January 8, 2024

Via Electronic Filing

Caroline Thomas Jacobs, Director
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California Natural Resources Agency
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Subject: **Development of Guidelines for the 10-Year Undergrounding Distribution Infrastructure Plan (Undergrounding Plan)**

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 the development of guidelines for the 10-year Undergrounding Distribution Infrastructure Plan (Undergrounding Plan). 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.

Respectfully submitted,

/s/ Darryl Gruen

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TABLE OF CONTENTS

I. INTRODUCTION

Pursuant to the Office of Energy Infrastructure Safety's (Energy Safety) December 13, 2023 memorandum to stakeholders (December Comment Letter),[1] the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) submits these comments about the development of guidelines to implement Senate Bill (SB) 884 (McGuire, Statutes of 2022).[2] Pursuant to the December Comment Letter, comments are due by January 8, 2024. Reply comments are due January 18, 2024.

SB 884 authorizes large electric utilities[3] (utilities) to submit ten-year plans to underground distribution lines. The bill leaves discretion to Energy Safety and the California Public Utilities Commission (CPUC or Commission) regarding implementation, such as the specifics of what must be included in the plan, the review and approval process, and accountability measures.

Energy Safety conducted outreach to stakeholders, including a joint public workshop with the CPUC in February 2023 and five public working group meetings held over the past two months. In October, Energy Safety invited stakeholder input on topics for the working group meetings.[4] Cal Advocates filed comments on those topics on November 2, 2023.[5] At the conclusion of the working groups, Energy Safety invited stakeholders to file comments on these topics and the guidelines generally.[6]

Cal Advocates has engaged with Energy Safety staff regarding the implementation of SB 884 since early December 2022. We look forward to further opportunities, beyond these

[1] Energy Safety, *Memorandum to Stakeholders regarding Dates for Additional Comments for the Development of Guidelines for the 10-Year Undergrounding Distribution Infrastructure Plan (Undergrounding Plan)*, December 13, 2023, in docket 2023-UPs (December Comment Letter).

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

[3] Many of the Public Utilities Code requirements relating to wildfires apply to "electrical corporations." See, e.g., Public Utilities Code section 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] 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, October Comment Request Questions) at 2.

[5] Public Advocates Office, *Public Advocates Office's Comments on Undergrounding Plan Guidelines*, November 2, 2023 (Cal Advocates, November Comments on Working Group Topics).

[6] December Comment Letter.

comments, to constructively engage with Energy Safety staff, share ideas, and develop effective policies.

II. KEY PRINCIPLES FOR IMPLEMENTATION OF SB 884

Cal Advocates, in a letter sent with The Utility Reform Network (TURN) and Mussey Grade Road Alliance (MGRA) (Joint Advocates) to CPUC Commissioners and Energy Safety Director Thomas Jacobs on April 26, 2023, offered five key policy principles to guide implementation of SB 884:

1. An undergrounding project should only be authorized for rate recovery when the utility has demonstrated that, compared to all other wildfire mitigation alternatives, it represents the best choice for the project location.
2. Undergrounding should be prioritized for the highest-risk locations, where it is most cost-effective given Commission-defined safety goals.
3. Decisions about whether to approve cost-recovery for particular undergrounding projects should be based on up-to-date, location-specific information for risks, costs, and alternative mitigations.
4. Utilities must be accountable for their promises regarding reductions in undergrounding costs and cost savings from undergrounding.
5. The scope of undergrounding projects approved for rate recovery must reflect bedrock ratemaking considerations such as affordability, the competing demands on ratepayer funds, the effect of elevated electric rates on achieving electrification objectives, and environmental and social justice goals.[7]

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[7] Cal Advocates, The Utility Reform Network, and Mussey Grade Road Alliance, *Letter to the California Public Utilities Commission and Office of Energy Infrastructure Safety re: Implementation of Senate Bill 884 – Ten-Year Undergrounding Plans*, (Cal Advocates, TURN and MGRA, April 2023 Letter to CPUC and Energy Safety on SB 884) April 26, 2023 at 2 and Appendix A.

