximately correct, and may be grounds for future modification to the undergrounding plans.[14]

Tracking will require specific project IDs in the memorandum account that enable the creation and tracking of individual caps for projects. These caps will allow the Commission to prevent any single project from exceeding the maximum total cap for the memorandum account. The project ID referenced in this section should also match the one used in the RO models mentioned in Section A.4.

2. The Commission Should Require the Utilities to Report Balancing Accounts as part of the GRC.

The utility should be required to provide details about the balancing account used to capture cost overrun on all EUP projects as part of any future GRC application. Providing details about the balancing account used would promote transparency between EUP and GRC applications, enable validation of GRC applications, and ensure that the Commission is fully cognizant of the full breadth of capital expenditure when reviewing a GRC.

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[12] *Comments of The Utility Reform Network (TURN) on Draft Resolution SPD-15 Implementing SB 884* at 9 – 10, Dec. 28, 2023.

[13] Appendix, Attachment 2, *Public Advocates Office's Informal Comments on the Staff Proposal for the SB 884 Program* at 6, Sept. 27, 2023.

[14] Planning Questions at 3.

3. The Commission should require cost variances to be recorded in a memorandum account.

TURN has previously submitted comments to the Commission[15] which recommend that, if recorded costs exceed forecasted costs by more than 5% for any project, the utility should be required to show that the change in cost would not have changed relative cost-effectiveness.[16] TURN also recommends that, if the increase in recorded costs would have altered the outcome of the alternative mitigation comparisons, then the excess costs should be disallowed from the account. Cal Advocates supports TURN's recommendations. In addition, the Commission should apply the above logic to variances in both the forecasted cost-benefit ratio (CBR) and the unit cost of a project in the Planned Questions scenario.[17, 18]

4. The Commission should adopt a CBR threshold.

Cal Advocates submitted informal comments to SPD ~~previously~~ that state,[19] "CBR minimums protect ratepayers from unreasonable rate increases that could result from inefficient undergrounding, where cheaper alternatives such as covered conductor are more efficient." Cal Advocates continues to recommend that the Commission ~~should~~ set

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[15] *Informal Comments of the Utility Reform Network (Turn) In Response to October 14, 2024 Questions from CPUC Staff Regarding SB 884 Implementation* at 5, Nov. 12, 2024.

[16] Comparison with alternative mitigations.

[17] Planned Questions at 3.

Section B.2. Option 1:

If the variance between the forecasted CBRs and unit cost of a project presented in an Application compared to the forecasted CBRs and unit cost of a project presented in a six month Progress Report (after a project passes Energy Safety's Screen 4) exceeds a certain threshold, then all costs for that project must be recorded in the MA.

[18] Even though TURN's comments were for recorded costs, the logic is applicable to variances in forecasted CBRs and unit costs.

[19] *Public Advocates Office's Informal Comments on Questions for Stakeholders Regarding the CPUC SB-884 Guidelines* at 2-4, Nov. 12, 2024.

a minimum value for the CBRs of all undergrounding projects.[20] For additional details, please refer to the Appendix.[21]

5. The Commission should require undergrounding projects to have a higher CBR than alternative mitigations.

Cal Advocates previously submitted informal comments to SPD identifying its concern that "utilities could select costly projects over alternatives with a higher benefit to cost ratio."[22] PG&E does not always the follow the CBR methodology, it sometimes uses a "net benefit" of a mitigation analysis instead.[23, 24] The Commission should require that utilities select undergrounding only when the CBR is higher than alternative mitigations. In addition, TURN has shared its concerns with the Commission on why utilities should be required to evaluate alternative mitigations compared to electrical undergrounding.[25, 26]

The Commission should also consider Executive Order N-5-24 and its impact on SB 884 alternative mitigation analysis requirements. Executive Order N-5-24, which directs the Commission to examine benefits and costs to electric ratepayers of the programs it oversees, has language related to wildfire mitigation and managing costs.[27]

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[20] The minimum value should be discussed in the proposed spring working group mentioned in Planning Questions at 3.

"Staff intend to hold data template working groups later in the spring."

[21] Appendix, Attachment 5, *Public Advocates Office's Informal Comments on Questions for Stakeholders Regarding the CPUC SB-884 Guidelines* at 2-4, Nov. 12, 2024.

[22] Appendix, Attachment 5, *Public Advocates Office's Informal Comments on Questions for Stakeholders Regarding the CPUC SB-884 Guidelines* at 2-4, Nov. 12, 2024.

[23] Net benefit definition: Mitigation is calculated by subtracting the capital and operating expenditures associated with a mitigation from the estimated benefits delivered by that mitigation. PG&E also calls this Wildfire Benefit Cost Analysis.

[24] *Public Advocates Office's Reply Comments on the Draft Decision Approving Pacific Gas and Electric Company's 2023-2025 Wildfire Mitigation Plan* at 4-6, December 14, 2023.

[25] Appendix, Attachment 5, *Public Advocates Office's Informal Comments on Questions for Stakeholders Regarding the CPUC SB-884 Guidelines* at 2-4, Nov. 12, 2024.

[26] *Informal Comments of the Utility Reform Network (Turn) In Response to October 14, 2024 Questions from CPUC Staff Regarding SB 884 Implementation* at 1-2, Nov. 12, 2024.

[27] Executive Order N-5-24, Oct., 30 2024.

C. What methods could the Commission use to address the Audits and/or Review Procedure?

The Commission's guidelines require that costs submitted in an SB 884 Application meet certain conditions (Phase 2 Conditions) for recovery via a one-way balancing account.[28] That one-way balancing account is subject to audit.[29] Among other things, the statute requires an up-front determination and that the recorded costs are just and reasonable, including satisfying the Phase 2 Conditions.[30] Cal Advocates has provided general auditing recommendations to SPD in the past.[31] However, intervenors should not be responsible for financial audits. If the Commission chooses to hire an external auditor, Cal Advocates supports TURN's recommendation that the audit be directed by the Commission, not the utility.[32]

D. How could the Commission address changes to approved projects?

Cost recovery for projects that fail to meet CBR thresholds, including the rolling average CBR, should be disallowed. These disallowances will be essential as a mechanism to ensure that customers accrue the most benefit and will help ensure proper utility selection and management of projects. The disallowance of projects that fail rolling average CBR thresholds from cost recovery overlaps with Section B.3.[33]

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https://www.gov.ca.gov/wp-content/uploads/2024/10/energy-EO-10-30-24.pdf [accessed Apr 16, 2025]

Language relating to wildfire mitigation and managing costs, "utility investments and activities on cost effective wildfire mitigation measures that reduce wildfire ignition risk while managing costs to electric ratepayers."

[28] Resolution SPD-15, *Attachment 1 - Staff Proposal for SB 884 Program* at 4, Mar. 8, 2024.

[29] Resolution SPD-15, *Attachment 1 - Staff Proposal for SB 884 Program* at 4, Mar. 8, 2024.

[30] Pub. Util. Code, § 8388.5, subd. (e)(6).

[31] Appendix, Attachment 5, *Public Advocates Office's Informal Comments on Questions for Stakeholders Regarding the CPUC SB-884 Guidelines* at 4-5, Nov. 12, 2024.

[32] *Informal Comments of the Utility Reform Network (Turn) In Response to October 14, 2024 Questions from CPUC Staff Regarding SB 884 Implementation* at 8, Nov. 12, 2024.

[33] Planning Questions at 5.

E. Should the Commission include an Appendix with guidance for calculating the CBR of an undergrounding project?

The Commission should discuss the specifics of CBR calculations in the upcoming data template working group. Cal Advocates and TURN have previously commented that the Commission should require utilities to follow Decision 24-05-064 for CBR calculations in SB-884 applications. For additional details, please refer to the Appendix.[34], [35], [36] Cal Advocates recommends that the scope of CBR calculations be included in the upcoming data template working group in the Spring of 2025 so that the process for reviewing complex and important calculations is thoroughly explored. The 10-year EUP could potentially cost ratepayers billions of dollars, and the upcoming data template working group will allow time to conduct the necessary analysis.[37]

II. CONCLUSION

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

Respectfully submitted,

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[34] Appendix, Attachment 5, *Public Advocates Office's Informal Comments on Questions for Stakeholders Regarding the CPUC SB-884 Guidelines* at 5, Nov. 12, 2024.

[35] Appendix, Attachment 6, *Informal Comments of the Utility Reform Network (Turn) In Response to October 14, 2024 Questions from CPUC Staff Regarding SB 884 Implementation* at 11, Nov. 12, 2024.

[36] The previous comments focused on discount rates and D.24-05-064 requirements. The utilities should also be consistent with D.24-05-064 in applying non-linear risk scaling.

[37] Energy and Safety Policy Division's other questions such as Monetized Value of Electric Reliability should also be discussed during this working group.

APPENDIX

Attachments	Description
A-1 to A-2	RAMP-2024_DR_CalAdvocates_005-Q001, October 24, 2024
Attachment 2	Public Advocates Office's Informal Comments on the Staff Proposal for the SB 884 Program, September 27, 2023
Attachment 3	Corrected Comments of the Public Advocates Office on Pacific Gas and Electric Company's Topics for Discussion on Revised Draft EUP Guidelines, August 9, 2024
Attachment 4	Public Advocates Office's Reply Comments on the Updated Revised Draft Guidelines for the 10-Year Electrical Undergrounding Plan, October 14, 2024
Attachment 5	Public Advocates Office's Informal Comments on Questions for Stakeholders Regarding the CPUC SB-884 Guidelines, November 12, 2024
Attachment 6	INFORMAL COMMENTS OF THE UTILITY REFORM NETWORK (TURN) IN RESPONSE TO OCTOBER 14, 2024 QUESTIONS FROM CPUC STAFF REGARDING SB 884 IMPLEMENTATION, November 12, 2024

A-1 TO A-2

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

PG&E Data Request No.:	CalAdvocates_005-Q001
PG&E File Name:	RAMP-2024_DR_CalAdvocates_005-Q001
Request Date:	October 10, 2024
Requester DR No.:	005
Requesting Party:	Public Advocates Office
Requester:	Miles Gordon
Date Sent:	October 24, 2024
PG&E Witness(es):	N/A

QUESTION 001

On page 1-88 of its 2024 Risk Assessment and Mitigation Phase (RAMP) Report, PG&E states that it plans a total of 1,711 miles of undergrounding for the years 2027-2030.

In response to Cal Advocates' data request CalAdvocates-PGE-2025WMP-04, PG&E states the following regarding future cost recovery for undergrounding projects:

> The cost recovery venue for undergrounding projects depends on the year in which the project becomes operational (i.e. is electrified). Any undergrounding project made operational in 2023-2026 will be recovered through PG&E's 2023 General Rate Case (GRC) via the Wildfire Mitigation Balancing Account (WMBA).
>
> PG&E plans to submit its SB [Senate Bill] 884 10-Year Undergrounding Plan with a currently anticipated program launch date of January 1, 2027 and proposes that any undergrounding project that is operational on or after January 1, 2027 would be recovered through PG&E's SB 884 10-Year Undergrounding Plan.

a. Please explain why PG&E is proposing 1,711 miles of undergrounding for the years 2027-2030 in its 2024 RAMP report, given the above-quoted statement that any project in the year 2027 or after will be recovered through PG&E's SB 884 10-Year Undergrounding Plan.

b. Does PG&E intend to recover costs for the abovementioned 1,711 miles of undergrounding in its forthcoming Test Year 2027 GRC application, for which PG&E's 2024 RAMP report is the precursor?

c. If the answer to Question 1.b is yes, please explain why PG&E is placing this specific number of miles of undergrounding in its upcoming Test Year 2027 GRC application (as opposed to a different number of miles) when it also intends to file an SB 884 10-Year Undergrounding Plan.

d. If the answer to Question 1.b is no, please explain why PG&E is including the abovementioned 1,711 miles of undergrounding in its 2024 RAMP Report.

e. Does PG&E plan to amend its 2024 RAMP Report after filing an SB 884 10-year Undergrounding Plan to remove or reduced the undergrounding mileage included in the 2024 RAMP Report? Please explain your answer.

ANSWER 001

a) At the time of filing the 2024 RAMP Report, the OEIS Electrical Undergrounding Plan (EUP) Guidelines had not been released for the SB 884 10-Year Undergrounding Plan Application. PG&E felt it was prudent to include the proposed undergrounding miles in the RAMP filing because the EUP Guidelines had not been finalized.

b) The amount of undergrounding work planned from 2027 onwards will be determined by the requirements outlined by the OEIS EUP Guidelines. The OEIS EUP Guidelines have not been finalized. PG&E plans to seek recovery of costs for eligible undergrounding projects consistent with the final guidelines received by OEIS and the CPUC SPD Resolution 15.

c) See response to subpart b).

d) See response to subpart b).

e) PG&E does not plan to make changes to the RAMP filing as the subsequent SB 884 applications would supersede any changes to proposed mitigations or control measures included in the 2024 RAMP filing.

ATTACHMENT 2

November 12, 2024

Via Electronic Filing

Danjel Bout, Director
Safety Policy Division
California Public Utilities Commission
505 Van Ness Avenue
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SB884@cpuc.ca.gov

Subject: **Public Advocates Office's Informal Comments on Questions for Stakeholders Regarding the CPUC SB-884 Guidelines**

Dear Director Bout,

The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) respectfully submits informal comments on the Questions for Stakeholders Regarding the CPUC SB-884 Guidelines.

Please contact Nat Skinner (Nathaniel.Skinner@cpuc.ca.gov) or Henry Burton (Henry.Burton@cpuc.ca.gov) with any questions relating to these informal comments.

We respectfully urge the Commission to adopt the recommendations discussed herein.

Sincerely,

/s/ ***Angela Wuerth***
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Attorney

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cc: SB-884 Notification List
Service List A.24-05-008

TABLE OF CONTENTS

I. INTRODUCTION

The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) provides these informal comments in response to Safety Policy Division's (SPD) Staff questions for Senate Bill (SB) 884 Guidelines issued October 14, 2024 (Staff Questions). Each utility that submits an undergrounding plan under SB 884 should be held accountable for executing its plan in a timely and cost-effective manner. If a utility fails to do so, it risks not meeting the California Public Utilities Commission's (Commission) affordability principle, wasting ratepayer resources, and failing to meet the utility's wildfire risk reduction targets.

The Staff Questions lend appropriate weight to these matters and inquiries about several reasonable requirements that utilities must meet in SB 884 applications at the Commission. Cal Advocates appreciates SPD's efforts to ensure that large-scale utility undergrounding programs developed under SB 884 will substantially improve the safety and reliability of electric distribution systems while minimizing detrimental impacts to ratepayers. In these informal comments, we propose refinements to the current Resolution SPD-15 to maximize the public benefit of these plans, tighten accountability measures, and ensure all undergrounding expenditures are just and reasonable.

II. ISSUES

A. The Commission should host another workshop on the results of operation models (RO models).

The Staff Questions on RO models are complex and should be explored in workshops.[1] In the past, Energy Division hosted a workshop on the uniformity of RO models, which explored standardization for the General Rate Case (GRC).[2] That SPD should collaborate with Energy Division to host a workshop on RO models uniformity in the SB 884 application, is confirmed by the fact that SPD is asking questions that have

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[1] SPD, Questions for Stakeholders Regarding the CPUC SB-884 Guidelines (Staff Questions), October 14, 2024 at Questions A.1-8.

[2] Energy Division, Uniformity in Results of Operations (RO) Model Workshop #3, November 19, 2020.

been partially explored by Energy Division.[3] A joint workshop would also benefit both the Energy Division and SPD, because it will provide insight into how Pacific Gas and Electric Company's (PG&E), or possibly any other utility's, mini-RO models in their SB 884 plans might affect cost recovery in the GRC. This approach is consistent with past practice where SPD and Energy Division partnered together.[4] A joint workshop on uniformity of RO models would be a good opportunity for further collaboration.

The joint workshop should explore SPD's questions about PG&E's usage of a separate and different standalone mini-RO model in their SB884 plans when compared to the RO model used in the GRC.[5] If cost recovery applications in different proceedings use different RO models, it may be difficult to determine whether overhead lines that have been undergrounded as part of an SB 884 plan have been removed from the rate base in future GRCs. In addition, the workshop can explore PG&E's mini-RO model and the lack of depreciation studies,[6] because the basic calculus of the RO model includes depreciation expense.[7]

B. The Commission should establish a per-project minimum cost-benefit ratio (CBR) threshold and ensure utilities follow CBR thresholds.

CBR minimums protect ratepayers from unreasonable rate increases that could result from inefficient undergrounding, where cheaper alternatives such as covered conductor are more efficient. The Commission currently has an average CBR threshold for all projects completed in any given two-year period (the current and the prior year) which must equal or exceed the approved threshold CBR for that current year.[8] In

[3] Energy Division, Uniformity in Results of Operations (RO) Model Workshop #3 Report at 2-3.

[4] Energy Division and SPD, R.20-07-013 and R.18-04-019 Joint Workshop, September 13, 2023.

[5] Staff Questions at Questions A.5.

[6] PG&E should explain the validity of depreciation expense calculations without depreciation studies (Staff Questions at Questions A.6) in the workshop.

[7] D.23-11-069 in A.21-06-021, *Decision on Test Year 2023 General Rate Case for Pacific Gas and Electric Company*, November 16, 2023, at 652-653.

[8] SPD, Resolution SPD-15, March 7, 2024 at 11.

addition, Cal Advocates has advocated for CBR thresholds for both the SB 884 undergrounding plan as whole and on per project basis.[9] Cal Advocates is concerned that utilities could select costly projects over alternatives with a higher benefit to cost ratio. These concerns are based on PG&E's recent issues in the 2024 Risk Assessment Mitigation Phase (RAMP).

Specifically, in discovery, Cal Advocates learned that PG&E's cost-benefits analysis overwhelmingly favored covered conductor as a wildfire mitigation over costly and slow undergrounding.[10] PG&E described its reasoning for selecting undergrounding over covered conductor in a brief, unsupported narrative response, even though its own cost-benefits analysis showed that covered conductor had a higher CBR.[11]

In addition, Cal Advocates is concerned that utilities could manipulate mitigation analyses to favor undergrounding over less costly alternatives. Cal Advocates commented on these issues in PG&E's 2023-2025 WMP. Among other things, Cal Advocates notes that:[12]

- PG&E does not always follow the CBR methodology adopted in R.20-07-013. Instead, PG&E sometimes uses a Wildfire Benefit Cost Analysis (WBCA), which is a "net benefit" of a mitigation analysis.[13]
- PG&E uses a WBCA analysis to claim undergrounding generates a higher estimated lifetime benefit compared to covered conductor. However, CBR calculations would show that for the same circuit segment, overhead hardening would have been more cost efficient.[14]

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[9] *Public Advocates Office's Reply Comments on Draft Resolution SPD-15 and the Staff Proposal for the SB 884 Program*, January 11, 2024 at 2-3.

[10] *PG&E's response to data request CalAdvocates-PGE-2024-RAMP-AYN04, question 2, Attachment 1, October 4, 2024.*

[11] *PG&E's response to data request CalAdvocates-PGE-2024-RAMP-AYN04, question 1, October 2, 2024.*

[12] *Public Advocates Office's Reply Comments on the Draft Decision Approving Pacific Gas and Electric Company's 2023-2025 Wildfire Mitigation Plan*, December 14, 2023 at 4-6.

[13] Net benefit definition: Mitigation is calculated by subtracting the capital and operating expenditures associated with a mitigation from the estimated benefits delivered by that mitigation.

[14] Level 4 Ventures, *Comparing the MAVF and RSE with the proposed Cost-benefit framework*, August 2022. Cost efficient definition: If the CBR is greater than one for a mitigation, it means that the dollar benefit is greater than its dollar cost.

Based on PG&E's recent issues, which show the need to prevent utilities from manipulating the mitigation analysis to favor undergrounding, the Commission should make CBR requirements more stringent.

C. The Commission should require timely audits that include a reexamination of the utility's alternative mitigation and CBR analyses and verification that the projects are complete.

The Commission's SB 884 Guidelines require that costs submitted in an SB 884 Application meet certain conditions (Phase 2 Conditions) for Commission to authorize the recovery of those costs via a one-way balancing account.[15] That one-way balancing account is subject to audit.[16] The statute requires an up-front determination, before cost recovery is authorized, that the recorded costs are just and reasonable, including satisfying the Phase 2 conditions.[17]

This audit should at a minimum include reexamination of the utility's alternative mitigation comparison and CBR analysis for each project. A reexamination of the utility's CBR analysis, with updates based on recorded costs rather than projected costs, would enable the Commission to more accurately compare alternatives.[18]

In addition, the Commission should verify that undergrounding projects are completed, risks are reduced, and undergrounding projects are operational before authorizing cost recovery for such projects. Energy Safety auditors on an annual basis issue a Notice of Violation (NOV) on Wildfire Mitigation Plan (WMP) projects that are identified as completed but were not actually done.[19] To prevent this issue from happening in SB 884, the Commission should require utilities to verify that projects are completed. For example, project verification could include a mix of mapped location

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[15] SPD, SB 884 Program: CPUC Guidelines, March 2024, at 4.

[16] SPD, SB 884 Program: CPUC Guidelines, March 2024, at 4.

[17] Public Utilities Code section 8388.5(e)(6).

[18] Alternatives to undergrounding include covered conductor with enhanced powerline safety settings (EPSS). PG&E uses the term EPSS. Other utilities use terms such as Fast Curve Settings, Sensitive Relay Profile, and etc.

[19] Energy Safety, *2023 COMPLIANCE PROCESS,* July 2023 at 8-9.

data, photographic evidence, and satellite imagery. Utility companies already provide photographs for grid hardening and other initiatives, along with spatial data in their WMP Geographic Information System (GIS) Quarterly Data Reports (QDR).[20] Therefore, utilities should be able to provide verification that projects are complete in the context of SB 884.

D. The Commission should require utilities to present NPV Benefits, NPV Costs, and CBR using each of these three discount rates in their SB-884 Applications.

Decision 24-05-064 requires utilities to present the results of three discount rate scenarios for their Risk-based Decision-making Framework (RDF) CBR calculations.[21] The Commission should require utilities to present NPV Benefits, NPV Costs, and CBR using each of these three discount rates in their SB-884 Applications.

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[20] Energy Safety, Data Guidelines v3.2, January 30, 2024 at 6.

[21] D.24-05-064 in R.20-07-013, *Phase 3*, July 6, 2024, at 102-05. The required three discounted rates scenario are listed below:

> Societal Discount Rate Scenario: apply the latest available near-term social rate of time preference (SRTP) provided by the U.S. Office of Management and Budget (OMB) in Circular A-4, as the discount rate to all components in both the numerator and denominator of the CBR. The latest available near-term SRTP is 2%,
>
> WACC Discount Rate Scenario: apply the IOU's most recent Weighted-Average Cost of Capital as the discount rate for all components in both the numerator and denominator of the CBR, and
>
> Hybrid Discount Rate Scenario: apply the discount rate derived from the effective compounded rate of the 10-year effective average inflation rate as measured by the California statewide consumer price index, the 10-year effective average per-capita real growth rate of wages as measured by California statewide mean hourly and total wages for all occupations, and the most recent near-term SRTP used in the Societal Discount Rate Scenario, to the safety and reliability components of the numerator and apply the IOU's most recent WACC as the discount rate for the financial components of the numerator and denominator of the CBR.

E. The Commission must not allow utilities to add miles of undergrounding to projects because it violates statutory requirements.

Public Utilities Code section 8388.5(c) requires each plan submitted to Energy Safety to include all projects that will be constructed.[22] Cal Advocates has submitted multiple comments on this statutory requirement to Energy Safety.[23, 24] Any project not included as part of a utility's initial SB 884 plan submission cannot be constructed as part

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[22] Public Utilities Code section 8388.5(c):

> In order to participate in the program, a large electrical corporation shall submit to the office a distribution infrastructure undergrounding plan that shall address or include, at minimum, all of the following components:
>
> (1) A 10-year plan for undergrounding distribution infrastructure.

(2) Identification of the undergrounding projects that will be constructed as part of the program, including a means of prioritizing undergrounding projects based on wildfire risk reduction, public safety, cost efficiency, and reliability benefits. Only undergrounding projects located in tier 2 or 3 high fire-threat districts or rebuild areas may be considered and constructed as part of the program.

[23] See discussions in:

Cal Advocates, TURN, and MGRA, Joint Letter: "Implementation of Senate Bill 884 – Ten-Year Undergrounding Plans," April 26, 2023 (filed in docket 2023-UPs on December 13, 2023) at 2 and Appendix A: "SB 884 requires the undergrounding plans to include detailed project-specific information demonstrating that undergrounding is the superior alternative when these factors are considered. … The SB 884 process should require utilities to make this showing for each project before rate recovery for undergrounding is allowed."

Public Advocates Office's Informal Comments on the Staff Proposal for the SB 884 Program, September 27, 2023 at 10 (filed as Appendix A of *Public Advocates Office's Comments on Undergrounding Plan Guidelines*, November 2, 2023 in docket 2023-UPs).

Discussion in Public Workshop on Draft Electrical Undergrounding Plan Guidelines, May 15, 2024.

Discussion in Public Workshop on Revised Draft Electrical Undergrounding Plan Guidelines, July 25, 2024.

Corrected Comments of the Public Advocates Office on Pacific Gas and Electric's Topics for Discussion on Revised Draft EUP Guidelines, August 9, 2024 in docket 2023-UPs, at 5-6:

> Energy Safety has stated that its responsibility is to approve electrical undergrounding plans rather than projects. Energy Safety's draft proposal defines a "plan" as a decision-making process for developing, selecting, and prioritizing undergrounding projects; Energy Safety does not regard a plan as entailing specific projects or workplans. This view is inconsistent with the language of SB 884. Energy Safety's interpretation of SB 884 relies on Public Utilities Code section 8388.5(d) while overlooking section 8388.5(c).

Public Advocates Office's Comments on the Updated Revised Draft Guidelines for the 10 Year Electrical Undergrounding Plan (EUP), October 3, 2024 in docket 2023-UPs at 11-12.

[24] Staff Questions at Questions F.1-6.

of the plan, and the Commission cannot approve cost recovery for such a project.[25] Allowing utilities to add miles by changing the scope of projects compared to the initial submission is inconsistent with Public Utilities Code section 8388.5(c). Utilities could pursue funding in their GRCs for additional undergrounding miles that are not included in the initial project list submitted with the SB 884 plan, instead of violating Public Utilities Code section 8388.5(c).

F. The Commission should require utilities to retain historical data and provide updated data quarterly.

Cal Advocates has submitted comments in the past to Energy Safety that are relevant to SPD's inquiries about tabular and GIS requirements.[26] GIS and tabular project data have been a standing requirement for the WMP QDRs since their inception.[27] Underground projects are already a subset of the data requested as part of the WMP QDRs. Because Energy Safety QDRs have been required for several years they form a *de facto* historic record of system updates and changes from which the impacts of wildfire mitigation can be synthesized. However, this record is imperfect and relies on substantial amounts of *post hoc* processing to make it useful. Cal Advocates recommends close coordination between SPD and Energy Safety to develop data requirements that ensure there are explicit spatial and tabular data retention policy requirements for projects in an SB 884 plan; this data should be part of the validation process discussed in Section C. The availability of historic spatial records for electrical systems is especially important for tracking the risk reduction accrued to SB 884 projects. Knowing exactly which assets have been removed from service is the only way to accurately estimate the risk reduction attributable to a specific project.

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[25] Public Utilities Code section 8388.5(c).

[26] *Corrected Comments of the Public Advocates Office on Pacific Gas and Electric Company's Topics for Discussion on Revised Draft EUP Guidelines*, August 9, 2024 at 3-4.

[27] Energy Safety, *GIS Data Reporting Standard v2.1*, September 22, 2021 at 114.

G. The Commission should require utilities to analyze all reasonable mitigation alternatives and the impacts on customer rates.

Cal Advocates has concerns with the alternatives analysis that PG&E submitted as part of its RAMP ahead of its GRC filing in 2025.[28] Cal Advocates previously shared these concerns with Energy Safety and reiterates these concerns here in response to some of the Staff Questions.[29], [30] PG&E's "alternative" to undergrounding was simply to not underground secondary and service lines.[31] Other alternatives were Grid Monitoring, reconfiguration of conductor attachments, and wildfire resilience partnerships (fuels) treatment.[32] However, PG&E fails to consider covered conductor with Enhanced Powerline Safety Settings (EPSS or fast trip) as an alternative mitigation.[33]

In addition, by its own admission, PG&E:[34], [35], [36]

- Did not analyze covered conductor as an alternative to its undergrounding proposal in the RAMP application.
- Reported its proposed undergrounding program would cost $6.5 billion.
- Reported an overhead covered conductor program alternative would cost $1.7 billion.
- Did not quantify the impacts of alternative mitigation programs on customer rates when selecting between risk mitigation programs in its RAMP.

[28] See A.24-05-008, *Application of PG&E to Submit its 2024 Risk Assessment and Mitigation Phase (RAMP) Report*, May 15, 2024 (PG&E's RAMP Report), at PG&E-4, 1-98 to 1-105.

[29] *Public Advocates Office's Reply Comments on the Updated Revised Draft Guidelines for the 10-Year Electrical Undergrounding Plan*, October 14, 2024 in docket 2023-UPs at 3-4.

[30] Staff Questions at Questions H.1-4.

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

[32] PG&E's RAMP Report at PG&E-4, 1-100, 1-102, 1-104, 4-48.

[33] PG&E's Ramp Report at PG&E-4 1-100 to 1-105.

[34] See generally PG&E's RAMP Report; *PG&E's response to data request CalAdvocates-PGE-2024-RAMP-AYN02*, question 1, September 10, 2024.

[35] *PG&E's response to data request CalAdvocates-PGE-2024-RAMP-AYN04, question 2, Attachment 1, October 4, 2024.*

[36] PG&E's response to data request CalAdvocates-PGE-2024-RAMP-AYN02, question 3, September 10, 2024.

Thus, as stated in previous comments, PG&E's comparisons of undergrounding with covered conductor are not reasonable.[37] PG&E consistently compares undergrounding to covered conductor as a standalone alternative, failing to combine covered conductor with EPSS.[38] PG&E's own estimates suggest that covered conductor with EPSS is approximately twelve percentage points more effective than covered conductor alone.[39] Further, in its reports to investors, PG&E estimates that PG&E's wildfire mitigation plans and the layers of protection provided by EPSS, Public Safety Power Shutoffs, enhanced situational awareness, and suppression resources reduce economic losses by 93 percent.[40]

The Commission should require utilities to analyze all reasonable mitigation alternatives in SB 884 to avoid the issues seen in the RAMP and WMP. In addition, the Commission should consider Executive Order N-5-24 and its possible impact on SB 884 alternative mitigations analysis requirements. Executive Order N-5-24 has language related to wildfire mitigation and managing costs.[41]

H. The Commission must not allow cost recovery for abandoned projects because such costs are not just and reasonable.

Utilities' cost recovery for abandoned undergrounding projects does not comport with Public Utilities Code Section 8388.5(e)(6), which requires SB 884 project costs

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[37] *Public Advocates Office's Comments on the Updated Revised Draft Guidelines for the 10 Year Electrical Undergrounding Plan (EUP)*, October 3, 2024 in Docket 2023-UPs at 1-3.

[38] *Comments of the Public Advocates Office on PG&E's 2025 Wildfire Mitigation Plan Update*, May 7, 2024 in docket 2023-2025 WMPs at 38.

[39] See Table ACI-PG&E-23-05-3 in PG&E, 2025 Wildfire Mitigation Plan Update R1, July 5, 2024 at 56. This table lists the effectiveness of covered conductor as 66.4 percent, the effectiveness of covered conductor with EPSS as 78.2 percent, and the effectiveness of undergrounding primary lines as 97.7 percent.

[40] PG&E Corporation 2024 Second Quarter Earnings, Slides 5, 20, 22, 30. https://s1.q4cdn.com/880135780/files/doc_financials/2024/q2/Q224-Earnings-Presentation.pdf

[41] Executive Order N-5-24, October 30, 2024.

https://www.gov.ca.gov/wp-content/uploads/2024/10/energy-EO-10-30-24.pdf

Language relating to wildfire mitigation and managing costs, "utility investments and activities on cost-effective wildfire mitigation measures that reduce wildfire ignition risk while managing costs to electric ratepayers."

authorized by the Commission to be just and reasonable.[42] Allowing recovery of costs for abandoned undergrounding projects is inconsistent with the "used and useful" principle, which provides that ratepayers should not pay for assets for which they are not receiving service.[43] Ratepayers have not and do not receive benefits from abandoned undergrounding projects.

Furthermore, allowing recovery of costs for abandoned undergrounding projects is inconsistent with the purpose of SB 884, which is to increase electrical reliability and reduce the risk of wildfires.[44] Abandoned undergrounding projects do not accomplish these goals. Therefore, the Commission cannot lawfully allow cost recovery for abandoned undergrounding projects.

III. CONCLUSION

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

Respectfully submitted,

/s/ *Angela Wuerth*

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[42] Public Utilities Code § 8388.5(e)(6); Public Utilities Code § 451.

[43] *See, e.g.,* D.18-12-021 at 154; D.84-09-055, 16 CPUC 2d 205, 228.

[44] See Public Utilities Code § 8388.5(d)(2) ("The office may only approve the plan if the large electrical corporation has shown that the plan will substantially increase electrical reliability by reducing the use of public safety power shutoffs, enhanced powerline safety settings, deenergization events, and any other outage programs, and substantially reduce the risk of wildfire."); Senate Bill 884 (2022), Bill Analysis, Assembly Committee on Utilities and Energy, June 22, 2022 Hearing, at 5 (Author's Statement).

APPENDIX

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

PG&E Data Request No.:	CalAdvocates_002-Q001		
PG&E File Name:	RAMP-2024_DR_CalAdvocates_002-Q001		
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 001

Please provide PG&E[s analysis of replacing primary conductors with covered conductors as a wildfire mitigation alternative to undergrounding primary conductors.

ANSWER 001

Below is the CBR results of the two scenarios for overhead hardening the primary line miles included in the proposed undergrounding plan M022 and alternative undergrounding plan A001,.

- Scenario 1: overhead hardening for primary miles included in M022
- Scenario 2: overhead hardening for primary miles included in A001

Scenario	Program 2027-2030 (NPV)			
	[A] Total Program Cost ($M)	[B] Foundational Activity Cost ($M)	[C] Risk Reduction	[C]/([A]+[B]) CBR
Scenario 1	$1,695	0.0	30,356	17.9
Scenario 2	$2,286	0.0	40,138	17.6

Aggregated analysis is provided in the RAMP-2024_DR_CalAdvocates_002-Q001Atch07.xlsx, and individual analysis in the CBR Input Files can be found in the attachments referenced below.

Scenario 1:

- RAMP-2024_DR_CalAdvocates_002-Q001Atch01_WLDFR.xlsx
- RAMP-2024_DR_CalAdvocates_002-Q001Atch02_DOVHD.xlsx
- RAMP-2024_DR_CalAdvocates_002-Q001Atch03_PCEEE.xlsx

Scenario 2:

- RAMP-2024_DR_CalAdvocates_002-Q001Atch04_WLDFR.xlsx
- RAMP-2024_DR_CalAdvocates_002-Q001Atch05_DOVHD.xlsx
- RAMP-2024_DR_CalAdvocates_002-Q001Atch06_PCEEE.xlsx

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.

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.

