November 2, 2023 **Via Electronic Filing**

Caroline Thomas Jacobs, Director
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California Natural Resources Agency
Sacramento, CA 95814
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Subject: **Public Advocates Office's Comments on Undergrounding Plan Guidelines**

Docket: **2023-UPs**

Dear Director Thomas Jacobs,

The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) respectfully submits the following comments on guidelines for implementing Senate Bill 884. Please contact Nathaniel 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.

Respectfully submitted,

/s/ ***Darryl Gruen***

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Contents

I. INTRODUCTION

Pursuant to the Office of Energy Infrastructure Safety's (Energy Safety) October 16, 2023 memorandum to stakeholders seeking comment on guidelines for utility distribution undergrounding plans (Comment Letter),[1] the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) submits these comments about the implementation of Senate Bill (SB) 884.[2] Pursuant to the Comment Letter, comments are due by November 2, 2023.

Governor Newsom signed SB 884 on September 29, 2022. The bill authorizes large electric utilities to submit ten-year plans to underground distribution lines. The bill leaves to Energy Safety and the California Public Utilities Commission (CPUC) discretion as to implementation, such as the specifics of what must be included in the plan, the review and approval process, and accountability measures. To ensure that the utilities' plans conform to the statutory goal of reducing wildfire risk while minimizing the cost and reliability impacts to ratepayers, Energy Safety should develop guidelines and rules regarding the plans and the review process.

Cal Advocates has engaged with Energy Safety staff regarding the implementation of SB 884 since early December 2022, and looks forward to further opportunities, beyond these comments, to constructively engage with Energy Safety staff, share ideas, and develop effective policies. Cal Advocates is committed to implementing SB 884 in a manner that measurably advances the public's interest in safe, reliable and affordable electric service.

[1] Energy Safety, Memorandum to Interested Stakeholders for Expedited Utility Distribution Undergrounding Plans, October 16, 2023, in docket 2023-UPs. (Comment Letter).

[2] SB 884 is codified as Public Utilities Code section 8388.5.

II. Requirements for Energy Safety Approval

A. Outage programs

Cal Advocates has no comments at this time.

B. Baseline for outage programs

Cal Advocates has no comments at this time.

C. Substantial increase in reliability

Cal Advocates has no comments at this time.

D. Developing a Baseline for Wildfire Risk

Developing and identifying the wildfire risk baseline is fundamental to the implementation of an undergrounding plan. All undergrounding projects should be benchmarked against the baseline to demonstrate how they have successfully reduced wildfire risk. The following principles are necessary to establish an effective baseline:

1) A baseline should be defined in terms that are common to all utilities. Fundamental to this is the location of the wildfire risk.
2) For any given plan, the wildfire risk[3] should be defined and mapped across the utility's entire service territory, not just High Fire Threat Districts (HFTDs).
3) Energy Safety should use the same definition and models for wildfire risk to benchmark, select, and prioritize projects.
4) The date of the risk baseline should be based on the location and state of utility assets at the time the utility estimates the wildfire risk as part of an SB 884 plan. More precisely, the date of the wildfire risk baseline should be set as the date at which the utility took a snapshot of its operational system for the purposes of modeling. This gives the most accurate understanding of the assets and the state of the operational system on which project selection decisions were made.
5) The risk baseline should be calculated for the entire utility territory (not merely individual projects) using consistent methods. This is essential to evaluate the overall impact of a plan and ensure compatibility between current and future risk models.

E. Substantial reduction of wildfire risk

Cal Advocates has no comments at this time.

III. Required Components of Undergrounding Plan

A. Definition of an undergrounding project

[3] The wildfire risk is assumed to be measured by the wildfire risk models that the electric utilities have developed for distribution infrastructure as part of the Wildfire Mitigation Plans.

A good project definition enables an effective analysis and allows utilities, regulators, stakeholders, and the public to determine whether undergrounding is the optimal wildfire mitigation solution. Such a definition should be focused on the primary objective of reducing the risk of catastrophic wildfires posed by existing bare overhead infrastructure in risk-prone areas. Therefore, the definition of an "undergrounding project" encompasses two related but distinct elements:

(1) The identification and eventual removal from service of existing utility assets that pose a wildfire risk: This element of the project should include a detailed understanding of the location, an estimate of wildfire risk, and the timing for removal from service of the existing bare overhead infrastructure which presents the known wildfire risk.

(2) The selection, design, and execution of the solution that is best suited to mitigate the wildfire risk: This element should include the location, timing of deployment, and efficacy of the proposed undergrounding project, as well as all other reasonable mitigation strategies.[4]

Utilities must provide Energy Safety and stakeholders sufficient information to enable parties to analyze projects, assess the alternatives, and audit the project selection process to ensure the best projects are being proposed.

1. An undergrounding project must be defined by its wildfire risk reduction characteristics.

The wildfire risk reduction offered by undergrounding projects occurs at the location of the existing bare overhead lines that would be taken out of service, and not the location of new proposed undergrounded lines. This can be substantially different. The following key principles should be used to define a project:

1) The definition of a project is a contiguous group of comparably high-risk assets that are to be mitigated simultaneously. When a project is complete, the entire set of existing overhead assets entailed in the project will be simultaneously removed from service.

2) Risk reduction benefit should be estimated at the scale of the assets to be removed from service; inclusion of assets that are not being taken out of service should be avoided.[5]

[4] As required by Public Utilities Code section 8388.5(c)(4).

[5] For example, it would be inappropriate to designate a twenty-mile section of circuit as a "project" if ten of those miles are low-risk and are unlikely to be replaced through a utility's SB 884 plan.

3) The project should be traceable through all stages of the project lifecycle. This begins at preliminary identification of high-risk locations, and continues to project completion. The decisions resulting in the ultimate project should be auditable.

To satisfy these three principles, a project should be a contiguous group of risky utility assets that will be simultaneously removed from service. This definition gives a clear basis in both the project plan, and the records of the utility's operational assets from which a project's benefits can be evaluated.[6]

2. The risk benefits of a project should be estimated based on a set of assets of comparable risk levels, not using the average or aggregate risk for a circuit-segment.

Risk benefits should be estimated from the assets that will be removed from service. Only the risk reduction associated with locations and conditions of the assets being taken out of service should be used to assess the risk reduction of a project. Aggregation at circuit or circuit segment levels should be avoided, since these larger spatial units typically include lower-risk assets that will remain in service. As a result, aggregation to a broader level will hide the actual impacts of the project.