These key principles underlie Cal Advocates' instant comments, as well as other comments to Energy Safety and the Commission in 2023.[8] These principles also underlie our positions expressed during the working group meetings in November and December 2023. The instant comments focus on the essential elements that Energy Safety should include in its guidelines to ensure that the SB 884 program meaningfully reduces wildfire risks at a just and reasonable cost. We specifically comment on risk mitigation alternatives, changes to approved plans, cost savings, the role of independent monitors, cost containment, and economies of scale.

Section VII recommends language that Energy Safety should include in its instructions to utility applicants regarding the required elements of an acceptable SB 884 plan.

III. RISK MITIGATION ALTERNATIVES

Working group meeting 2 considered issues regarding alternatives to undergrounding, including how risk mitigation strategies could be combined and how the costs of alternatives should be estimated.[9]

A. Energy Safety should set reasonable standards for comparisons of undergrounding to other wildfire mitigation strategies.

Public Utilities (PU) Code section 8388.5(c)(4) requires utilities to develop a comparison of undergrounding to other mitigation strategies (such as covered conductor or Ground-Level Distribution Systems)[10], and to evaluate the scope, cost, extent, and risk reduction of each of

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[8] Public Advocates Office, *Memorandum to the Office of Energy Infrastructure Safety re: Initial SB 884 Workshops Proposal*, January 19, 2023.

Public Advocates Office, *Memorandum to Safety Policy Division and the Office of Energy Infrastructure Safety re: Scope of Issues for an SB 884 Rulemaking*, February 21, 2023.

Public Advocates Office, *Informal comments of the Public Advocates Office on workshop regarding Senate Bill 884,* March 10, 2023.

Public Advocates Office, *Public Advocates Office's Informal Comments on the Staff Proposal for the SB 884 Program*, September 27, 2023.

Public Advocates Office, *Informal comments on workshop schedule and topics*, October 23, 2023.

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

Cal Advocates, *Public Advocates Office's Comments on Draft Resolution SPD-15 and the Staff Proposal for the SB 884 Program*, (Cal Advocates, Comments on Draft Resolution SPD-15), December 28, 2023.

[9] Energy Safety, *Memorandum to Stakeholders regarding Working Group #2 Topics*, November 7, 2023, in docket 2023-UPs at 2.

[10] PG&E Currents, December 20, 2023. "Neither Overhead nor Underground, PG&E Pilot Program

these alternative strategies.[11] This comparison is necessary to evaluate whether utilities propose the most appropriate wildfire mitigation strategy for each location, rather than defaulting to undergrounding.[12] To maximize the usefulness of these comparisons to Energy Safety and stakeholders, Energy Safety should adopt reasonable standards for the wildfire mitigation strategy comparisons included in a utility's SB 884 plan.

1. Energy Safety should prescribe specific wildfire mitigation strategies and metrics that utilities must consider in their SB 884 plans.

Energy Safety should require utilities to analyze, at minimum, the following three scenarios for each project location:

- Business as usual. This should assume ongoing operational mitigations[13] and vegetation management similar to what the utility currently employs (or reasonably expects to employ within 10 years), with no system hardening.
- Overhead hardening. This should include a combination of covered conductor and any operational mitigations the utility currently employs (or reasonably expects to employ within 10 years).
- Undergrounding.

The three scenarios or strategies outlined above include a baseline level of risk and reliability, as well as two common and effective system hardening strategies. A utility should include any additional system hardening strategies beyond these three that it believes may be appropriate for a given location.

To allow Energy Safety and stakeholders to accurately analyze and assess each strategy, Energy Safety should direct the utilities to provide the following metrics for each mitigation strategy:

Evaluates the Benefits of Putting Powerlines Right on the Ground." https://www.pgecurrents.com/articles/3901-overhead-underground-pg-e-pilot-program-evaluates-benefits-putting-powerlines-right-ground

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

[12] "Since late 2021, PG&E has prioritized undergrounding as the preferred approach to reduce the most system risk." PG&E, 2023-2025 Wildfire Mitigation Plan R3, September 27, 2023 at 401-402.