PACIFIC GAS AND ELECTRIC COMPANY
RAMP 2024
Application 24-05-008
PG&E File Name: RAMP-2024_DR_CalAdvocates_004-Q002Atch01

					Program 2027-2030 $M (NPV)				Program-Risk 2027-2030 $M (NPV)				Unit of Work				Capital ($000)			
FA	Risk ID	Program Type	Program ID	MWC or MAT	[A] Total Program Cost	[B] Foundational Activity Cost	[C] Risk Reduction	[C]/([A]+[B]) CBR	[A] Total Program Cost	[B] Foundational Activity Cost	[C] Risk Reduction	[C]/([A]+[B]) CBR	2027	2028	2029	2030	2027	2028	2029	2030
EO	WLDFR	Mitigation	WLDFR-M002 (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)	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)	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)	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)	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)	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)	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)	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)	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)	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)	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)	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

ATTACHMENT 3

August 9, 2024 **Via Electronic Filing**

Caroline Thomas Jacobs, Director
Office of Energy Infrastructure Safety
California Natural Resources Agency
Sacramento, CA 95184
efiling@energysafety.ca.gov

Subject: **Corrected Comments of the Public Advocates Office on Pacific Gas and Electric Company's Topics for Discussion on Revised Draft EUP Guidelines**

Docket: **2023-UPs**

Dear Director Thomas Jacobs,

The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) respectfully submits the following corrected comments on *Pacific Gas and Electric Company's Topics for Discussion on the Office of Energy Infrastructure Safety's Revised Draft SB 884/EUP Guidelines*. The comments that Cal Advocates submitted on August 8, 2024, included some minor errors. These corrected comments include revisions to correct the errors.

Please contact Nathaniel Skinner (Nathaniel.Skinner@cpuc.ca.gov), or Henry Burton (Henry.Burton@cpuc.ca.gov), with any questions relating to these corrected comments.

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

Sincerely,

/s/ ***Angela Wuerth***

Angela Wuerth
Attorney

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I. INTRODUCTION

The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) submits these comments to the Office of Energy Infrastructure Safety (Energy Safety) regarding implementation guidelines for Senate Bill (SB) 884 on electrical undergrounding plans (EUPs).[1] SB 884 authorizes large electric utilities (utilities) to submit ten-year plans to underground distribution lines and tasks Energy Safety and the California Public Utilities Commission (CPUC or Commission) to determine whether to approve, conditionally approve, or deny a utility's ten year plan.[2, 3]

In these comments, Cal Advocates responds to *Pacific Gas and Electric Company's (PG&E) Topics for Discussion on the Office of Energy Infrastructure Safety's Revised Draft SB 884/EUP Guidelines* (PG&E's Topics for Discussion), submitted on July 25, 2024.[4] We look forward to further opportunities, beyond these comments, to constructively engage with Energy Safety, share ideas, and develop effective policies to ensure wildfire mitigation is achieved consistent with the statutory mandate of SB 884.

II. PG&E's Topics for Discussion

A. High frequency outage program threshold.

Cal Advocates has no comments at this time.

B. If utilities are allowed to establish new thresholds when risk models are updated, then back-testing should be required.

Many of Cal Advocates' past comments on risk model updates to PG&E and Energy Safety are applicable to EUPs. Here, we reiterate critical points on the importance of back-testing models.[5]

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

[2] Many of the statutory provisions in the Public Utilities Code relating to wildfires apply to "electrical corporations." See, e.g., Public Utilities Code § 8388.5. These comments also use the more common term "utilities" to refer to the entities that must comply with the wildfire safety provisions of the Public Utilities Code.

[3] See Cal Pub. Util. Code §§ 8388.5 (c), (d), (e) and (f).

[4] PG&E, *Topics for Discussion on the Office of Energy Infrastructure Safety's Revised Draft SB 884/EUP Guidelines* (Topics for Discussion), July 25, 2024, docket 2023-UPs.

[5] *Public Advocates Office Opening Comments on Pacific Gas and Electric's 2025 Wildfire Mitigation*

Risk models, based on up-to-date information, are an important planning tool. Such models can help a utility direct limited funds to mitigate the maximum amount of wildfire risk for the lowest cost to ratepayers. To this end, Cal Advocates supports utilities' efforts to refine their wildfire risk models. However, utilities should evaluate whether the shift in updated risk models and thresholds affects the estimated cost-effectiveness of the submitted EUP.

Cal Advocates supports Energy Safety's proposed requirement for risk model back-testing, including the thresholds, as part of every semiannual progress report. Back-testing would avoid the situation where PG&E asserts it is unable to adequately describe and justify the thresholds it is proposing. In 2022, Energy Safety directed PG&E to "describe and justify the threshold at which projects move forward even as risk prioritization evolves."[6] PG&E has consistently ignored this directive and failed to establish such thresholds.[7] And, PG&E states that it has no plans to evaluate the cost-effectiveness of projects in its current workplan against the outputs of its Wildfire Distribution Risk Model v4.[8]

At each semiannual progress report, the new thresholds and risk models should be used to evaluate the cost-effectiveness of projects in the current EUP workplan, to ensure that the thresholds are meaningful and the project prioritization evolves to reflect current information.

C. Projects in wildfire rebuild areas must comply with section 8388.5(c)(2).

Public Utilities Code section 8388.5(c)(2) allows for undergrounding projects located in rebuild areas to be considered and constructed as part of the 10-year distribution undergrounding plan. However, the language for wildfire rebuild areas is specific to eligibility. Projects included in the plan must continue to comply with the other requirements of Public Utilities Code section 8388.5(c)(2), including "prioritizing undergrounding projects based on wildfire risk reduction, public safety, cost efficiency, and reliability benefits."[9]

Plan, May 7, 2024 at 5-18.

[6] Energy Safety, *Final Decision on 2022 Wildfire Mitigation Plan Update Pacific Gas and Electric Company*, November 10, 2022 at 184-185.

[7] *Public Advocates Office Opening Comments on Pacific Gas and Electric's Revised 2023-2025 Wildfire Mitigation Plan*, August 22, 2023 at 13-14.

[8] PG&E's response to data request CalAdvocates-PGE-2025WMP-08, question 5, April 5, 2024.

[9] Public Utilities Code section 8388.5(c)(2).

Energy Safety's current *Draft 10-Year EUP Guidelines* already incorporate rebuild area eligibility. Projects "not located in Wildfire Rebuild Area or Tier 2 or 3 High Fire-Threat-District will be eliminated in Screen 1."[10] Thus, Projects, including ones located in wildfire rebuild areas, must continue to pass the remaining screens.[11] All projects, even if located in a wildfire rebuild area, are required to reduce wildfire risk and increase electrical reliability.[12]

D. Despite its assertions to the contrary, PG&E can submit historical GIS data relating to undergrounding projects.

PG&E's states that it is unable to report the GIS data requested in Table C.1.12 (Project Construction Table) and that it "does not track historical changes or planned undergrounding work in GIS".[13] PG&E has previously raised a similar issue and proposes that it be allowed to submit KMZ files for planned undergrounding information.[14] While PG&E does not track this information, several facts suggest that PG&E is capable of maintaining a record of the locations of its current and historic electrical distribution system for planning purposes.

First, a snapshot of asset location is routinely taken from the GIS system to develop the risk models. This snapshot is fundamental data on which the risk models and by extension project selection and development is based. Cal Advocates has previously commented that this snapshot should act as the historic baseline for any assessment of project selection and efficacy.[15] The snapshot, at a minimum, will give the historic location of assets being removed from service against which completed projects should be compared.

Second, the request for PG&E to provide the location of projects is not new. Project location has been a standing requirement of the WMP Quarterly Data Reports (QDR) since their inception.[16] It is reasonable to consider the undergrounding projects as a subset of the data already requested as part to the WMP. Further, QDRs have been provided for several years and

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[10] Energy Safety, *Draft 10-Year EUP Guidelines*, May 8, 2024 at 11.

[11] Screen 2: Project Information and Alternative Mitigation Comparison; Screen 3: Project Risk Analysis; and Screen 4: Project Prioritization.

[12] Public Utilities Code section 8388.5(d)(2).

[13] PG&E, *Topics for Discussion* at 3.

[14] PG&E, *OEIS SB 884 Draft Guidelines Opening Comments*, May 29, 2024 at 18.

[15] *Public Advocates Office's Comments on Undergrounding Plan Guidelines*, November 2, 2023 at 2.

[16] Energy Safety, *GIS Data Reporting Standard v2.1*, September 22, 2021 at 114.

de facto form a historic record of system updates and changes from which the impacts of wildfire mitigation can be synthesized.

Thus, while historic information exists, PG&E is unwilling to submit GIS data through the single geodatabase (GDB) format, with the required data fields listed in the Draft 10-Year EUP Guidelines.[17] However, given that the proposed project location is now a requirement for both WMPs and for EUPs, PG&E should take this opportunity to develop processes that enable it to satisfy the demands of Energy Safety and the Commission. This approach would provide the most accurate understanding of the assets and system conditions on which project selection decisions were made.

E. Incorporation of new technology must be related to undergrounding.

PG&E requests clarification regarding the inclusion of new technologies in an undergrounding plan. However, PG&E does not explain its concern or confusion.[18]

SB 884 is specific to electrical undergrounding. New technologies should be considered as part of the alternatives analysis – that is, new technologies should be included in the risk reduction comparison between underground hardening and alternative mitigation strategies.[19] Energy Safety should direct utilities to include feasible new technologies (for example, rapid earth fault current limiters) in the alternatives analyses included under Screen 2 and Screen 3.

Deploying technologies other than undergrounding is outside of the scope of SB 884. If a utility identifies a new technology that reduces wildfire risk – either as a substitute or complement to undergrounding – then it should propose such a project in its general rate case. Energy Safety should not permit utilities to use an electrical *undergrounding* plan as a vehicle to propose other types of projects or operational practices.

Lastly, new technologies such as horizontal directional drilling may improve the feasibility or cost-effectiveness of undergrounding. Utilities should examine such technologies in

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[17] Energy Safety, *Draft 10-Year EUP Guidelines*, May 8, 2024 at C-41 and C-42.

[18] PG&E, *Topics for Discussion* at 3: "An Electric Corporation may want to introduce new technology as a potential mitigation for consideration in the EUP. The guidelines are silent on how these mitigations would be introduced and considered for inclusion in the plan."

[19] Public Utilities Code section 8388.5(c)(4) requires each plan to provide a comparison of undergrounding to alternative mitigation strategies.

their undergrounding plans. If the new technology is viable, then it may affect the cost-benefit ratios for underground projects and the comparison to alternatives.

III. Legal Issues

A. Energy Safety should establish submission requirements that are consistent with Public Utilities Code section 8388.5(c).

Energy Safety has stated that its responsibility is to approve electrical undergrounding *plans* rather than projects.[20] Energy Safety's draft proposal defines a "plan" as a decision-making process for developing, selecting, and prioritizing undergrounding projects; Energy Safety does not regard a plan as entailing specific projects or workplans.[21] This view is inconsistent with the language of SB 884. Energy Safety's interpretation of SB 884 relies on Public Utilities Code section 8388.5(d) while overlooking section 8388.5(c).

SB 884 specifically identifies what a properly submitted undergrounding plan entails. Among other things, the undergrounding plan "*shall* address or include, at minimum": a 10-year workplan for undergrounding distribution lines; a *list of projects that will be constructed* and a means of prioritizing those projects; timelines for completing the projects; and an analysis of alternatives (emphasis added).[22] These elements are prerequisite conditions for participation in the program.[23]

In a nutshell, section 8388.5(c) spells out the entry requirements to participate, while section 8388.5(d) describes the judging criteria for Energy Safety.[24] If this were an apple pie contest at the county fair, the entry requirements would include the ingredients that may be used and the entrant's residency; while the judging criteria might be flavor, crispness of the crust, and appearance. However, the judges would not even consider a purported apple pie that did not contain apples. A 10-year undergrounding plan without specific projects is a purported apple pie without apples.

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[20] Public Utilities Code section 8388.5(d)(2).

[21] Discussion in Public Workshop on Revised Draft Electrical Undergrounding Plan Guidelines, July 25, 2024.

[22] Public Utilities Code section 8388.5(c), paragraphs (1) through (4) respectively.

[23] Public Utilities Code section 8388.5(c).

[24] Section 8388.5(e) identifies the minimum review criteria for the California Public Utilities Commission, including cost.

Energy Safety must revise its guidelines so that they include a list of essential elements – that is, the minimum requirements for completeness. Any submitted plan should be reviewed to ensure that it contains all the essential elements (and should be rejected if incomplete) before Energy Safety undertakes a substantive analysis. The list of essential elements must include, at a minimum, all the items identified in Public Utilities Code section 8388.5(c).[25]

IV. CONCLUSION

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

Respectfully submitted,

/s/ ***Angela Wuerth***

Angela Wuerth
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[25] Public Utilities Code section 8388.5(c), paragraphs (1) through (6) respectively.

ATTACHMENT 4

The Public
ADVOCATES
OFFICE

October 14, 2024 **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 Updated Revised Draft Guidelines for the 10-Year Electrical Undergrounding Plan (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 Updated Revised Draft Guidelines for the 10-year Undergrounding Distribution Infrastructure Plan (Plan or EUP). 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 in response to the Office of Energy Infrastructure Safety's (Energy Safety) Updated Revised Draft Guidelines (Revised Draft), issued September 13, 2024.[1] The 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 (CPUC or Commission) to determine whether to approve, conditionally approve, or deny a utility's ten year plan.[5]

Cal Advocates has been actively engaged with Energy Safety and the Commission regarding the implementation of SB 884 since December 2022. Energy Safety should review our past comments, as many of PG&E's proposals have already been addressed,[6] especially in our most recent comments.[7] Our emphasis has been on ensuring cost-effective and feasible plans. We look forward to further opportunities, beyond these comments, to constructively engage with Energy Safety, share ideas, and develop effective policies to ensure wildfire mitigation is achieved consistent with the statutory mandate of SB 884.

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[1] Energy Safety, *Updated Revised Draft 10-Year Electrical Undergrounding Plan Guidelines* (Revised Draft), September 13, 2024, docket 2023-UPs.

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

[3] Many of the statutory provisions in the Public Utilities Code relating to wildfires apply to "electrical corporations." See, e.g., Public Utilities Code § 8388.5. These comments also use the more common term "utilities" to refer to the entities that must comply with the wildfire safety provisions of the Public Utilities Code.

[4] Cal. Pub. Util. Code § 8388.5(c).

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

[6] PG&E, *Comments on the Revised Draft 10-Year Electrical Undergrounding Plan Guidelines Issued by Energy Safety on September 13, 2024* (PG&E Comments on Revised Draft), October 3, 2024

[7] See discussions in:

Corrected Comments of the Public Advocates Office on Pacific Gas and Electric's Topics for Discussion on Revised Draft EUP Guidelines, August 9, 2024

Public Advocates Office's Comments on the Updated Revised Draft Guidelines for the 10-Year Electrical Undergrounding Plan, October 3, 2024

II. ISSUES

A. Energy Safety should allow for public review if a Change Order Process is implemented.

Pacific Gas and Electric Company (PG&E) recommends adding a Change Order Process to the EUP guidelines.[8] The Change Order Process includes two different proposals: 1) Utilities should be able to revise their submitted EUP; and 2) Energy Safety should be able to update EUP guidelines.

If Energy Safety adopts a Change Order Process, that process should include public review due to the potential size and scale of the SB 884 plans. Public review should include both workshops and public comments. Any Change Order Process should not excuse utilities from submitting all projects in their initial applications as required by Public Utilities Code § 8388.5(c)(2).[9] Cal Advocates make the following recommendations for the public comment schedule, which are essential to any Change Order Process adopted by Energy Safety:

1. If the Change Order Process allows utilities to revise their submitted EUP, Energy Safety should include a reasonable schedule for public comments. Cal Advocates commented recently on reasonable schedule proposals.[10]
2. If the Change Order Process allows Energy Safety to revise EUP guidelines, there should be at least 30 calendar days for public comments.

B. Energy Safety should not adopt proposals to include undergrounding outside of tier 2 or 3 high-fire threat districts (HFTD) and rebuild areas.

PG&E proposes to include electrical line undergrounding outside of tier 2 and 3 HFTDs and rebuild areas in the EUP.[11] Specifically, if the circuit segment crosses back and forth between HFTD and non-HFTD areas, PG&E proposes that the entire segment span be considered HFTD and eligible for inclusion in the EUP. [12, 13] Utilities previously recommended

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[8] PG&E Comments on Revised Draft at 22-23.

[9] *Public Advocates Office's Comments on the Updated Revised Draft Guidelines for the 10-Year Electrical Undergrounding Plan*, October 3, 2024 at 11-12.

[10] *Public Advocates Office's Comments on the Updated Revised Draft Guidelines for the 10-Year Electrical Undergrounding Plan*, October 3, 2024 at 6-7.

[11] PG&E Comments on Revised Draft at 14-15.

[12] PG&E Comments on Revised Draft at 14-15.

[13] PG&E defines span as "A span is the overhead electric line between two poles and is generally several hundred feet in length."

that Energy Safety allow undergrounding in utility-defined high-fire risk areas outside tier 2 or 3 HFTDs, and Cal Advocates objected to these proposals because they violate the requirements of SB 884.[14] Similarly, PG&E's proposal to expand the definition of HFTDs is inconsistent with SB 884. SB 884 specifies that "only undergrounding projects located in tier 2 or 3 [HFTDs] or rebuild areas may be considered and constructed as part of the program."[15] Public Utilities Code § 8388.5(c)(2) prohibits the "consideration and construction" of projects outside of tier 2 and 3 HFTDs or rebuild areas. The EUP guidelines are not the correct venue to redefine HFTDs. Instead, that authority lies with the Commission. If a utility wishes to request recovery of costs for undergrounding in areas outside of tier 2 and 3 HFTDs, that utility should pursue funding in its general rate case. Alternatively, a utility could also pursue a Petition for Modification with the Commission if updates to HFTD mapping is needed. Cal Advocates has submitted a Petition for Modification before the Commission in Rulemaking 15-05-006 for consideration of HFTD map modifications.[16]

C. Energy Safety should not adopt PG&E's proposed watering down of Alternative Mitigation Analyses

PG&E proposes various changes that would weaken the alternative mitigation analyses.[17] Cal Advocates is concerned about weakening the analyses because of PG&E's alternative analysis of undergrounding submitted as part of its Risk Assessment and Mitigation Phase ahead of its general rate case filing in 2025.[18] In that proceeding before the Commission, PG&E failed to provide and consider reasonable alternatives to its undergrounding proposals. For example, PG&E's "alternative" to undergrounding was simply to not underground secondary and service lines.[19] However, PG&E has already stated that service lines are not included in its

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[14] *Public Advocates Office's Reply Comments on the Development of Guidelines for the 10-Year Undergrounding Distribution Infrastructure Plan*, January 18, 2024 at 10.

[15] Public Utilities Code section 8388.5(c)(2).

[16] See R.15-05-006, *Public Advocates Office's Petition for Modification of Decision (D.)20-12-030, D.17-12-024 and D.17-01-009 In Order to Update High Threat Fire District Mapping,* April 19, 2023.

[17] PG&E Comments on Revised Draft at 5-7.

[18] See A.24-05-008, *Application of PG&E to Submit its 2024 Risk Assessment and Mitigation Phase (RAMP) Report*, May 15, 2024, at PG&E-4 1-98 to 1-105.

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

undergrounding program, with the service drops remaining overhead.[20] PG&E's other alternatives were Grid Monitoring, reconfiguration of conductor attachments to 'prevent line slap, and wildfire resilience partnerships (fuels treatment).[21] PG&E's assessment failed to consider other well-established wildfire mitigation options such as covered conductor with Enhanced Powerline Safety Settings (EPSS or fast trip) as an alternative mitigation. Reducing the consideration of alternative mitigations will deprive Energy Safety and stakeholders of crucial information and may result in the failure to analyze alternative mitigations that can quickly and less expensively reduce wildfire risk. Narrowing the scope of Energy Safety's consideration of wildfire mitigation options could result in customers remaining at higher wildfire risk for longer. As such, Energy Safety should reject PG&E's proposed watering down of alternative mitigation analyses.

III. CONCLUSION

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

Respectfully submitted,

/s/ ***Angela Wuerth***

____

Angela Wuerth
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October 14, 2024

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

[21] See A.24-05-008, *Application of PG&E to Submit its 2024 Risk Assessment and Mitigation Phase (RAMP) Report*, May 15, 2024, at PG&E-4 1-100 to 1-105.

ATTACHMENT 5

November 12, 2024

Via Electronic Filing

Danjel Bout, Director
Safety Policy Division
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102
SB884@cpuc.ca.gov

Subject: Public Advocates Office's Informal Comments on Questions for Stakeholders Regarding the CPUC SB-884 Guidelines

Dear Director Bout,

The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) respectfully submits informal comments on the Questions for Stakeholders Regarding the CPUC SB-884 Guidelines.

Please contact Nat Skinner (Nathaniel.Skinner@cpuc.ca.gov) or Henry Burton (Henry.Burton@cpuc.ca.gov) with any questions relating to these informal comments.

We respectfully urge the Commission to adopt the recommendations discussed herein.

Sincerely,

/s/ ***Angela Wuerth***
Angela Wuerth
Attorney

Public Advocates Office
California Public Utilities Commission
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San Francisco CA 94102
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cc: SB-884 Notification List
Service List A.24-05-008

TABLE OF CONTENTS

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I. INTRODUCTION

The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) provides these informal comments in response to Safety Policy Division's (SPD) Staff questions for Senate Bill (SB) 884 Guidelines issued October 14, 2024 (Staff Questions). Each utility that submits an undergrounding plan under SB 884 should be held accountable for executing its plan in a timely and cost-effective manner. If a utility fails to do so, it risks not meeting the California Public Utilities Commission's (Commission) affordability principle, wasting ratepayer resources, and failing to meet the utility's wildfire risk reduction targets.

The Staff Questions lend appropriate weight to these matters and inquiries about several reasonable requirements that utilities must meet in SB 884 applications at the Commission. Cal Advocates appreciates SPD's efforts to ensure that large-scale utility undergrounding programs developed under SB 884 will substantially improve the safety and reliability of electric distribution systems while minimizing detrimental impacts to ratepayers. In these informal comments, we propose refinements to the current Resolution SPD-15 to maximize the public benefit of these plans, tighten accountability measures, and ensure all undergrounding expenditures are just and reasonable.

II. ISSUES

A. The Commission should host another workshop on the results of operation models (RO models).

The Staff Questions on RO models are complex and should be explored in workshops.[1] In the past, Energy Division hosted a workshop on the uniformity of RO models, which explored standardization for the General Rate Case (GRC).[2] That SPD should collaborate with Energy Division to host a workshop on RO models uniformity in the SB 884 application, is confirmed by the fact that SPD is asking questions that have

[1] SPD, Questions for Stakeholders Regarding the CPUC SB-884 Guidelines (Staff Questions), October 14, 2024 at Questions A.1-8.

[2] Energy Division, Uniformity in Results of Operations (RO) Model Workshop #3, November 19, 2020.

been partially explored by Energy Division.[3] A joint workshop would also benefit both the Energy Division and SPD, because it will provide insight into how Pacific Gas and Electric Company's (PG&E), or possibly any other utility's, mini-RO models in their SB 884 plans might affect cost recovery in the GRC. This approach is consistent with past practice where SPD and Energy Division partnered together.[4] A joint workshop on uniformity of RO models would be a good opportunity for further collaboration.

The joint workshop should explore SPD's questions about PG&E's usage of a separate and different standalone mini-RO model in their SB884 plans when compared to the RO model used in the GRC.[5] If cost recovery applications in different proceedings use different RO models, it may be difficult to determine whether overhead lines that have been undergrounded as part of an SB 884 plan have been removed from the rate base in future GRCs. In addition, the workshop can explore PG&E's mini-RO model and the lack of depreciation studies,[6] because the basic calculus of the RO model includes depreciation expense.[7]

B. The Commission should establish a per-project minimum cost-benefit ratio (CBR) threshold and ensure utilities follow CBR thresholds.

CBR minimums protect ratepayers from unreasonable rate increases that could result from inefficient undergrounding, where cheaper alternatives such as covered conductor are more efficient. The Commission currently has an average CBR threshold for all projects completed in any given two-year period (the current and the prior year) which must equal or exceed the approved threshold CBR for that current year.[8] In

[3] Energy Division, Uniformity in Results of Operations (RO) Model Workshop #3 Report at 2-3.

[4] Energy Division and SPD, R.20-07-013 and R.18-04-019 Joint Workshop, September 13, 2023.

[5] Staff Questions at Questions A.5.

[6] PG&E should explain the validity of depreciation expense calculations without depreciation studies (Staff Questions at Questions A.6) in the workshop.

[7] D.23-11-069 in A.21-06-021, *Decision on Test Year 2023 General Rate Case for Pacific Gas and Electric Company*, November 16, 2023, at 652-653.

[8] SPD, Resolution SPD-15, March 7, 2024 at 11.

addition, Cal Advocates has advocated for CBR thresholds for both the SB 884 undergrounding plan as whole and on per project basis.[9] Cal Advocates is concerned that utilities could select costly projects over alternatives with a higher benefit to cost ratio. These concerns are based on PG&E's recent issues in the 2024 Risk Assessment Mitigation Phase (RAMP).

Specifically, in discovery, Cal Advocates learned that PG&E's cost-benefits analysis overwhelmingly favored covered conductor as a wildfire mitigation over costly and slow undergrounding.[10] PG&E described its reasoning for selecting undergrounding over covered conductor in a brief, unsupported narrative response, even though its own cost-benefits analysis showed that covered conductor had a higher CBR.[11]

In addition, Cal Advocates is concerned that utilities could manipulate mitigation analyses to favor undergrounding over less costly alternatives. Cal Advocates commented on these issues in PG&E's 2023-2025 WMP. Among other things, Cal Advocates notes that:[12]

- PG&E does not always follow the CBR methodology adopted in R.20-07-013. Instead, PG&E sometimes uses a Wildfire Benefit Cost Analysis (WBCA), which is a "net benefit" of a mitigation analysis.[13]
- PG&E uses a WBCA analysis to claim undergrounding generates a higher estimated lifetime benefit compared to covered conductor. However, CBR calculations would show that for the same circuit segment, overhead hardening would have been more cost efficient.[14]

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[9] *Public Advocates Office's Reply Comments on Draft Resolution SPD-15 and the Staff Proposal for the SB 884 Program*, January 11, 2024 at 2-3.

[10] *PG&E's response to data request CalAdvocates-PGE-2024-RAMP-AYN04, question 2, Attachment 1, October 4, 2024.*

[11] *PG&E's response to data request CalAdvocates-PGE-2024-RAMP-AYN04, question 1, October 2, 2024.*

[12] *Public Advocates Office's Reply Comments on the Draft Decision Approving Pacific Gas and Electric Company's 2023-2025 Wildfire Mitigation Plan*, December 14, 2023 at 4-6.

[13] Net benefit definition: Mitigation is calculated by subtracting the capital and operating expenditures associated with a mitigation from the estimated benefits delivered by that mitigation.

[14] Level 4 Ventures, *Comparing the MAVF and RSE with the proposed Cost-benefit framework*, August 2022. Cost efficient definition: If the CBR is greater than one for a mitigation, it means that the dollar benefit is greater than its dollar cost.

Based on PG&E's recent issues, which show the need to prevent utilities from manipulating the mitigation analysis to favor undergrounding, the Commission should make CBR requirements more stringent.

C. The Commission should require timely audits that include a reexamination of the utility's alternative mitigation and CBR analyses and verification that the projects are complete.

The Commission's SB 884 Guidelines require that costs submitted in an SB 884 Application meet certain conditions (Phase 2 Conditions) for Commission to authorize the recovery of those costs via a one-way balancing account.[15] That one-way balancing account is subject to audit.[16] The statute requires an up-front determination, before cost recovery is authorized, that the recorded costs are just and reasonable, including satisfying the Phase 2 conditions.[17]

This audit should at a minimum include reexamination of the utility's alternative mitigation comparison and CBR analysis for each project. A reexamination of the utility's CBR analysis, with updates based on recorded costs rather than projected costs, would enable the Commission to more accurately compare alternatives.[18]

In addition, the Commission should verify that undergrounding projects are completed, risks are reduced, and undergrounding projects are operational before authorizing cost recovery for such projects. Energy Safety auditors on an annual basis issue a Notice of Violation (NOV) on Wildfire Mitigation Plan (WMP) projects that are identified as completed but were not actually done.[19] To prevent this issue from happening in SB 884, the Commission should require utilities to verify that projects are completed. For example, project verification could include a mix of mapped location

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[15] SPD, SB 884 Program: CPUC Guidelines, March 2024, at 4.

[16] SPD, SB 884 Program: CPUC Guidelines, March 2024, at 4.

[17] Public Utilities Code section 8388.5(e)(6).

[18] Alternatives to undergrounding include covered conductor with enhanced powerline safety settings (EPSS). PG&E uses the term EPSS. Other utilities use terms such as Fast Curve Settings, Sensitive Relay Profile, and etc.

[19] Energy Safety, *2023 COMPLIANCE PROCESS,* July 2023 at 8-9.

data, photographic evidence, and satellite imagery. Utility companies already provide photographs for grid hardening and other initiatives, along with spatial data in their WMP Geographic Information System (GIS) Quarterly Data Reports (QDR).[20] Therefore, utilities should be able to provide verification that projects are complete in the context of SB 884.

D. The Commission should require utilities to present NPV Benefits, NPV Costs, and CBR using each of these three discount rates in their SB-884 Applications.

Decision 24-05-064 requires utilities to present the results of three discount rate scenarios for their Risk-based Decision-making Framework (RDF) CBR calculations.[21] The Commission should require utilities to present NPV Benefits, NPV Costs, and CBR using each of these three discount rates in their SB-884 Applications.

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[20] Energy Safety, Data Guidelines v3.2, January 30, 2024 at 6.

[21] D.24-05-064 in R.20-07-013, *Phase 3*, July 6, 2024, at 102-05. The required three discounted rates scenario are listed below:

> Societal Discount Rate Scenario: apply the latest available near-term social rate of time preference (SRTP) provided by the U.S. Office of Management and Budget (OMB) in Circular A-4, as the discount rate to all components in both the numerator and denominator of the CBR. The latest available near-term SRTP is 2%,
>
> WACC Discount Rate Scenario: apply the IOU's most recent Weighted-Average Cost of Capital as the discount rate for all components in both the numerator and denominator of the CBR, and
>
> Hybrid Discount Rate Scenario: apply the discount rate derived from the effective compounded rate of the 10-year effective average inflation rate as measured by the California statewide consumer price index, the 10-year effective average per-capita real growth rate of wages as measured by California statewide mean hourly and total wages for all occupations, and the most recent near-term SRTP used in the Societal Discount Rate Scenario, to the safety and reliability components of the numerator and apply the IOU's most recent WACC as the discount rate for the financial components of the numerator and denominator of the CBR.

E. The Commission must not allow utilities to add miles of undergrounding to projects because it violates statutory requirements.

Public Utilities Code section 8388.5(c) requires each plan submitted to Energy Safety to include all projects that will be constructed.[22] Cal Advocates has submitted multiple comments on this statutory requirement to Energy Safety.[23, 24] Any project not included as part of a utility's initial SB 884 plan submission cannot be constructed as part

---

[22] Public Utilities Code section 8388.5(c):

> In order to participate in the program, a large electrical corporation shall submit to the office a distribution infrastructure undergrounding plan that shall address or include, at minimum, all of the following components:
>
> (1) A 10-year plan for undergrounding distribution infrastructure.

(2) Identification of the undergrounding projects that will be constructed as part of the program, including a means of prioritizing undergrounding projects based on wildfire risk reduction, public safety, cost efficiency, and reliability benefits. Only undergrounding projects located in tier 2 or 3 high fire-threat districts or rebuild areas may be considered and constructed as part of the program.

[23] See discussions in:

Cal Advocates, TURN, and MGRA, Joint Letter: "Implementation of Senate Bill 884 – Ten-Year Undergrounding Plans," April 26, 2023 (filed in docket 2023-UPs on December 13, 2023) at 2 and Appendix A: "SB 884 requires the undergrounding plans to include detailed project-specific information demonstrating that undergrounding is the superior alternative when these factors are considered. … The SB 884 process should require utilities to make this showing for each project before rate recovery for undergrounding is allowed."

Public Advocates Office's Informal Comments on the Staff Proposal for the SB 884 Program, September 27, 2023 at 10 (filed as Appendix A of *Public Advocates Office's Comments on Undergrounding Plan Guidelines*, November 2, 2023 in docket 2023-UPs).

Discussion in Public Workshop on Draft Electrical Undergrounding Plan Guidelines, May 15, 2024.

Discussion in Public Workshop on Revised Draft Electrical Undergrounding Plan Guidelines, July 25, 2024.

Corrected Comments of the Public Advocates Office on Pacific Gas and Electric's Topics for Discussion on Revised Draft EUP Guidelines, August 9, 2024 in docket 2023-UPs, at 5-6:

> Energy Safety has stated that its responsibility is to approve electrical undergrounding plans rather than projects. Energy Safety's draft proposal defines a "plan" as a decision-making process for developing, selecting, and prioritizing undergrounding projects; Energy Safety does not regard a plan as entailing specific projects or workplans. This view is inconsistent with the language of SB 884. Energy Safety's interpretation of SB 884 relies on Public Utilities Code section 8388.5(d) while overlooking section 8388.5(c).

Public Advocates Office's Comments on the Updated Revised Draft Guidelines for the 10 Year Electrical Undergrounding Plan (EUP), October 3, 2024 in docket 2023-UPs at 11-12.

[24] Staff Questions at Questions F.1-6.

of the plan, and the Commission cannot approve cost recovery for such a project.[25] Allowing utilities to add miles by changing the scope of projects compared to the initial submission is inconsistent with Public Utilities Code section 8388.5(c). Utilities could pursue funding in their GRCs for additional undergrounding miles that are not included in the initial project list submitted with the SB 884 plan, instead of violating Public Utilities Code section 8388.5(c).

F. The Commission should require utilities to retain historical data and provide updated data quarterly.

Cal Advocates has submitted comments in the past to Energy Safety that are relevant to SPD's inquiries about tabular and GIS requirements.[26] GIS and tabular project data have been a standing requirement for the WMP QDRs since their inception.[27] Underground projects are already a subset of the data requested as part of the WMP QDRs. Because Energy Safety QDRs have been required for several years they form a *de facto* historic record of system updates and changes from which the impacts of wildfire mitigation can be synthesized. However, this record is imperfect and relies on substantial amounts of *post hoc* processing to make it useful. Cal Advocates recommends close coordination between SPD and Energy Safety to develop data requirements that ensure there are explicit spatial and tabular data retention policy requirements for projects in an SB 884 plan; this data should be part of the validation process discussed in Section C. The availability of historic spatial records for electrical systems is especially important for tracking the risk reduction accrued to SB 884 projects. Knowing exactly which assets have been removed from service is the only way to accurately estimate the risk reduction attributable to a specific project.

[25] Public Utilities Code section 8388.5(c).

[26] *Corrected Comments of the Public Advocates Office on Pacific Gas and Electric Company's Topics for Discussion on Revised Draft EUP Guidelines*, August 9, 2024 at 3-4.

[27] Energy Safety, *GIS Data Reporting Standard v2.1*, September 22, 2021 at 114.