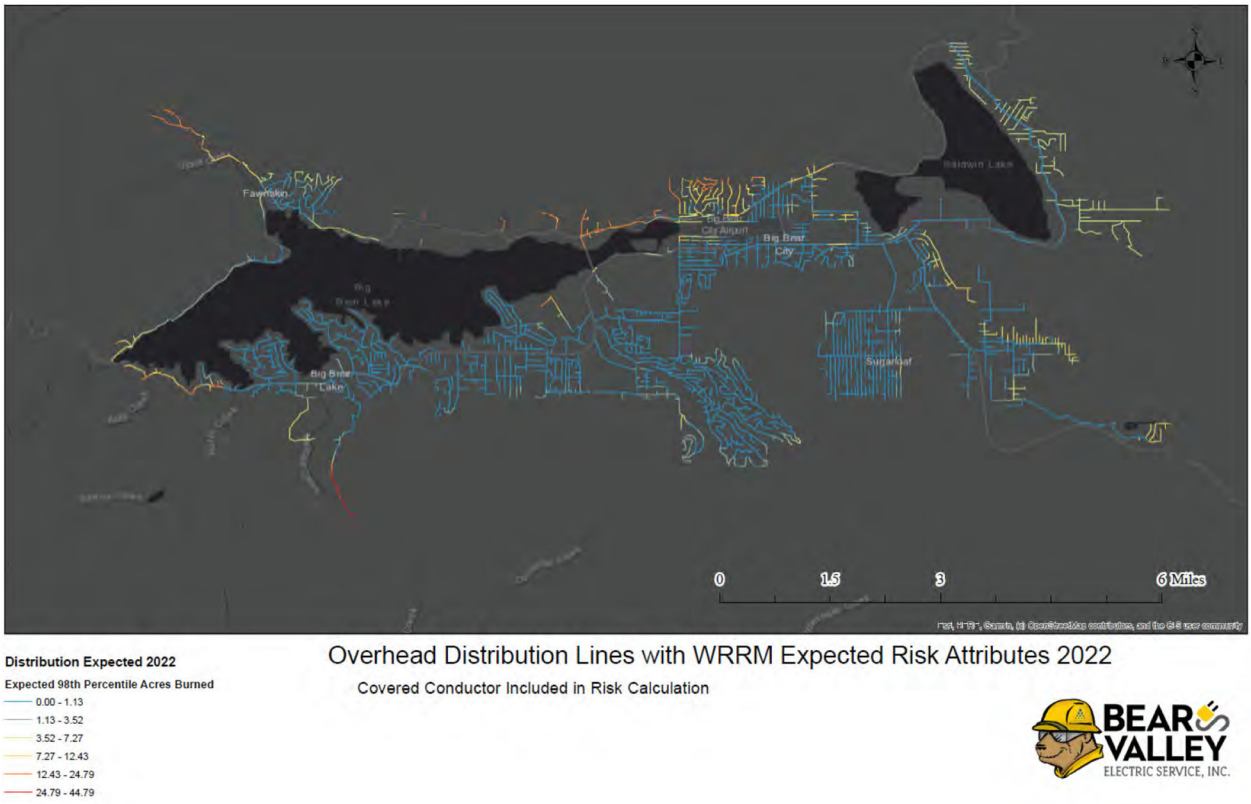
Among other things, the plan should not estimate risk benefits by using the average (mean) risk reduction for multiple discrete projects on the same circuit. That sort of calculation of risk reduction obfuscates the incremental risk attributable to a discrete project. As an illustrative example of the averaging issue, Figure 1 shows the risk assessment of Bear Valley Electric Services' (BVES) territory, which consists of 207 overhead circuit-miles.[7] This mileage would be equivalent to a couple dozen circuit segments for a larger utility with thousands of overhead circuit-miles.[8] Under a mean-risk risk assessment methodology, this entire region might be considered low-risk or moderate-risk, despite a small number of "hot spots" that

[6] The basis of any benefits analysis is in the utility's operational record of their asset locations, onto which are stacked engineering, management, and construction decisions that will ultimately resolve into the date at which the overhead lines are ultimately removed from service.

[7] Bear Valley Electric Service, Inc., *Bear Valley Electric Service 2023-2025 Wildfire Mitigation Plan*, originally submitted May 8, 2023 and revised June 7, 2023 to incorporate non-substantive errata, Table 5-2 at 27.

[8] For example, per PG&E's response to data request CalAdvocates-PGE-2022WMP-31, question 7, September 8, 2022, PG&E's circuit segments range in size from less than 1 overhead mile to 85 overhead miles.

present extreme wildfire risk.[9] As a result, those hot spots could be de-prioritized and could remain unhardened, leaving nearby Californians at risk of wildfire.



Risk assessment of BVES's service territory.[10]

Cal Advocates assumes that the basis for any undergrounding plan is the existing wildfire risk models developed for the Wildfire Mitigation Plans. Any project selection should be directly traceable from the risk model through project selection to completion. At a minimum the utility should provide as part of the project definition:

- The location of the lines that will be removed from service.
- The anticipated date that the assets will be removed from service.
- The risk model (and version) on which the project was predicated.

[9] While BVES is not eligible to submit an undergrounding plan under SB 884, Cal Advocates has reviewed the risk models of larger utilities and found similar risk variance. For example, Cal Advocates reviewed the 100m x 100m pixels associated with PG&E's Wildfire Distribution Risk Model, version 3 (provided in response to data request CalAdvocates-PGE-2022WMP-31, September 8, 2022) and noted locations where a circuit segment is comprised of both low-risk and high-risk locations. The data request was marked confidential, so Cal Advocates is utilizing publicly available data to illustrate the point.

[10] Bear Valley Electric Service, Inc., *Bear Valley Electric Service 2023-2025 Wildfire Mitigation Plan*, originally submitted May 8, 2023 and revised June 7, 2023 to incorporate non-substantive errata, Appendix C.

- Project justification memo (i.e., why did the utility scope it this way?): If the project scope changes during the utility's planning and design process, a narrative describing the decision to modify the location or scope of the project, including reasons for inclusion lower-risk areas.

In conclusion, project size should be defined by the wildfire risk of the assets and the date that an overhead line is to be taken out of service. Cal Advocates, therefore, does not recommend a size limit for projects. The level of detail provided for projects should be sufficient to allow stakeholders to perform a useful analysis of the project and ensure mitigation work is planned in areas of highest wildfire risk. Finally, the scale of projects should minimize the inclusion of regions with low wildfire risk (i.e., locations where other mitigation measures can effectively reduce risk).

3. Undergrounding projects must be comparable to alterative mitigations with comparable risk reduction.

The second part of the underground project definition is related to how the utility proposes undergrounding to mitigate the risk identified in the first part of the definition discussed above. To comply with statute, this part of the undergrounding project definition needs to support the comparison of undergrounding projects with alterative mitigation strategies.

As required by the Public Utilities (PU) Code section 8388.5(c)(4), the utility is required to provide "A comparison of undergrounding versus aboveground hardening of electrical infrastructure and wildfire mitigation for achieving comparable risk reduction."[11, 12] In comparing an undergrounding project against other possible mitigation methods, the utility should provide the following metrics:

- Location of undergrounding project.
- Estimated completion date for each project and alternatives.
- Efficacy of the project.

[11] Public Utilities Code section 8388.5(c)(4)

[12] The utility should justify why undergrounding is the best solution to reduce wildfire risk against other proposed solutions, including but not limited to:

- Covered Conductor (CC);
- Hybrid of Undergrounding/Newly Constructed Overhead/CC;
- Rapid Earth Fault Current Limiters (REFCLs) or other operational tools;
- A combination of any of the above; and
- The null or 'Business As Usual' option to continue Vegetation Management and periodic use of PSPS/EPSS events.

- Estimated risk reduced by the undergrounding project when compared to other mitigations.[13]
- Defined reliability improvements using each project and alternatives.[14]
- Estimated number of miles of new build of each project and alternatives required to reduce risk (in comparison to number of miles of overhead to be taken out of service).
- Estimated cost of each mitigation method.
- Cost efficiency of each mitigation method.[15]

Agencies and stakeholders must be able to make their own assessment of the benefits of all mitigation methods and to not assume undergrounding will be the optimum solution by default, as this violates the requirements of PU Code section 8388.5(c)(4). Both parts discussed above are necessary to define a project. Utilities must identify a discrete and contiguous set of overhead assets that would be removed from service, along with the planned date of removal from service, to allow effective, useful analysis of whether these regions require mitigation.

B. Projects in utility-identified high fire risk areas

Cal Advocates has no comments at this time.

C. Prioritization elements and approval criteria

PU Code section 8388.5(c)(2) requires utilities to provide a means of prioritizing undergrounding projects based on wildfire risk reduction, public safety, cost efficiency, and reliability benefits. PU Code section 8388.5(d) requires Energy Safety to meet certain conditions before it may approve a plan.

Energy Safety posed the question, *How should the prioritization elements* [explained in PU Code section 8388.5(c)(2)] *be distinguished from the Undergrounding Plan approval criteria in Section 8388.5(d)?*[16]

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[13] This risk estimation must be granular enough to account for location-specific factors. For example, a segment that crosses a low vegetation-density region and a high-vegetation density region should differentiate the vegetation-driven risk between these two regions.

[14] It should be noted that SCE has defined reliability improvements related to covered conductor while PG&E has not. A consistent method should be used to determine reliability improvements for various mitigations across peer utilities.

[15] The Staff Proposal from SPD uses the cost-benefit ratio (CBR) to estimate cost efficiency. For consistency, OEIS should consider the same metric.

[16] Energy Safety, *Electrical Undergrounding Plans (Docket #2023-UPs) Request for Comments on Development of Guidelines for the 10-Year Electrical Undergrounding Distribution Infrastructure Plan (Undergrounding Plan)*, October 16, 2023 (Energy Safety, Comment Request Questions) at 2. (Emphasis added.)