[13] The term "operational" mitigations typically refers to technologies that rapidly de-energize or reduce the electrical current on a line to prevent ignition. This can include fast-trip recloser settings, rapid earth-fault current limiters, downed-conductor detection, and more.

- Physical details of the mitigation strategy, such as the number of overhead miles to be hardened and the number of undergrounding miles to be installed.
- The estimated lifetime cost of implementing the mitigation strategy, disaggregated into capital and operating expenditures.
- The estimated lifetime benefit of implementing the scenario, calculated pursuant to the method adopted in Decision (D.) 22-12-027 in Rulemaking (R.) 20-07-013.[14]

2. Energy Safety should require utilities to analyze wildfire mitigation strategies using location-specific data.

Energy Safety should direct utilities to analyze each wildfire mitigation strategy it uses from section A.1 for each proposed project location, using location-specific data.[15] Location-specific data is critical because wildfire risk levels vary widely across a utility's service territory. Up to now, utilities have not provided estimated costs and benefits using location-specific data, and instead have sought to provide this data aggregated to (for example) the circuit or circuit-segment level.[16]

Such aggregated data is not sufficient for Energy Safety, the Commission, or stakeholders to analyze the costs and estimated benefits of proposed projects. A circuit segment can vary in size from just a few feet long to well over one hundred miles,[17] and may contain numerous smaller projects.[18]

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[14] Commission Decision (D.) 22-12-027 in Rulemaking (R.) 20-07-013, Ordering Paragraph 1 and Appendix A adopted a cost-benefit ratio (CBR).

[15] "Location-specific data" includes, but is not limited to, terrain, vegetation density, ingress and egress risks, site accessibility for equipment, etc.

[16] *See, e.g.*, PG&E, *Pacific Gas and Electric Company's Comments on Safety Policy Division Staff's Proposal for the Senate Bill 884 Expedited Undergrounding Program*, September 27, 2023 at 12: "The net benefit of each of the three sub-projects is the same as the net benefit of its CPZ [circuit protection zone] because PG&E's risk model measures risk at the CPZ level. While PG&E executes projects at the sub-project level, PG&E can only report risk reduction, and therefore net benefits, at the CPZ level."

In its final decision on PG&E's 2022 WMP, Energy Safety required PG&E to "Evaluate all alternatives to undergrounding, both as individual mitigations as well as combinations, **focusing on addressing location-specific risks**." See Energy Safety, *Final Decision on 2022 Wildfire Mitigation Plan Update Pacific Gas And Electric Company*, November 10, 2022 at 184 (emphasis added).

[17] PG&E's response to data request CalAdvocates-PGE-2022WMP-31, question 7, September 8, 2022. Per this response, PG&E's circuit segments range in size from .0014 miles to 394 miles in length.

[18] Cal Advocates defines the term "project" here in the same manner as in our prior comments filed on November 2, 2023. See Cal Advocates, November Comments on Working Group Topics.

In those comments, we outlined three key principles that should be used to define a project: 1) a project is

In the case of a very long circuit segment, it is reasonable to expect that the cost and benefit of various wildfire mitigation strategies may vary substantially for each project location along the length of that circuit segment, such that undergrounding may be the most appropriate mitigation strategy for some locations, while overhead hardening or business as usual may be the most appropriate strategy for other locations. A location-specific analysis for each individual proposed project is necessary to allow Energy Safety and stakeholders to accurately compare wildfire mitigation strategies and determine the most appropriate strategy is utilized for each project.

3. Energy Safety should require utilities to employ reasonable and comparable assumptions in their analyses of alternative mitigations.