G. The Commission should require utilities to analyze all reasonable mitigation alternatives and the impacts on customer rates.

Cal Advocates has concerns with the alternatives analysis that PG&E submitted as part of its RAMP ahead of its GRC filing in 2025.[28] Cal Advocates previously shared these concerns with Energy Safety and reiterates these concerns here in response to some of the Staff Questions.[29, 30] PG&E's "alternative" to undergrounding was simply to not underground secondary and service lines.[31] Other alternatives were Grid Monitoring, reconfiguration of conductor attachments, and wildfire resilience partnerships (fuels) treatment.[32] However, PG&E fails to consider covered conductor with Enhanced Powerline Safety Settings (EPSS or fast trip) as an alternative mitigation.[33]

In addition, by its own admission, PG&E:[34, 35, 36]

- Did not analyze covered conductor as an alternative to its undergrounding proposal in the RAMP application.
- Reported its proposed undergrounding program would cost $6.5 billion.
- Reported an overhead covered conductor program alternative would cost $1.7 billion.
- Did not quantify the impacts of alternative mitigation programs on customer rates when selecting between risk mitigation programs in its RAMP.

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[28] See A.24-05-008, *Application of PG&E to Submit its 2024 Risk Assessment and Mitigation Phase (RAMP) Report*, May 15, 2024 (PG&E's RAMP Report), at PG&E-4, 1-98 to 1-105.

[29] *Public Advocates Office's Reply Comments on the Updated Revised Draft Guidelines for the 10-Year Electrical Undergrounding Plan*, October 14, 2024 in docket 2023-UPs at 3-4.

[30] Staff Questions at Questions H.1-4.

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

[32] PG&E's RAMP Report at PG&E-4, 1-100, 1-102, 1-104, 4-48.

[33] PG&E's Ramp Report at PG&E-4 1-100 to 1-105.

[34] See generally PG&E's RAMP Report; *PG&E's response to data request CalAdvocates-PGE-2024-RAMP-AYN02*, question 1, September 10, 2024.

[35] *PG&E's response to data request CalAdvocates-PGE-2024-RAMP-AYN04, question 2, Attachment 1, October 4, 2024.*

[36] PG&E's response to data request CalAdvocates-PGE-2024-RAMP-AYN02, question 3, September 10, 2024.

Thus, as stated in previous comments, PG&E's comparisons of undergrounding with covered conductor are not reasonable.[37] PG&E consistently compares undergrounding to covered conductor as a standalone alternative, failing to combine covered conductor with EPSS.[38] PG&E's own estimates suggest that covered conductor with EPSS is approximately twelve percentage points more effective than covered conductor alone.[39] Further, in its reports to investors, PG&E estimates that PG&E's wildfire mitigation plans and the layers of protection provided by EPSS, Public Safety Power Shutoffs, enhanced situational awareness, and suppression resources reduce economic losses by 93 percent.[40]

The Commission should require utilities to analyze all reasonable mitigation alternatives in SB 884 to avoid the issues seen in the RAMP and WMP. In addition, the Commission should consider Executive Order N-5-24 and its possible impact on SB 884 alternative mitigations analysis requirements. Executive Order N-5-24 has language related to wildfire mitigation and managing costs.[41]

H. The Commission must not allow cost recovery for abandoned projects because such costs are not just and reasonable.

Utilities' cost recovery for abandoned undergrounding projects does not comport with Public Utilities Code Section 8388.5(e)(6), which requires SB 884 project costs

[37] *Public Advocates Office's Comments on the Updated Revised Draft Guidelines for the 10 Year Electrical Undergrounding Plan (EUP)*, October 3, 2024 in Docket 2023-UPs at 1-3.

[38] *Comments of the Public Advocates Office on PG&E's 2025 Wildfire Mitigation Plan Update*, May 7, 2024 in docket 2023-2025 WMPs at 38.

[39] See Table ACI-PG&E-23-05-3 in PG&E, 2025 Wildfire Mitigation Plan Update R1, July 5, 2024 at 56. This table lists the effectiveness of covered conductor as 66.4 percent, the effectiveness of covered conductor with EPSS as 78.2 percent, and the effectiveness of undergrounding primary lines as 97.7 percent.

[40] PG&E Corporation 2024 Second Quarter Earnings, Slides 5, 20, 22, 30. https://s1.q4cdn.com/880135780/files/doc_financials/2024/q2/Q224-Earnings-Presentation.pdf

[41] Executive Order N-5-24, October 30, 2024.

https://www.gov.ca.gov/wp-content/uploads/2024/10/energy-EO-10-30-24.pdf

Language relating to wildfire mitigation and managing costs, "utility investments and activities on cost-effective wildfire mitigation measures that reduce wildfire ignition risk while managing costs to electric ratepayers."

authorized by the Commission to be just and reasonable.[42] Allowing recovery of costs for abandoned undergrounding projects is inconsistent with the "used and useful" principle, which provides that ratepayers should not pay for assets for which they are not receiving service.[43] Ratepayers have not and do not receive benefits from abandoned undergrounding projects.

Furthermore, allowing recovery of costs for abandoned undergrounding projects is inconsistent with the purpose of SB 884, which is to increase electrical reliability and reduce the risk of wildfires.[44] Abandoned undergrounding projects do not accomplish these goals. Therefore, the Commission cannot lawfully allow cost recovery for abandoned undergrounding projects.

III. CONCLUSION

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

Respectfully submitted,

/s/ *Angela Wuerth*
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[42] Public Utilities Code § 8388.5(e)(6); Public Utilities Code § 451.

[43] *See, e.g.,* D.18-12-021 at 154; D.84-09-055, 16 CPUC 2d 205, 228.

[44] See Public Utilities Code § 8388.5(d)(2) ("The office may only approve the plan if the large electrical corporation has shown that the plan will substantially increase electrical reliability by reducing the use of public safety power shutoffs, enhanced powerline safety settings, deenergization events, and any other outage programs, and substantially reduce the risk of wildfire."); Senate Bill 884 (2022), Bill Analysis, Assembly Committee on Utilities and Energy, June 22, 2022 Hearing, at 5 (Author's Statement).

APPENDIX

Page #	Description
A-1	RAMP-2024_DR_CalAdvocates_002-Q001
A-2	RAMP-2024_DR_CalAdvocates_002-Q003
A-3	RAMP-2024_DR_CalAdvocates_004-Q001
A-4	RAMP-2024_DR_CalAdvocates_004-Q002Atch01

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

PG&E Data Request No.:	CalAdvocates_002-Q001		
PG&E File Name:	RAMP-2024_DR_CalAdvocates_002-Q001		
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 001

Please provide PG&E[s analysis of replacing primary conductors with covered conductors as a wildfire mitigation alternative to undergrounding primary conductors.

ANSWER 001

Below is the CBR results of the two scenarios for overhead hardening the primary line miles included in the proposed undergrounding plan M022 and alternative undergrounding plan A001,.

- Scenario 1: overhead hardening for primary miles included in M022
- Scenario 2: overhead hardening for primary miles included in A001

Scenario	Program 2027-2030 (NPV)			
	[A] Total Program Cost ($M)	[B] Foundational Activity Cost ($M)	[C] Risk Reduction	[C]/([A]+[B]) CBR
Scenario 1	$1,695	0.0	30,356	17.9
Scenario 2	$2,286	0.0	40,138	17.6

Aggregated analysis is provided in the RAMP-2024_DR_CalAdvocates_002-Q001Atch07.xlsx, and individual analysis in the CBR Input Files can be found in the attachments referenced below.

Scenario 1:

- RAMP-2024_DR_CalAdvocates_002-Q001Atch01_WLDFR.xlsx
- RAMP-2024_DR_CalAdvocates_002-Q001Atch02_DOVHD.xlsx
- RAMP-2024_DR_CalAdvocates_002-Q001Atch03_PCEEE.xlsx

Scenario 2:

- RAMP-2024_DR_CalAdvocates_002-Q001Atch04_WLDFR.xlsx
- RAMP-2024_DR_CalAdvocates_002-Q001Atch05_DOVHD.xlsx
- RAMP-2024_DR_CalAdvocates_002-Q001Atch06_PCEEE.xlsx

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.

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.

PACIFIC GAS AND ELECTRIC COMPANY
RAMP 2024
Application 24-05-008
PG&E File Name: RAMP-2024_DR_CalAdvocates_004-Q002Atch01

					Program 2027-2030 $M (NPV)				Program-Risk 2027-2030 $M (NPV)				Unit of Work				Capital ($000)			
FA	Risk ID	Program Type	Program ID	MWC or MAT	[A] Total Program Cost	[B] Foundational Activity Cost	[C] Risk Reduction	[C]/([A]+[B]) CBR	[A] Total Program Cost	[B] Foundational Activity Cost	[C] Risk Reduction	[C]/([A]+[B]) CBR	2027	2028	2029	2030	2027	2028	2029	2030
EO	WLDFR	Mitigation	WLDFR-M002 (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)	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)	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)	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)	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)	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)	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)	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)	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)	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)	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)	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

ATTACHMENT 6

INFORMAL COMMENTS OF THE UTILITY REFORM NETWORK (TURN) IN RESPONSE TO OCTOBER 14, 2024 QUESTIONS FROM CPUC STAFF REGARDING SB 884 IMPLEMENTATION

November 12, 2024

1.Ā Introduction

The Utility Reform Network (TURN) submits these comments in response to the October 14, 2024 questions circulated by the Commission's Safety Policy Division (SPD) related to the CPUC's implementation of SB 884.

TURN appreciates the thoroughness and thoughtfulness of SPD's questions and that SPD is providing an open and transparent opportunity for all interested parties to answer these questions simultaneously. These comments reflect TURN's best efforts to respond to these important questions.

However, it should be understood that time and resource constraints limit TURN's ability to answer every question with as much detail as we would like. In addition, because it is not clear that this question and answer process will contribute to a Commission decision that is eligible for intervenor compensation, TURN has not been able to retain an outside consultant to help with responding to the questions. Furthermore, TURN does not have the benefit of knowing the nature of the utility's plans for SB 884 applications and does not have a dedicated staff who can devote most or all of their time to thinking through issues and contingencies that may arise in the SB 884 process and the detailed mechanics of SB 884 implementation. For all of these reasons, TURN's responses below should be considered preliminary and subject to change as TURN gains a more detailed understanding of the utility requests and positions.[1]

2.Ā Section C – CBR Threshold

2.1.Ā When Utilities Should Be Required to Provide Additional Justification for Projects

Utilities should be required to provide additional justification for projects in at least two situations (SPD Question 1).

The first is when the undergrounding project CBR for a given location is less than the CBR of one or more alternative projects to address the risk at that location. (See Section H – Number of Alternatives below). Undergrounding is the most expensive alternative, one that increases utility rate base. Thus, utilities have a financial incentive to choose undergrounding over other more reasonable alternatives – one that needs to be kept in check by the CPUC's duty to ensure just and

[1] For these reasons, TURN is not able to respond to questions in certain sections of SPD's document. The questions in Section A, regarding RO models and depreciation, are one example of questions that require the expertise of an outside consultant and would benefit from being presented in a process that is certain to contribute to a Commission decision that is eligible for intervenor compensation.

reasonable rates.[2] Thus, in the Phase 2 review process,[3] the Commission has an obligation to ensure that, for each proposed project location, undergrounding is the most reasonable alternative. The CBR is an important measure of one of the key elements of reasonableness, cost-effectiveness. The CBR is designed to comprehensively measure all relevant benefits of risk mitigation projects in the numerator and all relevant costs in the denominator. Thus, when the undergrounding CBR is less than or equal to the CBR of one or more operationally feasible alternatives, the utility should be required to make the case for why the undergrounding solution is still the most reasonable solution.

When the undergrounding CBR is less than or equal to the CBR of one or more operationally feasible alternatives, the fundamental showing the utility needs to make is why, notwithstanding this situation, the Commission should still approve the project in question. A key showing should be why the CBR, as calculated, is not sufficiently accounting for the benefits of undergrounding compared to the other alternatives for this particular location – what important factors is the CBR calculation missing or not correctly valuing? Are there risk characteristics of the location that the CBR is not sufficiently capturing or is the calculation of risk mitigation benefits of the competing alternatives not accurate in a way that undervalues undergrounding for some reason? If so, the utility needs to explain in detail why the CBR results should not be relied upon.

The second situation in which a utility should be required to provide additional justification for a proposed undergrounding project is when the CBR of the project is below a CBR threshold. It is premature to specify this threshold now. The threshold should be one of the issues determined in Phase 2, based on the CBR information submitted with the Phase 2 application. As discussed below in this section, experience has shown that utilities have different ways of calculating RSEs and the same is likely to be true for CBRs, notwithstanding Commission efforts to the contrary. For example, if utilities use different scaling functions or have different ways of addressing tail risk in their calculations, the CBR values for the same activity could differ significantly.

Once the Commission sets this threshold, which should be an early determination in the Phase 2 proceeding, the utility should be required to submit a justification for any project that falls below the threshold. The showing should again be the utility's explanation of why the CBR is not an accurate reflection of the cost-effectiveness of the project in question and why, notwithstanding the low CBR, the project should still be approved.

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[2] PU Code Sections 451, 8388.5(e)(6).

[3] These comments use the Phase 1, Phase 2, and Phase 3 nomenclature, as those Phases are defined in SPD-15.

2.2.Ā Robust Scrutiny of the Utility's CBR Calculations and Methodology is Necessary

As SPD knows, CBRs (and their predecessor, RSEs) are complex calculations based on complex methodologies. When determined in accordance with Commission requirements and otherwise using reasonable inputs and assumptions, they provide extremely valuable information regarding the cost-effectiveness of proposed projects and competing alternatives. However, because of their complexity, utilities also have the ability to skew the calculations in favor of their preferred outcomes. Potentially controversial elements of CBRs include, but are not limited to: whether the utility is accurately reflecting the mitigation effectiveness of competing alternatives;[4] whether the utility is using accurate costs for competing mitigations;[5] whether the utility's analysis is sufficiently granular to take into account the specific risk factors and costs at a given location; whether the utility is using reasonable values for the cost of electric reliability consequences;[6] whether the utility is reasonably valuing property damage from wildfires;[7] whether the utility is correctly modeling the impact of climate change on the wildfire risk;[8] whether the utility is correctly valuing safety consequences;[9] the reliability of CBR results based on a risk-averse scaling function as compared to a risk-neutral scaling function in the circumstances under consideration; [10] and the discount rate used to determine present values of the costs and benefits.[11]

Because of this complexity and opportunity for utility-calculated CBRs to reflect the companies' financial interest rather than the public interest, the CPUC needs to require the Phase 2 application to include comprehensive workpapers explaining the CBR calculation methodology and documenting the inputs, assumptions, and calculations.[12] If a utility has recently provided such workpapers in other submissions, the utility could provide those same workpapers but would

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[4] In GRCs, intervenors have found that certain utilities understate the mitigation effectiveness of covered conductor based alternatives, including REFCL and other enhancements to covered conductor, compared to undergrounding.

[5] In GRCs, TURN has found that certain utilities overstate the relative cost of covered conductor based alternatives compared to undergrounding.

[6] See SPD's 11/8/24 Evaluation Report on PG&E's RAMP, A.24-05-008, p. 3, criticizing PG&E's method and noting that it inflates wildfire mitigation benefits.

[7] See SPD's 11/8/24 Evaluation Report on PG&E's RAMP, A.24-05-008, p. 56.

[8] See SPD's 11/8/24 Evaluation Report on PG&E's RAMP, A.24-05-008, p. 53.

[9] See SPD's 11/8/24 Evaluation Report on PG&E's RAMP, A.24-05-008, TURN's Informal Comments attached as Attachment 5, pp. 5-7.

[10] See SPD's 11/8/24 Evaluation Report on PG&E's RAMP, A.24-05-008, p. 4.

[11] See Section 8 below, responding to SPD's Section E questions.

[12] SPD-15, Attachment 1, p. 7.

need to clearly identify and explain any material changes. An application that fails to provide complete CBR workpapers should be rejected and a resubmission required.[13]

3.Ā Section H – Number of Alternatives

The Commission should not limit the alternatives presented and considered to those required by OEIS (SPD Question 1). The Commission, not OEIS, has the obligation to ensure that any plan approved in Phase 2 meets the just and reasonable standard. Ensuring that each undergrounding project is needed and superior to all other alternatives is essential to meeting that standard. In addition to the alternatives noted in the preface to the SPD questions for this item, the alternatives should include remote grids and EPSS/PSPS. In some locations, it may be far less expensive to use a combination of EPSS/PSPS and utility-supplied off-grid back-up power than undergrounding.

As discussed in Section 2 above, the utility should demonstrate for each project that undergrounding is the most reasonable alternative for that location. The alternative that utilities are required to compare should include all operationally feasible options for the location. When considering covered conductor, all operationally feasible enhancements to covered conductor, such as REFCL, Fast Curve, EPSS, and other current-limiting technologies should also be considered as a menu of options, each with different effectiveness and cost attributes. If an alternative is not feasible, the utility needs to explain why. Thus, depending on which alternatives are feasible at a location, the alternatives considered may vary by location (SPD Question 2).

For TURN's response to SPD's question 3, see Section 2 above regarding how CBR should be used in the comparison of alternatives, including the need for detailed workpapers showing how the CBR was calculated, which should include comprehensive information about costs and benefits.

4.Ā Section D – Audit

4.1.Ā Preliminary Matters

The inclusion of an "audit" in the CPUC's process was a change to draft SPD-15 in response to comments. As a result, parties have not been given an opportunity to comment on that change. TURN appreciates the opportunity to address at least some of TURN's concerns with that aspect of SPD-15 here.

As a preliminary matter, TURN continues to take the position that the statute requires an *up-front* determination, *before cost recovery is authorized*, that the recorded costs are just and reasonable, including satisfying the Phase 2 conditions.[14] TURN's comments here do not waive

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[13] *Id.*, p. 5.

[14] See TURN's 12/28/23 Comments on Draft SPD-15, pp. 3-5.

that legal contention but will assume, solely for purposes of discussion, that the CPUC can successfully defend its legal position.

As another preliminary matter, TURN notes its concern with the vague and inapposite term "audit." As will be discussed in this section, what SPD-15 describes as an "audit" needs to be a CPUC decision-making process – a post-implementation review -- that allows full participation by intervenors and results in an appealable decision made by the CPUC, not Staff. The necessary review cannot simply be outsourced to an "auditor" who makes the necessary determinations without a meaningful opportunity to participate by all interested parties and a decision by the Commission.[15]

4.2.Ā Questions 1 and 5

As identified in SPD-15, a key objective of the review must be to ensure that the conditions of approval have been satisfied. The conditions identified in SPD-15 primarily relate to ratemaking matters that would not likely be within the expertise of a traditional auditor, nor covered by professional auditing standards. Instead, the Commission should use a process that allows meaningful participation by all interested parties (and by CPUC Staff, if the CPUC so chooses) to enable the CPUC to determine whether the information the utility supplies to support satisfaction of each condition is accurate and based on a reasonable methodology with reasonable inputs and assumptions.[16]

To the extent that the utility fails to demonstrate compliance with any of the conditions, costs of implemented projects must be removed from the balancing account as necessary to bring the completed projects into compliance with the conditions. Those costs should not be included in rate base at any point, unless and until the CPUC finds them just and reasonable and appropriate for inclusion in rates.[17]

The CPUC's review process should also assess whether factual contentions on which the Phase 2 approval was predicated proved to be accurate. If recorded costs exceed forecast costs by more than 5% for any project, the utility should be required to show that the change in cost did not change any of the CPUC's findings relating to stand-alone or relative cost-effectiveness (i.e., compared to alternatives) on which the CPUC's approval was based. If the increase in project

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[15] Having noted its concern about the term "audit," TURN will use the term "review" in the remainder of this section.

[16] See Section 2.2 above regarding the need to carefully scrutinize the utility's calculated CBRs.

[17] It is unclear from SPD-15 whether costs that are removed in order to satisfy the Phase 2 conditions are eligible for inclusion in a Phase 3 application. To encourage cost efficiencies by the utility, TURN recommends that such costs not be eligible for recovery through Phase 3.

costs renders those findings invalid, the excess costs should be removed from the balancing account, as discussed in the prior paragraph.

In addition, the review should determine that the recorded costs were spent correctly by examining, among other things, whether: the project was completed as claimed, as supported by satellite imagery; all of the recorded costs directly related to the identified project and are properly treated as a cost of the project (not some other project); the costs were clearly described to demonstrate satisfaction of the foregoing requirements; no duplicate costs were included; if any recovery of cost overheads was allowed in the Phase 2 decision, overheads were properly calculated and reasonable; only categories of costs allowed by the CPUC in its Phase 2 decision are included in the balancing account. In contrast to the SPD-15 approval conditions, these sorts of requirements do not require ratemaking and cost analysis expertise and would benefit from review by a traditional auditor (fully independent of the utility – see Section 4.6 below) under professional auditing standards. The auditor's results should be made available to all interested parties for their comment. All recorded costs that were incorrectly assigned to approved projects must be removed from the balancing account.

The costs for any project that was included in the plan approved in the Phase 2 decision but not performed in the prescribed year should be removed and the price cap for that year reduced by the approved cost of the project. Costs should not be included in the balancing account until a project is complete. As discussed further in Section 7 below, ratepayers should not pay costs for projects that were not completed and are not attributable to a used and useful project.

It is critical that any previously recovered costs that are removed from the balancing account as a result of this review process (or any other process) be returned to ratepayers. The removed costs should include interest, to ensure that ratepayers are not made worse off by the time it may take to conclude the review process. The removed costs, plus interest, should be credited to ratepayers in the utility's annual electric true up advice letter.

The CPUC's review process must allow sufficient time and discovery opportunities for interested parties to analyze the utility information and prepare meaningful comments to inform an appealable CPUC decision that is eligible for intervenor compensation. As noted, the intent of the process is to ensure that the recorded costs are just and reasonable and appropriate for recovery in rates. Section 8388.5(e)(6) confirms that the Commission must determine that costs are just and reasonable. Intervenors have a statutory right to participate in ratemaking proceedings to assess whether costs are just and reasonable.[18] Nothing in SB 884 abridges such rights.

[18] *E.g.,* PU Code Sections 451, 1701.3.

4.3.Ā Question 2

The utility should also be required to make the labor and resource incrementality showing cited in question 2. Cal Advocates has focused on this aspect of the incrementality issue in cases seeking recovery of wildfire mitigation costs, so TURN would defer to Cal Advocates on the details of the necessary showing.

If the SB 884 plan period coincides with any period in which a GRC decision has allowed cost recovery for any undergrounding costs, the review process should require an incrementality showing to make sure none of the activities covered by the GRC are included in the SB 884 balancing account recorded costs. GRC cost overruns for activities covered by the GRC authorization should not be considered incremental and should not be included in the balancing account, for reasons TURN has explained in Section 7 of its opening brief in A.23-06-008. [19]

4.4.Ā Questions 3 and 4

The review process discussed in this Section should happen at least once per year, after the completion of each year of work authorized in the Phase 2 decision. The review for each year should be limited to only the costs of projects completed in that year, because only those costs should be included in the balancing account. The review after the first year would not be able to review Phase 2 conditions that require two years of recorded data (e.g., Conditions 3 and 4 in SPD-15, Att. 1, p. 11), but would be able to review the other conditions and other matters discussed in this response. The review for the first year of recorded costs should indicate that recovery of year 1 costs remains contingent on satisfaction of conditions 3 and 4 and any other conditions that require more than one year of information.

4.5.Ā Question 6

Regarding how any utility claim of cost savings should be addressed by the review process, it is premature to give a definitive answer to that question. The review process may have an important role to play, but the role would likely depend on the nature of the asserted cost savings and whether the costs in question have already been approved for recovery or whether they are costs that have not been the subject of a cost recovery request. In addition, as the SPD-15 Guidelines state, the utility's Phase 2 application must explain the methodology by which the Commission can ensure that all identified savings are passed on to ratepayers. TURN would be better able to offer an answer to this question after first considering the methodology proposed by the utility.

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[19] For a discussion of the type of showing the utility should be required to make to demonstrate incrementality compared to the GRC authorization, see, e.g., TURN's Opening Brief in A.23-06-008, found here, pp. 46-48.

4.6.Ā Question 7

To the extent that a traditional auditor is used for any aspects of this review process, the auditor must be either on the CPUC staff or directed exclusively by the CPUC, not by the utility. The review of recorded costs is intended to fulfill the CPUC's obligation to ensure the costs are just and reasonable. As a result, any auditor should be thoroughly independent and overseen solely by the CPUC. Results from utility-retained auditors should not be considered dispositive of any issue in the review process. Prior cases have shown that utility retained auditors have missed key problems with the incrementality and reasonableness of the costs they supposedly audited.[20]

5.ĀSection F – Changes to a Utility's Plan[21]

Under SB 884, the plan submitted to the CPUC for its Phase 2 review will be a group of proposed projects with detailed information for each project as required by the statute[22] and by the rules of the two reviewing agencies. The statute allows OEIS to require that this plan be modified,[23] but only the OEIS approved plan can be presented to the CPUC for its review and approval.[24] Thus, the statute does not allow a utility to add any new projects to the plan approved by OEIS or make material changes to projects, as the new or changed projects will not have been vetted through the mandated OEIS review process. Because each project must be reviewed by OEIS, a utility cannot attempt to add a new project after the OEIS Phase 1 decision by claiming that it is "offset" by a removed project.

However, after OEIS approval and up to a certain point in the CPUC's Phase 2 review process, a utility should be allowed to *remove* any projects and all associated costs from its plan. If a utility no longer wishes to pursue a project, there is no reason to require continued inclusion of the project in the plan and the attendant use of CPUC and party resources to review a dropped project. Of course, the cost of the plan should be reduced by the cost of any dropped projects. However, at some "point of no return", when the CPUC needs to draft its final Phase 2 decision and identify the approved projects, the CPUC should make clear that no more projects can be dropped. The costs of those removed projects should be removed through the review process discussed in Section 4 above.

A utility that wishes to add projects to its approved SB 884 plan after the OEIS decision can seek funding for such additional projects through its GRC process. However, the utility

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[20] See, e.g., TURN's Opening Brief in A.23-06-008, found here, p. 66.

[21] This section responds to some, but not all, of questions 1, 3 and 4 in Section F of SPD's questions.

[22] PU Code Section 8388.5(c)(2), (3), (4) and (6).

[23] *Id.*, Section 8388.5(d)(2).

[24] *Id.*, Section 8388.5(e)(1).

should be aware that if it seeking cost recovery for undergrounding activities via both the SB 884 and GRC processes, it will be subject to a rigorous requirement that only the cost of incremental activities will be funded via whichever cost recovery vehicle turns out to be secondary to the primary vehicle (see Section 4.3 above regarding incrementality).

The statutory requirement that SB 884 plans that are reviewed by the CPUC must be the same group of projects approved by OEIS is a wise and necessary one. It comports with the need for the Commission to have a defined set of projects to review under the just and reasonable requirements. For the ratemaking process to be manageable, the list of projects cannot be a moving target that is augmented during or after the CPUC's Phase 2 process. The CPUC should discourage OEIS from adopting rules that are contrary to the statutory scheme. In any event, the CPUC is responsible for the approval of plan costs and is obligated to follow the statute and not allow utilities to add projects that were not included in OEIS's approved plan.

If, in implementation of its approved plan, the utility finds that it needs to add a small amount of contiguous miles to a project (no more than 5-10% of total miles for a project), such minor changes could be allowed, in order to accommodate the minor increase in mileage, provided that such minor modifications do not increase the cost cap. But this accommodation should be kept limited (to no more than 5-10% of miles for a project, as described above) in order to prevent a utility from moving ahead with projects that are materially different from what has been vetted and approved by OEIS and the CPUC.

6.ĀSection I – Delayed Implementation of Approved Projects

If a project is completed in the year after it was scheduled to be completed in the Phase 2 application (say, in Year 2 instead of Year 1), the general approach should be that the cost cap for Year 1 should be reduced by the forecast cost for the project and the forecast for year 2 increased by the cost of the project.

However, the CPUC should be aware of the possibility that a utility could game the timing of project completion in order to manipulate the results of the calculations for the CBR and unit cost Phase 2 conditions. This would serve the utility's financial interests but undermine the ratepayer protective purposes of the Phase 2 conditions that SPD-15 touts at length.[25]

To discourage such gaming, the Commission should, first, not allow any escalation of the cost of the approved project costs because of the delay. And if the approved plan called for unit costs of undergrounding to decline from year to year, the delayed project costs that are added to the price cap in year 2 should be determined by the lower approved unit cost for year 2. In addition, the Commission should require the utility to explain why the delay was outside the

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[25] SPD-15, pp. 9-12.

company's control and reserve the right to remove the costs of delayed projects from the cost cap entirely if the Commission finds that gaming is occurring.

7.ĀSection J – Rejected or Abandoned Projects[26]

As discussed in Sections 4.2 and 4.4 above, only costs associated with a completed project should be recorded to the balancing account, and the costs of any project approved in the Phase 2 decision that is not completed should be removed. Those costs should be subtracted from the price cap for the applicable year as soon as the utility decides not to complete the project.

TURN agrees with Cal Advocates that both the longstanding "used and useful" requirement[27] and SB 884 do not allow recovery for costs of work that is not associated with a completed project, as there would be no undergrounded facilities providing the benefits that are supposed to be obtained from approved projects. Utilities should not be allowed to evade these requirements by including costs related to uncompleted projects, including costs recorded as AFUDC, in any GRC account.

In addition, if a project is rejected in the Phase 1 or Phase 2 review processes, costs incurred for denied projects should not be recovered from ratepayers for the same reason.[28] The Commission should recognize that the utility's approved cost of capital includes compensation for such known risks. Ratepayers should not be required to pay additional compensation for those risks. In addition, the Commission should not reduce the utility's incentive to select undergrounding only where such a project is likely to succeed.[29] Moreover, it should be remembered that the SB 884 process is voluntary and that the GRC process is an alternative means of seeking funding for undergrounding projects.

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[26] This response addresses SPD questions 1-3 in Section J. As noted below, questions 4-7 are mooted by TURN's response to these prior questions.

[27] *See, e.g.,* D.18-12-021, p. 154; D.84-09-055, 16 CPUC 2d 205, 228.

[28] D.84-09-055 contains a good discussion of the policy reasons for not approving recovery of planning, permitting, and other preliminary costs for projects that are not completed. The exception to the rule that costs of projects that are not used and useful are not recoverable – for projects that are prudently pursued "during a period of great uncertainty" (16 CPUC 2d at 229)– does not apply here. At this point in California's journey with respect to utility-caused wildfires, there is no significant uncertainty about the importance of prudent and cost-effective wildfire mitigation strategies. Nor is there any uncertainty that, in appropriate locations, undergrounding can be the superior wildfire mitigation choice. Managerial acumen is needed to propose undergrounding where it is the best use of limited ratepayer funds and not to attempt an excessive deployment of undergrounding to further shareholders' interests.

[29] D.84-09-055, 16 CPUC 2d at 229.

The challenges and complications posed by SPD questions 4 through 7 are mooted by following the clear rule that costs of projects that are not completed are not recoverable.

8. Section E – Present Value Calculations[30]

TURN appreciates that SPD is attentive to the requirements of recently enacted AB 2847. The Commission should make clear in a decision or ruling in advance of the submission of Phase 2 applications that those applications must include both nominal and present value (PV) lifetime calculations for the capital costs of their proposed plans. To account for the fact that different projects will start at different times over the duration of the proposed plan, the utility should include workpapers showing the lifetime costs for each proposed project.

Consistent with D.24-05-064,[31] the utility's Phase 2 application should provide CBRs and PV of lifetime revenue requirement values using the three discount rate scenarios identified in that decision.

9. Section B – Third Party Funding

Unfortunately, TURN does not expect utilities to obtain third party funding for a meaningful portion of undergrounding costs. However, if any such funding is obtained, it must be deducted from plan costs that are included in the balancing account. Utilities should not be allowed to include in rates or rate base any costs that were covered by third party funding. In GRCs, a utility would be able to seek recovery of any reasonable maintenance costs for third party funded underground plant to the extent that such maintenance costs are not covered by the third party funding source.

10. Conclusion

TURN appreciates the opportunity to respond to SPD's questions – and to see other parties' responses – in an open and transparent process. Please contact the undersigned with any questions about TURN's responses.

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[30] TURN believes "present value" not "net present value" is the correct term in this context (costs and benefits are not netted against each other in CBRs and revenue requirement calculations) so TURN uses the former term. This section addresses questions 1-3 in Section E. Question 4 is addressed to some extent in Sections 2.1 and 2.2 above, which point out that utilities have, to date, used different methodologies for calculating RSEs, which make these cost-effectiveness measures not comparable among utilities.

[31] D.24-05-064, pp. 102-105.

Dated: November 12, 2024 Prepared by:

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COMMENTS OF THE UTILITY REFORM NETWORK (TURN)
IN RESPONSE TO APRIL 11, 2025 POST-WORKSHIP QUESTIONS
FROM CPUC STAFF REGARDING SB 884 IMPLEMENTATION

TURN
THE UTILITY REFORM NETWORK
Lower bills. Livable planet.

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April 25, 2025

TABLE OF CONTENTS

1. Introduction

The Utility Reform Network (TURN) submits these comments in response to the April 11, 2025 questions circulated by the Commission's Staff related to the CPUC's guidelines for implementation of SB 884.

TURN appreciates the thoughtfulness of Staff's questions and that Staff is providing an open and transparent opportunity for all interested parties to answer these questions simultaneously. Before directly addressing the questions, TURN's comments will address in Sections 2 through 5 below, thematic issues raised by the April 8, 2025 workshop and by the April 11, 2025 questions. These sections are intended to provide a coherent explanation of the processes and conditions that TURN is advocating and the reasons for TURN's positions that might not otherwise come across in response to the questions. Following these sections, in Section 6, TURN directly responds to the Staff's questions.

2. The Utility Must Demonstrate that Each Proposed Undergrounding Project Is Superior to the Alternatives

Question B4 asks whether the updated guidelines should include a condition that requires a comparison of Cost Benefit Ratios (CBR) between undergrounding and overhead hardening alternatives. TURN wholeheartedly supports this comparison as a key condition to approval and funding of an undergrounding project, as such a condition is compelled by both the statute and sound policy.

SB 884 recognizes the importance of demonstrating that undergrounding is more cost-effective than other grid hardening alternatives. Section 8388.5(c)(4) requires the utility's application to Energy Safety to include a comparison of undergrounding with aboveground hardening for each project, comparing, among other things, risk reduction and cost – which are the two elements of the Cost Benefit Ratio (CBR) calculation. This cost-effectiveness comparison is to be made "separately" for each project.[1] SB 884 reiterates this requirement for the application presented to the CPUC. Section 8388.5(e)(1)(A) requires the plan submitted to the Commission to show substantial improvements in risk reduction and cost of undergrounding *compared to alternative mitigations*.

These statutory requirements are consistent with the record in both WMP proceedings before Energy Safety and in CPUC General Rate Cases, which show that whether undergrounding is more cost-effective than alternatives can depend significantly on which risk drivers are present

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[1] Public Utilities Code Section 8388.5(c)(4).

in a particular location, as well as the cost and time to complete an undergrounding project, which is highly variable depending on local characteristics.