1. Energy Safety should consider public safety and cost efficiency in its evaluation of a plan.

First, while PU Code Section 8388.5(d) does not explicitly state that Energy Safety should consider public safety or cost efficiency in its evaluation of a plan, it does not prohibit consideration of these criteria either.[17] In fact, to comprehensively evaluate the safety and reliability impacts of a plan, considering cost efficiency is a necessary part of Energy Safety's review. For example, PG&E's proposed plan to underground 10,000 circuit-miles would cost at least $20 billion, and likely more than $30 billion, while still leaving approximately 17,000 circuit-miles of unhardened, overhead distribution circuits in high fire-threat districts. Failing to consider the cost of this plan is unrealistic because it means ignoring whether the plan represents the best way to use PG&E's finite resources to reduce system-wide risk.

Wildfire risk in utility service territories is not homogenous; rather, it is concentrated in a relatively small number of circuit-miles.[18] While any undergrounding will incrementally improve wildfire safety and reliability, the degree to which it is effective depends greatly on location-specific risk factors such as available fuels, prevalent weather conditions, and the density of nearby vegetation, to name a few.

To "substantially reduce the risk of wildfire,"[19] a utility should prioritize system hardening in the highest-risk portions of its territory. If a utility does not prioritize the portions of its territory that present the greatest risk, it would leave large amounts of risk unaddressed in the early years of the plan.[20] It would be unreasonable to conclude that such a plan "substantially" reduces risk.

Any discussion of cost efficiency should also consider a holistic approach to wildfire mitigation. For example, portions of a utility's system may be both high-risk *and* sub-optimal to underground (for instance, because the terrain is very challenging). Failing to harden these areas

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

[18] *See, e.g.*, Public Advocates Office, *Comments of the Public Advocates Office on the 2023 to 2025 Wildfire Mitigation Plans of the Large Investor-Owned Utilities*, May 26, 2023 (Cal Advocates, May 2023 Comments on 2023 to 2025 WMPs of the Large IOU) Figure 1 at 19.

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

[20] *See, e.g.*, Energy Safety, *Office of Energy Infrastructure Safety Issuance of Revision Notice for Pacific Gas and Electric Company's 2023-2025 Wildfire Mitigation Plan*, June 22, 2023 (Revision Notice for PG&E's 2023-2025 WMP), RN-PG&E-23-05: "PG&E's undergrounding plan may leave wildfire risk unaddressed in highest risk areas" at 14-17.

would leave unacceptable risk in the system.[21] By contrast, prioritizing them for undergrounding would be an inefficient use of ratepayer funds. In these situations, it is likely that alternative mitigations such as covered conductor — which is more cost-efficient and less terrain-dependent than undergrounding — should be utilized to rapidly and efficiently reduce risk. A plan that "substantially" reduces wildfire risk must take such alternative methods into account and prioritize them to the highest-risk locations.

As this discussion shows, the four prioritization criteria (wildfire risk reduction, public safety, cost efficiency, and reliability benefits) discussed in PU Code section 8388.5(c)(2) are interrelated. To determine if a utility is optimally reducing risk and improving reliability, Energy Safety should examine the impacts of a plan on public safety (which is generally highly correlated to wildfire risk) and cost-effectiveness (which directly influences the total mileage, and therefore the total risk, that a plan can address with a given budget).

Cal Advocates therefore recommends Energy Safety include public safety and cost efficiency in its evaluation of a plan to determine whether it substantially reduces risk and improves reliability.

2. Energy Safety should bridge the requirements of the Wildfire Mitigation Plan and the Risk-Based Decision-Making Framework with the SB 884 statute.

SB 884 does not require a utility to address the same risk considerations as the wildfire mitigation plan (WMP) requirements[22] or the Risk-Based Decision-Making Framework.[23] The absence of these requirements in SB 884 does not preclude Energy Safety from taking them into consideration. In fact, PU Code section 8388.5(f) requires utilities with an approved undergrounding plan to "include ongoing work plans and progress in annual wildfire mitigation plan filings."

There is a strong nexus between SB 884, WMPs, and general rate cases (GRC). The latter is the venue for consideration of whether a WMP's costs are just and reasonable.[24] Insofar as the Commission requires a risk assessment mitigation phase (RAMP) filing one year prior to a

[21] *See, e.g.*, Energy Safety, Revision Notice for PG&E's 2023-2025 WMP at 14-17.

[22] Public Utilities Code Section 8386(c)(12).

[23] Commission Decision (D.) 22-12-027, Appendix A.

[24] Public Utilities Code section 8386.4(b)(1).

utility's GRC application filing, the RAMP and GRC proceedings are inextricably linked.[25] Given the strong linkages among SB 884, WMPs, and the Risk-Based Decision-Making Framework, Energy Safety should evaluate the latter requirements and incorporate them into the forthcoming guidelines.

D. Metrics and targets for undergrounding plans

In September 2023, the Commission's Safety Policy Division published a Staff Proposal for the SB 884 program.[26] This proposal included a list of 18 required elements for an application submitted pursuant to PU Code section 8388.5(e).[27] It also included a proposed list of data requirements for undergrounding projects.[28]

Cal Advocates generally supports the proposed elements and recommends that Energy Safety adopt them as requirements for a utility's undergrounding plan, including the elements that consider cost, even though cost is not explicitly mandated as part of Energy Safety's review.[29] As discussed earlier in these comments, cost efficiency is a relevant metric to consider in project prioritization, and project prioritization is necessary to consider in the determination of whether a plan will "substantially" increase reliability and reduce wildfire risk.[30]

In addition, Cal Advocates recommends several changes to SPD's proposed plan elements.[31] We recommend Energy Safety adopt, at minimum, the following elements that we recommend to SPD:

- Utilities should provide testimony and workpapers supporting cost-benefit estimates, and should provide cost-benefit ratios for individual projects.[32] This will allow Energy Safety and stakeholders to perform an effective comparison of

[25] 8386(c)(12) and (13)

[26] CPUC Safety Policy Division, *Staff Proposal for SB 884 Program*, September 13, 2023 (Staff Proposal).

[27] Staff Proposal at 5-8.

[28] Staff Proposal at 13-16.

[29] Public Utilities Code Section 8388.5(d)(2).

[30] Public Utilities Code Section 8388.5(d)(2).

[31] Public Advocates Office, *Public Advocates Office's Informal Comments on the Staff Proposal for the SB 884 Program*, September 27, 2023 (Informal Comments on SPD Staff Proposal) at 7-11.

[32] Cal Advocates, Informal Comments on SPD Staff Proposal at 8-9.

undergrounding to alternative mitigations that takes into account project-specific variations.

- Utilities should employ reasonable and comparable assumptions in analyses of alternative mitigations.[33] As we have raised in comments on wildfire mitigation plans, utilities have sometimes used assumptions that do not lead to a fair and accurate comparison of alternatives.[34] To enable a true comparison of alternatives, Energy Safety should direct utilities to assume that each alternative mitigation (or combination of mitigations) would be performed in place of undergrounding and at the same scale. Each option would therefore benefit from similar cost reductions over time due to efficiencies, economies of scale, and new technologies.
- Utilities should provide information on all planned undergrounding projects, regardless of funding source.[35] While SB 884 plans might cover a large portion of a utility's undergrounding efforts, the utility may have other planned undergrounding projects that were approved through the most recent GRC or another venue. Energy Safety should direct utilities to include a complete list and a complete set of GIS data for all undergrounding projects, including those approved through a venue other than an SB 884 application. This holistic view will enable Energy Safety to evaluate the reliability and risk impacts of the plan in the context of the utility's broader wildfire mitigation work.

In addition to the requirements identified in SPD's Staff Proposal, Cal Advocates recommends that Energy Safety require utilities to provide both (1) the number of underground miles to be installed for a given project and (2) the number of *overhead miles to be removed*. The overhead mileage is necessary because the risk reduction of a project must be measured by the risk of assets *removed*, that is, the bare overhead mileage that is taken out of service. If utilities include this data, Energy Safety and stakeholders can perform a comprehensive analysis of the risk reduction associated with a proposed project, determine whether the projects are prioritized to the highest-risk locations, and ultimately determine whether the plan will substantially reduce wildfire risk.