Utilities have in the past used assumptions that did not lead to a reasonable and accurate comparison of alternatives. For example, in its 2023-2025 Wildfire Mitigation Plan (WMP), PG&E's comparison of overhead and underground system hardening assumed that the unit cost of undergrounding would decrease over time, while the unit cost of covered conductor would increase over time.[19] These assumptions arose from the utility's own choices: specifically, its plan to increase undergrounding mileage and to decrease covered conductor mileage.[20] In other words, PG&E pre-determined its preferred mitigation strategy, used that strategy to influence its unit cost calculations, and then used those calculations to justify its pre-determined choice of mitigation measure. This pre-determination prioritized PG&E's interests over those of its

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a contiguous group of comparably high-risk assets that are to be mitigated simultaneously; 2) Risk reduction benefit should be estimated at the scale of the assets to be removed from service; 3) The project should be traceable through all stages of the project lifecycle.

[19] See discussion in *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.

[20] In response to data request CalAdvocates-PGE-2023WMP-09, April 7, 2023, question 13, attachment 1, PG&E provided calculations supporting its estimated risk-spend efficiencies (RSE). The RSEs in this document cannot be directly compared, since PG&E's forecast unit cost for overhead system hardening in this attachment ranges from $1.56 million per mile to $1.67 million per mile, nearly double PG&E's *actual* unit cost in 2022 of $0.83 million per mile (PG&E, *2023-2025 Wildfire Mitigation Plan R1*, April 6, 2023, Table PG&E-22-11-3 at 903).

Per PG&E's response to data request CalAdvocates-PGE-2023WMP-22, May 5, 2023, question 4, these increased costs are due to "an assumed loss of economies of scale" related to its planned reduction in overhead hardening miles.

ratepayers, who may be better served with faster and more cost-efficient wildfire mitigation measures.

In the situation described above, PG&E did not use reasonable and comparable assumptions to evaluate alternative mitigations to undergrounding. If a utility were to take a similar approach in an SB 884 application, it could artificially improve the cost-benefit ratio of undergrounding while decreasing the estimated cost-benefit ratio (CBR) of alternative mitigations. This could lead to Energy Safety approval of undergrounding plans for locations that (with a fair comparison) may have been better suited to faster and cheaper wildfire mitigation methods.

IV. CHANGES TO APPROVED PLANS

Working group meeting 3 considered the issue of flexibility options and updates for 10-year undergrounding plans.[21]

The need to modify approved plans based on external and internal factors over a 10-year period is reasonable. Accordingly, the adoption of processes and methods to update approved plans is reasonable. But the impact of changes to a plan should not be understated. Changes to a plan could render the plan vulnerable to excessive, uncontrolled, and unregulated costs. Changes to a plan could also skew the prioritization of projects, resulting in unmitigated wildfire risk and decreased reliability. To be consistent with legislative intent and the Joint Advocates' key principles for implementation (discussed in Section II above), changes to a plan should be governed by a clear framework, use a defined process, follow well described requirements for justifying the change, and be managed transparently with appropriate regulatory oversight.

During the third working group meeting, the utilities argued for flexibility to change their approved plans – in effect, a carte blanche approval to change projects or elements of projects as long as the utility meets the objectives of the approved plan. PG&E averred that utilities should report changes to the plan and explain them in the six-month progress reports, and each utility should define "substantial change." San Diego Gas & Electric Company (SDG&E) agreed with PG&E that meeting the objectives of the original plan should be controlling and thus changes to the plan should not trigger a re-review.

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[21] Energy Safety, *Memorandum to Stakeholders regarding Working Group #3 Topics*, November 15, 2023, in docket 2023-UPs at 1-2.

Energy Safety and the Commission will need to provide consistent instructions for how and when utilities can propose changes to approved plans. The agencies should sketch out the broad outlines in their respective guidelines. However, neither agency needs to address this prior to the adoption of both agencies' SB 884 guidelines. Cal Advocates recommends that the agencies conduct a joint public process to take input from stakeholders on the impact of external and internal drivers that could require changes over the life cycle of an undergrounding plan.[22]

The following sections discuss in greater depth the framework, process, requirements, and transparency necessary to reasonably manage plan changes.