For these reasons, TURN recommends in these comments that the Commission's updated guidelines include an explicit condition that an undergrounding project may only move forward if the undergrounding CBR is higher than the CBR of any feasible alternatives (or combination of alternatives) providing comparable reduction of ignition risk. Such a condition is necessary to counter the utility's financial incentive to choose the mitigation that will cause the largest increase in rate base, which in most cases will be undergrounding.

See TURN's further discussion of this recommended condition in Section 4.2.1 and in the response to Question B4, found in Section 6.2.

3. As Required by SB 884, the Commission Must Ensure that the Utility Has a Strong Incentive to Constrain and Reduce Costs; the CPUC Should Therefore Either Eliminate the Memorandum Account or Impose a Tight Cap on It

Question B1 asks whether the Commission should impose conditions on the memorandum account allowed by SPD-15. TURN welcomes this question, as this issue warrants revisiting.

TURN continues to urge its previously expressed position that no memorandum account should be allowed because creating such an opportunity to recover cost overruns defeats the cost reduction and containment goals that are central to SB 884.[2] Limiting such opportunities is vital to the CPUC's efforts to regain control of runaway electric rates. In Executive Order N-5-24, the Governor calls for "decisive action to rein in" California's rapidly increasing utility rates.[3] The Executive Order further directs OEIS and the CPUC to:

> consult with each other on adjustments to utility wildfire safety oversight processes, procedures, and practices that would yield administrative efficiencies and focus utility investments and activities on cost-effective wildfire mitigation measures that reduce wildfire ignition risk while managing costs to electric ratepayers."[4]

Managing costs imposed on ratepayers is especially important as electric rates have risen significantly for all IOUs over the past five years. For example, between January 1, 2020 and

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[2] TURN's Comments on Draft Resolution SPD-15, pp. 8-12.

[3] The Executive Order is available at: https://www.gov.ca.gov/wp-content/uploads/2024/10/energy-EO-10-30-24.pdf.

[4] Executive Order N-5-24, Ordering Paragraph #5.

January 1, 2025, PG&E residential electric rates have risen by 74% for bundled non-CARE customers and 78% for bundled CARE customers.[5]

Moreover, as discussed below in this section, there are other ways to address the uncertainties related to ten-year undergrounding plans that do not require creating another memorandum account.[6] If any memorandum account is allowed, it should be capped at no more than 10% of a utility's total Plan costs.[7]

3.1. Allowing a Memorandum Account Undermines the Cost Control Requirements of SB 884 and, As Experience Has Shown, Invites Runaway Spending

SB 884 makes clear that achieving efficiencies and reductions in undergrounding costs must be a key condition of the CPUC's cost approval process. Section 8388.5(e)(6) shows that the Legislature was highly focused on cost control by requiring that the utility's application for conditional approval of plan's costs address the following:

> (A) Any substantial improvements in . . . *reduction in costs* compared to other hardening and risk mitigation measures over the duration of the plan.
>
> (B) The *cost reductions, at a minimum, that result in feasible and attainable cost reductions* as compared to the large electrical corporation's historical undergrounding costs.
>
> (C) How the cost targets are expected to *decline over time* due to *cost efficiencies and economies of scale*.
>
> (D) A strategy for *achieving cost reductions* over time.[8]

The Legislature's emphasis on the achievement of cost reductions is thus reflected in its specification of *four separate requirements* for the utility to achieve cost reductions – both as compared to alternative mitigations and historical undergrounding costs, and as a demonstration

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[5] TURN analysis based on PG&E Annual Electric True-Up (AET) submissions, including: PG&E Advice Letter 6805-E (2023 AET filing effective 1/1/2023), PG&E Advice Letter 7116-E (2024 AET filing effective 1/1/2024), and PG&E Supplemental Advice Letter 7426-E-A (2025 AET filing effective 1/1/2025).

[6] See also Sections 4.2.2 and Section 5.3

[7] This recommendation is further discussed in response to Question B1 in Section 6.2.

[8] Section 8388.5(e)(1) (emphasis added).

that utilities will deliver on their claims of realizing cost efficiencies with the benefit of time and economies of scale.

Allowing utilities to seek recovery of recorded cost overruns defeats the purpose of these requirements. SB 884 clearly intends for the Commission to require utilities to achieve more efficient implementation, *i.e.,* declining unit cost caps over time. Utility incentives to actually achieve this statutory requirement will be dulled, if not eviscerated, if utilities know that will have the opportunity to recover cost overruns in later applications.

By now, the Commission is well aware that memorandum accounts create a disincentive to utility cost control and causes the Commission to lose control over utility rates. The Commission has had several years of recent experience with a ratemaking model, pursuant to AB 1054, that allows utilities to record wildfire mitigation plan (WMP) costs in excess of authorized GRC amounts to memorandum accounts, and then seek recovery of those costs.[9] Despite admonitions in the statute and Commission decisions that only just and reasonable costs will be allowed to be included in rates and that unreasonable costs will be disallowed, the utilities have engaged in wildfire mitigation spending that dwarfs the forecast amounts authorized in their GRCs.

For example, PG&E's 2020 GRC decision authorized forecast costs for wildfire mitigation in 2020-2022 of $4.7 billion.[10] During that period, PG&E *actually* spent $11.7 billion related to CPUC-jurisdictional activities, more than double its GRC authorization.[11] As of the end of 2023, this excess spending had already resulted in PG&E applications and advice letters seeking to recover an additional $5.2 billion in rates, a significant portion of which is still pending authorization for rate recovery.[12]

The lesson is that utilities show no reluctance to incur costs above authorized forecast levels if they can be booked to a memorandum account for future potential recovery. In the context of SB 884, utilities would continue to expect that the Commission will find it difficult to disallow a significant portion of costs once they have been spent on infrastructure that is serving customers, even if that money could and should have been better spent.

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[9] Section 8386.4(a) and (b).

[10] TURN Opening Brief in A.23-06-008, Nov. 5, 2024, p. 30. Found at: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M545/K343/545343978.PDF

[11] *Id.*

[12] *Id.*, pp. 30-31.

3.2. The Uncertainties in a Ten-Year Plan Horizon Can Be Addressed Without Resorting to a Memorandum Account

SPD-15 stated that a memorandum account was warranted because of "significant uncertainties in undergrounding . . . that are likely to grow over a 10-year period."[13] But the SB 884 statute that created the 10-year undergrounding plan opportunity, unlike AB 1054, did not find the 10-year horizon a reason to direct the CPUC to allow a memorandum account for cost overruns in an Undergrounding Plan. Instead, as noted, SB 884 makes clear that the purpose of the 10-year period was to *reduce* unit costs through economies of scale and scope.

Importantly, there are other ways to address the uncertainty of a 10-year time horizon that do not require extending a blank check to the utilities. In these comments, as discussed in Section 4.2.2 and in response to Question B2, TURN recommends the adoption of a variance condition that would require the utility to seek re-review of a project when project costs or CBRs vary by more than a prescribed percentage from the values on which original project approval was based. In this way, the Commission can ensure that a project whose economic metrics have changed is still worth funding, *before the utility begins construction of the project.* The result is a win-win for utilities, which gain the certainty of pre-approval of a changed project (and the terms attached to that pre-approval), and ratepayers, who gain an opportunity to present their concerns about the reasonableness of a modified project before the funds are spent.

In addition, as discussed in response to Question D1 in Section 6.4, the utility can, if warranted, submit a petition for modification (PFM) of the Phase 2 decision to seek changes to adopted conditions. This is another available vehicle to gain an advance determination from the CPUC of the costs that would be eligible for ratepayer funding, thereby avoiding the need for a memorandum account. As noted in response to Question D2, such a PFM would need to show, at a minimum, that the changed conditions that prompt the PFM are wholly outside of the utility's control.

In sum, TURN urges the Commission to resist the impulse to defer costs that fail to satisfy the Phase 2 conditions to a memorandum account. Such an account could allow several billion dollars of additional costs to accumulate, which would constitute a ticking time bomb that could destroy the Commission's efforts to regain control over electric rates and promote electrification. Instead, the revised guidelines should specify that utilities must gain the Commission's approval before incurring costs that do not satisfy the Phase 2 conditions.

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[13] SPD-15, p. 8.

These issues – whether a memorandum account is needed and how a memorandum account can be avoided – are further discussed in Section 4.2.2, and in response to Questions B1 and B2, found in Section 6.2, and in response to Questions D1 and D2, found in Section 6.4.

4. Summary of TURN's Proposed Revisions to the Phase 2 Process and Conditions

This section has two purposes. First, in Section 4.1, TURN offers what it hopes is a coherent blueprint of the key issues that need to be addressed in the Commission's review of a Phase 2 application. Second, Section 4.2 presents TURN's recommendations for cost recovery conditions that should be added to the conditions already specified in SPD-15. Both sections are in response to the April 8, 2025 Workshop discussion and the April 11, 2025 questions.

4.1. The Commission's Review of the Phase 2 Application Should Determine the Conditions that Must Be Met to Satisfy the Just and Reasonable Standard and Other Requirements of SB 884

The CPUC's Guidelines adopted in SPD-15 specify 20 categories of information that must be included in the utility's Phase 2 application, including the information required in Appendix 1.[14] (The Guidelines (item 11) note that Appendix 1 is preliminary and will be updated based on Energy Safety's rules, which have now been issued.) As the Guidelines correctly note, the Phase 2 application may request "conditional approval," not final approval, of the plan's costs.[15]

Thus, a key purpose of the proceeding to review the Phase 2 application is to determine the conditions that plan costs must satisfy before they can be added to rates. SPD-15 correctly explains that the Phase 2 Conditions are those that are necessary and sufficient to determine that the costs are just and reasonable.[16] The "just and reasonable" requirement is fundamental and is imposed both by Section 451 and by SB 884 in Section 8388.5(e)(6). However, it is important to recognize that SB 884 specifies other required elements that should inform the Phase 2 conditions, including showings that:

- The Phase 2 plan will achieve substantial improvements in costs compared to other hardening and risk mitigation measures over the duration of the plan;
- The Phase 2 plan includes cost targets that, at a minimum, will result in feasible and attainable cost reductions as compared to the utility's historical undergrounding costs;
- The Phase 2 plan specifies declining cost targets due to cost efficiencies and economies of scale; and

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[14] SPD-15 Guidelines, pp. 7-10.

[15] SPD-15 Guidelines, p. 10; Public Utilities Code Section 8388.5(e)(1).

[16] SPD-15, p. 5.

- The Phase 2 plan demonstrates a strategy for achieving cost reductions over time.[17]

Based on the Phase 2 conditions currently specified in SPD-15, some of the key tasks of the Phase 2 proceeding will be the following:

(1) Determining the total annual cost cap for each year of the plan, per Condition 1.
(2) Determining the average unit cost cap for each year of the plan, per Condition 3.
(3) Determining the average threshold CBR for each year of the plan, per Condition 4.
(4) Determining any further reasonable conditions, per item 5 in the SPD Guidelines.[18]

TURN anticipates that the Scoping Ruling for Phase 2 will include each of these issues, which will then be litigated in the proceeding.

4.2. The Commission Should Add Phase 2 Conditions to Ensure that Plan Costs Are Just and Reasonable and Satisfy SB 884's Additional Requirements

The April 11, 2025 questions indicate that the Commission is considering whether to specify *additional* Phase 2 conditions in a resolution updating SPD-15. In response to those questions, TURN urges the Commission to adopt the following additional conditions.

4.2.1. The Commission Should Require Each Undergrounding Project to Be More Cost-Effective than Alternatives Providing Comparable Ignition Risk Reduction

First and most important, in response to Question B4, the Commission should add a condition that undergrounding projects may not move forward if the undergrounding CBR is lower than the CBR of any feasible alternatives (or combinations of alternatives) providing comparable reduction of ignition risk. As explained in Section 2, this condition is needed to give effect to the provisions of SB 884 that emphasize the need for undergrounding projects to be more cost effective than the alternatives. It also is necessary to satisfy the just and reasonable requirement. Undergrounding costs are not just and reasonable when comparable risk reduction can be achieved by less costly mitigations.

It is now beyond dispute that risk reduction comparable to undergrounding can be achieved by overhead hardening combined with other mitigations. PG&E's 2026-2028 WMP acknowledges two alternatives that, on average, are 97% effective or higher in reducing ignition risk and therefore highly comparable to undergrounding in that regard: (1) Line Removal with Remote

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[17] Section 8388.5(e)(1)(A)-(D).

[18] These conditions and item 5 are set forth in the SPD-15 Guidelines, p. 11.

Grid (98% effectiveness) and (2) Covered Conductor + EPSS + PSPS (97% effectiveness).[19] While the alternatives for a given project should not necessarily be limited to these options, this information in PG&E's WMP shows that, for virtually all projects, there should be at least one feasible alternative providing comparable ignition risk reduction. In addition, over time, more options are likely to become feasible for at least some circuits (e.g., REFCL), thereby increasing the alternatives, including combinations, that should be considered.

TURN also notes that the CBRs for overhead hardening alternatives that involve temporary outages include the offset to the risk reduction benefits from the outage impact. Thus, an accurately calculated CBR – based on a reasonable methodology for calculating reliability costs (see the response to Question E1, found in Section 6.5) offers a fair cost-effectiveness comparison that takes into account any reliability disadvantages of overhead hardening alternatives that include fast trip settings (EPSS) and PSPS. This means that, when comparing undergrounding with Covered Conductor + EPSS +PSPS, a lower CBR for undergrounding for a given location would show that, even when the outage impacts of EPSS and PSPS are considered, the combination of overhead hardening mitigations is more cost-effective – i.e., provides more net risk reduction benefits per dollar – than undergrounding.

TURN understands that Energy Safety's rules will require that the Screen 2 Undergrounding Projects List (which would become the basis for the CPUC Phase 2 application) include for each project a CBR comparison with at least two alternative mitigations or combinations of mitigations.[20] Thus, this information will be available when the utility submits its Phase 2 application and should be required by the CPUC, as further discussed in response to Question A1.

Because the utility will have already calculated these comparative CBRs for each project, the Commission should specify that this condition *applies to the utility's application* – meaning that only projects that satisfy the condition should be included in the Phase 2 application – and that *the condition should continue to apply throughout the SB 884 process*. That is, if at any point in the development of the project, the undergrounding CBR falls below the CBR of an alternative (or combination of alternatives) offering comparable ignition risk reduction, the utility will know that the undergrounding project will not gain CPUC approval and should not move forward. In this way, the Commission will ensure that undergrounding is only approved where the utility has demonstrated that it is the most cost-effective mitigation to achieve comparable ignition risk

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[19] PG&E 2026-2028 Base WMP (R0), Table 6.1.3-1, p. 128.

[20] OEIS Guidelines, p. 18.

reduction, consistent with Section 8388.5(e)(1)(A) (the plan provides substantial reductions in risk *and costs* compared to alternatives).

4.2.2. The Commission Should Adopt a Condition Denying Phase 2 Cost Recovery When a Project's Unit Costs and CBR Vary By More than a Prescribed Percentage from the Values in the Phase 2 Application

In response to Question B2, TURN recommends that the Commission adopt a condition that does not allow cost recovery via the one-way balancing account authorized in the Phase 2 decision when recorded values differ by more than a prescribed percentage from the key assumptions on which a project's approval was premised – such as unit cost and CBR. When this condition is triggered, the utility should be required to seek and obtain pre-approval of the changed project before construction begins. The percentage variances that trigger this condition need not be determined now; this should be an issue to be resolved in the Phase 2 application proceeding.

TURN has discussed the benefits of this condition in Section 3 above and will discuss further details in Section 5.3 and in its response to Question B2. Here, we note that TURN recommends a different process than suggested in Question B2 when a utility learns that a project will not satisfy this condition. Rather than allowing the utility to book to a Phase 3 memorandum account the costs of any projects that fail this condition, the utility should be required to gain an advance authorization from the Commission to proceed with the project notwithstanding the variance, in effect an exemption from the condition. In this way, once the utility knows about the variance, it can seek a Commission determination regarding the terms under which the project would be funded. This process serves the interests of both ratepayers and utilities. Utilities can avoid an uncertain Phase 3 proceeding and would be able to recover the costs meeting the Commission's terms via the one-way balancing account. Ratepayers will have an opportunity to raise concerns about projects with significant variances from original assumptions – e.g., those that are materially more costly than forecast in Phase 2 – before the project is constructed and before most project costs are incurred.

4.2.3. The Commission Should Adopt a Condition Establishing a CBR Threshold that Each Project Must Meet

In response to Question B3, TURN recommends that the Commission adopt Option 1 in that question by adding a condition that all undergrounding projects demonstrate that they have a CBR above a prescribed value, to be determined in the Phase 2 proceeding. If, as TURN strongly urges, the comparative CBR condition described in the previous section is added, the main purpose of this condition would be to weed out undergrounding projects in relatively low risk areas that would not be sufficiently cost-effective to justify funding.

Unlike the comparative CBR condition, which can be applied to the application itself, this condition would apply beginning with the review process after the Phase 2 decision (discussed in Section 5 below). Establishing the value for the CBR threshold would be an issue to be resolved in the Phase 2 proceeding. Notwithstanding the CPUC's efforts to standardize CBR calculations in R.20-07-013, there are still likely to be differences in the utilities' methodologies that would cause similar projects to have different CBR scores. For example, as TURN understands will be discussed in Mussey Grade Road Alliance's (MGRA) comments, the utility can use the risk scaling function to unreasonably distort and inflate risk scores, risk reduction calculations, and CBRs. Parties should have an opportunity to understand a utility's methodology and, if necessary, make recommendations to correct flaws, before recommending an appropriate CBR threshold.

5. TURN's Recommended Process After the Phase 2 Decision for Ensuring Compliance with the Specified Conditions

This section describes TURN's recommended process after the Phase 2 decision to ensure that all applicable Phase 2 conditions have been satisfied before costs may be added to rates.[21]

5.1. SB 884 Requires the CPUC to Determine that Recorded Costs of Projects Are Just and Reasonable *Before* Costs May Be Added to Rates

Although SPD-15 is not crystal clear on this point, it seems to contemplate that, after the Phase 2 decision, a utility could automatically book incurred costs to implement the approved plan to a one-way balancing account and then recover them in rates. SPD-15 alludes to a subsequent process that would occur in Phase 3, sometimes referred to as an "audit," to assess whether the booked costs satisfy the Phase 2 conditions. Costs that do not meet the conditions would be subject to refund.[22] According to SPD-15, the details of this "audit" process would be determined in a later decision or order.[23] In sum, as TURN understands SPD-15, it would allow *up-front* recovery in rates of costs to implement a plan *before a determination that the Phase 2 conditions were satisfied*.

As TURN has previously explained, <u>an up-front cost recovery process is contrary to SB 884 and therefore would constitute clear and obvious legal error</u>.[24] As discussed in Section 4.1, the Phase 2 application process allows a utility to seek and obtain only *conditional* approval of Plan costs.[25] Section 8388.5(e)(6) provides that, after issuing a Phase 2 conditional approval

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[21] TURN uses the word "applicable" because, as explained in Section 4.2.2, TURN is recommending a process by which a utility could gain project exemptions from the Question B2 variance condition that TURN is recommending.

[22] SPD-15, pp. 2-3, 4-5, 16.

[23] SPD-15, pp. 5-6.

[24] TURN Comments on Draft SPD-15, December 28, 2023, pp. 3-5.

[25] Section 8388.5(e)(1).

decision, the Commission "shall authorize recovery of *recorded* costs that are *determined to be just and reasonable.*"[26] This provision means that the Commission cannot authorize recovery until the Commission has determined that recorded costs presented for cost recovery satisfy all conditions necessary for a just and reasonable determination. A process that allows up-front recovery of recorded costs before a determination that the Phase 2 conditions have been satisfied would therefore violate Section 8388.5(e)(6). For this reason, the Commission must reject the process described in Question C2 to the extent it allows rate recovery before a Commission determination that the Phase 2 conditions have been met and instead relies on a post-rate recovery review and refund process.

5.2. TURN's Recommended Process In Response to the April 11, 2025 Questions

Given the legal invalidity of the process that SPD-15 describes (as TURN understands it), TURN is pleased that, in Questions C1 through C3, the Commission is now re-visiting the process by which costs would be approved for cost recovery. TURN recommends a version of the process described in Question C1. Under TURN's recommended process, no costs would be booked to the balancing account until the Commission has determined in an annual process that recorded costs for that year have met all applicable Phase 2 conditions, as well as the used and useful requirement.[27]

Previously, TURN recommended an expedited application process for the Commission's required determination that recorded costs satisfy the Phase 2 conditions and are just and reasonable.[28] TURN continues to believe that process would best ensure a complete and high quality record for the CPUC's determination.

Nevertheless, TURN here outlines a process – a variant of what is proposed in Question C1 -- that would yield a faster decision than TURN's previously proposed expedited application process. The Commission should consider it to be the minimum process necessary to supply the Commission with the information it needs to make an informed determination of whether conditions have been satisfied and to comport with basic requirements of due process.

[26] Section 8388.5(e)(6) (emphasis added).

[27] As Question C1(c) implies, in addition to satisfying the Phase 2 conditions, costs must satisfy the "used and useful" requirement to qualify for recovery in rates.

[28] TURN Comments on Draft SPD-15, December 28, 2023, pp. 5-7.

TURN recommends a Resolution process that requires utilities to present complete and fully supported requests for cost recovery[29] and allows sufficient opportunity for intervenor discovery, analysis and comments. Specifically, TURN recommends:

- Three-business day turnaround on data requests, as Energy Safety specifies for WMPs;
- At least 75 days for interested parties to submit comments on the request and 20 days thereafter for reply comments;
- Issuance of a Draft Resolution with an opportunity for opening and reply comments.

While this recommended process has some similarities (as well as differences) compared to the Tier 3 advice letter process, this process should be considered to be distinct from the General Order (GO) 96-B process to avoid importing unintended rules and requirements from that General Order.[30]

In response to Question C1, TURN will explain why 75 days should be the minimum period for intervenor comments and why a longer period may prove necessary, depending on how the CPUC decides to deal with updates to risk models and CBR methodology and calculations, topics addressed in the Section D and E questions.

5.3. TURN's Recommended Process for Re-Review of Projects With a Significant Variance from Original Estimates

In Sections 3 and 4.2.2, TURN recommended, in response to Question B2, inclusion of a condition to re-review projects in which the utility has determined that that there will be a significant variance in one or more key project assumptions (e.g., unit cost, total project cost, CBR) compared to the values for the project in the approved Plan. Once the utility learns of such a variance, the utility should be required to either remove the project from the Plan or gain a full or partial exemption from the variance condition by presenting a justification to continue with the project. As discussed in Sections 3 and 4.2.2, this re-review to gain an exemption from the variance condition should take place before the utility proceeds with construction of the project.

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[29] As TURN stated on page 5 of its December 28, 2023 comments, to facilitate such an expedited process, the Commission must specify (in its Phase 2 decision) the detailed data submission requirements that the utility must meet in its cost recovery request based on the Phase 2 conditions that must be satisfied. In addition, if a utility were to claim confidentiality for any of the information in its request, it should be required to include a model nondisclosure agreement to facilitate the parties' prompt receipt of such data.

[30] Section 5.1 of GO 96-B states that the advice letter process is not appropriate for matters that are expected to be controversial, which is likely to be the case with rate recovery requests for hundreds of millions of dollars of capital expenditures.

TURN recommends that the same process for the annual cost recovery requests described in Section 5.2 be used for any requests for an exemption from the variance condition. Such exemption requests would be separate from the cost recovery requests but proceed on the same schedule: expedited discovery, 75 days for opening comments, 20 days for reply comments, and opening and reply comments on a Draft Resolution. The Commission's options in acting upon the request would include establishing a new set of project metrics that must be met for the project costs to be approved in a future cost recovery request, e.g., new conditions for unit costs, total project costs, and CBR. Such determinations would ensure that projects with significant variations from original estimates in the Phase 2 application satisfy the just and reasonable standard and other SB 884 requirements and provide the utility with clear guidance regarding the costs that will (and will not) be funded.

6. Response to Questions

6.1. Section A: Should the Commission Consider Supplementing the Phase 2 Application Requirements?

SPD-15 included a list of 20 requirements that must be included in any Application submitted to the Commission seeking conditional approval of Plan costs. Would it be appropriate for the Commission to consider adding the following requirements?:

1. *Include the data associated with the list of all projects (SB 884 Project List Data Requirements) as required by Screen 2 of the Energy Safety Guidelines*
    a. *Require the utility to provide us with a forecasted scope of all projects for the ten-year plan, with the expectation that projects far in the future would change.*
    b. *This requirement would make it explicit that the Underground Project List, which is an output from Screen 2 in the Energy Safety Guidelines, must be ready for the Commission to review before an Application can be submitted.*

Response to Question 1

Yes, the information in both subparts should be provided in the Phase 2 application. Utilities should be encouraged to make their best efforts to describe the projects as accurately as possible in the Phase 2 application. To that end, rather than stating a Commission "expectation" that projects far in the future "would" change, TURN recommends rephrasing to "recognize the possibility that projects far in the future may change."

2. *Require the utilities to provide a detailed explanation for any spans that extend beyond the HFTD for any project included in the Underground Project List from Screen 2 of the Energy Safety Guidelines.*
    a. *The Energy Safety Guidelines allow for undergrounding circuit segments with assets inside the HFTD, then each span that crosses the Tier 2 or 3 HFTD boundary and up to two adjacent spans outside of a Tier 2 or 3 HFTD may*

also be included in a project.

b. *This requirement would ask the utilities to provide a detailed explanation regarding why they must include any spans that extend beyond the HFTD.*

Response to Question 2

Without addressing whether Energy Safety's provisions for the inclusion of non-HFTD spans in the utility's Plan comport with SB 844,[31] TURN agrees that this information should be required in the Phase 2 application.

3. *Require utility to submit a depreciation study with updated information of the type of assets that are impacted by an SB-884 Application*
   a. *Depreciation studies are typically updated when a utility files its GRC.*
   b. *Because undergrounding projects have large capital expenditures, there is a potential that depreciation and salvage costs may be contested in an EUP cost recovery Application.*
   c. *This would require a depreciation study be included in the record, but it should be a depreciation study with updated information since an EUP cost recovery Application will not necessarily be submitted in the same time frame as a GRC.*

Response to Question 3

TURN agrees that the utility should be required to submit an updated depreciation study for the assets at issue in the SB 884 application. Whether that updated study needs to be a disputed issue in the Phase 2 proceeding would depend on the timing of the SB 884 Phase 2 application in relation to the utility's GRC and whether the depreciation issues for the SB 884 assets have been addressed in the GRC. If the relevant issues have recently been resolved in the GRC and the changes to the depreciation study are minor or non-existent, then it would likely be unnecessary to re-visit those issues in the SB 884 Phase 2 proceeding.

4. *Require both nominal and present value lifetime calculations for the capital expenditures for each project included in the Undergrounding Project List from Screen 2 of the Energy Safety Guidelines.*
   a. *PUC 739.15 specifically calls out the need for greater clarity on the lifetime cost and benefit of a capital expenditure project such as those submitted in an EUP cost recovery Application.*

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[31] Section 8388.5(c)(2) states: "Only undergrounding projects located in tier 2 or 3 high fire-threat districts or rebuild areas may be considered and constructed as part of the program."

b. *This would require both nominal and present value lifetime calculations for the capital expenditure of each undergrounding project.*

Response to Question 4

TURN agrees that the utility should be required to provide nominal and present value calculations for the forecast capital costs for each undergrounding project included in the Phase 2 application. The costs presented in the application should be based on the *full costs* to ratepayers of each project, and those full costs based on lifetime revenue requirement estimates should be used in the CBRs. Direct capital costs paid by utilities do not include such elements as rate of return, taxes and other loaders, and thus very likely understate the total costs to ratepayers over the life of a capital asset.

Moreover, as subpart (a) recognizes, including the full revenue requirement impact of capital investments is consistent with the intent of Public Utilities Code Section 739.15, recently added by AB 2847 (2024), which specifically authorizes the Commission, including *in SB 884 applications*, to require utilities to estimate the revenue requirement impacts for each year that the capital costs will remain in rate base.[32]

TURN expects utilities to contend that calculating revenue requirements on a project basis is unduly burdensome. However, the utility will ultimately need to calculate the revenue requirement impact of each project when it seeks rate recovery. If this exercise can be done later, it can be done when the application is presented. TURN recognizes that some long-term inputs into the revenue requirement calculation will need to be estimated and may be subject to change. However, provided that the utility makes good faith estimates, lifetime revenue requirement impact is much more representative of the total costs that ratepayers will face than the direct costs to the utility, for the reasons stated. The benefit to the decision-making process of having more accurate cost information outweighs any burden to the utility.

To be clear, TURN is not recommending that the annual cost caps required for Condition 1 of SPD-15 be based on annual revenue requirement calculations. Instead, those should be based on the capital expenditures for each year approved by the Commission, as the cap is intended to serve as a cap on expenditures. Moreover, *annual* revenue requirements (as opposed to the lifetime revenue requirement estimates discussed above) are affected by tax issues that cause the first year of revenue requirement for an undergrounding project to be low or even negative and for the succeeding years' revenue

[32] Public Utilities Code Section 739.15(b) (applying the statute's information requirements to "an application for conditional approval of the costs of an undergrounding plan pursuant to 8388.5….")

requirements to be higher to make up for the deferred tax liability in the first year.

5. *Require data retention policy for lifetime of EUP for tabular and geodatabase data. This should be required for both the initial application and any of the data updated through the six-month progress reports.*
    a. *Since there are no additional requirements for data retention related to an EUP, this will require the utility to retain all tabular and geodatabase information submitted as part of the EUP and any data included in six-month progress reports.*
    b. *Staff intend to hold data template working groups later in the spring.*

<u>Response to Question 5</u>

TURN supports this requirement.

6. *Require utilities to submit the same Key Decision-Making Metrics (KDMM) data for Commission review as provided for in the submission to Energy Safety.*

<u>Response to Question 6</u>

TURN supports inclusion of the seven KDMMs specified by Energy Safety in the Phase 2 application. Those all provide useful information. Energy Safety also allows the utility to add up to five more KDDMs of the utility's choosing. Without knowing those additional KDMMs, TURN cannot opine as to whether they will provide useful information.

6.2. Section B: What, if Any, Additional Phase 2 Conditions Should the Commission Consider?

1. *Should the Commission consider imposing Conditions on the Memorandum Account (MA)? Ifso, what Conditions should be considered?*
    a. *Option 1: Establish a maximum total cap for the MA, limiting it to no more than 25% ofthe total sum of the ten-year annual caps established for the balancing account.*
    b. *Others?*

<u>Response to Question 1</u>

TURN's primary recommendation is that no memorandum account be allowed, for the reasons explained in Section 3.

If a memorandum account is allowed, it should be capped at no more than 10% of the total ten-year Plan costs approved in the Phase 2 decision. Even a 10% cap could allow for the opportunity for multiple billions of dollars of additional cost recovery, depending on the size of the utility's approved Plan.

As discussed in Section 3, Section 4.2.2, and Section 5.3, a memorandum account would undermine cost control incentives by permitting utilities to seek recovery of cost overruns after the money has been spent and undergrounding plant has become operational. Instead, the Commission should focus on ways to require re-review and pre-approval of revised projects when project plans – and associated costs and CBRs -- change materially over time.

2. *Should the Commission consider assessing the variance between the forecast data submitted according to the SB 884 Project List Data Requirements in the initial cost-recovery Application to the Commission and the updated data submitted according to the SB 884 Project List Data Requirements in a six-month progress report and if so how?*
    a. *Option 1: If the variance between the forecasted CBRs and unit cost of a project presented in an Application compared to the updated CBRs and unit cost of a project presented in a six month Progress Report (after a project passes Energy Safety's Screen 4) exceeds a certain threshold, then all costs for that project must be recorded in the MA.*
    b. *Others?*

Response to Question 2

As discussed in Section 3, Section 4.2.2 and Section 5.3, TURN recommends that the Commission adopt a new condition based on Option 1: no cost recovery would be allowed for projects if there is a significant variance (the amount of the variance to be determined in the Phase 2 proceeding) in one or more key project assumptions (e.g., unit cost, total project cost, CBR) compared to the values for the project in the approved Plan.

The important difference in TURN's recommendation compared to subpart (a) is that TURN is recommending that costs of projects that trigger this condition would not be recorded in a memorandum account. Instead, projects to which this condition applies would either be removed from the Plan or would be the subject of a re-review request using the process described in Sections 4.2.2 and Section 5.3. That process would give all parties an opportunity to address whether the project is still worth funding in the face of changed economic features of the project – such as increased unit or total costs or a reduced CBR.

Unless the utility gained such pre-approval, effectively an exemption from this condition, the utility would know that the Commission will not fund the project. The Commission's Resolution authorizing a changed project would specify any changes to the conditions for cost recovery, such as revised cost caps (unit and total) and a revised CBR threshold. The revised conditions specified by the Commission could differ from those proposed by the utility -- e.g, the project is authorized for up to $20 million (not the utility's requested $22 million) at a unit cost no higher than $2 million/per mile (not the utility's requested $2.2 million/mile).

3. *Should the Commission consider adopting a CBR Threshold, and if so, what should the criteria be?*
    a. *Option 1: Require all projects to have a CBR greater than a specified value.*
    b. *Option 2: If a project's recorded CBR is less than a specified value, the utility must provide a detailed justification for this project.*
    c. *Option 3: After Screen 2, any project ranked below a certain CBR percentile threshold is ineligible for cost recovery via the BA.*
    d. *Others?*

Response to Question 3

See Section 4.2.3, recommending Option 1. Alternatively, Option 3 is another way to weed out projects that do not compare favorably with other projects in terms of cost-effectiveness.

4. *Should the Commission consider requiring a comparative CBR analysis of project alternatives? If so, how should this analysis be conducted?*
    a. *Option 1: If an Undergrounding Project has a CBR above a specified CBR Threshold but the Alternative(s) has a CBR that is a specified amount greater than the Undergrounding Project's CBR, then the undergrounding project should not move forward.*
    b. *Others?*

Response to Question 4

TURN urges the Commission to adopt a condition that requires each undergrounding project to have a higher CBR than the CBR of any feasible alternatives (or combinations of alternatives) providing comparable reduction of ignition risk. In Sections 2 and 4.2.1, TURN has explained the need for this condition and how it should be applied.

5. *Should the Commission consider applying some of Energy Safety's KDMMs to the Commission's consideration of whether to grant cost recovery for projects and if so, how?*
    a. *Option 1: After Screen 3, if the reduction in Ignition Risk and/or Outage Program Risk does not meet the required Project Level Standard set in the approved Plan, the project will not be eligible for cost recovery via the one-way balancing account.*
    b. *Others?*

Response to Question 5

TURN understands this question to ask whether the KDDMs required by Energy Safety should provide the basis for additional Phase 2 conditions. TURN believes this is a good issue for the Phase 2 proceeding, at which time parties will have access to the actual

KDDM data and can better assess its usefulness for framing additional conditions.

6.3. Section C: What methods could the Commission use to Address the Audits and/or Review Procedure?

1. *Should the Commission consider adopting the following review structure to ensure a rigorous review of the costs associated with an EUP?*
    a. *Annual post-implementation review process with intervenor participation.*
    b. *Objectives of the review should include verifying project completion, cost overheads, CBR methodology and an incrementality showing.*
    c. *Once deemed "used and useful" in a progress report, a project's costs may be included in rate base via an Advice Letter that must be disposed via Commission Resolution.*
    d. *Commission Resolution will determine whether recorded costs met the Phase 2 Conditions and other objectives of the review.*
    e. *Approved costs would enter rates via Annual True-up.*

Response to Question 1

As discussed in Section 5.2, TURN recommends a process similar to the process described in this question, with some important differences. TURN responds to the subparts as follows:

Subpart (a): Yes, there should be an annual post-implementation review process with intervenor participation. TURN describes its recommended process in Section 5.2.