IV. Other Issues

A. Energy Safety should adopt accelerated party discovery rules for undergrounding plans.

Pursuant to Public Utilities Code section 8388.5(d)(2), Energy Safety is required to

[33] Cal Advocates, Informal Comments on SPD Staff Proposal at 9-10.

[34] *See, e.g.*, Cal Advocates, May 2023 Comments on 2023 to 2025 WMPs of the Large IOUs at 15.

[35] Cal Advocates, Informal Comments on SPD Staff Proposal at 10.

approve or deny a utility's application within nine months. This is a short time period for review of plans that are likely to be voluminous, detailed, and consequential.

To promote transparency and the effective use of ratepayer resources, Energy Safety and parties should be able to perform thorough and detailed analyses of a utility's plan. To enable all parties to obtain essential facts and to understand the implications of each plan, Energy Safety should establish an accelerated timeline for discovery. Cal Advocates proposes Energy Safety adopt a discovery deadline of three business days, consistent with the timelines established in the WMP process.[36] The WMPs are an appropriate comparison, since they are also extensive plans that are reviewed on an expedited schedule.

It should be noted that, during WMP review, utilities often request extensions on the three-day deadline. Most of the time, stakeholders are able to accommodate those requests. As a result, three-day deadline functions as an expectation or baseline rather than an absolute rule. However, an expectation of accelerated discovery will ensure Energy Safety and parties can obtain sufficient information in a timely manner to analyze the safety and reliability impacts of a utility's undergrounding plan.

V. CONCLUSION

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

Respectfully submitted,

/s/ ***Darryl Gruen***

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November 2, 2023

[36] Office of Energy Infrastructure Safety, *2023-2025 Wildfire Mitigation Plan Process And Evaluation Guidelines*, December 6, 2022 at 12-13.

Appendix A: Comments on the Safety Policy Division's Staff Proposal

Title: Public Advocates Office's Informal Comments on the Staff Proposal for the SB 884 Program

Date: September 27, 2023

September 27, 2023 **Via Email to SB884@cpuc.ca.gov**

Danjel Bout, Director
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Subject: Public Advocates Office's Informal Comments on the Staff Proposal for the SB 884 Program

Dear Director Bout,

The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) respectfully submits the following informal comments on the Staff Proposal for the SB 884 Program. Please contact Nathaniel Skinner (Nathaniel.Skinner@cpuc.ca.gov), Program Manager, or Henry Burton (Henry.Burton@cpuc.ca.gov), Program and Project Supervisor, with any questions relating to these comments.

We respectfully urge the Safety Policy Division to adopt the recommendations discussed herein.

Respectfully submitted,

/s/ Darryl Gruen

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Table of Contents

I. INTRODUCTION

The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) provides these informal comments regarding Safety Policy Division's (SPD) *Staff Proposal for SB 884 Program* issued September 13, 2023 (Staff Proposal).

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 Proposal lends appropriate weight to these matters and imposes a number of 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 comments, we propose refinements to the Staff Proposal to maximize the public benefit of these plans, tighten accountability measures, and ensure all undergrounding expenditures are just and reasonable.

II. COST RECOVERY PROCESS

A. The Staff Proposal's approach to cost recovery is flawed.

The Staff Proposal urges a two-stage recovery process. In Phase 1, the Commission will review the submitted application for conditional approval.[1] Then the utility will execute undergrounding projects and record the actual costs in a memorandum account. Next, at Phase 2, the utility will seek cost recovery through tier 3 advice letters in connection with the execution of any conditionally approved plan, and that will entail an *ex post* reasonableness review of the recorded costs.[2] There are important flaws in the Staff Proposal's approach.

First, if the Commission the conditionally approves costs in Phase 1, that will blunt the utility's ongoing responsibility to prudently manage ratepayer funds. Once the Commission approves annual cost caps, the utility has zero incentive to reduce costs below the adopted cost caps. Instead, the utility will have a strong profit motive to spend as much as the Commission allows, rather than finding ways to effectively reduce costs.

Second, tier 3 advice letters do not provide adequate scrutiny for large cost recovery requests. As discussed in the next section of these comments, the advice letter process is an expedited review that is inappropriate for utility requests that are controversial, complex, or fact-dependent.[3]

B. SPD should require SB 884 applicants to request cost recovery through formal proceedings.

PG&E has proposed 10,000 circuit-miles of undergrounding over ten years. By PG&E's own unproven estimates, such a program will cost at least $20 billion, but more likely over $30

[1] Staff Proposal at 4.

[2] Staff Proposal at 4.

[3] General Order 96-B, Rules 5.1, 5.2, 7.4.1, and 7.4.2.

billion.[4]

The Staff Proposal states, "Phase 2 of the program will be initiated by a large electrical corporation filing a Tier 3 Advice Letter seeking recovery of recorded costs, to be disposed of by Commission Resolution."[5] The advice letter process is both inadequate and inappropriate for litigating the recovery of billions of dollars. As General Order 96-B states, "The advice letter process provides a quick and simplified review of the types of utility requests that are expected *neither to be controversial nor to raise important policy questions*."[6] As a rule, matters that do not fit this description belong in a formal proceeding.[7]

More specifically, reviewing the costs of SB 884 plans through an advice letter process is inappropriate for the following reasons:

- Recovery of SB 884 plan costs requires a determination that the costs are just and reasonable. Reasonableness is intrinsically a policy judgment and is frequently a controversial matter.
- Approving costs of the SB 884 plans will raise a variety of important policy questions, such as whether the utility has prudently selected projects in the places with the greatest wildfire risk, whether the utility has exercised prudent oversight to minimize the costs of undergrounding projects, whether ratepayer resources should be allocated to undergrounding or other public policy goals, and whether the costs will have a harmful impact on low-income customers.
- Approving SB 884 costs will undoubtedly provoke public controversy, because it is likely to have a large impact on customer bills.

Furthermore, the advice letter process is inappropriate for matters that involve factual disputes, because the advice letter process provides no venue (such as evidentiary hearings) for the Commission to adjudicate factual disputes.[8] Indeed, the existence of "material disputed facts" requires rejection of an advice letter.[9] This legal standard renders an advice letter

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[4] The Proposed Decision and the Alternate Proposed Decision in Application (A.) 21-06-021 (PG&E's general rate case), published on September 13, 2023, approve PG&E's estimated unit cost of $3.3 million per mile in 2023.

[5] Staff Proposal at 9.

[6] General Order 96-B, Rule 5.1 (emphasis added).

[7] General Order 96-B, Rules 5.1 and 5.2.

[8] "The advice letter process does not provide for an evidentiary hearing; a matter that requires an evidentiary hearing may be considered only in a formal proceeding." General Order 96-B, General Rule 5.1. See also, Rule 5.2(1).

[9] Pursuant to General Order 96-B, General Rule 7.6.1, Commission staff are *required* to reject advice letters that involve factual disputes or errors: "the Industry Division will … reject without prejudice an advice letter whose disposition would require an evidentiary hearing or otherwise require review in a formal proceeding." This rule must be read in conjunction with General Rules 5.1, 5.2, 7.4.1 and 7.4.2 of General Order 96-B.

Material disputed facts in an advice letter are justification to hold an evidentiary hearing in a formal proceeding: "If the protestant believes that the Commission should hold an evidentiary hearing, the protest must … identify material disputed facts and say why a hearing must be held." See Rule 7.4.1.

inappropriate in the present circumstances because it is highly likely that there will be material disputed facts regarding a request to recover SB 884 costs:

- Parties may disagree about whether the utility has satisfied all the conditions that the Commission adopts if it "conditionally approves" plan costs.[10]
- Factual disagreements are especially likely with respect to the cost-benefit ratios that the utility reports.[11] Estimating cost-benefit ratios is not mechanical or simple; these ratios will rely on risk models with numerous data inputs and sources of uncertainty.[12] Verifying the accuracy of the reported cost-benefit ratios will require examining the utility's calculations, understanding the utility's methodology, and auditing (or at least spot-checking) the accuracy of the input data. Parties may wish to present their own estimates of the cost-benefit ratios.
- Costs may be the easiest aspect of a cost recovery request to verify, but even so, the facts can be disputed. With billions of dollars at stake, there will be questions about whether the utility's accounts have been properly audited to eliminate accounting errors, double-counting, non-incremental costs, and other mistakes. Cal Advocates normally conducts discovery and audits for large cost-recovery requests; this due diligence often results in material factual disputes.
- PG&E has asserted that its undergrounding costs will decrease,[13] yet also states "there continues to be significant uncertainty and variability associated with wildfire mitigation activities and their associated costs."[14]

An important limitation of the advice letter process is that non-utility parties do not have an opportunity to present evidence or to offer alternative proposals – only to identify deficiencies in a utility's submission.[15] This is because, by definition, the facts should never be in dispute where an advice letter is concerned. Thus, as a matter of law, General Order 96-B unequivocally precludes using an advice letter (of any tier) to review the costs of SB 884 plans. Cal Advocates proposes alternative cost recovery venues below, each of which would provide a more robust process than a series of advice letters.