A. Framework for understanding a change to an approved plan: Energy Safety should establish categories of acceptable changes, governed by the impact of the change on reducing wildfire risk and increasing reliability.

In response to Energy Safety's prompts during the third working group discussion, various stakeholders indicated agreement with the elements Energy Safety identified in its presentation as subject to change:

- risk models,
- technology,
- mitigation techniques,
- costs,
- High Fire Threat District (HFTD) maps,[23] and
- viability or timeline of individual projects.

Over ten years, a plan may change beyond what can be envisioned today. Fundamentally, though, all updates or changes to an approved plan should do the following:

- Substantially reduce the risk of catastrophic wildfires, and
- Substantially increase electrical reliability by reducing the use of public safety power shutoffs (PSPS), enhanced powerline safety settings, de-energization events, and any other outage programs.

[22] This process could include, for example, comments and workshops after the agencies both issue their proposed processes for revisions to SB 884 plans.

[23] Cal Advocates, *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, in docket R.15-05-006.

Therefore, Cal Advocates recommends that Energy Safety frame changes as falling into one of two groups:

1. Changes in wildfire risk models (inputs, methods, and parameters) – in other words, changes to the risk landscape. These include, but are not limited to, changes in an HFTD map, wildfire events, changes in wildfire behavior, vegetation changes, and events or other circumstances that influence changes in the risk landscape. Such changes influence risk model outputs and may thereby alter project prioritization or project selection.
2. Changes in the projects and the alternatives: for example, new cost estimates, revised analysis about where undergrounding is most effective, new mitigation techniques/technologies, and any other factors that change the projects' ability to cost effectively reduce wildfire risk.

B. Process for utilities to request a change: Energy Safety, in concert with the Commission, should develop an appropriate process and mechanism for utilities to request a change to an approved plan.

As discussed above, agencies and stakeholders should evaluate proposed changes for their overall impact on wildfire risk and reliability and assess the triggering event that causes the change. Energy Safety and the Commission should develop criteria that will guide the utility on the appropriate process.

The appropriate process should vary depending on the nature of the change and the validating criteria it meets. For example, cost changes (which are the purview of the Commission) should be addressed through a petition for modification (PFM) that is subject to stakeholder scrutiny.

Cal Advocates' comments on the Commission's current Staff Proposal for the SB 884 Program recommend the following:

- The Commission should adopt an expedited process for petitions for modification to adjust cost caps and cost-benefit ratio (CBR) minimums.
- The Commission and Energy Safety should coordinate to avoid conflicts between the guidelines.
- The Commission and Energy Safety should allow stakeholders as well as utilities to request changes to a utility's approved SB 884 plan.[24]

[24] Cal Advocates, Comments on Draft Resolution SPD-15.

Energy Safety should coordinate with the Commission to develop the process and mechanisms to manage changes to a plan. Cal Advocates recommends that guidelines for changes to a plan include criteria a utility must meet to obtain approval for a change to an approved plan. For example, each proposed change should:

- Describe the change in terms of location, length, and priority,
- Identify the trigger event or circumstance for the change,
- Justify the change (discussed below),
- Consider alternative mitigations,
- Specify the impact on the wildfire mitigation plan (WMP),
- Quantify the strength of the change in terms of significance,
- Provide project-level detail,
- Describe the impact of the change on wildfire risk and reliability,
- Demonstrate that continuing with the original plan is untenable or materially worse than the proposed change, and
- Fully describe the impact of the change on the totality of the approved plan, including how it changes prioritization.

C. Requirements for justifying a proposed change: Energy Safety should set thresholds for justifying changes to an approved plan.

Energy Safety should require each utility to not only justify any proposed change to an approved plan, but also justify the changes to the individual projects involved. Each proposal for a plan update should address:

- How the CBR for each project and the plan changes as a result of the proposed change.
- The recalculation of reliability impacts caused by PSPSs, enhanced powerline safety settings, de-energization events, and any other outage programs.
- Proposed changes caused by changes in risk models, cost estimates, prioritization of projects, and changes to the highest risk circuits.