Subpart (b): The objectives of the review should include each of the items identified in the question – verification of project completion, inclusion of (no more than) appropriate cost overheads, (TURN would add inclusion of only costs needed to implement the project), use of a reasonable CBR methodology, and an incrementality showing. In addition, a key objective not listed in Subpart (b) should be a determination that all applicable Phase 2 conditions – as determined in the update to SPD-15 and in the CPUC decision on the Phase 2 application -- have been satisfied.

Subpart (c): TURN agrees that "used and useful" is an important showing that the utility must make before the costs may be included in rates. However, this is just one showing that must be made in this post-implementation review process. Commission precedent is clear that a used and useful showing is insufficient to justify inclusion of costs in rate base; the costs must also satisfy the just and reasonable standard.[33] Thus, in addition to used and useful, the utility must show all of the elements discussed in response to Subpart (b), including the important showing that all applicable Phase 2 conditions have been satisfied.

As discussed in Section 5.2, the process TURN recommends would not be an advice letter process under GO 96-B, although it would result in a Commission Resolution.

Subpart (d): TURN agrees that a Commission Resolution should determine whether all applicable requirements for cost recovery have been met.

Subpart (e): Only after the Commission has determined that all applicable requirements for cost recovery have been met, the costs in question would then become eligible to be booked in the one-way balancing account. The disposition of those costs in rates would be addressed in the Annual Electric True-Up advice letter proceedings.

Need for a minimum 75-day period for analysis and comment. Here, as previewed in Section 5.2, TURN explains the need for its recommended 75-day period (as a minimum) for analysis and comment on whether the recorded costs presented by a utility should be authorized for rate recovery. TURN bases this recommendation on its assessment, as best as can be determined at this point, of the nature of the analysis that will be necessary to determine whether the applicable requirements, including the additional conditions recommended by TURN in these comments, have been met.

Some of the requirements are best assessed, in the first instance, by the review of accountants who report to the CPUC, not the utility. Those requirements include assessing whether the claimed costs are adequately supported, are necessary for the project in question, and do not include excessive overheads. In addition, an auditor could offer an assessment regarding compliance with Conditions 1 and 3 in SPD-15, as these conditions require determining that the utility has included appropriate costs and accurately calculated the numbers for these conditions. In addition, an auditor could opine as to whether Condition 2 has been satisfied by seeking documentation of any available external funding amounts.

(In TURN's experience, the Commission should be wary of expecting an auditor to provide a valuable assessment of incrementality. In the SB 884 context, the incrementality issue is

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[33] *E.g.,* D.23-11-069, p. 775 ("PG&E asserts that it may receive cost recovery for any capital investment in assets that are used and useful regardless of whether the Commission has reviewed the costs for reasonableness. That is not correct.")

likely to be whether the utility's SB 884 plan is incremental to the undergrounding work that has been funded in its GRC or other proceedings. To do this analysis correctly, the reviewer needs to determine whether the undergrounding mileage that was authorized in the GRC was completed, not just whether the GRC authorized funds were fully spent. For example, the utility may have been authorized $300 million for 100 miles of undergrounding, but only performed 50 miles for that $300 million cost. In this case, ratepayers should not be required to pay the utility again to fund the 50 miles of work that was supposed to be completed with the GRC authorization, i.e., those 50 miles are not incremental to what was funded in the GRC. Determining whether the SB 884 undergrounding application is seeking to have ratepayers pay a second time to underground those 50 miles requires legal and policy judgments that are not typically within the expertise of auditors.)

If the Commission were to use an auditor to provide an opinion on these matters, the auditor's opinion should be subject to comment by the parties. Because the auditor's recommendations speak to whether the costs should be recoverable in rates, ratepayer representatives, and other interested parties should be able to address such matters as whether the auditor used appropriate and thorough procedures and reached reasonable conclusions. For the parties to have a meaningful comment opportunity on an auditor's opinions, the auditor's report - which should be fully documented -- should be finished before the utility costs are presented in the utility's annual cost recovery request and should be distributed to the utility and interested parties at the same time.

As discussed in TURN's November 12, 2024 Informal Comments, some of the conditions – particularly those involving CBR calculations – would not be appropriate for an auditor opinion.[34] As the Commission knows, CBRs (and their predecessor, RSEs) are complex calculations based on complex methodologies. When determined in accordance with Commission requirements and otherwise using reasonable inputs and assumptions, they can provide extremely valuable information regarding the cost-effectiveness of proposed projects and competing alternatives. However, because of their complexity, utilities also have the opportunity to skew the calculations in favor of their preferred outcomes. Commission requirements still afford utilities a significant measure of discretion and judgment in how they calculate CBRs.

TURN understands that, through the questions presented in Section E, the Commission is exploring whether it should limit that discretion, and, if so, how. As discussed at the workshop, TURN understands CPUC Staff's notion to be that the Commission could prescribe a methodology that the utility would be required to use in its SB 884 application and in each cost

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[34] Informal Comments of TURN, November 12, 2024, pp. 3, 5-6.

recovery request for the full ten years of an SB 884 Plan, thereby minimizing the scope of potential disputes regarding CBR calculations. However, the questions in Section E raise complex and likely controversial issues that may be difficult to fully resolve in the updated Resolution that will emerge from these comments.

In addition, even if the Commission specified a prescriptive *methodology* for calculating CBRs for purposes of SB 884 Plans <u>and</u> required that same methodology to be used in every submission for the full ten-year program (which could be characterized as a methodology "freeze"), there remains the issue of whether it is appropriate to freeze all of the *inputs and assumptions* in applying that methodology. Over the course of ten years, assumptions and inputs regarding ignition risk, mitigation effectiveness, and consequences of an ignition are likely to change. As just a few examples, covered conductor effectiveness could improve, REFCL could prove to be more reliable and effective, wildfire consequences could become more severe based on advances in climate change modeling, or less severe as properties are required to be hardened against wildfires by insurance companies, among other changes. Any or all of these changes could affect CBRs and would need to be reviewed and addressed in utility cost recovery requests.

For this reason, TURN believes that 75 days – with the expedited discovery recommended by TURN -- is the minimum period necessary for intervenors to be able to analyze and meaningfully comment upon any changes to the utility's models and assumptions for calculating CBRs in the annual cost review process.

2. *Should the Commission instead consider adopting the following review structure to audit the costs associated with an EUP?*
    a. *Annual audit by independent auditor with CPUC oversight.*
    b. *Objective of the audit should include verifying project completion, cost overheads, andan incrementality showing.*
    c. *Once deemed "used and useful" in a progress report, a project's costs may be included in rates via annual True-up and become subject to audit.*
    d. *If the audit finds that project costs were incorrectly recorded to the Balancing Account, then the utility must issue a refund to ratepayers*.

<u>Response to Question 2</u>

For the reasons explained in Section 5.1, a process that allows up-front recovery of Plan costs before the CPUC has made a determination that the costs are just and reasonable and satisfy all other applicable requirements is contrary to SB 884 and should be rejected. Moreover, the process described in this question would be both contrary to due process and extremely unwise in that it would allow cost recovery without providing a meaningful opportunity for ratepayer representatives and other intervenors to be heard regarding whether the auditor opinion is accurate and complete and whether the requested costs are legally entitled to be added to rates.

3. *Supporting Questions:*
    a. *How should the timing of the Independent Monitor's (IM) review and the utility's right to correct a deficiency found by the IM within 180 days (PUC 8838.5 (g)(2)) interact with the annual review of the costs of a project?*
    b. *How should projects that fail to meet key criteria be treated vis-a-vis cost recovery? What key criteria should be considered?*
    c. *Should intervenors participate in Options 1 and 2 above? If so, how and where?*
    d. *Should the Commission consider using a different option than 1 or 2 above? If so, explain each step in the proposed process. How and where would intervenor participation be accounted for in the proposed option?*

<u>Response to Question 3</u>

Subpart (a): The Commission can and should consider any unresolved issues found by the Independent Monitor in making its determination whether cost recovery should be allowed, in the process described by TURN in Section 5.2 and in response to Question C2.

Subpart (b): Costs that do not meet all prescribed conditions and other applicable requirements should not be recovered in rates at any time. Utilities will have full knowledge of the conditions and applicable requirements and can plan their work accordingly. As discussed in Sections 4.2.2 and 5.3, projects that trigger the variance condition (and that the utility still wishes to pursue) should be re-reviewed and pre-approved before construction, using the process described in those sections.

Subpart (c): It is critical that intervenors participate in the review of costs before they can be added to rates. Depriving ratepayers of this opportunity would be contrary to the letter and spirit of Section 454, which requires notice to customers and an opportunity to be heard before allowing rate increases. Preventing ratepayers and their representatives from presenting their analysis and views regarding whether all applicable requirements have been satisfied would deprive the Commission of a complete and balanced record for its determination.

Subpart (d): TURN recommends the process described in Sections 5.2 and 5.3 and in response to Question C1.

6.4. Section D: How could the Commission address changes to approved projects?

1. *Should new costs added to approved projects after the Phase 2 Decision be booked to the Memo Account?*
    a. *If the updated rolling average CBR falls below the Phase 2 Condition threshold, should all new costs be deemed non-recoverable?*

Response to Question 1

For the reasons discussed in Section 3, the Guidelines should avoid allowing costs that violate applicable conditions and other requirements to be recovered after they have been incurred. For this reason, TURN has proposed the variance condition discussed in Section 4.2.2 and Section 5.3, which would allow the utility to seek re-review and pre-approval of projects that vary materially from the approved Phase 2 projects. If a utility wishes to seek relief from *other* conditions (e.g, annual cost caps, unit cost caps, average CBR threshold), it can submit a petition for modification (PFM) of the Phase 2 decision (just as ratepayer representatives who believe that the Phase 2 conditions have proven ineffective in achieving just and reasonable rates can submit a PFM). By submitting a PFM, the utility can gain an up-front determination of whether any conditions will be relaxed, before it builds a project and spends the money. Either way, there is no need to book to a memorandum account recorded costs that violate conditions that have been found necessary to ensure just and reasonable rates.

2. *Should certain categories of cost overruns (e.g., inflation-driven, safety-driven) be treated differently from discretionary cost increases?*

In light of SB 884's focus on cost control and promotion of declining costs over time, a utility that is seeking to increase Plan costs above Phase 2 approved levels, either through TURN's proposed process for the variance condition or through a PFM, should be required to demonstrate the increased costs result from conditions wholly outside of the utility's control. Utilities need to know that the Commission will not allow additional recovery for costs that could be avoided through managerial and operational acumen.

6.5. Section E: Should the Commission include an Appendix with guidance for calculating the CBR of an undergrounding project?

1. *What level of granularity[16] should the utility use when applying the Interruption Cost Estimator (ICE) Calculator to generate a Monetized Value of Electric Reliability? Should the analysis be based on:*
   a. *HFTD and PEDS-activated circuits*
   b. *Operational Region and HFTD[17]*
   c. *Others?*

Response to Question 1

For calculating the Monetized Value of Electric Reliability, TURN recommends that the utilities use a disaggregated approach based on both geographic risk tiers and customer classes to accurately reflect the varied impacts of outages across different locations. The minimum required level of granularity should follow Safety and Policy Division's (SPD) four-tier geographic categorization model:

1. HFTD Tier 3 (Extreme)

2. HFTD Tier 2 (Elevated)
3. Non-HFTD with PEDS/EPSS Enabled
4. Non-HFTD with PEDS/EPSS Non-Enabled

This approach is supported by the recent ALJ Ruling in PG&E's RAMP (A.24-05-008), which required PG&E to "provide parallel reliability cost calculations using the disaggregated approach recommended in the SPD Evaluation Report."[35] The SPD analysis showed significant variations in $/CMI values across these four tiers (as well as within the three customer classes in each tier) demonstrated in the table below:[36]

Table 1: Customer Distribution and Reliability Costs by Geographic Tier (SPD)

Geographic Tier	Residential	Small C&I	Medium and Large C&I	2023 $/CMI SPD Report
PG&E - HFTD Tier 3-Extreme	315,786	29,975	5,168	1.47
PG&E - HFTD Tier 2-Elevated	152,264	11,237	1,567	2.05
PG&E - NONHFTD-EPSS	1,143,635	115,614	33,122	2.94
PG&E - NONHFTD-NONEPSS	3,349,740	312,761	124,103	3.43
System Average				**2.47**

However, SPD's four-category typology, although an improvement from the systemwide average, still falls short of addressing the issue of appropriate reliability valuation across the three

[35] April 22, 2025 ALJ Ruling, A.24-05-008, p. 10

[36] Table reproduced from SPD's Evaluation Report on PG&E's 2024 RAMP Application (A.24-05-008), Nov. 8, 2014, p.18, found here: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/reports/spd-evaluation-report-2024-pge-ramp-final-with-attachments.pdf

customer classes. For example, rural California, where fire risk is high, has a low concentration of C&I customers who distort outage costs ($/CMI) for residential customers located there.[37] [38]

TURN therefore recommends further disaggregation to a twelve-tier model that combines the four geographic tiers with three customer classes (Residential, Small C&I, and Medium/Large C&I). Table 2 below shows the customer class distribution across these 12 categories.

Table 2: Customer Distribution Percentages by Geographic Tier and Customer Class

Geographic Tier	Residential (%)	Small C&I (%)	Medium and Large C&I (%)
PG&E - HFTD Tier 3-Extreme	90%	9%	1%
PG&E - HFTD Tier 2-Elevated	92%	7%	1%
PG&E - NONHFTD-EPSS	88%	9%	3%
PG&E - NONHFTD-NONEPSS	88%	8%	3%

TURN's twelve-tier approach (i.e., 4 geo tier * 3 customer classes) would yield more accurate reliability valuations for CBR calculations, especially in rural HFTD areas where reliability impacts for residential customers have been over-estimated under both system-wide, and geo-tier only averages, when averaging $/CMI across the three customer classes for each of the four geo-tiers.[39] The ICE calculator already outputs these costs in its main output segregated

[37] This concern is supported by multiple findings in PG&E's RAMP proceeding: SPD's Evaluation Report (Nov. 8, 2024, p.17) noted that "system-wide average...incorporates the high costs of an outage to Commercial and Industrial customers despite large parts of PG&E's territory having few, if any, such customers." The above-referenced ALJ Ruling (April 22, 2025, p.9) affirmed this observation, stating that, "Rural parts of California where certain risks are more likely to occur, such as wildfire, have few Commercial and Industrial customers." MGRA's analysis (Oct. 11, 2024, p.11) also quantified this disparity, demonstrating that "in the HFTD areas, 30 percent of customers live on circuit segments without Commercial and Industrial businesses" with a significantly lower reliability value of only "$0.68/CMI".

[38] https://www.latimes.com/environment/story/2022-12-27/more-than-half-of-rural-california-in-very-high-fire-zone

[39] For example, per PG&E's original calculations in RM-RMCBR-8 Module_1-Estimate_Interruption_Costs_w PGE Input.xlsm, residential cost per CMI ($0.06) is dramatically lower than either Small C&I ($9.99) and Medium/Large C&I ($77.89) costs (2023

by the three customer tiers, and residential customer costs per CMI as well as costs per unserved kWh are found to be consistently lower (in some cases orders of magnitude lower), compared to the two non-residential classes. The customer-segregated reliability values can be further refined using customer type-specific inputs, including backup generation prevalence, MWh consumption patterns by customer type/time, and regional economic data.

This enhanced granularity will ensure more accurate CBR calculations that properly reflect both wildfire risk reduction and reliability benefits for SB 884 undergrounding projects, preventing systemwide averages from overvaluing projects based on reliability benefits.

2. *How should the utility calculations of CBR be presented when using the three discount rate scenarios (Weighted Average Cost of Capital, Social and Hybrid) required by D.24-05-064?*

Response to Question 2

Discount rates can have a significant impact on CBR calculations. In R.20-07-013, TURN has raised particular concerns about CBRs that use different discount rates in the numerator and denominator, which TURN believes can bias and distort the results.[40] TURN is concerned that a utility may choose a discount rate option to further its financial interests, highlight the results of its chosen option in its Phase 2 pleadings, and effectively bury in dense workpapers the CBR calculations using the other required options.

The Commission should be aware that the appropriate discount rate will be an issue in the Phase 2 proceeding that it will need to resolve. In order to make clear the impact of different discount rate options on CBR calculations, the Commission should require the utility to provide in its Phase 2 pleadings (i.e., not just in the workpapers) tables showing alternative CBR calculations using alternative discount rates.

3. *Since the Energy Safety Guidelines allow the utility to consider an Ignition Tail Risk Threshold and High Frequency Outage Program Threshold, if the utility applies a convex risk scaling function to the calculation of CBR, how should the utility also present calculations that do not apply a convex risk scaling function, as required by D.24-05-064?*

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dollars). This difference between residential and non-residential $/CMI persists in the 4 geo-tiered calculation.

[40] TURN White Paper on Discount Rates, R.20-07-013, October 31, 2023, pp. 8-9, found at: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M520/K763/520763597.PDF

Response to Question 3

Consistent with the April 22, 2025 Ruling in the PG&E RAMP (A.24-05-008), any utility that chooses to use a convex (risk-averse) scaling function – which furthers the utility's financial interest in justifying higher rate base levels[41] -- should also include parallel results using a risk-neutral scaling function. Specifically, the utility should:

- Provide parallel monetized levels of each attribute or attributes without applying its risk-averse Risk Attitude Function; and
- Provide CBRs (and any other cost-benefit analysis) without applying its risk-averse Risk Attitude Function.[42]

TURN understands that MGRA's comments will discuss in detail the problems with risk-averse scaling functions and why CBR results based on such functions are not useful for purposes of estimating risks and CBRs.[43] TURN agrees with MGRA that the Commission should base its decisions and conditions in SB 884 proceedings on risk-neutral scaling functions.

4. *How should the Commission consider the combined CBR benefits of Ignition Risk reduction and Outage Program Risk reduction, given that a proposed mitigation may also reduce outage program risk?*
    a. *Option 1: Calculate the CBR benefit based on the Ignition Risk reduction only.*
    b. *Option 2: Calculate the CBR benefit based on a combination of Ignition Risk reduction and Outage Program Risk reduction?*
        i. *Should the CPUC assume mutual exclusivity between Ignition Risk and Outage Program Risk when aggregating the CBR benefits? If not, how should these risks be combined?*

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[41] See TURN's January 3, 2025 Comments in R.20-07-013, pp. 8-13, discussing the utilities' financial interest in a risk-averse approach to risk analysis that justifies higher risk mitigation spending, as compared to the interest of many ratepayers whose risk attitude is shaped by the affordability of an essential service they cannot live without. These comments can be found at: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M553/K185/553185395.PDF

[42] ALJ Ruling in A.24-05-008, April 22, 2025, p. 8.

[43] TURN has also previously addressed this issue. *See, e.g.,* TURN's Opening Comments in PG&E's RAMP, A.24-05-008, Dec. 6, 2024, pp. 2-6, found at: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M549/K057/549057536.PDF

Response to Question 4

In general, the benefits of a mitigation should be based on the reduction of risk (pre-mitigation risk minus post-mitigation risk). Risk is calculated as the product of likelihood and consequence of a risk event. In that calculation, all consequences should be considered including the impact of the mitigation on reliability. If a mitigation reduces the need for outage programs, that reliability benefit should be included in the benefit calculation.

The challenge is ensuring that the utility's assumptions and calculations of such reliability benefits are reasonable and are not tainted by the utility's financial interest in enhancing rate base. For example, while overhead hardening can reduce the need for PSPS and EPSS (although likely not as much as undergrounding), a utility that seeks to justify a large undergrounding footprint may understate these reliability benefits of overhead hardening in the comparison of grid hardening alternatives. This concern is one illustration of the detailed CBR-related issues that may arise in cost recovery requests that underscore the need for TURN's minimum 75-day analysis and comment period recommended in response to Question C1 in Section 6.3.

The subpart (i) question regarding "mutual exclusivity" may be raising a significant issue. However, outside the context of specific calculations and illustrations, TURN does not fully understand the issue and is not able to provide a generalized answer at this time.

5. *What is the appropriate point in time for utilities to use as CBR Year Zero in CBR calculations?*
    a. *Option 1: The first year of application cycle.*
    b. *Option 2 : The year the project is expected to become used and useful.*

Response to Question 5

TURN is inclined to support Option 2, that CBR Year Zero in the Phase 2 application be based on the year the utility expects the project to become operational. This means that Year Zero could differ by project. This CBR will be the CBR on which CBR-based conditions will be based. The same Year Zero should be used when the utility seeks cost recovery for the project, in order to yield an apples-to-apples comparison. Indeed, this may be the more important point – that whatever CBR Year Zero is used for a project in the Phase 2 application should be the same CBR Year Zero that is used when requesting cost recovery.[44]

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[44] TURN is not confident that it has been able to think through all nuances associated with this issue, so offers this response somewhat tentatively.

7. Conclusion

TURN appreciates the opportunity to respond to SPD's questions. Please contact the undersigned or Elise Torres (ETorres@turn.org) with any questions about TURN's responses.

Dated: April 25, 2025

Prepared by:

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

SB 884 - TBD

Informal SB84

MUSSEY GRADE ROAD ALLIANCE RESPONSE TO THE

POST-WORKSHOP QUESTIONS REGARDING THE CPUC SB 884 GUIDELINES

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Dated: April 25, 2025

1. INTRODUCTION

The Mussey Grade Road Alliance (MGRA or Alliance) provides these responses to the post-workshop questions regarding the April 8th workshop, authored and issued by Commission Staff on April 11, 2025,[1] with responses to the questions requested by April 22, 2025.[2]

MGRA did not attend the workshop but has been actively involved in the development of the SB 884 guidelines since the bill (which MGRA opposed) was passed.

MGRA will only respond to those questions on which it has a subject matter expertise and believes are urgent.. Lack of response to a particular question at this time does not imply that it may not present additional information or opinion at a future date.

MGRA comments have been prepared by Alliance expert Joseph W. Mitchell, Ph.D.

Sections are adopted from the Questions.

2. STAFF QUESTIONS

A. SHOULD THE COMMISSION CONSIDER SUPPLEMENTING THE PHASE 2 APPLICATION REQUIREMENTS?

"SPD-15 included a list of 20 requirements that must be included in any Application submitted to the Commission seeking conditional approval of Plan costs. Would it be appropriate for the Commission to consider adding the following requirements?:

1. *Include the data associated with the list of all projects (SB 884 Project List Data Requirements) as required by Screen 2 of the Energy Safety Guidelines"*

   It would be appropriate and necessary for the application package submitted by the utilities to contain all data used during the Energy Safety approval phase. As there are

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[1] SB-884; Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines; April 11, 2025. (Questions)

[2] Email: From: Amin.Emrani@cpuc.ca.gov; Subject: Postworkshop questions for potential updates to the CPUC Guidelines for SB 884; April 11, 2025.

only nine months for intervenors and staff to review the application, all data that has gone into the initial analysis should be instantly available at the time of application.

a. *Require the utility to provide us with a forecasted scope of all projects for the ten-year plan, with the expectation that projects far in the future would change.*

It is essential that the utility provide a forecasted scope for projects in the ten year plan. Otherwise, the Commission would effectively be issuing a "blank check" to the utilities for future work that has not been fully analyzed yet.

b. *This requirement would make it explicit that the Underground Project List, which is an output from Screen 2 in the Energy Safety Guidelines, must be ready for the Commission to review before an Application can be submitted*

MGRA concurs with this requirement for the aforementioned reason.

5. *Require data retention policy for lifetime of EUP for tabular and geodatabase data. This should be required for both the initial application and any of the data updated through the six-month progress reports.*

a. Since there are no additional requirements for data retention related to an EUP, this will require the utility to retain all tabular and geodatabase information submitted as part of the EUP and any data included in six-month progress reports.

b. Staff intend to hold data template working groups later in the spring.

Retention of data records including tabular and geodatabase data is essential for tracking of the project execution and ensuring that the utility is not engaging in untracked "scope creep", or expansion of initially small projects. Data records will also be essential for tracking and auditing purpose.

However, as IT and data processing best practices change over time, and additionally utility wildfire mitigation practices and priorities will change over a decade, it may be that some fields may need to be added, deleted or have their definitions changed over time. If this is the case, it may become necessary to maintain multiple copies of data, each with a different schema, in order to guarantee backwards compatibility and traceability.

B. WHAT, IF ANY, ADDITIONAL PHASE 2 CONDITIONS SHOULD THE COMMISSION CONSIDER?

Background:

SPD-15 listed five Phase 2 Conditions that must be met for the costs of any project to be booked to a one-way balancing account. The parameters or threshold values of the Conditions will be established in the Phase 2 Decision based on the forecasted numbers presented in the cost recovery Application. As explained in the Instructions above, the five Conditions listed in SPD-15 include a total annual cost cap, a two-year rolling average recorded unit cost cap, a two-year rolling average recorded CBR threshold, a requirement to apply third-party funding to reduce the cost cap, and any further reasonable Conditions supported by the record of the proceeding and adopted by the Commission in the Phase 2 Decision.

2. *Should the Commission consider adopting a CBR Threshold, and if so, what should the criteria be?*

Yes, the Commission should consider adopting a CBR threshold for undergrounding projects. However, to the degree that CBR calculations can be adjusted by choice of the scaling function, the CBR must be regarded as arbitrary.

Therefore the Commission should only consider neutral risk scaling when evaluating utility projects in terms of CBR.

MGRA has been involved in risk scaling deliberations in both the RDF proceeding R.20-07-013 and the PG&E RAMP A.25-05-008. MGRA has supported TURN and other intervenors in requesting that a neutral risk scaling function be adopted, arguing that the power law distribution adopted by PG&E as a basis for their enterprise wildfire risk modeling (tail-risk) is inherently risk-averse and no further adjustments are necessary. MGRA was originally open to evaluating PG&E's purported "market-based" scaling function to account for uncertainty risk. However, when the details of PG&E's risk scaling adjustments were examined during the PG&E RAMP evaluation MGRA's final assessment of PG&E's risk scaling was extremely negative. MGRA's analysis was included in Safety Policy Division's PG&E Evaluation Report.[3] For convenience, excerpts from these comments dealing with CBR, risk scaling, and the ICE calculator are attached to these comments as Attachment 1.

The purpose of cost/benefit analysis – an approach that MGRA has been championing since 2009 – is to make the decisions regarding wildfire mitigations and spending as objective as possible, and to quantify both mitigation costs and the benefit of avoided harm in a way that allows them to be directly compared. For 17 years the Commission, Energy Safety, utilities, intervenors, and other stakeholders have invested tens and probably hundreds of thousands of hours studying and quantifying wildfire risks. Whatever the shortcomings of current risk models and Commission processes, it certainly isn't through a lack of effort. It is therefore extremely frustrating to get to a point where risks and costs are finally being generated in a way that at least in principle allows direct comparison, and then to have PG&E adjust these numbers with a multiplier that might as well have been pulled from a Magic 8 Ball.

The PG&E case is used as an example because it clearly illustrates the peril of allowing a utility-provided scaling function to be used to make decisions as part of the SB 884. The attached appendix provides plentiful technical detail regarding issues of PG&E's methodology. To summarize them briefly:

- PG&E claims that its risk adjustment is based upon a "market-based" estimate of risk. It isn't. PG&E's risk multiplier value derives from a CAT bond issued from a single vendor specific to its own business.
- Because the CAT bond vendor's methodology is proprietary, there is no way of validating whether its own methodology for determining risk for its own purposes is

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[3] A.24-05-008; December 2, 2024 Ruling, Attachment 2
EMAIL RULING GRANTING CAL ADVOCATES' REQUEST TO SET DECEMBER 4, 2024, DEADLINE FOR COMMENTS ON MOTION AND ENTERING SAFETY POLICY DIVISION REPORT INTO THE A.24-05-008 RECORD:
Safety Policy Division Evaluation Report on PG&E 2024 RAMP Application (A.)24-05-008; November 8, 2024; p. 309/407:
https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M548/K361/548361466.PDF
MUSSEY GRADE ROAD ALLIANCE INFORMAL COMMENTS TO THE SAFETY POLICY DIVISION REGARDING PACIFIC GAS AND ELECTRIC COMPANY'S RAMP FILING, REVISION 1; October 9, 2024. Revised October 11, 2024.

remotely comparable to that used by PG&E and whether it would be applicable for the purpose for which PG&E is using it.

- Specifically, unless the CAT bond market is using the same truncated power law distribution that PG&E does for estimating enterprise risk, it is very likely that PG&E is "double counting" (in fact double multiplying) risk values that inherently incorporate significant "risk aversion".
- Risk premium traditionally is increased by 25-40% when uncertainty is incorporated. PG&E increases theirs by 650%. Even if uncertainty is amplified by the power law dependency, PG&E has done a sensitivity analysis with regard to its choice of power law truncation that would allow it to incorporate this as parametric uncertainty.
- A specific example from PG&E's RAMP illustrates one implication. PG&E intends to propose a $1 billion dollar program to underground service drops and secondary lines. Without PG&E's risk scaling, this program would have a CBR less than 1.0, i.e. would not provide estimated benefits in excess of its costs.

If the Commission decides to use CBRs as a determinative factor in evaluating undergrounding plans, it is important that these CBRs mean something objective. Allowing the utilities to introduce a scaling function effectively allows them to determine the CBR. Therefore, only a neutral scaling function should be used for this kind of evaluation.

a. Option 1: Require all projects to have a CBR greater than a specified value.

Needless to say, a CBR must be greater than 1.0 to justify a project. A higher value might be chosen, but first it will be necessary to see what the range of project CBRs is.

It is more important that the CBR of the undergrounding project be comparable to the CBR for alternatives that would provide equivalent risk reduction.

b. Option 2: If a project's recorded CBR is less than a specified value, the utility must provide a detailed justification for this project.

A detailed project justification should be provided in any case. The justification should include why the undergrounding project should be chosen over alternatives.

c. Option 3: After Screen 2, any project ranked below a certain CBR percentile threshold is ineligible for cost recovery via the BA.

Also acceptable but requires some familiarity of the CBR distribution for undergrounding projects and alternatives.

d. Others?

See answers to #4.

4. Should the Commission consider requiring a comparative CBR analysis of project alternatives? If so, how should this analysis be conducted?

Yes, comparative CBR should be provided for undergrounding projects and alternatives to undergrounding. These should be conducted using the utility's standard risk analysis and should use neutral risk scaling.

Note that detailed analysis of SCE covered conductor data has led MGRA to conclude that the wildfire reduction effectiveness of covered conductor is substantially higher (>75% at 95% confidence level) than that used by PG&E in its analysis (68%). This will lead to CBRs being artificially suppressed for the covered conductor alternative.

a. Option 1: If an Undergrounding Project has a CBR above a specified CBR Threshold but the Alternative(s) has a CBR that is a specified amount greater than the Undergrounding Project's CBR, then the undergrounding project should not move forward.

If the CBR for Alternatives is substantially larger than that for the proposed undergrounding project, then there must be some other compelling argument for use of undergrounding (for example egress issues or extreme wind locations). This is particularly necessary in light of the fact that CBR for covered conductor is likely to be underestimated.

b. Others?

E. SHOULD THE COMMISSION INCLUDE AN APPENDIX WITH GUIDANCE FOR CALCULATING THE CBR OF AN UNDERGROUNDING PROJECT?

Background:

The calculation of the CBR for undergrounding and alternative projects is a critical factor in determining project eligibility for cost recovery. In addition, the selection of CBR Year Zero plays a pivotal role in accounting for the time value aspect of CBR calculations. Notably, the Energy Safety Guidelines define Total Utility Risk as the sum of Ignition Risk and Outage Program Risk.

Briefly, yes, the Commission should provide guidance regarding how to calculate the CBR for undergrounding projects and alternatives.

1. What level of granularity16 should the utility use when applying the Interruption Cost Estimator (ICE) Calculator to generate a Monetized Value of Electric Reliability? Should the analysis be based on:

a. HFTD and PEDS-activated circuits

b. Operational Region and HFTD

c. Others?

Please see Attachment 1, MGRA PG&E RAMP comments. In summary, MGRA analysis of individual circuits showed that the vast majority outage risk calculated by ICE was due to impacts on large and medium sized businesses. Individual customers, according to the ICE model, are not heavily weighted. Consequently, circuits that serve no large businesses and limited medium sized businesses do not merit undergrounding on the basis of reliability, at least according to the ICE model. Granularity should be chosen so that a utility does not lump together circuits which include long, sparsely populated areas with circuits serving major industrial customers in order to benefit from this distinction in ICE modeling.

Additionally, in the MGRA 2025 WMP Update Comments,[4] individual circuits that had been undergrounded by PG&E and SDG&E were analyzed using outage data in order to estimate

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[4] OEIS Docket 2023-2025-WMPs; MUSSEY GRADE ROAD ALLIANCE COMMENTS ON THE 2025 UPDATE OF THE WILDFIRE MITIGATION PLANS OF PG&E, SCE, AND SDG&E; pp. 27-38.

the overall CMI costs from PSPS, and this was compared to the cost of undergrounding. MGRA concluded that:

"*The data shows that for many circuit segments, particularly in the vast PG&E service area, the cost of undergrounding exceeds, often greatly exceeds, what it would cost to install stand-alone power systems for all customers served by that segment. In the case of PG&E's 2024-2025 projects, the overall cost for undergrounding is over double what the cost would be in the hypothetical situation where off-grid solutions were built for each customer on high cost per customer circuits. While that may not be a feasible solution, it does beg the question of whether it is appropriate to choose the most expensive mitigation solution for those circuit segments unless it can be demonstrated that alternatives to undergrounding cannot provide adequate wildfire risk reduction for high cost-per-customer circuit segments.*

Likewise, the cost to avoid a customer PSPS minute varies from less than $1 for some circuits to in excess of $20 for other circuits. Circuit segments with excessive cost to reduce PSPS for customers should not be given preference for undergrounding. It can be seen that this value varies greatly from circuit to circuit, and provides a means of identifying circuits for which PSPS avoidance makes little economic sense. For such circuits, covered conductor should be deployed in combination with other complimentary mitigations, which might include aggressive EPSS and PSPS thresholds. Impacts to reliability could potentially be offset with grants or rebates to customers implementing off-grid or backup solutions at a considerably lower cost than undergrounding."

The answer to Staff's question then is "as granular as possible", since PSPS avoidance benefits vary greatly from circuit to circuit and cost scales with the length of the circuit.

3. Since the Energy Safety Guidelines allow the utility to consider an Ignition Tail Risk Threshold and High Frequency Outage Program Threshold, if the utility applies a convex risk scaling function to the calculation of CBR, how should the utility also present calculations that do not apply a convex risk scaling function, as required by D.24-05-064?

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https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=56615&shareable=true

I'm not sure that I understand this question. As stated in answers in Section B, using a convex risk scaling function in tandem with circuits selected for tail risk is likely to multiplicatively amplify risk in an inappropriate and incorrect way. Energy Safety's mandate is to reduce risk, both wildfire and outage risk, whereas the Commission's mandate is to ensure reliable and safe service at reasonable rates. Undergrounding projects that pass Energy Safety's screening are not automatically eligible for approval by the Commission. Additionally the utilities must show these projects are cost-effective. As described in Section B and in Attachment 1, use of a neutral scaling function is necessary for an objective assessment of the CBR.