1. The Staff Proposal could allow each utility to seek cost recovery in its next general rate case (GRC).

GRCs offer a tried and true venue for the Commission to consider the recovery of large costs. General rate cases now include a dedicated track for requests to recover balances recorded

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Additionally, valid grounds for protest include that the advice letter either contains "material errors or omissions" or requests relief that "requires consideration in a formal hearing" (e.g., relief that can only be granted "after holding an evidentiary hearing, or by decision rendered in a formal proceeding"). See Rules 7.4.2 and 5.2.

[10] Public Utilities Code section 8388.5(e)(1).

[11] Staff Proposal at 7.

[12] For example, Cal Advocates noted several deficiencies in PG&E's risk-spend efficiency calculations in its most recent wildfire mitigation plan. *See*, *Comments of the Public Advocates Office on the 2023 to 2025 Wildfire Mitigation Plans of the Large Investor-Owned Utilities*, May 26, 2023 at 15.

[13] PG&E Reply Brief in A.21-06-021 at 362.

[14] PG&E Ex-04 at 4-23 in A.21-06-021.

[15] General Order 96-B, Rule 7.4.1. See also, Rule 7.4.2(3).

in memorandum accounts.[16] It would be straightforward and appropriate to address the recorded costs of SB 884 plans through this process.

In this scenario, the utility would seek recovery of the full amount of recorded plan costs in its next GRC, which would allow the Commission and parties sufficient opportunity for analysis and discovery to determine whether the utility's recorded expenditures during that four year period are just and reasonable. Cost recovery through the GRC would ensure that all costs undergo a transparent and accountable process.

2. The Staff Proposal could require cost recovery through periodic application proceedings.

A standard and appropriate mechanism for the recovery of large costs is a standalone application proceeding. This approach is used for energy resource recovery and wildfire expenses, among many other examples. An application venue would be appropriate to litigate (1) disagreement on the facts, (2) utility estimates of cost-benefit ratios, and (3) utility reasonableness and prudence. The prudence of utility management includes whether the utility has taken appropriate steps to minimize costs, to oversee contractors, to manage procurement and contracting processes, and to seek out and implement cost-saving techniques or technologies.

Cal Advocates proposes that each utility with an approved SB 884 plan be required to file a cost-recovery application every two years. These biennial applications should be scheduled to align with the GRC cycle: the applications would alternate between filing as part of the GRC (or a simultaneous filing to be consolidated into the GRC) and as a standalone application at the mid-point of the GRC cycle. Either venue would apply the Commission's well-established "just and reasonable" standard for cost recovery.[17]

3. Utilities could use other established procedural venues.

In addition to the options described above, participating utilities could seek recovery through other established cost-recovery proceedings. For example, utilities could seek recovery of SB 884 plan costs through wildfire mitigation and catastrophic event applications. Such application proceedings could be appropriate, as long as they provide a reasonable schedule to examine the prudence of the recorded costs and they follow the well-established "just and reasonable" standard for recovery of costs.

C. SPD should establish a Project and Procurement Review Group (PPRG) to improve oversight.

The Staff Proposal does not provide for reasonable oversight of utility spending.[18] SPD should improve the Staff Proposal by creating a Project and Procurement Review Group (PPRG),

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[16] For example, in PG&E's test year 2023 GRC proceeding, Track 2 addresses memorandum account balances. See A.21-06-021, *Assigned Commissioner's Scoping Memo and Ruling* at 12 and 14-15: "Track 1 will address the majority of matters presented in this proceeding, including PG&E's requested revenue requirement… Track 2 will address the narrower matters of the reasonableness of the 2019-2021 actual costs recorded in the named memorandum accounts and balancing accounts."

See also, Public Utilities Code section 8386.4(b)(1): "The commission shall consider whether the cost of implementing each electrical corporation's plan is just and reasonable in its general rate case application."

[17] Public Utilities Code section 451.

[18] Staff Proposal at 11.

modeled on the Procurement Review Groups that the Commission has established for energy efficiency.[19] PRGs can provide and improve transparency about whether and how utilities are managing ratepayer funds efficiently, which would help resolve the problems described in Section II.A. In the SB 884 context, the PPRG should review undergrounding projects and forecasted costs on an *ex ante* basis.

1. A PPRG benefits both ratepayers and utilities by averting mistakes and reducing financial risk.

Establishing a PPRG will serve public safety goals, ratepayer interests, and utility interests. A properly established PPRG is beneficial to all stakeholders because it will help the utility prevent mistakes and may reduce conflict over the prudence of projects and reasonableness of costs.

The function of a PPRG for SB 884 plans is to increase dialogue and transparency between the utility and interested stakeholders when undergrounding projects are at the planning and execution stages. This should reduce financial risk to the utility, because problems can be identified and disagreements addressed before the project is built and the money is spent.

In short, a PPRG is a venue for proactive problem-solving and oversight. By giving stakeholders meaningful input early in the process, the PPRG allows stakeholders to understand why the utility is implementing a specific set of projects in a given year and whether the utility is paying the right price for the job. This oversight should make the subsequent reasonableness reviews simpler and less contentious.[20]

2. A PPRG provides a quality assurance step between Phase 1 and Phase 2 of the Staff Proposal.

SPD should revise the Staff Proposal by adding a PPRG as an intermediate stage of oversight between conditional approval in an SB 884 application (Phase 1 in the Staff Proposal) and a cost recovery request (Phase 2). A PPRG can provide quality assurance between project planning and execution, because stakeholders can identify concerns and suggest corrections.

The PPRG's role should be to perform *ex ante* review of undergrounding projects before construction begins. The PPRG should be a group of stakeholders with relevant expertise, including Commission staff, Office of Energy Infrastructure Safety (Energy Safety) staff, other parties who choose to participate (such as Cal Advocates), and the independent monitor (IM) described in Public Utilities Code section 8388.5. Crucially, the IM supports all members of the PPRG by providing expertise and thorough analysis.

After obtaining conditional approval in Phase 1, the utility should submit small batches of projects to the PPRG for review. Each batch of projects should be homogeneous and limited in scope to allow for an efficient but diligent and effective review by the PPRG.[21]

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[19] See Decision 18-01-004, which established the structure and purpose of procurement review groups for energy efficiency programs.

[20] *Ex post* reasonableness reviews entail financial risk for the utility. The utility faces the risk of disallowances, which represent a loss of the capital invested.

[21] Each batch of projects should comprise no more than 10 projects and no more than 50 circuit-miles in total. All projects in a batch should be in the same work category (i.e., base hardening, fire rebuild, etc.), in the same region of the territory, and planned to begin construction in the within a year of each other. This is similar to how proposals are reviewed in the energy efficiency PRGs.

When the utility submits a batch of projects to the PPRG, the IM should first review the batch and prepare a report evaluating the prudence of moving forward. The IM should examine several issues, including whether forecasted costs for each project are reasonable and realistic, the accuracy of forecasted cost-benefit ratios, the adequacy of the utility's controls for managing project costs, and the prudence of the projects. These issues fall within the scope of the plan "objectives" noted in Public Utilities Code section 8388.5(g)(1), because delivering substantial public safety gains with just and reasonable costs is among the fundamental objectives of any SB 884 plan. Therefore, analyzing these issues is within the scope of the IM's statutory responsibilities.