D. Cost savings - Energy Safety should require utilities to credit estimated operational cost savings to customers or omit them from estimated ratios CBR.

Utilities have claimed that undergrounding will lead to savings in vegetation management and operational costs over the lifetime of the asset. It is possible, therefore, that a utility will include these estimated operational savings in its cost-benefit ratio (CBR) calculations, which would increase the estimated CBR for undergrounding.

Because these cost savings are currently speculative, it is inappropriate to include them in CBR calculations unless a) the utility provides substantial quantitative data to support the proposed operational cost savings, and b) the utility commits to returning the estimated cost savings as a credit to ratepayers. For example, an undergrounding project included in an SB 884 plan but not the utility's general rate case (GRC) would result in the utility retaining GRC-authorized funding for items such as vegetation management or other operational mitigations that it no longer needs to perform due to the undergrounding project going into service.

Energy Safety should direct utilities to exclude speculative operational savings in estimated CBRs for undergrounding unless the utility can provide evidence to support its inclusion. If the utility includes such savings in its estimated CBRs, Energy Safety should require the utility to return the cost savings to ratepayers via a Commission-approved mechanism. To do this, a utility should forecast the operational cost savings for the lifetime of the project and calculate the present value of those savings. When the project is complete and its capital costs go into rates, the utility should include a credit for the present value of forecasted operational savings in the annual electric true-up advice letter. This approach will hold utilities accountable for their predictions and ensure that the predicted customer savings are real, rather than allowing utilities to improve their undergrounding CBRs based on rosy assumptions that may not come to pass.

V. ROLE OF INDEPENDENT MONITORS

Working group meeting 4 considered the role of independent monitors.[25] Regarding the scope and definitions applicable to the independent monitors' work (question 3a),[26] the independent monitors should (1) report separately on each component of PU Code section 8388.5(c), addressing in each respect whether a utility has followed its plan and complied with the statutory requirements; (2) report on costs and related information; and (3) report on the electrical corporation's efforts to apply for federal, state, and other non-

[25] Energy Safety, *Memorandum to Stakeholders regarding Working Group #4 Topics*, November 22, 2023, in docket 2023-UPs at 2-3.

[26] See question 3.a and its subparts. Energy Safety, *Memorandum to Stakeholders regarding Working Group #4 Topics*, November 22, 2023, in docket 2023-UPs at 2-3.

ratepayer funds. The independent monitor report should evaluate the extent and severity of any non-compliance, including providing an independent assessment of the causes of failure (a failure here is a deviation from an approved plan). The independent monitor should also audit the utility's methods used to calculate costs, benefits, and any other calculations that support project selection and prioritization.

Specifically, the independent monitor should assess the effectiveness of the utility's mitigation efforts, cost containment and risk reduction efforts, compliance with its plan, ability to meet deadlines, achieve cost-benefit ratios, and meet expenditure forecasts.

The use of independent monitors will not reduce the regulatory responsibility of Energy Safety and the Commission; rather the role of independent monitors is to inform and support regulatory decision-making. The agencies retain their discretionary abilities to decide which failures are significant in the context of a plan and what the appropriate remedies are. The independent monitor's work is not limited to the review of utilities' stated objectives (whether those are general or specific).

A. Zero-tolerance standard: Energy Safety should direct the independent monitors to apply a zero-tolerance standard when assessing compliance and documenting failures.

The function of the independent monitors should be to collect data from a utility about each plan component, analyze the data provided, document their findings and any specified deficiencies, and make recommendations in an annual report. Energy Safety and the Commission, vis à vis the independent monitor reports, should evaluate the report and determine if the findings and any specified deficiencies meet pre-established criteria to merit remedial action or penalties. The agencies should direct the independent monitors to apply a zero-tolerance standard when assessing a utility's compliance with its plan: that is, the independent monitor should document and describe all deviations from an approved plan.

If a utility fails to follow its SB 884 plan, the independent monitor's report should be used to consider whether to penalize the utility for failing to promote the safety of its system in compliance with PU Code section 451 and other regulations, such as Commission General Orders.