4. *How should the Commission consider the combined CBR benefits of Ignition Risk reduction and Outage Program Risk reduction, given that a proposed mitigation may also reduce outage program risk?*

a. Option 1: Calculate the CBR benefit based on the Ignition Risk reduction only.

b. Option 2: Calculate the CBR benefit based on a combination of Ignition Risk reduction and Outage Program Risk reduction?

i. Should the CPUC assume mutual exclusivity between Ignition Risk and Outage Program Risk when aggregating the CBR benefits? If not, how should these risks be comibined?

As noted in previous discussion and in the attached appendix, as well as in the cited WMP comments, it is fine if Outage Program Risk is combined into the CBR calculation, with the caveat that a finer granularity is beneficial in identifying Outage Program Risk. The ICE model is a CBR model, whatever its issues, and so it is capable of determining outage costs over time. This should be straightforward to aggregate with the wildfire reduction CBR, by summing avoided outage costs with avoided wildfire costs.

An important consideration is that all alternatives must also analyze both ignition risk reduction and outage risk reduction, and this must be done in a realistic way. Specifically, introduction of covered conductor allows a modest increase in PSPS shutoff threshold, which will yield a modest benefit in outage risk reduction. Likewise, we do not yet know how deployment of covered conductor affects EPSS rates, but it is likely that it will reduce them (outages themselves purportedly reduce by 60%, but EPSS may or may not follow the same pattern). The Commission and intervenors should request this information at the time of initial application.

3. PROCESS CONCERNS AND PROPOSED ESCALATION PROCESS

An MGRA representative did not attend the most recent workshop, but did review the recording, for which we are grateful. Attendees raised a number of very important points.

One item that raised a lot of concern with intervenors was the fact that after Phase 2 there would be little to no opportunity for intervenors or even staff to comment on or challenge changes to basic assumptions or modifications or additions to the Plans. If I understood correctly, the process of handling Phase 3 and Phase 4 work would be handled by either:

1. An advice letter, on which intervenors could comment.
2. An independent auditor hired for the specific purpose of managing the Plans

There are many ways that either of these could go wrong.

- Intervenors would not be able to obtain discovery on an advice letter
- Intervenors might not even know about advice letters
- Utilities would have limited options if their advice letter were rejected
- Any work done by intervenors in these later phases would likely be uncompensible.
- An auditor with insufficient background in the detailed considerations and history of wildfire and outage risk might either
  - Allow changes that benefit the utility without any ability for ratepayers to challenge those changes, or
  - Conversely, deny the utility the ability to make reasonable changes.

MGRA therefore recommends that an escalation process be incorporated that would allow a potentially harmed party (which could be either ratepayer representatives or the utility) to request an Investigation be initiated if there are irregularities in later phases. The Investigation would allow discovery and enable all interested stakeholders to examine the basis for changes to assumptions or scope, and would allow a binding Commission determination. This would provide an important safety valve if flaws in initial planning become evident a few years down the road. Threshold criteria for initiating an investigation should be relatively strict (major changes to utility risk models, major new circuits added, etc.) in order to prevent its overuse. This would help to reduce the utility incentive to 'back-load' major changes beneficial to the utility after the initial phases have completed. It would also provide a mechanism for intervenors and staff to conduct discovery, and potentially enable intervenors to be compensated. Finally, it would allow the utility to challenge what it considers arbitrary decisions by either an auditor or the Commission. As hundreds of millions of dollars of project could easily slip in and out of Plans after they've been approved, adding an escalation path is simply ensuring due process rights for all stakeholders and ensuring that rates charged to customers are fair and reasonable.

4. CONCLUSION

MGRA thanks the Commission staff for laying the groundwork for what promises to be both complex and hurried application processes. We urge staff to prepare well for what may be confusing inputs, and to ensure that the CBR data provided are reproducible, transparent, and objective. We also request that an escalation mechanism be put in place to allow major irregularities in Phase 3 or Phase 4 to be challenged.

Respectfully submitted this 25th day of April, 2025,

By: __/S/____***Joseph W Mitchell***____________________

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ATTACHMENT 1

EXCERPT FROM MGRA COMMENTS ON PG&E 2024 RAMP

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 (filed May 15, 2024)

MUSSEY GRADE ROAD ALLIANCE INFORMAL COMMENTS TO THE SAFETY POLICY DIVISION REGARDING PACIFIC GAS AND ELECTRIC COMPANY'S RAMP FILING

REVISION 1

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Dated: October 9, 2024
Revised: October 11, 2024

2.2.2. Reliability and the ICE Calculator

As PG&E explains in its RAMP:

"*The RDF Proceeding Phase II Decision requires each IOU to use the most current version of the Lawrence Berkeley National Laboratory Interruption Cost Estimate (ICE) Calculator to determine a standard dollar valuation of electric reliability risk for the Reliability Attribute.*

As shown in Figure 2-1, the main output section of the ICE Calculator produces results for three customer classes – Medium and Large Commercial and Industrial (C&I),30 Small C&I, and Residential – as well as the average results for all customer classes, weighted by the number of customers in each class…

The ICE Calculator categorizes Medium and Large C&I as customers with annual electricity usage exceeding 50,000 kWh."[16]

PG&E calculated imputed costs per Customer Minutes of Interruption (CMI) using ICE and PG&E-specific inputs, as shown in the table below.

FIGURE 2-3
$/CMI USING ICE DEFAULT DATA AND PG&E-SPECIFIC DATA

	ICE Data (California)		PG&E Data	
Sector	Cost per CMI (2016$)	**Cost per CMI (2023$)**	Cost per CMI (2016$)	**Cost per CMI (2023$)**
Medium and Large C&I	$70.37	$89.34	$61.35	$77.89
Small C&I	$5.36	$6.81	$7.87	$9.99
Residential	$0.04	$0.06	$0.04	$0.06
All Customers	**$1.53**	**$1.94**	**$2.50**	**$3.17**

Figure 1 - PG&E ICE calculations of cost per customer minute interruption (CMI) for medium and large businesses, small businesses, and residential customers.[17]

What is remarkable about this estimate compared with historical utility estimates of PSPS consequences is the fact that reliability costs are overwhelmingly dominated by medium and large business outages. Unfortunately, the "recent" version of the ICE model, ICE 1.0 was released in 2016 and does not include important factors like backup generation.[18] The utilities are collaborating

[16] RAMP; PG&E-2; p. 2-12.
[17] Id.; p. 1-16
[18] RAMP; PG&E-4; p. 2-57.

in ICE 2.0 model development, and this will include results of a backup generation survey, but the new model is not planned for use in PG&E analysis until Q1 2027.[19] This also means that PSPS risks that are currently not informed by wildfire-related risks. MGRA has made filings in a number of CPUC proceedings stating the case that current utility PSPS risk models insufficiently capture a number of elements, such as loss of communication, traffic impacts, potential for fire starts due to generator and cooking fires, and other impacts, elements that IOU analyses lack.[20] PG&E's PSPS safety risk estimate is based only on historical disasters and does not account for these factors.[21] When PG&E compares PSPS reliability risk to PSPS safety risk using its cost/benefit analysis, its estimates for reliability risk are 100 times larger than safety risks.[22] Consequently, the story of "PSPS risk reduction" is almost wholly the story of preventing risk to large businesses. To compensate for this,

"*PG&E already prioritizes some of its investments by customer types on a non-economic basis, and introducing Tranche-specific, economically-based values of Reliability from ICE could lead to unforeseen impacts. For example, in determining tranche-level impact of PSPS, customers that provide critical services like hospitals and fire stations were given a higher weighting than others based on a weighting scheme that balances myriad considerations which was comprehensively analyzed and reviewed by stakeholders*."[23]

During workshops, SPD inquired why PG&E chose to use the average $3.17/CMI rather than finer granularity.[24] PG&E provided plausible answers, portions of which are cited above. However, examination of the segment-level structure of PSPS risk shows variations that are leading to significant misallocation of resources if expensive mitigation such as undergrounding is deployed.

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[19] DR Response RAMP-2024_DR_MGRA_001-Q010.
[20] Examples are MGRA 2022 WMP Comments; pp. 85-86;
R.20-07-013; MUSSEY GRADE ROAD ALLIANCE ADDITIONAL COMMENTS REGARDING DEVELOPMENT OF SAFETY AND OPERATIONAL METRICS; March 1, 2021; pp. 1-2.
[21] RAMP; PG&E-2; p. 2-8.
[22] RAMP; PG&E-4; p. 1-6. Figure 1-2 shows PSPS total risk as 3,655 and Figure 1-3 shows PSPS safety risk as 44.
[23] RAMP; PG&E-4; p. 2-57.
[24] Id.

MGRA Data Request MGRA-01, Question 6 addressed the question of how customer types are distributed across circuit segments, and PG&E's response can be seen in RAMP-2024_DR_MGRA_001-Q006 and attached Excel spreadsheet. MGRA's request erroneously requested data for PG&E's HFRA when it intended to request PG&E's HFRA+HFTD. Nevertheless, data for PG&E's HFRA should be representative of its customer distribution with the caveat that medium and large business customers may be more likely to be found in the periphery of PG&E's HFTD, which is largely rural. MGRA is also issuing another data request to PG&E for the HFRA+HFTD data, and we would invite SPD to monitor its response. The MGRA analysis of the HFRA data calculates a number of metrics and can be found in workpaper RAMP-2024_DR_MGRA_001-Q006Atch01-CMI-jwm.xlsx.

The total number of circuit segments provided was 4,143, with a total of 415,816 customers, and estimated CMI total of $884,698, which works out to an average $2.13 CMI per customer versus the $3.17 per customer used for PG&E's tranche estimates, reflecting a higher ratio of non-business customers than in the PG&E customer pool as a whole.

Results are broken down into customer types in the table below:

Customer Type	**Segments**	**Customers**	**CMI Total**
Medium and Large Business	1,805	5,972	$465,816
Small Business	3,410	39,260	$392,600
Residential	3,651	438,031	$26,282
Total	**4,143**	**465,816**	**$884,698**
On segments without M/L	2,338	142,109	$96,893
On segments without M/L/Small	733	7,925	$476

Table 1 - Breakdown of PG&E circuit segments crossing HFRA by customer type. Total number of segments with the customer type, number of customers, and total CMI per customer type are given. Number of customers on circuits without medium/large businesses, and with no businesses are shown in the last two rows.

One would expect that the overall cost of mitigation will scale with the number of circuits mitigated, and that the benefits will scale with CMI avoided. Safety benefits will generally scale with number of customers, but critical infrastructure will also factor in in ways that are not accounted for in the tallies above. 1,805 circuits, 44% of the total, with 5,972 medium and large business customers are responsible for 53% of the total CMI costs. 142,109 customers, 30% of the total, live on the 2,338 segments without large businesses, but are responsible for only $96,893 (11%) of CMI costs, reflecting an average per customer CMI of $0.68. Similar results for small businesses were obtained but very few customers live on circuit segments without small business.

The analysis shows that circuits that have no medium or large businesses have a much lower benefit from avoided outages both in aggregate and per customer than circuits with medium or large businesses. Therefore, when selecting circuits for undergrounding mitigation for the purposes of mitigation, from a risk reduction standpoint it would make sense to restrict the selection to:

- Circuits segments required for medium and large businesses,
- Circuits segments required for critical infrastructure lacking adequate backup capacity, and
- Circuits segments required for many residential customers.

Circuit segments not meeting these criteria may still be given priority for mitigation based on their wildfire risk, but using other measures such as covered conductor + DCD/EPSS which is far more cost effective.

These are common-sense restrictions and if applied as a pre-screen would greatly improve the post-mitigation cost/benefit ratio. One might ask, because these are common-sense measures, whether PG&E is already applying them. We have the data from PG&E's underground program to date and its planned undergrounding program through 2025, and the answer is definitively "***no***". The analysis supporting this conclusion is found in Section 3.2.2.

Recommendations:

- Underground mitigation should be prioritized over overhead mitigation (covered conductor) only when specific criteria are met:
    - The circuit segment provides services for medium and large businesses, large numbers of residential customers, or critical infrastructure without adequate backup generation, and is significantly affected by PSPS and/or EPSS.

- The circuit segment is in an area with high safety hazard due to extreme winds, high tree fall-in probability, or where ingress and egress from populated areas in the event of wildfire would be compromised.

- PG&E should provide number of customers served and CMI per circuit segment and aggregated over its proposal in its HFTD+HFRA areas along with its GRC filing.

2.2.3. Risk Scaling

PG&E has adopted a novel method for risk scaling, adopting a "Risk Premium Multiplier" to create a risk-averse attitude in its scaling function. It defines three ranges for its risk scaling function: Routine, Elevated, and Catastrophic, where "Catastrophic" is defined as losses over $1 billion, while the Elevated range describes losses between $100 million and $1 billion.[25]

These multipliers were shown during PG&E's workshops:

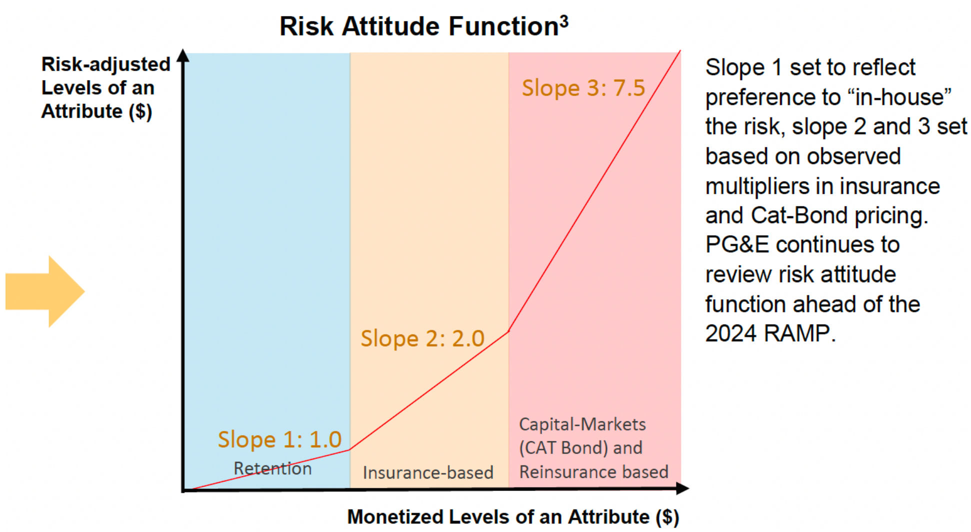

Figure 2 - PG&E's risk multipliers for different levels of consequence. Categories are Retention (<$100m), Insurance-based ($100m-$1b), and Catastrophic (>$1b).[26]

As seen in Figure 2, PG&E's risk function uses a multiplier for each attribute level. PG&E's method for obtaining its Catastrophic multiplier "*is to use available, objective data to determine the Risk Scaling Function(s). Risk Premiums/Prices from Insurance and Capital Markets meet these*

[25] RAMP; PG&E-2; p. 2-26.
[26] A.24-05-008; PG&E 2024 Risk Assessment and Mitigation Phase Workshop #1; February 7, 2024.

criteria because they are for products from independent entities that mitigate the same underlying risk presented in this Report such as wildfires, Loss of Containment (LOC) on gas pipelines, cyber-attacks, etc."[27]

2.2.3.1. CAT bonds as a risk attitude proxy

What PG&E uses for "objective data" (as opposed to the detailed analysis it has done to quantify its geographical vegetation data, ignition data, fire data, customer data, etc.) is data from the reinsurance market in the form of catastrophic (CAT) bonds.[28] Its justification for doing so is that "*Market theory tells us that the prices obtained from a perfect market maximize value to society. Of course, no market is perfectly competitive, complete, or truly representative of societal preferences—for instance, in addressing ESJ concerns—but there are established practices that can be employed within the market-based approach to account for shortcomings while still preserving its function of communicating societal values. Markets are often used to determine the fair value of goods and services, but whether one should obtain the said goods or services is dependent on individual circumstances. Hence, market data… can be used, in part, to determine the value of mitigations, and whether to fund such programs is part of the IOU's General Rate Case process, and should include budget considerations, overall priorities, risk tolerance and other factors*."[29]

This justification merits skepticism. The efficient market hypothesis defines "*a market to be 'informationally efficient' if prices always incorporate all available information*."[30] The assumption that CAT bond prices efficiently reflect risk, and do so better than PG&E itself, is only correct if the insurance companies have more complete information regarding wildfire consequences directly applicable to PG&E's circuits than PG&E itself does. Once consequence of this assumption, if it is true, is that CAT bond prices would align well with each other. PG&E lists the CAT bond prices it used to obtain its estimate:

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[27] RAMP; PG&E-2; p. 2-20.
[28] RAMP; PG&E-2; p. 2-23.
[29] Id; p. 2-21.
[30] Chen, J., Kelly, R.C., Kvilhaug, S., 2022. Informationally Efficient Market: Meaning, Hypothesis, Criticism [WWW Document]. Investopedia. URL https://www.investopedia.com/terms/i/informationallyefficientmarket.asp (accessed 10.8.24). See also: Grossman, S.J., Stiglitz, J.E., 1980. On the Impossibility of Informationally Efficient Markets. The American Economic Review 70, 393–408. https://www.jstor.org/stable/1805228

TABLE 2-9
CAT BOND DATA SUMMARY

Line No.	Issue	Risk	Date	Attachment	Coverage	Premium Multiplier
1	PG&E Cat Phoenix Re	Wildfire	Aug 2018	$1.25b	$200m	7.5
2	Sempra SD Re Ltd (series 2018-1)	Wildfire	Oct 2018	$1.326b	$125m	19
3	Sempra SD Re Ltd (series 2020-1)	Wildfire	Jul 2020	$1b	$90m	5-4 - 6.4
4	LA DWP Power Protective RE Ltd (series 2021-1)	Wildfire	Dec 2020	$125m	$50m	15 - 18
5	Sempra SD Re Ltd (series 2021-1) class B	Wildfire	Oct 2021	$1.2b	$135m	5 – 6
6	LA DWP Power Protective Re Ltd (series 2021-1)	Wildfire	Oct 2021	$125m	$30m	20 - 23
7	PoleStar Re Ltd (series 2024-1)	Cyber	Dec 2023	N/A	$140m	10.3
8	Matterhorn Re Ltd (Series 2023-1)	Cyber	Dec 2023	N/A	$50m	7.0
9	East Lan Re VII Ltd (Series 2024-1)	Cyber	Dec 2023	N/A	$150m	6.7
10	Long Walk Reinsurance Ltd (Series 2024-1)	Cyber	Nov 2023	N/A	$75m	5

Table 2 - CAT bond premium prices used by PG&E to estimate its Catastrophic Level risk multiplier.[31]

As can be seen, CAT bond prices for wildfire risk show significant variation, with premium multipliers ranging from 5 to 23. PG&E would appear to have based its own multiplier on the estimate of only one insurer – the aptly named Phoenix Reinsurance – with a premium multiplier value of 7.5. The lack of agreement on the range of reinsurance estimates is a red flag that insurers have very different methods for assessing risk, and not all of these can be "right". MGRA raised its point during the workshops: "*MGRA questioned whether markets can account for risk better than IOUs themselves, since IOUs presumably have more information about their service territories, assets and operating conditions. MGRA reasons that if market participants do not possess as much information and expertise as the IOUs, then the prices would not be an accurate reflection of risk.*

PG&E cannot comment on the level of knowledge that market participants possess but notes they have access to at least as much information as regulators and intervenors do, from PG&E's RAMP, GRC and WMP filings."[32]

This admission is noteworthy, and shows the implicit assumption PG&E makes in trusting its own risk estimate to Phoenix Reinsurance:

- That the company has an ignition probability algorithm that either uses PG&E's own results or calculates its own in a more accurate way than PG&E's,

[31] Op. Cite; p. 2-25.
[32] RAMP; PG&E-2; p. 2-61.

- That the company also performs a consequence analysis that incorporates a truncated power law distribution as PG&E's does, or uses PG&E's calculation, and
- That the company runs wildfire simulations superior to those of PG&E, incorporating PG&E's own highly customized vegetation modeling based on field observations, or uses PG&E's own calculation.

PG&E provides no evidence that any of these conditions are met, in fact it says it admits it does not know anything about how Phoenix Reinsurance calculates its premium. So the CAT bond price is a magical black box, lacking all transparency, into which PG&E can project anything it wishes. PG&E argues that this is the market, risk management is how these reinsurers make their money, so we should trust that they know their business. There is reason to be skeptical of this view.

As noted previously, the market requires knowledge, and detailed knowledge of risk is very difficult to get, as the Commission and intervenors have watched PG&E struggle over many years to build a defendable risk management framework, dedicating tremendous expense and many thousands of hours of person-time. PG&E has presented no evidence that Phoenix Re has done this. Furthermore, as MGRA discussed in depth in a filing ten years ago, when there is a small probability of loss during the tenure of an employee or manager at a company, the personal interest of the manager or employee deviates from the long-term interest of the company. Therefore, it is improper for PG&E to make the implicit assumption that the risk estimation made by a third party is superior to its own even if calculating risk is central to that party's business.

Finally, there is also the assumption in PG&E's model that the risk attitude of the insurer reflects the risk attitude of PG&E ratepayers and residents of wildfire-prone areas. This is not the case. There are areas of common interest between the insurer and ratepayer/residents: neither wants property or life losses from major wildfires. However, interests significantly diverge in a number of areas:

- Ratepayers care about the cost of their electric bill, very much so. Insurers do not.
- Residents care whether their power is reliable. No utility is being sued over reliability issues, and it is not clear whether a CAT bond issuer would be liable even if they were. It's reasonable to conclude that insurers don't care about reliability.

- People can be harmed by wildfire smoke quite far from the source. However, nobody to my knowledge has ever sued a utility over health effects of inhaling smoke from a wildfire the utility ignited. It's reasonable to conclude that insurers don't care about wildfire smoke.

2.2.3.2. Power law risk distribution versus CAT bonds

Unless the reinsurer is using PG&E's consequence model or its results, it is highly unlikely that it is modeling losses with a truncated power law, an innovation that originated with work by MGRA and tested, adopted and owned by PG&E with the encouragement of SPD. If indeed the reinsurer is not using a truncated power law model, then by using the insurer's model and its own, PG&E is double-counting the effect of extreme wildfires. Actually, it is much worse than double-counting: in double-counting things are being added together that shouldn't. In the PG&E's "market[of one]-based" risk calculation numbers are being multiplied together that shouldn't be. A truncated power law is an inherently and naturally very risk-averse function, with the great majority of risk coming from the extreme end of the model near the cutoff.[33] Hence: "*There is no explicit necessity to inject a risk scaling function in order to incorporate uncertainty properly*."[34] To apply an external multiplier on top of a truncated power-law is likely to grossly overestimate maximum risk. In this case, the consequence cut-off was set by PG&E after a sensitivity analysis to be approximately 5X the losses due to the Camp fire.[35] These were approximately $20 billion, and so the cut-off is approximately $100 billion. It is not likely that we reach this level of loss, because maximum area that can burn is reaching its limit with modern fires, thus causing a deviation from power law distribution. Nevertheless, applying a multiplier of 7.5 as PG&E does creates a potential loss of $750 billion, 37.5X the losses of the Camp fire, which strains all credulity.

PG&E claims that modification of its risk calculation is necessary to incorporate uncertainty. PG&E is correct in this claim, and MGRA's previous suggestion in R.20-07-013 was to use a

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[33] R.20-07-013; MGRA Tail Risk Whitepaper; TAIL RISK AND EVENT STATISTICS FOR UTILITY PLANNING; August 1, 2022; pp. 20-24.

[34] R.20-07-013; MUSSEY GRADE ROAD ALLIANCE REPLY TO PARTY COMMENTS ON WORKSHOP 4 AND RISK SCALING; November 13, 2023; p. 8 (MGRA RDF Workshop 4 Reply)

[35] Pacific Gas and Electric Company; "Power Law Distribution"; September 3, 2021. (PG&E Whitepaper) Available at: https://data.mendeley.com/public-files/datasets/8nds4cx88k/files/c0178e67-92fc-4ab3-9ea7-7fdcdf3b4556/file_downloaded

Monte Carlo methodology to incorporate this uncertainty.[36] Additionally, the question of how much risk premium is introduced by uncertainty has been well studied,[37] and has been estimated to be 25-40%, far from the 750% introduced by PG&E. In the same proceeding PG&E makes a detailed and seemingly plausible argument against this proposed approach based on the Central Limit Theorem.[38] PG&E cites Nassim Taleb in their correct assertion that calculations of means and estimation of uncertainty have no value for Pareto (power law) distributions, because the total consequences over time diverge as the variable (wildfire size in our case) gets larger and larger.[39]

PG&E's core argument against the MGRA position is that using a Monte Carlo method will not address *epistemic* uncertainty, i.e. the unknown unknows.[40] "The market" that PG&E assumes is an efficient risk calculator puts a 25-40% additional premium on all risk, including epistemic risk. There is only one uncertainty capable of driving much larger variations, and that is variation on a power law cut-off point.

PG&E uses a ***truncated*** power distribution, and this makes all the difference. The mean is calculable and does not diverge. What about the uncertainty? PG&E's risk calculation is very dependent on the cut-off value, since most of the risk occurs near that value. For Pareto distributions, Taleb warns that we should "fuhgetaboudit" when it comes to mean or standard deviation.[41] This warning would also apply to uncertainty, and the 25-40% discussed by Kunreuther et. al. likely applies to uncertainties with normal distributions and not to Pareto distributions. This would be a serious issue if PG&E had not already done a sensitivity analysis of the cut-off.

PG&E's analysis described in the PG&E Whitepaper describes how the cut-off value was determined, and the risk was studied as a function of the cut-off value. It concludes: "*In summary,*

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[36] Op. Cite.
[37] Kunreuther, Howard and Erwann O. Michel-Kerjan with Neil A. Doherty ... [et al.]; At war with the weather: managing large-scale risks in a new era of catastrophe; 2009; pp. 129-133.
[38] R.20-07-013; OPENING COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY ON WORKSHOP #4; November 6, 2023; pp. 4-10.
[39] *Statistical Consequences of Fat Tails: Real World Preasymptotics, Epistemology, and Applications (The Technical Incerto Collection), Nassim Nicholas Taleb, STEM Academic Press, 2023*; p. 149. https://arxiv.org/abs/2001.10488
[40] R.20-07-020 OPENING COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY ON PROPOSED PHASE 3 DECISION; May 16, 2024; pp. 11-13. (PG&E RDF Phase 3 Comments)
[41] Op. Cite; pp. 27-28.

PG&E finally considered a multiplier of 5 to strike the balance of not flattening the curve too much but also preserve the tail risk of extreme events."[42] MGRA's suggestion of a Monte Carlo method to incorporate uncertainty would be to apply a lognormal variation around the mean value of cutoff, with a width determined by SMEs, either fundamentally as an input to PG&E's Monte Carlo or as a scaling factor applied afterwards. This would incorporate uncertainties in a transparent manner that is defensible in the real world.

PG&E's argues against such an approach, noting that the Method of Moments it used for its sensitivity analysis is frowned upon by Taleb for Pareto distributions.[43] This depends on what exactly we mean by "cut-off parameter". If this is a fit value, and this appears to be how PG&E implemented it, then Taleb's admonition applies. "Cut-off" value, however, is supposed to represent a "worst case" wildfire, where basically all available connected landscape burns. During the RDF proceeding, SCE presented comparisons of 8 and 24 hour simulations (arguing that 8 hour is sufficient, which MGRA opposed), and their geospatial model clearly showed that in many if most cases very large fires are already running up against physical boundaries: built and developed environments, agricultural lands, the ocean and other water features.[44] By jumping to 5X the maximum historical visible loss, and with simulations showing that it is hard to find scenarios at much larger levels the value that PG&E picked by fit is a plausible maximum upper bound. Of course the uncertainty of this bound can be tested with PG&E's sensitivity analysis data, using the method suggested by MGRA. This reframing is consistent with Taleb's guidance, described in his book The Black Swan:

"*… we do not realize the consequences of the rare event.*

What is the implication here? Even if you agree with a given forecast you have to worry about the real possibility of significant divergence from it… I would go even further and, …state that it is the lower bound of estimates (i.e. the worst case) that matters when engaging in a policy — the worst case is far more consequential than the forecast itself. This is particularly true if the bad scenario is not acceptable."[45]

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[42] p. 16.
[43] PG&E RDF Phase 3 Comments; p. 12. Cites:
Taleb 2022; p. 34.
[44] MGRA Tail Risk Whitepaper; pp. 35-36.
[45] Taleb, Nassim Nicholas. The Black Swan - The Impact of the Highly Improbable. Second edition. New York: Random House, 2010; pp. 161-162.

In the current case, the "worst-case" – based upon physical limitations – is used as input for the cut-off parameter. We have additional knowledge: that wildfires smaller than worst-case follow a power law distribution that has been measured and parameterized. Uncertainty in worst-case can be tested using the method described.

No other uncertainty other than cut-off is likely to affect the output at the order of magnitude level, except one: wildfire smoke.

2.2.3.3. Wildfire smoke, again

Uncertainty due to wildfire smoke risk is a unidirectional dependency. PG&E's wildfire safety risk estimate is too low because it ignores wildfire smoke safety and health risks. MGRA has analyzed and discussed this risk extensively in its filings, and it has been reviewed in an OEIS workshop, but inclusion of wildfire smoke risk into OEIS or CPUC processes has been determined to be a "hard problem" and tabled by both organizations. MGRA filings have argued that regardless of the fact that a "good" model of wildfire smoke exposure is beyond current capabilities, that the approximation introduced by SDG&E using more up-to-date references would be "less wrong" than ignoring what is almost certainly a very substantial source of risk. The approximate approach yields a correction of one fatality per 1,000 to 10,000 acres burned.[46]

2.2.3.4. Perverse incentive

Finally, bias that PG&E might have regarding its choice of risk calculation methodology should be discussed. As has been previously mentioned, PG&E can maximize its profit by choosing the most expensive capital mitigation. Much of the rest of these comments relate to choice of mitigation to reduce wildfire risk. However, the introduction of the cost/benefit ratio (CBR, and more properly benefit/cost ratio) introduces a precondition for a mitigation. In order to have a reasonable argument for mitigation, CBR must be greater than 1.0. According to PG&E's proposal, CBR for undergrounding is 13.[47] If the cost is inflated by a factor of 7.5 (as would be all

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[46] MUSSEY GRADE ROAD ALLIANCE COMMENTS ON 2022 WILDFIRE MITIGATION PLANS OF PG&E, SCE, AND SDG&E; April 11, 2022; pp. 47-50. (MGRA 2022 WMP Comments)
[47]DR Response RAMP-2024_DR_SPD_015-Q001, refers to:
MGRA Workpaper RAMP-2024_DR_SPD_015-Q001_804549Atch01_804550-Secondaries-jwm.xlsx

other mitigations), then CBR is reduced to 1.7. The argument for using an undergrounding mitigation in preference to other mitigations that have higher CBR, as PG&E does, is severely compromised by this rescaling, as individual circuits will be more likely to have undergrounding CBR less than 1.0.

PG&E's proposal gets even weaker. In this GRC cycle, PG&E proposes substantial mileage of secondary lines and service drops. SPD Data Request 15 Q1 addressed this issue and PG&E responded with a file published as an MGRA workpaper called MGRA Workpaper RAMP-2024_DR_SPD_015-Q001_804549Atch01_804550-Secondaries-jwm.xlsx.[48] PG&E's CBR for secondary lines is 9.4, and if this is reduced by 7.5X the CBR hovers over 1.0 at 1.3. However, PG&E's CBR estimate for service drops is only 2.4, and if rescaled this would be only 0.3 – far below the breakeven CBR of 1.0. Therefore, it is only the risk rescaling by PG&E's risk-averse multiplier that makes this effort viable, in the sense it is in the public interest. PG&E's proposed service drop program cost is $750 million. The cost for secondaries is $135 million. Nearly $1 billion in capital costs (almost $100 million in profit for PG&E) is totally dependent on PG&E's risk scaling function. There is a strong perverse incentive for PG&E to try to amplify its wildfire risk.

2.2.3.5. Risk scaling conclusion

The original MGRA position regarding PG&E's "market based" CAT bond proposal was skeptical but open to seeing what PG&E's proposal entailed.[49] Having now examined PG&E's RAMP filing and data request responses, it is necessary to reach the conclusion that PG&E has not provided sufficient information supporting its proposal, and that information which it has provided tends to discredit its proposal. PG&E's new risk scaling function has a number of critical flaws:

- The wildfire CAT bond market is extremely small and its risk premium estimates vary substantially,

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Note: PG&E RAMP tables and data request responses list two different CBR values for undergrounding, one ~8 and another ~13. This was late-discovered in the analysis, and SPD should apply whichever that it has determined is the value currently supported by PG&E. PG&E doubtless will clarify in its comments as well.

48 Id.

49 MGRA RDF Workshop 4 Reply; p. 5.

- The "market" for wildfire CAT bonds is extremely illiquid and likely to lack information, explaining some of this variability,
- PG&E appears to be basing its risk scaling function on only one CAT bond,
- Neither PG&E, the Commission nor any stakeholder has visibility into how risk premium is determined by the reinsurer,
- Unless the reinsurer is using PG&E's risk estimates as the basis of its risk premium, it is extremely unlikely that its risk estimation is anywhere near that developed by PG&E, and therefore it may be no more than an educated guess,
- Unless the re-insurer is using a Pareto risk distribution for wildfire, a bespoke approach that does not seem to be yet in use outside of PG&E and SDG&E, or unless PG&E itself has abandoned the Pareto approach to consequence modeling, the use of a risk multiplier to amplify the predicted wildfire risk is entirely inappropriate and would lead to estimated losses up to $750 billion. (Reminder, that is indeed a 'b'.)
- Classical estimates for uncertainty premium range from 25-40%, whereas PG&E's uncertainty premium is 650%.
- Even allowing for the fact that an uncertainty premium for a Pareto distribution should be significantly higher than classical estimates, PG&E has a transparent way to estimate this premium using the sensitivity analysis it performed for its consequence cap, currently set to 5X the losses of the Camp fire.
- PG&E has a significant perverse incentive to amplify risk, because it is proposing a nearly $1 billion undergrounding program for secondary and service drops that would not meet the criterion of a favorable CBR.

PG&E's new risk averse scaling approach is patently inferior to its existing risk calculation, which was developed over many years at great effort and expense, and thoroughly vetted by stakeholders. For PG&E to arbitrarily multiply its risk by a number that neither it nor stakeholders understands undoes much of that work and compromises the goal of creating a CBR, which is intended to calculate risk in terms of cost. PG&E needs to incorporate uncertainty, but it can do so using the sensitivity analysis it has already done for cut-off threshold.

Intervenors, particularly TURN, have been pushing for linear risk scaling, and to at least have a reference with linear risk scaling to compare to any new model. The Commission, so far, has not been ready to intercede on this issue. However, given the state of PG&E's new risk scaling it is imperative that the Commission ensure that there is a transparent model available for comparison and potentially for use.