After the IM provides its report, the utility should meet with the PPRG to explain the merits of the batch of projects. PPRG members will be able to ask questions, clarify points of uncertainty, and potentially recommend improvements. The utility should then submit a tier 2 advice letter to the Commission that seeks approval to proceed with the batch of projects.[22] The IM's report would be attached to the advice letter, along with written feedback to the utility from any PPRG members who choose to provide it.

A well-designed PPRG will reduce conflict over *ex post* reasonableness reviews in Phase 2, because it can help the utility avoid mistakes and or control spending in advance. The IM's involvement is critical because the IM's report should facilitate informed discussions and efficient action.

D. Safety Policy Division should make improvements to accounting in memorandum accounts.

Undergrounding plans are likely to result in billions of dollars of annual expenditures related to a large number of undergrounding projects. The Staff Proposal states that these costs will be tracked "in a memorandum account or similar means as determined in the Commission's decision on the Application."[23] Cal Advocates recommends that SPD remove the underlined text and adopt memorandum accounts as the cost recording tool. To improve accountability, SPD should additionally adopt several improvements to these memorandum accounts.

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.

The utility should additionally track when each project becomes used and useful (e.g., when the underground infrastructure is operational). In keeping with longstanding practice for capital expenditures, a utility should only seek full cost recovery for projects that are used and useful.[24] Ratepayers should not pay for underground infrastructure that is incomplete.

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[22] This is an appropriate use of the advice letter process because any disagreements between the utility and the PPRG members are likely to revolve around whether the utility is properly following the requirements that the Commission will establish in the prior application proceeding (Phase 1) and other legal requirements – in particular, whether the utility's planned projects are reasonable and prudent.

[23] Staff Proposal at 11 (emphasis added).

[24] It is possible that subparts of large projects may become used and useful before the entire project is

III. APPLICATION REQUIREMENTS

A. Cal Advocates supports the detail and scope of the Staff Proposal's application requirements.

The proposed application requirements in the Staff Proposal set reasonable expectations for a utility's SB 884 application for conditional cost recovery.[25] Cal Advocates supports the level of detail these requirements set for an application. We endorse the following key requirements:

- Requirements #1 and #2 appropriately direct the utility to provide all documentation necessary to evaluate proposed costs and cost forecasts for each year of the 10-year period. These requirements comport with the "just and reasonable" standards for cost recovery set in Public Utilities Code section 451.[26]
- Requirement #3 appropriately directs the utility to identify undergrounding targets and cost forecasts that are currently under consideration in another cost recovery venue or were previously disallowed by the Commission. Undergrounding plans have been discussed at length in both wildfire mitigation plans and recent GRCs, and may become relevant to other proceedings during the ten years of a utility's plan. This requirement will discourage possible "forum shopping" for recovery of costs that the Commission has elsewhere found unjustified. Requirement #3 will also help protect against the risk of double counting. If the Commission has another proceeding that considers overlapping undergrounding targets or cost targets, the Commission can more easily identify such overlap if it is clearly identified in the SB 884 application.
- Requirement #4 appropriately directs the utility to provide annual revenue requirements and ratepayer impacts. Undergrounding costs are likely to amount to tens of billions of dollars over the 10-year plan period and may have substantial effects on electricity rates. This requirement promotes transparency as to the short-term and long-term effects that these capital-intensive undergrounding plans will have on ratepayers. This requirement will better inform the Commission and stakeholders about whether the expected ratepayer impacts comport with the Commission's affordability and equity principles.
- Requirements #9 and #10 appropriately direct utilities to calculate cost-benefit ratios, as defined in Commission Decision (D.) 22-12-0276. This adopts a standard metric that will likely be utilized in multiple proceedings, which improves transparency.
- Requirements #12 and #13 appropriately direct utilities to provide detailed data for each undergrounding project, which comports with the direction and clear

finished, in which case the utility could seek recovery of costs for the portion of the project that is used and useful.

[25] Staff Proposal at 5-8.

[26] "All charges demanded or received by any public utility, or by any two or more public utilities, for any product or commodity furnished or to be furnished or any service rendered or to be rendered shall be just and reasonable. Every unjust or unreasonable charge demanded or received for such product or commodity or service is unlawful."

intent of SB 884.[27]

B. The utilities should provide greater support for forecast cost savings.

1. The Staff Proposal should be modified to require utilities to provide analyses and workpapers to support forecast unit cost reductions (requirements #7 and #8).

The Staff Proposal directs utilities to explain how cost targets are expected to decline, and to describe a strategy for achieving cost reductions over time.[28] PG&E has frequently claimed that undergrounding costs will decline over time. So far, though, PG&E's explanations for forecast cost reductions (notably in its wildfire mitigation plans and its GRC application) have been vague and unsupported.[29]

The Staff Proposal should require utilities to provide quantitative analyses that comply with D.22-12-027 or its successor—including relevant workpapers—to support its explanations for all forecast cost reductions that are expected to result from efficiencies, economies of scale, new technologies, and any other factors. The utility should clearly describe its methods and assumptions used in developing these analyses.

2. The Staff Proposal should require utilities to identify increased, accelerated, or new costs associated with undergrounding (requirement #5).

The Staff Proposal states that utilities shall identify forecast costs that will be "reduced, deferred, or avoided because of implementing the proposed undergrounding plan."[30] While utilities have argued that vegetation management costs are likely to be lower for an underground segment compared to an overhead segment, it is possible that other costs may be higher, incurred faster, or unique to underground infrastructure. This may include, for example, the costs to repair an underground line. The Staff Proposal should therefore direct utilities to provide an analysis of reduced or increased, deferred or accelerated, and avoided or newly incurred forecast costs.

C. Utilities should provide improved justification for project selection.

1. The Staff Proposal should require utilities to provide testimony and workpapers supporting cost-benefit estimates, and to

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[27] Public Utilities Code section 8388.5(c) clearly requires utilities to identify specific undergrounding *projects* rather than general mileage targets.

[28] Staff Proposal at 7.

[29] *See, e.g.*: A. 21-06-021, *Proposed Decision On Test Year 2023 General Rate Case For Pacific Gas And Electric Company*, September 13, 2023 at 265-266. "PG&E's arguments that costs will decline during this rate case period are not persuasive."

Comments of the Public Advocates Office on the 2023 to 2025 Wildfire Mitigation Plans of the Large Investor-Owned Utilities, May 26, 2023 at 16-17. "PG&E states that its forecasts are not based on any specific calculation; it merely represents a 'strategy to reduce unit costs over time.' In other words, PG&E's forecasts are not based on a quantitative analysis of prices and supply chains: they are an unsupported projection. PG&E's failure to plan has already resulted in an 11 percent increase in estimated costs."

[30] Staff Proposal at 6.

provide cost-benefit ratios for individual projects (requirements #9 and #10).

The Staff Proposal directs utilities to calculate cost-benefit ratios for both the undergrounding plan and for all alternative mitigations, including combinations of mitigations.[31] For transparency, utilities should be required to provide *testimony and workpapers* regarding its cost-benefit ratio estimates. The testimony should describe the utility's methods for calculating all cost-benefit ratios, the risk model used, the data inputs, important assumptions, and the key sources of uncertainty in the estimates.

For alternative mitigations, the Staff Proposal only requires average cost-benefit ratios for each year of the plan. This should be revised because an overall, annual estimate does not support the selection of specific projects. Local circumstances can dramatically affect the cost, implementation time, and cost-benefit ratio of undergrounding projects. To effectively compare undergrounding to alternative mitigations, the analysis of alternatives must be performed at the project level, not merely at the aggregate level. Moreover, SB 884 requires such a project-level analysis.[32]

Additionally, the Staff Proposal does not clarify the time period over which a utility should calculate the benefit and cost of undergrounding and alternative mitigations. For example, should the benefit and cost of projects be calculated for a single year, over the 10-year plan period, or over the lifetime of the new assets? For consistency and transparency, the Staff Proposal should set clear requirements in this regard.

2. The Staff Proposal should require utilities to employ reasonable and comparable assumptions in analyses of alternative mitigations (requirements #10 and #11).

The Staff Proposal directs utilities to analyze the cost-benefit ratios, safety impacts, and cost impacts of "alternative wildfire mitigation measures, including combinations of alternative measures."[33] This raises the issue of what assumptions may be used to make this analysis.