The independent monitor selection process is also critical to the success of the SB 884 program. Transparency regarding the process for selecting the independent monitors would further protect ratepayers.

B. Timing: Energy Safety should establish an annual independent monitor reporting cadence that minimizes the gap between occurrence of a failure and its correction.

During the fourth working group meeting, stakeholders discussed the cadence of utility progress reports and independent monitor reports following implementation of the plan. A poorly designed reporting cycle could result in a lag of nearly two years to cure deficiencies, which is harmful to ratepayer interests. Energy Safety should provide the independent monitors with a robust list of plan elements to review. The independent monitors should be empowered with the same broad discovery powers as Energy Safety or the Commission, authorizing them to request data from the utility, visit worksites, audit records, and interview utility personnel and contractors. The independent monitors can also use the utility's semi-annual progress reports as a supplemental source of data and a way to confirm the independent monitor's own findings. Primarily, though, the independent monitors should rely on their own analysis and data requests (and responses to those requests), rather than the utility's reports.

VI. COST CONTAINMENT AND ECONOMIES OF SCALE

Working group meeting 5 considered the issues of cost containment and economies of scale. Energy Safety posed four questions.[27]

A. Project Costs: Energy Safety should define project costs from the selection process through energization and through the normal service life of the facility, and require equivalent analysis with the same timeframe for each alternative mitigation.

Cal Advocates contends that project costs should include the following:

- Engineering, design, construction materials and labor, capital costs, and operations and maintenance (O&M) costs,
- Costs to remove the overhead line,
- Costs for future vegetation management,
- Costs to sell or dispose of existing rights-of-way and utility assets,
- In sum, all the costs associated with the project life cycle: all costs of putting together a project from planning to permitting to implementation, construction and energization.

[27] Energy Safety, *Memorandum to Stakeholders regarding Working Group #5 Topics*, November 30, 2023, in docket 2023-UPs at 2.

SB 884 does not address utility reporting requirements to support project costs, although the statute implies in other subsections that utilities must justify costs. For example,
PU Code section 8388.5(c)(2) provides for identification of projects;
PU Code section 8388.5(c)(3) discusses timelines and unit cost targets;
PU Code section 8388.5(c)(4) requires comparison of alternatives including evaluation of the cost; and discussion of cost targets is included in PU Code section 8388.5(e)(1).

Energy Safety should require each utility applicant to provide the same life cycle analysis for every alternative. This includes workpapers, methodologies employed, assumptions, and all information needed to evaluate and implement a cost cap and cost-benefit ratio targets. Utilities should be required to provide documentation of their models and methods for benchmarking project costs that is sufficient to enable thorough agency and stakeholder review.

B. Economic Benefits: Energy Safety should require utilities to define economic benefits over the life cycle of the project.

Economic benefits should include the following:

- Avoided costs, for example:
  - Vegetation management costs that are minimized or obviated when an overhead circuit is undergrounded,
  - Inspection costs (labor and materials) no longer required when a circuit is undergrounded,
  - Maintenance costs,
  - Costs associated with utility management of a PSPS, such as staffing an emergency operations center, providing community resource centers during PSPS, etc., and
- Reliability benefits.

Life cycle costs include economic benefits and possible liabilities as well. Some assets may be stranded rather than sold or disposed, wherein their original cost has not fully depreciated, leaving the ratepayer to continue paying for the amortized value until the end of the stranded asset's expected useful life. Because utilities use group depreciation rather than tracking the depreciation of each discrete piece of equipment, ratepayers pay for the new underground facilities while continuing to pay for some portion of the retired assets.

Telecommunications companies argue that a comprehensive analysis of the costs and benefits of undergrounding should account for impacts on telecommunications service.

Specifically, removing poles may compromise telecommunications providers' ability to maintain resilient networks.[28]

Energy Safety should require utilities to capture all costs and benefits in their alternatives analyses as well. An accurate accounting of all impacts may affect whether the alternatives analysis favors undergrounding or covered conductor.