Recommendations:

- PG&E's GRC application should not be considered unless it includes calculation of CBR assuming linear risk scaling.
- PG&E's GRC application should not be considered unless it provides additional information supporting its use of the Phoenix Reinsurance bond and showing that the risk premium of this bond is based on quality risk analysis that is as good as or better than PG&E's risk analysis. This showing must indicate whether the CAT bond is using a Pareto distribution for wildfire loss estimates, and whether PG&E itself continues to use its Pareto based consequence model.
- PG&E should incorporate uncertainty into its risk calculation through a mechanism other than the CAT bond. The suggested mechanism is to use the function derived from PG&E's consequence cap analysis to provide the basis for a Monte Carlo varying around the 5X Camp fire value using a lognormal distribution with deviation suggested by SMEs.
- PG&E should adopt SDG&E's methodology for approximating wildfire smoke impacts, and use current references which have an imputed risk per acre burned of between 1,000 and 11,000.

3. ELECTRICAL OPERATIONS – WILDFIRE, PSPS, AND EPSS

3.1. Assumptions – Covered Conductor versus Undergrounding

Covered conductor has been extensively deployed by Southern California Edison, and has led to an extremely rapid and significant drop in wildfire risk, as shown in the figure below.

Pacific Gas and Electric Company

Megan Ardell
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April 25, 2025

Mr. Fred Hanes
California Public Utilities Commission, Safety Policy Division
505 Van Ness Avenue
San Francisco, CA 94102

Re: **Pacific Gas and Electric Company's Responses to Safety Policy Division's Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines**

Dear Mr. Hanes

Thank you for the opportunity to provide responses to Safety Policy Division (SPD) SPD's post April 8 workshop questions on the CPUC's SB 884 Guidelines. Please feel free to contact me if you have questions about these items or need additional information from me at Megan.Ardell@pge.com.

Very truly yours,

/s/ Megan Ardell

Megan Ardell

PG&E's Response to Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines

Introduction

On April 8, 2025, the Safety Policy Division (SPD) staff hosted a workshop to review potential changes to Resolution SPD-15 (SPD-15), which was originally approved in March 2024. SPD is considering updating the Electrical Undergrounding Plan (EUP) cost recovery guidelines with new requirements and cost-recovery conditions. The Office of Energy Infrastructure Safety's (Energy Safety) final EUP guidelines (Energy Safety EUP Guidelines), in combination with SPD-15, meet Senate Bill (SB) 884 legislative requirements and provide sufficient governance and oversight for project selection and cost recovery. Both sets of guidelines were thoroughly considered and reviewed by stakeholders through multiple rounds of public comment.

PG&E strongly supports the current cost recovery controls in SPD-15 that require a utility to meet portfolio-level cost recovery conditions (annual cost caps and rolling average CBR and unit costs). The portfolio-level Conditions for Recovery address project execution realities where some projects cost less than forecast and others cost more, while still requiring a utility to prudently manage its overall project portfolio.

During the workshop, SPD indicated that it was considering changes to the conditions for cost recovery that may include new project-level requirements and/or thresholds that would be established in the Phase 2 Decision. PG&E opposes introducing project-level requirements as a condition for cost recovery via the Balancing Account in the Phase 2 Decision. By the time the CPUC issues a Phase 2 Decision, PG&E will have spent more than 20 months selecting and scoping at least 100 individual undergrounding projects and subprojects in alignment with its EUP Plan Mitigation Objective (PMO), standards, thresholds and project acceptance framework, and will have submitted four 6-monthly progress reports documenting that work. If project-level requirements were established in the Phase 2 Decision, any number of the selected and scoped projects could be at risk of not meeting those new requirements even though the projects were identified using approved project selection framework. This very late determination of ineligibility would lead to significant time and cost for rework to select and scope new projects.

Additionally, PG&E will make commitments to Energy Safety such as a Plan Mitigation Objective (PMO—the amount of change in wildfire and reliability risk that is necessary to meet the requirements contained in section 8388.5(d)(2)) and targeted numbers of overhead miles removed and undergrounding miles installed over the life of a plan. Meeting these commitments is premised on selecting projects using the approved EUP framework. If a Phase 2 Decision introduces project-level requirements that could eliminate projects from our portfolio, we may not be able to meet commitments approved in our EUP, thus jeopardizing the viability of the entire EUP. The current SPD-15 portfolio-level cost recovery conditions allow a utility to select and scope projects for the EUP knowing that even if some projects exceed the established average unit cost or fall below the average CBR values, those individual projects are not necessarily at risk because the utility can still meet the portfolio-level requirements by carefully managing its portfolio. Introducing project-level conditions for recovery via the Balancing Account in a Phase 2 Decision could result in contradictory requirements between the Energy Safety EUP Guidelines. For example, Energy Safety requires a utility to select projects that meet approved thresholds representing the amount of risk reduced (Section 2.7.9.1) but CPUC project-level thresholds could exclude some of those projects that Energy Safety determined were appropriate to be included in our EUP.

The types of cost recovery changes that are being considered based on the issues raised during the workshop and in these post-workshop questions will require significant time to implement given that the CPUC would need to issue a new cost recovery draft resolution with time for party comment before it could be finalized and adopted by the Commission. Because utilities would not file an EUP until the cost recovery guidelines are finalized, this process to re-issue cost recovery guidelines would significantly delay when a utility could file an EUP. When the California State Legislature and Governor of California enacted SB 884 in September of 2022 the title of the bill, "expedited utility distribution infrastructure undergrounding program," made clear the legislature's intention that the CPUC and OEIS move expeditiously to enable a utility to file an EUP and thereby create benefit for Californians from this legislation. To be more than 30 months since SB 884 was signed into law and to be considering undertaking a significant, time-consuming overhaul to guidelines that have already been formally adopted and are sufficient to enact SB 884 is, in PG&E's view, contrary to the intention of SB 884.

SB 884 created a path for utilities to expedite utility distribution infrastructure programs through long-term planning, appropriate oversight and regulatory certainty. Further delays in issuing the guidelines needed for utilities to file an EUP undermines the customer benefits an EUP can deliver.

The existing SPD-15 requirements already meet the SB 884 legislative requirements and provide sufficient governance and oversight for project selection and cost recovery. PG&E strongly recommends that any changes to the cost recovery guidelines be limited to the scope of Technical Working Groups (TWG) as set forth in SPD-15 which is to "review and align the preliminary CPUC SB 884 Project List Data Requirements and GIS data requirements with Energy Safety EUP Guidelines, adding any data elements necessary for Commission conditional approval purposes."

A. Should the Commission Consider Supplementing the Phase 2 Application Requirements?

Background:

SPD-15 included a list of 20 requirements that must be included in any Application submitted to the Commission seeking conditional approval of Plan costs. Would it be appropriate for the Commission to consider adding the following requirements?

1. **Include the data associated with the list of all projects (SB 884 Project List Data Requirements) as required by Screen 2 of the Energy Safety EUP Guidelines**

    a. **Require the utility to provide us with a forecasted scope of all projects for the ten-year plan, with the expectation that projects far in the future would change.**

<u>PG&E's Response</u>

The existing SPD-15 requirements, already meet the SB 884 legislative requirements and provide sufficient governance and oversight for project selection and cost recovery. PG&E believes that additional requirements are not necessary. If consideration of additional requirements is to be undertaken, PG&E supports providing the CPUC with: (1) the list of all Eligible Circuit Segments as required by Screen 2 of the Energy Safety EUP Guidelines; and (2) the forecasted scope for all Screen 2 projects (circuit segments) which would be limited to the information required in the EUP Screen 2 Table (Table C.11) and SPD-15, Appendix 1.

It is expected that the Screen 2 list of projects and forecasted scope of projects will change over the life of an EUP for several reasons.

(1) Consistent with the Energy Safety EUP Guidelines, Circuit Segments that pass Screen 2 (Eligible Circuit Segments) are further analyzed through the project development process in Screen 3 and projects that complete Screen 3 are reported as Confirmed Projects. Through this process a utility will identify the most appropriate mitigation alternative(s) for a circuit segment which means that *not all projects identified in Screen 2 will become confirmed undergrounding projects in the EUP* because for many projects we will select covered conductor, remote grid, or hybrid mitigations.

(2) The list of eligible circuit segments could change after a utility submits its EUP if the boundaries of the High Fire Threat District (HFTD) change and/or the boundaries of a wildfire rebuild area change. If

either of these events occur, a utility would revisit its Screen 1 analysis and may update its list of Eligible Circuit Segments.

(3) Potential changes in PG&E's risk model landscape over the 10-year EUP period, including improvements in risk modeling methodologies, tools, and data, may introduce or exclude Eligible Circuit Segments through Screen 1.

(4) Introduction of emerging technologies into the portfolio of mitigations which may change the outcome of the alternatives analysis required under Screen 2.

While PG&E supports providing a list of Eligible Projects as required by Screen 2, PG&E does not support providing a list of Confirmed Undergrounding Projects that would be constructed over the life of our EUP at the time we submit our Phase 2 Application. PG&E strongly supports the process established in the Energy Safety EUP Guidelines that requires a utility to submit a new portfolio of projects with each six-month progress report. The EUP process recognizes the challenges and significant uncertainty in attempting to forecast undergrounding projects many years in advance due to potential changes that could impact the program in future years. In order to provide the most cost-effective wildfire mitigation that will reduce risk and customer costs, utilities should not be locked into a single, static list of projects for a ten-year period. Instead, Energy Safety's approach allows for the appropriate flexibility and regulatory oversight that will both benefit customers and most effectively reduce wildfire risk.

b. **This requirement would make it explicit that the Underground Project List, which is an output from Screen 2 in the Energy Safety EUP Guidelines, must be ready for the Commission to review before an Application can be submitted.**

<u>PG&E's Response</u>

PG&E will submit its Screen 2 Table when we submit our EUP. Therefore, the undergrounding project list—all Eligible Circuit Segments required by Screen 2 of the Energy Safety EUP Guidelines—would be available to review before a Phase 2 Application is submitted.

2. **Require the utilities to provide a detailed explanation for any spans that extend beyond the HFTD for any project included in the Underground Project List from Screen 2 of the Energy Safety EUP Guidelines.[1]**

   a. **The Energy Safety EUP Guidelines allow for undergrounding circuit segments with assets inside the HFTD, then each span that crosses the Tier 2 or 3 HFTD boundary and up to two adjacent spans outside of a Tier 2 or 3 HFTD may also be included in a project.**

   b. **This requirement would ask the utilities to provide a detailed explanation regarding why they must include any spans that extend beyond the HFTD.**

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[1] For details see California Public Utilities Code (PUC) § 8388.5(c)(2) and Energy Safety EUP Guidelines, Section 2.4.3.1 at 16.

PG&E's Response

PG&E does not oppose providing an explanation about why we may need to include up to two adjacent spans that cross the HFTD Tier 2 or Tier 3 boundary as part of an EUP Undergrounding project.

3. **Require utility to submit a depreciation study with updated information of the type of assets that are impacted by an SB-884 Application**

    a. **Depreciation studies are typically updated when a utility files its GRC.**

    b. **Because undergrounding projects have large capital expenditures, there is a potential that depreciation and salvage costs may be contested in an EUP cost recovery Application.**

    c. **This would require a depreciation study be included in the record, but it should be a depreciation study with updated information since an EUP cost recovery Application will not necessarily be submitted in the same time frame as a GRC.**

PG&E's Response

PG&E opposes this recommendation for three reasons:

(1) The depreciation study in PG&E's GRC includes all distribution assets. In subsequent years this will include both the undergrounding work planned in the EUP and the estimated asset retirements due to EUP projects. No separate analysis would be needed since the EUP work is considered in the GRC depreciation study. Moreover, since the depreciation study will be fully litigated in the GRC, there is no need for a duplicative review in the Phase 2 Application. Given the statutory nine-month approval period for a Phase 2 Application, adding in the submission and review of a depreciation study, which will already be reviewed in other proceedings, is unnecessary, inefficient and puts undue administrative burden on Phase 2 process participants during the nine-month expedited EUP review and approval period.

(2) PG&E relies on "group accounting," which studies all our distribution assets to develop depreciation rates as opposed to individual assets in separate filings. In group accounting, all units having like mortality characteristics or all units of an account are considered together. Accruals for the group are based on composite or weighted average values of salvage and service life expectancy. The resulting values are applied to the surviving plant balances each year or each accounting period. A deficiency due to early retirement of a particular unit is made up through other accruals on a unit which outlives the average. Because of greater simplicity in maintaining records, the group basis is more feasible for most "classes of utility property" where large numbers of units are involved. It is the more generally used base among electric, gas, telephone and water utilities (California Public Utilities Commission Utilities Division, Determination of Straight-Line Remaining Life Depreciation Accruals, Standard Practice U-4).

(3) In filings outside of the GRC, PG&E uses currently adopted depreciation parameters which will be updated with amounts adopted in successive GRCs. The same approach should be used for the Phase 2 Application.

4. **Require both nominal and present value lifetime calculations for the capital expenditures for each project included in the Undergrounding Project List from Screen 2 of the Energy Safety EUP Guidelines.**[2]

    a. **PUC 739.15 specifically calls out the need for greater clarity on the lifetime cost and benefit of a capital expenditure project such as those submitted in an EUP cost recovery Application.**

    b. **This would require both nominal and present value lifetime calculations for the capital expenditure of each undergrounding project.**

PG&E's Response

PG&E supports providing both nominal and present value lifetime calculations for the capital expenditure of each undergrounding project.

5. **Require data retention policy for lifetime of EUP for tabular and geodatabase data. This should be required for both the initial application and any of the data updated through the six-month progress reports.**

    a. **Since there are no additional requirements for data retention related to an EUP, this will require the utility to retain all tabular and geodatabase information submitted as part of the EUP and any data included in six-month progress reports.**

PG&E's Response

At the April 8 workshop, PG&E asked for additional information about this potential change to SPD-15. SPD responded that it was concerned that a utility may not retain previous risk model outputs when new risk models are generated, and this requirement would ensure an audit trail of risk rankings over time.

Section 2.7.6 in the Energy Safety EUP Guidelines already requires a utility to establish model and calibration retention policies and states that utilities must retain models and calibrations data for the life of the EUP. Therefore, it is unnecessary to add new data retention requirements related to SPD-15 as they would be duplicative of the Energy Safety Guidelines.

    b. **Staff intend to hold data template working groups later in the spring.**

PG&E's Response

PG&E looks forward to participating in data template working groups. We encourage SPD to expedite this process where possible because we are currently developing tools and reports that address both Energy and SPD-15 requirements.

6. **Require utilities to submit the same Key Decision-Making Metrics (KDMM) data for Commission review as provided for in the submission to Energy Safety.**

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2 *See also* PUC § 739.15

PG&E's Response

At the April 8 workshop, PG&E asked when SPD anticipates that a utility would submit KDMM information for Commission review and how it would differ from the KDMM information a utility will provide to Energy Safety. SPD responded that it anticipates a utility would submit KDMM data with its Phase 2 Application and this would constitute an update to information provided to Energy Safety. This update would reflect better information about KDMMs because projects would be more fully scoped.

PG&E does not support requiring utilities to provide updated KDMM information to SPD when it files a Phase 2 Application given that utilities will submit KDMM information to Energy Safety in two different tables, at the portfolio level and circuit segment level, that will reflect the most current information as of each six-month progress report submission. Updates of the KDMM data every six months, which is already required and would be publicly available, is sufficient to allow visibility into the EUP projects and portfolio to support consideration of a Cost Recovery application.

PG&E will submit KDMM information to Energy Safety in Table C.1.5 (Risk Model Backtesting Table) and in Table C.1.8 (Circuit Segment Risk Score Table). Both tables, C.1.5 and C.1.8, are submitted when the EUP is filed and with every six-month progress report.

- Table C.1.5 requires a utility to provide the value of the KDMM based on a particular baseline and portfolio. With each update to the Risk Modeling Methodology (either a new model or a new calibration), a utility will report KDMM values by applying the current risk model to all prior Baselines and Portfolios.

- Table C.1.8 requires a utility to provide overall utility risk, ignition risk, ignition consequence, ignition likelihood, outage program risk, outage program consequence, and outage program likelihood—the elements of the required KDMMs—for each circuit segment. The information in Table C.1.8 must reflect the most current information as of each progress report submission. The Energy Safety EUP Guidelines also require that a utility report any proposed KDMMs at the same resolution and frequency as the required KDMMs (Energy Safety EUP Guidelines, Section 2.7.3).

With our Phase 2 Application, PG&E can provide the most recent six-month progress report which will include the most current KDMM information. In addition, PG&E can provide the next available progress report issued after its Application. We do not support requiring utilities to provide *updated* KDMM information beyond what is provided in those six-month progress report submissions.

B. What, if Any, Additional Phase 2 Conditions Should the Commission Consider?

Background:

SPD-15 listed five Phase 2 Conditions that must be met for the costs of any project to be booked to a one- way balancing account. The parameters or threshold values of the Conditions will be established in the Phase 2 Decision based on the forecasted numbers presented in the cost recovery Application. As explained in the Instructions above, the five Conditions listed in SPD-15 include a total annual cost cap, a two-year rolling average recorded unit cost cap, a two-year rolling average recorded CBR threshold, a requirement to apply third-party funding to reduce the cost cap, and any further reasonable Conditions supported by the record of the proceeding and adopted by the

Commission in the Phase 2 Decision.[3]

1. **Should the Commission consider imposing Conditions on the Memorandum Account (MA)? If so, what Conditions should be considered?**

    a. **Option 1: Establish a maximum total cap for the MA, limiting it to no more than 25% of the total sum of the ten-year annual caps established for the balancing account.**

PG&E's Response

PG&E opposes establishing a maximum total cap for the Memorandum Account until all cost recovery conditions are established. It would be unfair to establish a cost cap before all cost recovery conditions are known because the extent of those conditions would directly impact how a cost cap should be established and what the cost cap should be.

The required reasonableness review for any costs recorded to the Memorandum Account is already a sufficient control such that a maximum total cap is not necessary.

However, if no new cost recovery conditions are established, PG&E would not oppose establishing a reasonable maximum total cap for the Memorandum Account, in general, if there are no restrictions on what costs can and cannot be included. A utility should be allowed to record any type of incurred project costs to the Memorandum Account subject to reasonableness review. A utility must be allowed to provide input about how the cost cap will be developed and any potential restrictions on the cap.

    b. **Others?**

PG&E's Response

PG&E does not have other recommendations regarding a potential cost cap on the memorandum account.

2. **Should the Commission consider assessing the variance between the forecast data submitted according to the SB 884 Project List Data Requirements in the initial cost-recovery Application to the Commission and the updated data submitted according to the SB 884 Project List Data Requirements in a six-month progress report and if so how?**

    a. **Option 1: If the variance between the forecasted CBRs and unit cost of a project presented in an Application compared to the updated CBRs and unit cost of a project presented in a six month Progress Report (after a project passes Energy Safety's Screen 4) exceeds a certain threshold, then all costs for that project must be recorded in the MA.**

PG&E's Response

PG&E has no position as to whether the Commission should consider assessing the variance between initial project forecasts, updated forecasts over the lifecycle of the project and final actual costs (and CBR) results. All of that information will be available in the six-month progress reports and can be assessed by the

[3] For details see SPD-15 at 10-11.

Commission. The relevant policy question is if any defined action should be taken because of such assessment. PG&E does not support changes to SPD-15 based on assessing the variance between initial project forecasts, updated forecasts over the lifecycle of the project and recorded costs and CBRs results.

Option 1 is an example of a potential changes to SPD-15 based on assessing the variance between initial and updated forecast data. It would be unreasonable to require a utility to record in the Memorandum Account the costs for every project where the estimated cost and/or the estimated CBR changed between the Screen 2 initial estimate and Screen 4 updated estimate. It is not unusual for estimated costs and CBRs to vary between the initial estimate and the updated estimate as we learn more about project scope, schedule and cost through the project scoping process.

Between Screens 2 and 4, we will revise our cost estimates (which impacts CBRs) to account for better information we learn during the scoping process such as more precise route selection and addressing tree-strike, ingress/egress, and/or feasibility issues. Additionally, in Screen 2 we are analyzing projects at the circuit segment level whereas by the time circuit segments pass Screen 4 many circuit segments will have been divided into sub-projects where portions of an overhead line are undergrounded and other portions are replaced with covered conductor. At that point there would not be a direct comparison between the Screen 2 and Screen 4 cost estimates and therefore an inaccurate basis for recording and reviewing in the Memorandum Account.

SPD-15 already defines that cost recovery via the Balancing Account is contingent on meeting a portfolio-level annual cost cap, rolling average CBR and rolling average unit cost based on recorded costs, which is appropriate for a program made up of multiple projects like an EUP. These appropriate, portfolio-level measures are wholly distinct from conditions based on differences in individual project-cost estimates. Requiring a utility to record project costs in the Memorandum Account due to changes between CBR estimates and cost estimates, which are preliminary and expected to change —and then defend those changes during reasonableness review—is unnecessary and burdensome.

b. **Others?**

<u>PG&E's Response</u>

PG&E does not have other recommendations related to recording variances between forecast and updated CBR and unit cost estimates.

3. **Should the Commission consider adopting a CBR Threshold, and if so, what should the criteria be?**

a. **Option 1: Require all projects to have a CBR greater than a specified value.**

<u>PG&E's Response</u>

PG&E supports requiring all projects to have an estimated CBR greater than or equal to 1.0 at Screen 2 because that is indicative of a good investment.

PG&E does not support requiring all projects to have a recorded/final CBR greater than or equal to 1.0 because issues can arise during construction that may result in a final CBR less than 1.0. Some of these issues may be outside of PG&E's control (*e.g.*, inflation, new regulatory requirements) and it would be unreasonable to deny cost recovery for a single project that was constructed to reduce risk just because the costs increased during construction. It is PG&E's responsibility to manage its portfolio to achieve the rolling two-year average CBR thresholds approved in the Phase 2 Decision.

b. **Option 2: If a project's recorded CBR is less than a specified value, the utility must provide a detailed justification for this project.**

PG&E's Response

It is unnecessary to include additional requirements in SPD-15 for a utility to provide additional justification for a project with a CBR less than a specified value. As discussed previously, PG&E will manage its portfolio to recover costs via the Balancing Account by achieving the rolling two-year average CBR which could include some projects with CBRs below a specified value. No additional justification should be required if a utility meets the portfolio-level CBR requirements.

If a project had a CBR whose value was far enough below the rolling two-year average to necessitate recording costs for that project in the Memorandum Account, PG&E would provide a detailed justification for it during reasonableness review.

c. **Option 3: After Screen 2, any project ranked below a certain CBR percentile threshold is ineligible for cost recovery via the BA.**

PG&E's Response

PG&E opposes this proposal because cost recovery via the Balancing Account is based on meeting certain conditions at the portfolio level and it is unreasonable to automatically exclude individual projects with a CBR ranked below a certain percentile threshold. PG&E supports the portfolio approach because it recognizes that CBRs for projects will vary and that the utility is required to manage its portfolio to achieve the Conditions for Recovery.

Requiring costs for all projects with an estimated CBR at Screen 2 below a certain threshold to be recorded in the Memorandum Account is unnecessary and burdensome. The existing Conditions for Approval (achieving portfolio-level CBR thresholds) provide adequate controls for managing costs.

The concept of "CBR percentile" is a relatively novel calculation approach that has not been reviewed in-depth through the Energy Safety Guidelines or prior SPD-15 development processes to determine important details like precise calculation methodology or unintended consequences of focusing on this measure.

d. **Others?**

PG&E's Response

PG&E does not have other recommendations related to adopting a CBR threshold.

4. **Should the Commission consider requiring a comparative CBR analysis of project alternatives? If so, how should this analysis be conducted?**

a. **Option 1: If an Undergrounding Project has a CBR above a specified CBR Threshold but the Alternative(s) has a CBR that is a specified amount greater than the Undergrounding Project's CBR, then the undergrounding project should not move forward.**

PG&E's Response

PG&E strongly opposes this proposal as being duplicative or potentially conflicting with Energy Safety EUP Guidelines. In the Energy Safety EUP screening process, a utility compares undergrounding to alternative mitigations at Screen 2 and Screen 3. While CBR is the primary consideration when selecting a mitigation solution, it should not be the only one. PG&E's Screen 2 analysis considers both the CBR value and outcomes from other analyses. The Commission has stated that "the utility is not bound to select its mitigation strategy based solely on the CBRs produced by the Cost-Benefit Approach,"[4] which supports PG&E's use of CBR plus other factors to select mitigation alternatives. PG&E considers multiple factors in selecting alternatives because an over-emphasis on CBR devalues projects that are both high cost and high benefit. CBR does not consider the absolute benefits and holistic value of permanent risk mitigation and, when used as the sole criteria, results in situations where significant risk is permanently left on the system, including on circuit segments where the benefits of undergrounding are greater than those of overhead hardening. PG&E's Screen 3 analysis considers the full range of benefits, including mitigation of tree strike risks, reliability risks created by operational mitigations, and ingress/egress. A utility must be able to consider multiple factors when selecting a mitigation alternative and not be limited in its decision-making based on a single factor.

Additionally, there are scenarios where a CBR calculation will produce a negative CBR value for one or more mitigation alternatives when the benefits—specifically operations and maintenance savings over the life of the asset—are greater than the capital construction costs. Establishing a CBR threshold would exclude the mitigations where these savings exceed the costs over the life of the assets. PG&E wants to select projects that would be most beneficial to our customers when considering both risk reduction and affordability. Establishing a minimum CBR threshold would automatically exclude these beneficial projects.

To address the issue of negative CBRs, PG&E conducts two economic analyses for each circuit segment, CBR and Net Benefit (calculated as: Net Benefit= Benefits – Costs). The Net Benefit analysis shows which mitigation alternative will result in the most benefit (including cost savings) over the life of the asset, and provides valid outputs in the limited number of cases that would result in a negative CBR – where traditional CBR logic (bigger CBR is better) no longer applies.

As discussed above, PG&E supports requiring all projects to have an estimated CBR greater than or equal to 1.0 at Screen 2 because that is indicative of a good investment.

b. **Others?**

PG&E's Response

PG&E does not have other recommendations.

5. **Should the Commission consider applying some of Energy Safety's KDMMs to the Commission's consideration of whether to grant cost recovery for projects and if so, how?**

   a. **Option 1: After Screen 3, if the reduction in Ignition Risk and/or Outage Program Risk does not meet the required Project Level Standard set in the approved Plan, the project will not be eligible for cost recovery via the one-way balancing account.**

PG&E's Response

PG&E opposes this recommendation. Under the Energy Safety EUP Guidelines, it is not necessary for every undergrounding project in a portfolio to meet the project-level standards, but any confirmed project which does not meet them must be further justified (Section 2.7.9.2).

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[4] Decision (D.) 22-12-027, Appendix A, Row 26.

PG&E supports Section 2.7.9.2 which recognizes that an individual project can be below the project-level standards while still meriting inclusion in an undergrounding portfolio. It would be unfair to exclude a project from cost recovery via the Balancing Account if it meets the project selection criteria defined in an approved EUP Plan and if the project contributes to meeting the portfolio-level Conditions for Approval. It should be up to the utility to decide whether to record individual projects in the Memorandum Account while delivering on the portfolio-level conditions determined in the Phase 2 decision.

b. **Others?**

PG&E's Response

PG&E does not have other recommendations related to applying KDMMs to the Commission's consideration of granting cost recovery to projects.

C. What methods could the Commission use to address the Audits and/or Review Procedure?

Background:

The Commission's SB-884 Guidelines require that costs submitted in an SB-884 Application meet certain Conditions (Phase 2 Conditions) before they can be authorized for recovery via a one-way balancing account.[5] That one-way balancing account is subject to audit. If the audit finds that costs were incorrectly recorded or failed to meet the Phase 2 Conditions, the Commission may order a refund. SPD- 15 stated that the details of this audit would be determined in a later decision or order. The questions below explore two potential structures for determining whether costs were appropriately recorded to the balancing account.

PG&E's Response

PG&E understands that the Commission is presenting two possible options for a review structure to audit the costs associated with an EUP. PG&E supports Option 2 below.

Questions:

1. **Should the Commission consider adopting the following review structure to ensure a rigorous review of the costs associated with an EUP?**

    a. **Annual post-implementation review process with intervenor participation.**

PG&E's Response

PG&E supports an annual post-implementation review process (e.g. an independent auditor's review of the costs recorded to the Balancing Account) but opposes stakeholder participation in an audit of the Balancing Account after the Commission issues its Phase 2 Decision. PG&E supports stakeholder participation after a utility files a Phase 2 Application (before a decision is issued) and in any Phase 3 reasonableness proceeding. However, once Conditions for Approval are established by the Phase 2 Decision, only the auditor, the Commission, and the utility should participate in an audit of the Balancing Account. PG&E

5 The Phase 2 Conditions will include, but are not limited to, a total annual cost cap, two-year rolling average recorded unit cost cap, two-year rolling average recorded CBR threshold, and applying third-party funding to reduce the cost cap. For details see SPD-15 at 10-11.

notes that it is not standard practice to include stakeholder participation in an audit after a Commission Decision is issued and we see no compelling reason to change this practice. The auditor, under the CPUC's guidance and oversight, will protect customer interests by rigorously reviewing the costs recorded to the Balancing Account.

b. **Objectives of the review should include verifying project completion, cost overheads, CBR methodology and an incrementality showing.**

PG&E's Response

PG&E supports these objectives.

c. **Once deemed "used and useful" in a progress report, a project's costs may be included in rate base via an Advice Letter that must be disposed via Commission Resolution.**

PG&E's Response

PG&E does not support a process that requires a Staff Resolution before a project can be included in rate base. This proposal would introduce significant uncertainty into the cost recovery process given the time needed to prepare and finalize a resolution, including comments and protests.

d. **Commission Resolution will determine whether recorded costs met the Phase 2 Conditions and other objectives of the review.**

PG&E's Response

PG&E opposes this proposal. Once the Commission determines that a project has met the Phase 2 Conditions for Recovery, it is unreasonable to delay recovery by instituting a resolution process. PG&E supports the more streamlined review structure outlined in item 2 below.

e. **Approved costs would enter rates via Annual True-up.**

PG&E's Response

While PG&E does not support requiring a Commission Resolution to determine if recorded costs met the Phase 2 Conditions, PG&E does not oppose having approved costs entering rates via the Annual Electric True-Up process.

2. **Should the Commission instead consider adopting the following review structure to audit the costs associated with an EUP?**

   a. **Annual audit by independent auditor with CPUC oversight.**

   b. **Objective of the audit should include verifying project completion, cost overheads, and an incrementality showing.**

   c. **Once deemed "used and useful" in a progress report, a project's costs may be included in rates via annual True-up and become subject to audit.**

   d. **If the audit finds that project costs were incorrectly recorded to the Balancing Account, then the utility must issue a refund to ratepayers.**

PG&E's Response

PG&E supports the review structure outlined in items (a) through (d) immediately above, with one exception.

Item (d) states that if the audit finds that project costs were incorrectly recorded to the Balancing Account, then the utility must issue a refund to customers. PG&E does not oppose issuing a refund to customers if the auditor discovers an error but recommends that a utility have an opportunity to review the auditor's findings and address any issues identified as opposed to automatically issuing a refund. This opportunity for the utility to review and/or remediate any auditor findings is consistent with the approach to Independent Monitor findings, as addressed in the next section. If after a utility reviews and addresses findings, the auditor determines there is still an error, PG&E supports issuing a refund to customers.

3. **Supporting Questions:**

   a. **How should the timing of the Independent Monitor's (IM) review and the utility's right to correct a deficiency found by the IM within 180 days (PUC 8838.5 (g)(2)) interact with the annual review of the costs of a project?**

PG&E's Response

A utility should have the opportunity to correct administrative errors and other deficiencies found by the Independent Monitor within 180 days and the opportunity to subsequently adjust any project costs if those costs are impacted by the Independent Monitor's findings.

   b. **How should projects that fail to meet key criteria be treated vis-a-vis cost recovery? What key criteria should be considered?**

PG&E's Response

As discussed above, cost recovery for project costs recorded to the Balancing Account should be considered at the portfolio level, not the individual project level. The criteria that should be considered at the portfolio level is—did the portfolio meet the Conditions for Approval—there should not be any criteria for individual projects vis-à-vis cost recovery. If the utility determines that the costs for an individual project will jeopardize the portfolio's ability to meet the Conditions for Approval, the utility can record those costs to the Memorandum Account that will be subject to reasonableness review.

   c. **Should intervenors participate in Options 1 and 2 above? If so, how and where?**

PG&E's Response

Options 1 and 2: Consistent with all other audit processes, only the independent auditor, the Commission and the utility should participate in the audit process.

   d. **Should the Commission consider using a different option than 1 or 2 above? If so, explain each step in the proposed process. How and where would intervenor participation be accounted for in the proposed option?**

PG&E's Response

No. PG&E supports Option 2 above.

D. How could the Commission address changes to approved projects?

Background:

Changes to project costs and implementation status can impact cost recovery under the SB-884 framework. Except for 25 projects that Energy Safety's Guidelines will require to pass through all four Screens, cost and risk data (including CBR calculations) presented will be associated with projects having passed Screen 2 at the time of Application submittal. However, it isn't until after projects have passed Screen 4 that their full scope is determined and more accurate data associated with project cost and risk (including CBR calculations) are provided. These updated data are expected to be received throughout the life of the 10-year Plans and submitted via the six-month progress reports. Accordingly, how should the Commission handle new costs added to projects after the Phase 2 Decision is issued, based primarily on Screen 2 data? How should the Commission treat costs from abandoned or incomplete projects? The following questions explore potential approaches for managing these changes.

1. **Should new costs added to approved projects after the Phase 2 Decision be booked to the Memo Account?**

PG&E's Response

The definition of "new costs" is unclear in this example. "New costs" could mean additional spending for the types of costs identified in the project estimate (e.g. the estimate included costs for materials and the forecast costs for materials increased during project development)—a standard occurrence on a construction project. "New costs" could also refer to a *new cost type* (e.g. the cost estimate did not include costs for traffic control but the recorded costs include traffic control) but again, project scopes and specific factors (like whether construction will be close enough to the road to require traffic control) should be expected to vary. Utilities should manage project-specific variations between estimated and recorded costs within the appropriate portfolio-level thresholds.

Neither new costs nor new cost types that will be recorded to projects after the Phase 2 Decision is issued (that will be issued based on estimated project costs) should be booked to the Memorandum Account. We anticipate that estimated costs will change for many projects as they proceed through the scoping, design and estimating stages. Typically, the cost estimate for a scoped project (consistent with projects coming out of Screen 4) can vary significantly from a final project estimate. The Association for the Advancement of Cost Engineering (AACE) states that projects in the scoping phase are generally classified as AACE Class 5 estimates. Per the AACE, Class 5 estimates can vary significantly, from +100% to -50%, when compared to a project's recorded costs. It would be unreasonable to require utilities to book new costs or new cost types to the Memorandum Account, subject to reasonableness review, that exceed an initial Screen 2 project estimate. The Memorandum Account should only be used to record costs for projects that utility determines will impact cost recovery based on the portfolio-level Conditions for Approval.

It would be logistically very difficult, if not impossible, to separate new costs or new cost types incurred on a project from all the other costs of that project and have them separated out onto a unique order number to record to a Memorandum Account. This proposal is likely infeasible to implement at the project level.

   a. **If the updated rolling average CBR falls below the Phase 2 Condition threshold, should all new costs be deemed non-recoverable?**

PG&E's Response

It is unclear what the "updated rolling average CBR" refers to. It is our understanding that the annual average CBR thresholds will be established in the Phase 2 Decision and that the audits will determine if a utility meets the average CBR threshold based on recorded values, not estimates. PG&E supports cost recovery for all projects in a portfolio if the rolling average for the portfolio across the two-year period meets or exceeds the established threshold.