Utilities have sometimes used assumptions that do not lead to a fair and accurate comparison of alternatives. In its 2023-2025 WMP, PG&E's comparison of overhead and underground system hardening assumed that the efficiency of undergrounding would increase over time, while the efficiency of covered conductor would decrease over time.[34] These assumptions arose from the utility's plan to increase undergrounding mileage and to decrease covered conductor mileage.[35] In other words, PG&E had pre-determined its preferred mitigation strategy, used that strategy to influence its efficiency calculations, and then used those

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[31] Staff Proposal at 7.

[32] Public Utilities Code section 8388.5(c)(4) requires a utility's plan to include "a comparison of undergrounding versus aboveground hardening … or any other alternative mitigation strategy… for those prioritized undergrounding projects." This provision clearly calls for a comparison of alternatives at the *project* level.

[33] Staff Proposal at 7.

[34] *Comments of the Public Advocates Office on the 2023 to 2025 Wildfire Mitigation Plans of the Large Investor-Owned Utilities*, May 26, 2023 at 15.

[35] *Comments of the Public Advocates Office on the 2023 to 2025 Wildfire Mitigation Plans of the Large Investor-Owned Utilities*, May 26, 2023 at 15.

calculations to justify its pre-determined choice of mitigation measure. It is neither reasonable nor accurate to influence efficiency calculations in this manner, as doing so makes a true apples-to-apples comparison of alternative mitigations impossible.

The Staff Proposal should therefore direct utilities to assume that each alternative mitigation (or combination of mitigations) would be performed in place of undergrounding and at the same scale. Each option would therefore benefit from similar cost reductions over time due to efficiencies, economies of scale, and new technologies.

Lastly, the Staff Proposal should require the utility to provide testimony and workpapers to support its comparative analyses. As in the previous section of these comments, the testimony regarding analysis of alternatives should describe the utility's analytical methods, the risk model used, the data inputs, important assumptions, and the key sources of uncertainty in the estimates.

D. Utilities should provide comprehensive undergrounding project data.

1. The Staff Proposal should require utilities to provide information on all undergrounding projects, regardless of funding source (requirements #12 and #13).

The Staff Proposal appropriately directs utilities to provide substantial data for each project in the approved plan. While SB 884 plans might cover a large portion of a utility's undergrounding efforts, the utility may have other planned undergrounding projects that were approved through the most recent GRC or another venue.

To provide Energy Safety, the Commission, and stakeholders a holistic view of a utility's undergrounding efforts, the Staff Proposal should direct utilities to include a complete list and a complete set of GIS data for *all* undergrounding projects, including those approved through a venue other than an SB 884 application. This list should note the funding source for each project. The GIS data should clearly identify which undergrounding projects are to be funded through SB 884 and which are not.

This complete project list would provide all stakeholders a transparent view into which projects were funded and approved under various proceedings, would prevent a utility from seeking double recovery (either intentionally or inadvertently), and would ensure that projects are not moved between funding streams. (For example, if the costs for an SB 884 project were to exceed projections, a utility might want to remove that project from its SB 884 plan and instead fund it through its GRC.)

To provide the holistic and accurate view described above, it is essential to obtain complete and comparable data on all undergrounding projects that a utility is undertaking during the period of its SB 884 plan. The Staff Proposal should include a new field in Appendix 1 to denote the funding source for each project (e.g., SB 884 application, GRC specifying test year, WMP approval with costs tracked in a memorandum account, Rule 20, or other).

As noted in section VI.A of these comments, the project list should be updated regularly as part of a utility's 6-month progress reports.

E. Utilities should identify non-ratepayer funding.

1. The Staff Proposal should require utilities to file biennial reports regarding non-ratepayer funding sources (requirements #14 through #17).

The Staff Proposal appropriately directs utilities to provide comprehensive details

regarding non-ratepayer funds for which they have applied.[36] However, the Staff Proposal does not require ongoing documentation throughout the ten-year period that the utility has continued to seek non-ratepayer funding. To fill this gap, the Staff Proposal should require utilities to submit a progress report to the Commission at least every other year on its success in obtaining third-party funds, which should include the same data listed in requirements #14-16, and an updated attestation as described requirement #17. Such continuous efforts are required by SB 884.[37]

IV. CONDITIONAL APPROVAL

A. SPD should set strict caps on total cost, unit cost and cost-benefit ratio requirements for every individual year.

The Staff Proposal includes strict caps on total cost, unit cost, and cost-benefit ratios.[38] These conditions are important to limit the impact to ratepayers if a utility's forecasts are inaccurate, and to ensure that utilities have achieved an appropriate level of risk reduction through its plan.

SPD can strengthen the Staff Proposal by clarifying that the caps for costs and cost-benefit ratios will be set for every individual year, not just a single value for the duration of the plan. This appears to be the intent of the Staff Proposal, but it could benefit from clarification.[39] Targets for each year will hold a utility accountable to its forecast unit cost decreases (by imposing lower caps on unit costs in later years) and can be used to direct a utility to prioritize high-risk locations (by requiring higher cost-benefit ratios in the early years of the plan).

V. PROCEDURAL REQUIREMENTS

A. The Staff Proposal should accelerate party discovery.

Pursuant to Public Utilities Code section 8388.5(e)(5), the Commission is required to approve or deny a utility's application within nine months. This is a short time period for review of plans likely to cost ratepayers billions of dollars. Moreover, the plans are likely to be voluminous and detailed.

To promote transparency and effective use of ratepayer resources, the Commission and parties must be able to perform thorough and detailed analyses of a utility's application. To enable all parties to obtain essential facts and to understand the implications of each plan, the Commission should establish an accelerated timeline for discovery. Cal Advocates proposes the Commission adopt a discovery deadline of three business days, consistent with the timelines established in the WMP process at Energy Safety.[40] The WMPs are an appropriate comparison, since they are also large and expensive plans that are reviewed on an expedited schedule.

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[36] Staff Proposal at 8.

[37] Public Utilities Code section 8388.5(j) requires utilities to "apply for available federal, state, and other nonratepayer moneys *throughout the duration* of its approved undergrounding plan, and any moneys received as a result of those applications shall be used to reduce the program's costs on the large electrical corporation's ratepayers." (Emphasis added.)

[38] Staff Proposal at 8-9.

[39] Staff Proposal at 8-9: Conditions for Approval # 1, #3, and #5 include the words "for that year."

[40] Office of Energy Infrastructure Safety, *2023-2025 Wildfire Mitigation Plan Process And Evaluation Guidelines*, December 6, 2022 at 12-13.

Recently, the WMP review process has taken four to twelve months from initial submission to final approval by the Energy Safety.[41]

B. The Staff Proposal should incorporate a pre-submission period during which Energy Safety and SPD verify the utility's compliance with the application requirements.

The Staff Proposal implements the legislature's expedited timeline of nine months for Commission consideration of an application and establishes application requirements. The Staff Proposal should incorporate a pre-submission period during which both Energy Safety and SPD can review the utility's compliance with the requirements. After conducting a completeness review, the two agencies should notify the utility of any deficiencies with the pre-submission version. After the agencies approve the pre-submission version, the utility can submit its plan to Energy Safety and the review clock will start.

Energy Safety employs a pre-submission to verify completeness in its reviews of wildfire mitigation plans, and it has proven to be useful for correcting errors and omissions. By fixing problems at the beginning of the process, the pre-submission process helps reduce the need for time-consuming corrections (or rejections of a plan) later in the process. For example, in 2022, Energy Safety rejected two wildfire mitigation plans due to incompleteness, but after the pre-submission process was adopted in 2023, there were no comparable rejections.[42]

C. The Staff Proposal should clarify the interagency coordination between the Commission and Energy Safety.

The Staff Proposal states that Energy Safety will review a utility's undergrounding plan to determine whether it will substantially increase reliability and substantially reduce wildfire risk. Following Energy Safety's approval of the plan, the Commission will review a utility's application for cost considerations.[43]

While the Public Utilities Code is clear on this division of authority, it is possible that, during the Commission's review of an application, the Commission may find the utility's proposed costs to be unreasonable. This would necessarily render the plan itself also unreasonable. While the Commission has the option to require a utility to modify and resubmit its application, it is unclear how the Commission would coordinate with Energy Safety, whose own review of the plan would already be complete at this point.