2. **Should certain categories of cost overruns (e.g., inflation-driven, safety-driven) be treated differently from discretionary cost increases?**

PG&E's Response

Yes, certain categories of costs such as inflation-driven, new regulatory requirements and similar costs over which a utility does not have control, should be treated differently from discretionary cost increases. PG&E recommends that the Phase 2 Decision allows for adjustments to the annual cost caps, rolling average CBRs and rolling average unit costs for the life of the EUP to address these types of cost increases. This is consistent with other cost recovery proceedings that include escalation or inflation factors for multi-year target setting.

E. Should the Commission include an Appendix with guidance for calculating the CBR of an undergrounding project?

Background:

The calculation of the CBR for undergrounding and alternative projects is a critical factor in determining project eligibility for cost recovery. In addition, the selection of CBR Year Zero[6] plays a pivotal role in accounting for the time value aspect of CBR calculations. Notably, the Energy Safety EUP Guidelines define Total Utility Risk as the sum of Ignition Risk and Outage Program Risk.[7] The following questions explore how utilities should apply existing methodologies and present their results.

PG&E's Response

No, PG&E believes that each utility should clearly define how they are calculating CBR in their EUP Phase 2 application. There are many details impacting the CBR calculation including factors like avoided maintenance costs and discount rates. Litigating all of them through the SPD-15 Guidelines (or a related appendix) is unnecessary and will add additional delay to issuing any updated cost recovery guidelines. For example, PG&E disagrees with the background statement, "[i]n addition, the selection of CBR Year Zero plays a pivotal role in accounting for the time value aspect of CBR calculations**"** The selection of CBR Year Zero does not impact the CBR as long as the discount rate is the same between numerator and denominator, however, the discount rate selected does impact the CBR. Each utility should define in their filing how they are incorporating these considerations into the CBR calculation.

[6] The year that all Costs and Risk Reductions are discounted to for the purpose of CBR calculations.

[7] For details see Energy Safety EUP Guidelines, Section 2.7.3 at 31.

1. **What level of granularity[8] should the utility use when applying the Interruption Cost Estimator (ICE) Calculator to generate a Monetized Value of Electric Reliability? Should the analysis be based on:**

    a. **HFTD and PEDS-activated circuits**

PG&E's Response

PG&E plans to apply the ICE Calculator in the EUP at the customer level using fixed values based on customer type (residential, small C&I, medium C&I) across the entire service territory. These values are independent of location (HFTD or non-HFTD). When aggregated to the PEDS-activated (PG&E's EPSS and PSPS programs) circuit segment, the reliability values may differ by location due to the varying distribution of customer types within those areas.

    b. **Operational Region and HFTD[9]**

PG&E's Response

PG&E assumes that "operational region" equates to PG&E's divisions. PG&E does not support applying the ICE Calculator differently by operational region and HFTD. The analytical requirements in the Energy Safety EUP Guidelines for identifying and selecting undergrounding projects is based on circuit segments in HFTD. It would be unnecessary to require an individual analysis at a division-level for the purposes of cost recovery when all other analyses are conducted at the circuit segment level.

    c. **Others?**

PG&E's Response

PG&E does not have other recommendations regarding the level of granularity for applying the ICE Calculator.

2. **How should the utility calculations of CBR be presented when using the three discount rate scenarios (Weighted Average Cost of Capital, Social and Hybrid) required by D.24-05-064?[10]**

PG&E's Response

PG&E supports presenting CBRs using the three discount rate scenarios required by D.24-05-064. Ultimately, PG&E recommends using the Weighted Average Cost of Capital (WACC) CBR scenario to facilitate decision-making, because it is most representative of the opportunity cost that utility investors consider when making investments.

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8 "Level of granularity," as used in this context, refers to the spatial scale at which it is expected the utility will organize data inputs for use with the ICE Calculator.

9 For details see R.20-07-013, ALJ Ruling Entering Phase 4 Technical Working Group Materials and Related Staff Proposal into the Record and Setting Comment Schedule, Attachment 2: Proposed Data Template Guideline for RAMP and GRC Applications, February 7 at 5 and 18-19. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M556/K602/556602764.PDF.

10 See the requirement in D.24-05-064 at 102-105 and D.24-05-064, Appendix A, Row 25.

3. **Since the Energy Safety EUP Guidelines allow the utility to consider an Ignition Tail Risk Threshold and High Frequency Outage Program Threshold,[11] if the utility applies a convex risk scaling function to the calculation of CBR, how should the utility also present calculations that do not apply a convex risk scaling function, as required by D.24-05-064?[12]**

PG&E's Response

PG&E will apply its convex scaling function to cost benefit ratio inputs in accordance with the Risk-Based Decision-Making Framework, D.24-05-064. However, PG&E will also provide unweighted and unscaled values for ignition consequence and outage program likelihood, the metrics used to establish Ignition Tail Risk and High Frequency Outage Program Thresholds, in Table C.8 in compliance with the Energy Safety EUP Guidelines. PG&E emphasizes the continued need for non-linear scaling throughout the decision-making process as this function appropriately emphasizes the low-frequency, high-consequence risks posed by all locations, in contrast to the handful of locations with highest overall consequence identified by the Ignition Tail Risk Threshold.

PG&E adopts a convex risk scaling function as an integral part of its assessment of mitigation programs. However, the Risk-based Decision-Making Framework (RDF) also states that:

> 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.[13]

PG&E considers the Ignition Tail Risk Threshold and High Frequency Outage Program Threshold as some of the "other factors" influencing mitigation selection, and as such, will present supplemental analysis as necessary to explain how these (and other) factors affected mitigation selection, consistent with the RDF requirements above and as required by the Energy Safety EUP Guidelines Section 2.7.9. PG&E will establish and explain an Ignition Tail Risk Threshold and High Frequency Outage Program Threshold in its EUP submittal.

4. **How should the Commission consider the combined CBR benefits of Ignition Risk reduction and Outage Program Risk reduction, given that a proposed mitigation may also reduce outage program risk?**

    a. **Option 1: Calculate the CBR benefit based on the Ignition Risk reduction only.**

PG&E's Response

PG&E does not support Option 1 because SB 884 and the Energy Safety EUP Guidelines require a utility to demonstrate substantial reduction in both ignition risk and outage program risk.

[11] For details see Energy Safety EUP Guidelines, Section 2.7.9.1 at 42.

[12] See the requirement in D.24-05-064 at 97-98 and D.24-05-064, Appendix A, Row 7.

[13] D.24-05-064, Appendix A, Row No. 26 at p. A-16.

b. **Option 2: Calculate the CBR benefit based on a combination of Ignition Risk reduction and Outage Program Risk reduction?**

PG&E's Response

PG&E supports Option 2 because calculating a CBR benefit based on the combination of ignition risk reduction and outage program risk (defined as overall utility risk in the Energy Safety EUP Guidelines) addresses SB 884 and the Energy Safety EUP Guideline requirements. SB 884, PUC § 8388.5(d), states that a utility's distribution infrastructure undergrounding plan can only be approved by Energy Safety if it substantially increases electric reliability and substantially reduces wildfire risk. The Energy Safety EUP Guidelines require a Large Electrical Corporation to establish a Plan Mitigation Objective and other specific tracking objectives in its EUP that are necessary to meet this requirement (Section 2.3.1).

i. **Should the CPUC assume mutual exclusivity between Ignition Risk and Outage Program Risk when aggregating the CBR benefits? If not, how should these risks be combined?**

PG&E's Response

No, the CPUC should not assume mutual exclusivity between ignition risk and outage program risk because they are not exclusive or even offsetting factors. Different mitigations (undergrounding, covered conductor, etc.) will address both ignition risk and outage program risk differently, with different benefit values identified for each of those two factors. Ignition risk and outage program risk should each be represented as a unique value—two of the benefits—in the CBR calculation and those two unique values should be combined when calculating CBRs. This is in alignment with the requirements of SB 884 and the Energy Safety EUP Guidelines.

5. **What is the appropriate point in time for utilities to use as CBR Year Zero in CBR calculations?**

   a. **Option 1: The first year of application cycle.**

   b. **Option 2: The year the project is expected to become used and useful.**

PG&E's Response

CBR year zero should be the year the project is expected to become used and useful because the risk reduction and other benefits of an undergrounding project do not start to accrue until the underground line is energized (used and useful). As noted above, if the discount rate of the numerator and the denominator of the CBR calculation is the same then the "Year Zero" decision may be less important in calculating CBRs than initially thought as moving 'Year Zero' has the same effect on both the numerator and denominator.

SDG&E Response to CPUC Postworkshop Questions SB-884 Guidelines
April 25, 2025

Post-Workshop Questions for Stakeholders Regarding the CPUC SB-884 Guidelines

April 11, 2025

Instructions:

- If any question in this document calls for a "yes" or "no" answer, please explain your answer rather than simply providing a one-word answer.
- The reference to Office of Energy Infrastructure Safety (Energy Safety) Guidelines are available at https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=58006&shareable=true.
- The Commission SB-884 Guidelines refers to Resolution SPD-15, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M526/K984/526984185.pdf

Definitions:

- **Cost Benefit Ratio (CBR)**: calculated by dividing the dollar value of Mitigation Benefit by the Mitigation cost estimate.[1]
- **Circuit Segment**: refers to a specific portion of an electrical circuit that can be separated or disconnected from the rest of the system without affecting the operation of other parts of the network. This isolation is typically achieved using switches, circuit breakers, or other control mechanisms.[2]
- **Electric Undergrounding Program (EUP):** an expedited utility distribution infrastructure undergrounding program established by the CPUC pursuant to section 8388.5(a).[3]
- **Investor Owned Utility (IOU)**: Utility regulated by the Commission that seeks SB 884 cost recovery or submits an SB 884 Application or seeks Energy Safety approval for an SB 884 Plan.
- **Key Decision-Making Metric (KDMM):** Energy Safety's 10-Year Electrical Undergrounding Plan Guidelines describe Key Decision-Making Metrics as a collection of top-level metrics that the Large Electrical Corporation is allowed to use to evaluate the efficacy of an Undergrounding Project. They do not reflect financial considerations. The utility must report on seven mandatory KDMMs, and may include 5 additional KDMMs of its choice. The mandatory KDMMs include Ignition Risk and Outage Program Risk.[4]
- **Memorandum Account (MA):** In the context of Senate Bill (SB) 884 Program: CPUC Guidelines, the Memorandum Account refers an account where a large electrical corporation may record implementation costs that do not meet the Phase 2 Conditions. In Phase 3, the large electrical corporation may file an application and request rate recovery for these costs.
- **Office of Energy Infrastructure Safety (Energy Safety) Guidelines**: explained in "Instructions," above.
- **Phase 2 Conditions (Conditions):** The Phase 2 Conditions will include, but are not limited to, a total annual cost cap, two-year rolling average recorded unit cost cap, two-year rolling average recorded CBR threshold, and applying third-party funding to reduce the cost cap.[5]
- **Protective Equipment and Device Settings (PEDS)**: advanced safety settings implemented

[1] D.24-05-064, Appendix A at A-3.
[2] This concept refers to the same concept found within the Energy Safety Guidelines Appendix A.
[3] Energy Safety 10-Year Electrical Undergrounding Plan Guidelines, A-1.
[4] For details see Energy Safety 10-Year Electrical Undergrounding Plan Guidelines, Section 2.7.3 at 31-32.
[5] For details see SPD-15, SB-884 Program: CPUC Guidelines at 10-11.

by electric IOUs on electric utility powerlines to reduce wildfire risk.[6]

- **SB 884 Project List Data Requirements**: the list of data fields that the utility must complete for each project the utility includes in its EUP cost recovery Application. This data set must be submitted with the initial cost recovery Application and updated in the six-month progress reports. The detailed requirements are listed in Appendix 1 of SPD-15 or any future update to Appendix 1.
- **Screen 2 (Project Information and Alternative Mitigation Comparison)**: confirms there is sufficient information available on a Circuit Segment and requires comparison of undergrounding to alternative mitigations in order to determine which Eligible Circuit Segments can be treated as Undergrounding Projects.[7]
- **Screen 3 (Project Risk Analysis)**: the procedure for evaluating an individual Undergrounding Project in the context of the Portfolio of Undergrounding Projects and includes information obtained through the project development process resulting in a list of Confirmed Projects.[8]
- **Screen 4 (Project Prioritization and Finalization):** the procedure for prioritizing Confirmed Projects using the means of prioritization approved by Energy Safety in the Electrical Undergrounding Plan (EUP).[9]
- **Undergrounding Project**: an Eligible Circuit Segment that has completed Screen 2 including the SB 884 Project List Data Requirements from Appendix 1 of SPD-15 or any future update to Appendix 1.

[6] For details see https://www.cpuc.ca.gov/industries-and-topics/wildfires/protective-equipment-device-settings
[7] For details see Energy Safety 10-Year Electrical Undergrounding Plan Guidelines, Section 2.4.4 at 18-19
[8] For details see Energy Safety 10-Year Electrical Undergrounding Plan Guidelines, Section 2.4.5 at 19-20
[9] For details see Energy Safety 10-Year Electrical Undergrounding Plan Guidelines, Section 2.4.6 at 20

A. Should the Commission Consider Supplementing the Phase 2 Application Requirements?

Background:

SPD-15 included a list of 20 requirements that must be included in any Application submitted to the Commission seeking conditional approval of Plan costs. Would it be appropriate for the Commission to consider adding the following requirements?:

1. Include the data associated with the list of all projects (SB 884 Project List Data Requirements) as required by Screen 2 of the Energy Safety Guidelines
   a. Require the utility to provide us with a forecasted scope of all projects for the ten-year plan, with the expectation that projects far in the future would change.
   b. This requirement would make it explicit that the Underground Project List, which is an output from Screen 2 in the Energy Safety Guidelines, must be ready for the Commissionto review before an Application can be submitted.

SDG&E Response: The text of SB 884 requires:

> Identification of the undergrounding projects that will be constructed as part of the program, including a means of prioritizing undergrounding projects based on wildfire risk reduction, public safety, cost efficiency, and reliability benefits. Only undergrounding projects located in tier 2 or 3 high fire-threat districts or rebuild areas may be considered and constructed as part of the program.

Requiring all Screen 2 data for all projects for the ten-year EUP would be a significant expansion of the submission requirements, unnecessarily extending the time for application preparation. Review of the 25+ project Portfolio developed for the EUP along with fulfilling the already thorough requirements for application is sufficient to assess the analysis and preparation of the EUP. If additional information is necessary to render a decision on the EUP, such information can be obtained and developed during the course of the review through the data request process or additional testimony.

2. Require the utilities to provide a detailed explanation for any spans that extend beyond the HFTD for any project included in the Underground Project List from Screen 2 of the Energy Safety Guidelines.[10]
   a. The Energy Safety Guidelines allow for undergrounding circuit segments with assets inside the HFTD, then each span that crosses the Tier 2 or 3 HFTD boundary and up to two adjacent spans outside of a Tier 2 or 3 HFTD may also be included in a project.
   b. This requirement would ask the utilities to provide a detailed explanation regarding why they must include any spans that extend beyond the HFTD.

SDG&E Response: This additional requirement is unnecessary. SDG&E expects that in the majority of cases, expansion of any undergrounding outside of the HFTD will support a reasonable transition from underground to overhead through construction at an already existing structure such as a substation, pole or switch. This approach is a cost-efficient means of minimizing the cost of construction by avoiding

[10] For details see PUC 8388.5(c)(2) and Energy Safety 10-Year Electrical Undergrounding Plan Guidelines, Section 2.4.3.1 at 16.

building a new structure at the boundary of the HFTD. To the extent other circumstances merit an extension of undergrounding outside the HFTD, those circumstances can be addressed on a case-by-case basis through the application process, data requests, and testimony. Requiring an overly detailed explanation for each span, as envisioned by the question, would result in unnecessary repetition throughout the application causing potential confusion and delay.

3. Require utility to submit a depreciation study with updated information of the type of assets that are impacted by an SB-884 Application
    a. Depreciation studies are typically updated when a utility files its GRC.
    b. Because undergrounding projects have large capital expenditures, there is a potential that depreciation and salvage costs may be contested in an EUP cost recovery Application.
    c. This would require a depreciation study be included in the record, but it should be a depreciation study with updated information since an EUP cost recovery Application will not necessarily be submitted in the same time frame as a GRC.

SDG&E Response: The utility performs a depreciation study for all assets as part of the GRC process and uses this depreciation study for any subsequent filings or proceedings. As SDG&E explained in its 2024 GRC testimony,[11] a depreciation study is a comprehensive analysis of the property characteristics of a utility's assets. It is specific to each utility and that utility's assets determine the appropriate annual depreciation accrual rate for each asset account. The primary factors that influence the depreciation rate for an account are the remaining investment to be recovered in the account, the depreciable life of the account, and the net salvage for the account. For SDG&E's depreciation study in the GRC, there are seven general classes, or functional groups, of depreciable property that are analyzed: (1) Common Plant, (2) Electric Production Plant, (3) Electric Distribution Plant property, (4) Electric General Property, (5) Gas Storage and Transmission Plant, (6) Gas Distribution Plant property, and (7) Gas General Property. Assets addressed in any EUP could be in multiple classes or functional groups of depreciable property. Only doing a depreciation study on limited classes or functional groups of assets would not provide a comprehensive look at depreciation.

Further, depreciation is a complex accounting process. In setting depreciation expense, the CPUC may use information outside of the depreciation study. For example, the CPUC has applied a gradualism policy based upon concerns about growing cost burdens associated with increasing cost trends for negative net salvage. Thus, depreciation expense that is implemented in rates may not be reflective of a depreciation study. Additionally, the purpose of a EUP is not to set depreciation expense or address complex accounting issues. The appropriate subject matter experts, parties, and staff that analyze depreciation and other ratemaking issues (tax, for example) will likely not be involved in EUPs, nor should they be. Accordingly, complex accounting and ratemaking considerations, including depreciation, should continue to be addressed in GRCs.

Rather than requiring a depreciation study in EUPs, future GRC depreciation studies will fold in the EUP results. In other words, future GRC depreciation studies will analyze assets constructed as part of an EUP. Performing a duplicative depreciation study on the assets affected by the EUP is redundant and could result in contradictory and confusing findings.

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[11] *See* Exhibit SDG&E-36 (Watson), available here: [Microsoft Word - Revised Direct Testimony_Depreciation_SDGE-36-R_1374.docx]().

4. Require both nominal and present value lifetime calculations for the capital expenditures for each project included in the Undergrounding Project List from Screen 2 of the Energy Safety Guidelines [12]
    a. PUC 739.15 specifically calls out the need for greater clarity on the lifetime cost and benefit of a capital expenditure project such as those submitted in an EUP cost recovery Application.
    b. This would require both nominal and present value lifetime calculations for the capital expenditure of each undergrounding project.

SDG&E Response: SDG&E has no objection to this proposal as it is already calculated as part of the process.

5. Require data retention policy for lifetime of EUP for tabular and geodatabase data. This should be required for both the initial application and any of the data updated through the six-month progress reports.
    a. Since there are no additional requirements for data retention related to an EUP, this will require the utility to retain all tabular and geodatabase information submitted as part of the EUP and any data included in six-month progress reports.
    b. Staff intend to hold data template working groups later in the spring.

SDG&E Response: A new data retention policy for the EUP tabular and geodatabase data is unnecessary at this time. The utilities already have data retention policies to address retention of necessary data, and this additional requirement will not add value. SDG&E is open to discussions on data templates during future working groups as contemplated by the question.

6. Require utilities to submit the same Key Decision-Making Metrics (KDMM) data for Commission review as provided for in the submission to Energy Safety.

SDG&E Response: SDG&E does not support the addition of the KDMM data as it would create duplicative and potentially contradictory regulatory outcomes. The Commission will have access to the KDMM information and data included in the Energy Safety review process. However, any changes made to KDMMs following Energy Safety approval of the EUP could invalidate the outcome of that process and blur the jurisdictional lines established by SB 884.

B. What, if Any, Additional Phase 2 Conditions Should the Commission Consider?

Background:

SPD-15 listed five Phase 2 Conditions that must be met for the costs of any project to be booked to a one- way balancing account. The parameters or threshold values of the Conditions will be established in the Phase 2 Decision based on the forecasted numbers presented in the cost recovery Application. As explained in the Instructions above, the five Conditions listed in SPD-15 include a total annual cost cap, a two-year rolling average recorded unit cost cap, a two-year rolling average recorded CBR threshold, a requirement to apply third-party funding to reduce the cost cap, and any further reasonable Conditions

[12] See also PUC 739.15

supported by the record of the proceeding and adopted by the Commission in the Phase 2 Decision.[13]

1. Should the Commission consider imposing Conditions on the Memorandum Account (MA)? If so, what Conditions should be considered?
    a. Option 1: Establish a maximum total cap for the MA, limiting it to no more than 25% of the total sum of the ten-year annual caps established for the balancing account.
    b. Others?

SDG&E Response: SDG&E opposes establishing a maximum total cap for the Memorandum Account at this time. Such action could result in unreasonable limitations in light of unforeseen market conditions, shortages, and other conditions outside the control of the electrical corporation. Given the duration of the EUP, this could be unduly restraining on the electrical corporation's ability to complete work that meets the approved risk reduction goals. SDG&E recommends that the Commission follow the process by which any memorandum account is reviewed for reasonableness—by which the utility is required to demonstrate the reasonableness of its costs by an established burden of proof—without any caps. Memorandum accounts record costs that are already incurred. The utility finances the costs upfront recognized that costs recorded to memorandum accounts are at risk and subject to a reasonableness review at the Commission. The utility also recognizes that there is not a guarantee of cost recovery. Thus, even without caps, the Commission has the ability to determine what costs are just and reasonableness and can any deny costs that are not just and reasonable.

2. Should the Commission consider assessing the variance between the forecast data submitted according to the SB 884 Project List Data Requirements in the initial cost-recovery Application to the Commission and the updated data submitted according to the SB 884 Project List Data Requirements in a six-month progress report and if so how?
    a. Option 1: If the variance between the forecasted CBRs and unit cost of a project presented in an Application compared to the updated CBRs and unit cost of a project presented in a six month Progress Report (after a project passes Energy Safety's Screen 4) exceeds a certain threshold, then all costs for that project must be recorded in the MA.
    b. Others?

SDG&E Response: No. SDG&E intends to manage assets at the portfolio level and not at the individual project level. We anticipate that some project CBRs may change at completion of construction from what is presented at the end of Screen 4. This requirement would inequitably penalize the utility when CBR lowers but not reward the utility when CBR rises through the process resulting in an overall loss.

3. Should the Commission consider adopting a CBR Threshold, and if so, what should the criteria be?
    a. Option 1: Require all projects to have a CBR greater than a specified value.
    b. Option 2: If a project's recorded CBR is less than a specified value, the utility must provide a detailed justification for this project.
    c. Option 3: After Screen 2, any project ranked below a certain CBR percentile threshold is ineligible for cost recovery via the BA.
    d. Others?

SDG&E Response: SDG&E objects to a CBR Threshold. The OEIS Guideline for implementing the Project Acceptance Framework requires a narrative description of how the screening process is applied

[13] For details see SPD-15, SB-884 Program: CPUC Guidelines at 10-11.

and the rationale for the proposed portfolio. This approach is a component of the approved EUP, and subsequent CBR thresholds imposed by the Commission could result in inconsistent regulatory outcomes, particularly if the review is changed to the project level. SDG&E will manage the EUP portfolio to achieve the CBR threshold approved by Energy Safety.

Further, tying cost recovery through the balancing account to CBR thresholds is unnecessary and burdensome. The existing conditions for approval provide adequate controls for managing costs and addressing cost recovery across the portfolio of projects.

4. Should the Commission consider requiring a comparative CBR analysis of project alternatives? If so, how should this analysis be conducted?
    a. Option 1: If an Undergrounding Project has a CBR above a specified CBR Threshold but the Alternative(s) has a CBR that is a specified amount greater than the Undergrounding Project's CBR, then the undergrounding project should not move forward.
    b. Others?

SDG&E Response: SDG&E opposes this proposal as it is unduly restrictive and fails to consider factors and analyses that support the selected mitigations across the portfolio. During the Energy Safety EUP screening process, a utility compares undergrounding to alternative mitigations during Screen 2 and Screen 3. While CBR is the primary consideration when selecting a mitigation solution, it should not be the only one. The OEIS Guideline for implementing the Project Acceptance Framework requires a narrative description of how the screening process is applied and the rationale for the proposed portfolio. These are part of the basis of approval of the EUP. A utility must be able to consider multiple factors when selecting a mitigation alternative and not limited in its decision-making based on a single one.

5. Should the Commission consider applying some of Energy Safety's KDMMs to the Commission's consideration of whether to grant cost recovery for projects and if so, how?
    a. Option 1: After Screen 3, if the reduction in Ignition Risk and/or Outage Program Risk does not meet the required Project Level Standard set in the approved Plan, the project will not be eligible
    b. Others?

SDG&E Response: SDG&E opposes this proposal. The Guideline already requires the Project Level Standard reduce the risk to below the Project Level Threshold as a minimum. See the definition of Project Level Standard in Appendix A of the Guideline. This requirement would be redundant.

C. What methods could the Commission use to address the Audits and/or Review Procedure?

Background:

The Commission's SB-884 Guidelines require that costs submitted in an SB-884 Application meet certain conditions (Phase 2 Conditions) before they can be authorized for recovery via a one-way balancing account.[14] That one-way balancing account is subject to audit. If the audit finds that costs

[14] The Phase 2 Conditions will include, but are not limited to, a total annual cost cap, two-year rolling average recorded unit

were incorrectly recorded or failed to meet the Phase 2 Conditions, the Commission may order a refund. SPD- 15 stated that the details of this audit would be determined in a later decision or order. The questions below explore two potential structures for determining whether costs were appropriately recorded to the balancing account:

Questions:

1. Should the Commission consider adopting the following review structure to ensure a rigorous review of the costs associated with an EUP?
   a. Annual post-implementation review process with intervenor participation.
   b. Objectives of the review should include verifying project completion, cost overheads, CBR methodology and an incrementality showing.
   c. Once deemed "used and useful" in a progress report, a project's costs may be included in ratebase via an Advice Letter that must be disposed via Commission Resolution.
   d. Commission Resolution will determine whether recorded costs met the Phase2 Conditions and other objectives of the review.
   e. Approved costs would enter rates via Annual True-up.

SDG&E Response: Once Conditions for Approval are established by the Phase 2 Decision, only the auditor, the Commission, and the Utility should participate in audits or review of the balancing account. The auditor will protect customer interests through its independent review of the costs. This approach provides the CPUC a structure to accomplish its oversight role while not adding a separate process. The six month progress reports could form the information source for conducting the review.

2. Should the Commission instead consider adopting the following review structure to audit the costs associated with an EUP?
   a. Annual audit by independent auditor with CPUC oversight. Results of the audit could be made available to intervenors.
   b. Objective of the audit should include verifying project completion, cost overheads, and an incrementality showing.
   c. Once deemed "used and useful" in a progress report, a project's costs may be included in rates via annual True-up and become subject to audit.
   d. If the audit finds that project costs were incorrectly recorded to the Balancing Account, and the utility does not contest the audit results, then the utility must issue a refund to ratepayers.

SDG&E Response: No. This proposal introduces a process redundant to the Independent Monitor process with no apparent advantages over the annual review process proposed in Question C.1.

3. Supporting Questions:
   a. How should the timing of the Independent Monitor's (IM) review and the utility's right to correct a deficiency found by the IM within 180 days (PUC 8838.5 (g)(2)) interact with the annual review of the costs of a project?
   b. How should projects that fail to meet key criteria be treated vis-a-vis cost recovery? What key criteria should be considered?
   c. Should intervenors participate in Options 1 and 2 above? If so, how and where?
   d. Should the Commission consider using a different option than 1 or 2 above? If so,

cost cap, two-year rolling average recorded CBR threshold, and applying third-party funding to reduce the cost cap. For details see SPD-15, SB-884 Program: CPUC Guidelines at 10-11.

explain each step in the proposed process. How and where would intervenor participation be accounted for in the proposed option?

SDG&E Response:
A. The IM and Annual Review should be treated as separate processes.
B. The program should be evaluated at the portfolio and not the project level. Assigning key criteria and withholding cost recovery when they are not met while providing no complementary reward when criteria are exceeded at a project level is inconsistent and unfairly impacts the utility.
C. Intervenors should not participate in interactions between the CPUC and the utility following process development and approval of the Application.
D. SDG&E supports Option 1 above. Intervenor participation should be limited to providing comments before and after the review.

D. How could the Commission address changes to approved projects?

Background:

Changes to project costs and implementation status can impact cost recovery under the SB-884 framework. Except for 25 projects that Energy Safety's Guidelines will require to pass through all four Screens, cost and risk data (including CBR calculations) presented will be associated with projects having passed Screen 2 at the time of Application submittal. However, it isn't until after projects have passed Screen 4 that their full scope is determined and more accurate data associated with project cost and risk (including CBR calculations) are provided. These updated data are expected to be received throughout the life of the 10-year Plans and submitted via the six-month progress reports. Accordingly, how should the Commission handle new costs added to projects after the Phase 2 Decision is issued, based primarily on Screen 2 data? How should the Commission treat costs from abandoned or incomplete projects? The following questions explore potential approaches for managing these changes.

1. Should new costs added to approved projects after the Phase 2 Decision be booked to the Memo Account?
    a. If the updated rolling average CBR falls below the Phase 2 Condition threshold, should all new costs be deemed non-recoverable?
2. Should certain categories of cost overruns (e.g., inflation-driven, safety-driven) be treated differently from discretionary cost increases?

SDG&E Response: No. The costs of project construction are expected to vary significantly as permitting timelines, labor and material costs vary and it is unreasonable to expect any cost greater than that estimated at Screen 2 to be booked to the Memorandum Account. The Memorandum Account should be used to record costs when the portfolio level Conditions for Approval are exceeded.

E. Should the Commission include an Appendix with guidance for calculating the CBR of an undergrounding project?

Background:

The calculation of the CBR for undergrounding and alternative projects is a critical factor in determining project eligibility for cost recovery. In addition, the selection of CBR Year Zero[15] plays a pivotal role in accounting for the time value aspect of CBR calculations. Notably, the Energy Safety Guidelines define Total Utility Risk as the sum of Ignition Risk and Outage Program Risk.[16] The following questions explore how utilities should apply existing methodologies and present their results.

1. What level of granularity[17] should the utility use when applying the Interruption Cost Estimator (ICE) Calculator to generate a Monetized Value of Electric Reliability? Should the analysis be based on:
    a. HFTD and PEDS-activated circuits
    b. Operational Region and HFTD[18]
    c. Others?

SDG&E Response: Each utility should retain the flexibility to determine the appropriate level of granularity when applying the ICE Calculator model and other alternative models. SDG&E currently uses data inputs for the ICE 1.0v2 model that represent all SDG&E customers, thus reflecting the reliability impact ($/CMI) that does not consider the region customers belong to. In the context of general reliability risk reduction, this approach promotes consistency in decision-making, providing a clear, transparent, useful, and equitable method. The ICE model continues to evolve, thus SDG&E's perspective on best practices in applying the tool are subject to change.

2. How should the utility calculations of CBR be presented when using the three discount rate scenarios (Weighted Average Cost of Capital, Social and Hybrid) required by D.24-05-064?[19]

SDG&E Response: SDG&E will present CBRs with the three discount rate scenarios for each feeder segment. This has been completed in the 2026-2028 WMP and will be completed in SDG&E's 2025 RAMP.

3. Since the Energy Safety Guidelines allow the utility to consider an Ignition Tail Risk Threshold and High Frequency Outage Program Threshold,[20] if the utility applies a convex risk scaling function to the calculation of CBR, how should the utility also present calculations that do not apply a convex risk scaling function, as required by D.24-05-064?[21]

SDG&E Response: SDG&E employs the WiNGS-Planning model to assess baseline risk (pre-mitigated), risk reduction, and residual risk (post-mitigated) for feeder segments selected for Strategic Undergrounding and Combined Covered Conductor grid hardening measures. The model can also generate CBRs with and without considering risk aversion (convex risk scaling function).

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[15] The year that all Costs and Risk Reductions are discounted to for the purpose of CBR calculations.
[16] For details see Energy Safety 10-Year Electrical Undergrounding Plan Guidelines, Section 2.7.3 at 31.
[17] "Level of granularity," as used in this context, refers to the spatial scale at which it is expected the utility will organize data inputs for use with the ICE Calculator.
[18] For details see R.20-07-013, ALJ Ruling Entering Phase 4 Technical Working Group Materials and Related Staff Proposal into the Record and Setting Comment Schedule, Attachment 2: Proposed Data Template Guideline for RAMP and GRC Applications, February 7 at 5 and 18-19.
https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M556/K602/556602764.PDF
[19] See the requirement in D.24-05-064 at 102-105 and D.24-05-064, Appendix A, Row 25.
[20] For details see Energy Safety 10-Year Electrical Undergrounding Plan Guidelines, Section 2.7.9.1 at 42
[21] See the requirement in D.24-05-064 at 97-98 and D.24-05-064, Appendix A, Row 7.

SDG&E's decision-making process is guided by risk aversion, enabling the SDG&E to differentiate and prioritize projects involving low-probability, high-consequence events over those with high-probability, low-consequence events. At a basic level, risk associated with an undesirable event is its probability multiplied by its consequence. As a result, the calculated risk of a low-consequence, high-probability event might be the same as the risk of a high-consequence, low-probability event. While equating these risks may be mathematically rigorous and accepted in some risk assessment frameworks, multiple studies suggest that society may not view these risks as equivalent. Society tends to be more accepting of frequent, low consequence events (e.g., short-duration outages) but is intolerant of rare but devastating events, such as large-scale wildfires.

SDG&E's risk-informed decision-making framework recognizes this aversion towards devastating events and better aligns the consequences of potential disasters with society's perception of the costs.

4. How should the Commission consider the combined CBR benefits of Ignition Risk reduction and Outage Program Risk reduction, given that a proposed mitigation may also reduce outage program risk?
    a. Option 1: Calculate the CBR benefit based on the Ignition Risk reduction only.
    b. Option 2: Calculate the CBR benefit based on a combination of Ignition Risk reduction and Outage Program Risk reduction?
        i. Should the CPUC assume mutual exclusivity between Ignition Risk and Outage Program Risk when aggregating the CBR benefits? If not, how should these risks be combined?

SDG&E Response: The intent of SB 884 is to substantially reduce Ignition Risk and Outage Program Risk, thereby benefiting customers by making them safer from wildfire with high reliability electrical service. The Guideline therefore appropriately requires calculating both and combining them into an Overall Utility Risk for comparison to the Alternative Mitigation of covered conductor combined with a fast trip mechanism. The OEIS Guideline gives sufficient guidance to answer this question. This guidance is in accordance with SB 884 which clearly states the intent of providing an expedited funding mechanism for undergrounding power lines is to provide more reliable electric service as well as to reduce wildfire risk.

5. What is the appropriate point in time for utilities to use as CBR Year Zero in CBR calculations?
    a. Option 1: The first year of application cycle.
    b. Option 2: The year the project is expected to become used and useful.

SDG&E Response: Option 2. The life cycle of the assets is assumed to be 55 years and the EUP requires calculating benefits associated with the assets out to this point. The calculation should be from the year the project becomes used and useful in calculating its cost and benefits. This will provide a more accurate view of project value than subtracting up to ten years from the project life.