To remove ambiguity, SPD should modify the Staff Proposal to describe the interagency

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[41] For example, in 2022, the large utilities made their initial WMP submissions on February 25, 2022. Energy Safety issued final decisions four to eight and a half months later (July 5 for SDG&E, July 20 for SCE, and November 10 for PG&E).

In 2023, the large utilities made their initial WMP submissions on February 13, 2023. Energy Safety is likely to issue final decisions on SCE's and SDG&E's WMPs in October or November. OEIS intends to issue a final decision on PG&E's WMP on December 29, 2023 (ten and a half months after the initial submission).

[42] See, *Office of Energy Infrastructure Safety Issuance of Rejection for Incompleteness and Order to Resubmit for Liberty Utilities' 2022 Wildfire Mitigation Plan Update,* and *Office of Energy Infrastructure Safety Issuance of Rejection for Incompleteness and Order to Resubmit for PacifiCorp's 2022 Wildfire Mitigation Plan Update*, both issued June 15, 2022 in docket 2022-WMPs.

[43] Staff Proposal at 5.

coordination that will occur between Energy Safety and the Commission. A reasonable way to address this coordination would be to state that, as part of the Commission's authority to require a utility to modify its application, the Commission may require modification of the SB 884 plan if it finds the costs to be unreasonable. Following such modification, Energy Safety would perform a second review of the plan's safety and reliability impacts.

To ensure that Energy Safety is able to complete a reasonably diligent review, any substantive modification of a utility's plan should restart the clock on the statutory 9-month application review period.[44]

D. The Staff Proposal should describe parameters for orders to modify or resubmit a plan.

SB 884 did not specify how the Commission's timeline would be affected by a Commission order to the utility to modify its application. The Staff Proposal states that the timeline would not restart for a modification, only for a resubmission.[45] The Staff Proposal should set criteria for modification or resubmission.[46] The Staff Proposal should list *substantive* issues that would require a modification and resubmission (restarting the nine-month clock) and *non-substantive* issues that would require only a modification (not restarting the clock).

VI. PROGRESS REPORTS

A. The 6-month progress reports should include updated project lists.

The Staff Proposal lists nine reasonable elements that utilities shall include in their 6-month progress reports.[47] Cal Advocates supports these items, which provide necessary information to Energy Safety, the Commission, and the public in order to evaluate a utility's progress and compliance with its SB 884 undergrounding plan.

We recommend one addition to allow a more granular analysis of a utility's progress and compliance: these progress reports should include an updated project list containing the updated information that meets requirement #12 in the application.[48] In the progress reports, the updated project list should only change the "status" field; any other change should go through a formal plan update process (discussed further in section VII.B of these comments). As noted earlier (section III.D.1), this updated project list should provide a holistic view of the utility's undergrounding program by including *all* undergrounding projects, regardless of funding source.

B. The Staff Proposal should specify whether and how the 6-month progress reports will be reviewed and approved.

The Staff Proposal lists the elements to be included in the progress reports but does not specify which division will review the progress reports, whether the reports are subject to an approval process, whether the Commission will use the reports to assess a utility's compliance with the decision approving its application, or whether public comments will be accepted.

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[44] Staff Proposal at 4.

[45] Staff Proposal at 2.

[46] Staff Proposal at 5, section "Application Conditional Approval, Denial, or Modification & Resubmittal."

[47] Staff Proposal at 10.

[48] Staff Proposal at 7.

Since the progress reports are to be filed with both the Commission and Energy Safety,[49] SPD should coordinate with Energy Safety regarding the items listed above. Following such coordination, either Energy Safety or SPD should publish a draft staff proposal to outline the process for review and approval of the 6-month progress reports. The agencies should accept informal comments on this staff proposal, and the proposal should be completed and adopted by the Commission before any utility files an SB 884 application to the Commission.

VII. AREAS FOR ADDITIONAL POLICY DEVELOPMENT

A. SPD should issue additional guidelines on compliance matters.

Public Utilities Code section 8388.5(i)(2) states that the Commission may assess penalties on a utility if it fails to substantially comply with a Commission decision approving its plan. Neither the Code nor the Staff Proposal describe how the Commission will determine noncompliance, or what penalties the Commission may impose.

One area of particular concern is the role of the independent monitor (IM). Utilities will retain an IM who will submit annual compliance reports to Energy Safety.[50] While Energy Safety may recommend penalties to the Commission based on these reports,[51] it is unclear to what extent the Commission will review the IM's report and how the report will inform the Commission's evaluation of cost recovery requests. For example, will cost recovery applications be timed to follow the IM reports? Will the IM's findings be entered into the evidentiary record of Commission proceedings? Will penalties primarily consist of denial of cost recovery or penalties levied under Public Utilities Code section 2107? Will the Commission consider other actions under its Enforcement Policy or will the Commission consider an expanded Enhanced Oversight and Enforcement Process?[52]

SPD should augment the Staff Proposal with additional guidelines on compliance issues. To this end, SPD should accept informal comments on compliance issues related to SB 884 and develop a draft staff proposal. SPD should then convene a workshop focused on the draft staff proposal and take public comments. These compliance guidelines should be completed and adopted by the Commission before any utility files an SB 884 application to the Commission.

B. The Staff Proposal should describe a process for updates to a utility's SB 884 plan after a decision in Phase 1 of the application is issued.

The Staff Proposal identifies conditions that will apply as part of the Commission's "conditional approval" of plan costs. These conditions appear to allow a utility to change its risk model and consequently update the list of remaining projects.[53] However, the Staff Proposal does not include a process for managing changes to risk models, which could have substantial effects on project selection and prioritization.

The Staff Proposal also does not list other provisions that may warrant updating an

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[49] Staff Proposal at 10.

[50] Public Utilities Code section 8388.5(f)(3) and section 8388.5(g)(3).

[51] Public Utilities Code section 8388.5(i)(1).

[52] The enhanced oversight and enforcement process was adopted in Decision 20-05-053 and currently applies only to PG&E.

[53] Staff Proposal at 9 (condition for approval #4) and 12 (consequences for failure to satisfy conditions of approval #4).

approved SB 884 plan. There are many reasons why a utility may need to update its plan, including an evolving understanding of risk, updated feasibility studies, new technologies that make alternative mitigations more appealing, the emergence of new rebuild areas due to future disasters, and other unforeseen events. The ability to update a plan is important to avoid locking a utility into undergrounding projects that, due to evolving circumstances, may no longer be in the best interests of customers and the public.

It is also important to minimize unnecessary changes to a utility's plan. Frequent updates to address temporary circumstances or marginal changes to a risk model could create confusion and impose undue burdens on the Commission, Energy Safety, parties, and the public.

The Staff Proposal should be modified to state that the Commission and Energy Safety will jointly develop a process to allow for utilities to update SB 884 plans. These update guidelines should address the following, at a minimum:

- A review process for Energy Safety to evaluate the safety and reliability impacts of the updated plan,[54]
- A review process for the Commission to assess and conditionally approve the costs of the updated plan,[55]
- Whether and how updated plans and project lists would be made available for public review and comment prior to implementation,
- How frequently and at what times a utility can update its plan,
- A list of circumstances that could warrant an update,[56]
- A list of circumstances that do *not* warrant an update,
- Guidance for the kind of summary utilities should provide to explain that the updated plan complies with SB 884, to explain the circumstances that merit the updated plan, and to provide reasonable data to support these explanations.

SPD should develop and publish guidelines on plan updates in a separate staff proposal. SPD should then convene a workshop focused on the draft staff proposal and take public comments. The updated guidelines should be finalized and adopted by the Commission prior to the submission of the first SB 884 plan to Energy Safety.

VIII. CONCLUSION

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

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[54] Per Public Utilities Code section 8388.5(d)(2), Energy Safety "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."

[55] Pursuant to the Commission's responsibility and authority in Public Utilities Code section 8388.5(e)(1).

[56] Pursuant to Public Utilities Code sections 8388.5(d)(2) and 8388.5(e)(1)(A), an updated plan should substantially increase electrical reliability, substantially reduce the risk of wildfire, and substantially reduce the cost compared to other hardening and risk mitigation measures.