C. Cost containment assumptions and economies of scale: Energy Safety should require utilities to regularly review their cost containment strategies.

It is important that utilities continue to improve their cost estimates and cost containment efforts over the life of a 10-year plan, by developing better operational standards, new strategies, and new technologies. Continuous review of cost containment assumptions may lead to a reduction in forecasted costs over the life of the plan.

PU Code section 8388.5(c)(6) requires utilities' 10-year plans to evaluate project costs, projected benefits over the life of the assets, and any cost containment assumptions. A utility that achieves efficiency as it scales up the projects, locks in long-term contracts, and continually reviews cost containment assumptions will comport with the requirement, which should lead to a steady reduction in forecasted costs over the life of the plan.

VII. RECOMMENDED GUIDELINES

Cal Advocates recommends that Energy Safety incorporate the following requirements into its draft SB 884 implementation guidelines.

A. Working Group 2: Alternative Mitigations

The electrical corporation must:

1. Adhere to the standards established by Energy Safety for comparison of an undergrounding plan to other wildfire mitigation strategy plans, which should include, at a minimum, a business-as-usual alterative, and an overhead alternative.
2. Provide at a minimum, a business-as-usual and overhead project alternative for each undergrounding project that the utility proposes to undertake.
3. Provide the following metrics for each mitigation strategy:

[28] Comments made by Steve Bowen on behalf of Sonic Telecom at Working Group 5 on December 12, 2023.

a. Physical details of the mitigation strategy, such as the number of overhead miles to be hardened, number of overhead miles to be taken out of service, and the number of undergrounding miles to be installed.

b. The estimated lifetime cost of implementing the mitigation strategy, disaggregated into capital and operating expenditures.

c. The estimated lifetime benefit of implementing the scenario, calculated pursuant to the method adopted in Decision (D.) 22-12-027 in Rulemaking (R.) 20-07-013.

4. Analyze each wildfire mitigation strategy for each proposed project location, using location-specific data.

5. Employ reasonable and comparable assumptions in analyses of alternative mitigations.

B. Working Group 3: Changes to an approved plan

The electrical corporation must:

1. Provide details and explanations that transparently explain the proposed change and provide regulatory oversight and stakeholder review.

2. Contextualize the change in terms of (1) reducing the risk of wildfires, (2) increasing electrical reliability, or both.

3. Identify the change to the plan, and the cause for it, such as changes in the risk landscape.

4. Provide detailed information about the proposed change to an approved plan, including, but not limited to:

    a. Describe the change in terms of location, length, and priority,

    b. Identify the trigger event for the change,

    c. Justify the change,

    d. Consider alternative mitigations,

    e. Specify the impact on the wildfire mitigation plan (WMP), including the specific language and page number of the WMP that will be impacted, and a statement of the corrected WMP language,

    f. Provide project-level detail,

    g. Describe the impact of the change on wildfire risk and/or reliability,

    h. Demonstrate that following the original plan is untenable or is materially worse than the proposed change,

    i. Describe the impact of the change on the totality of the approved plan, including how it changes prioritization of projects.

C. Working Group 3: Cost Savings

The electrical corporation must:

1. Credit estimated operational cost-savings to customers in the year that the project's capital costs enter rates or omit such forecasted savings from estimated cost-benefit ratios (CBR).

D. Working Group 4: Independent Monitor

The electrical corporation should:

1. Report and document its implementation of the plan.
2. Comply with the approved plan.
3. Provide all data and documentation requested by the independent monitor in a timely manner.
4. Prepare semi-annual progress reports to provide full and transparent documentation of the plan for review by the independent monitor, the agencies, and stakeholders. Be subject to penalties for violating Public Utilities Code Section 451 if the independent monitor finds the corporation is not following its SB 884 plan.

The independent monitor should:

1. Have full access to utility accounts, project records, GIS databases, project worksites, and any other information that it deems necessary to complete its work.
2. Be permitted to interview utility personnel and contractors regarding the implementation of the utility's plan and any compliance matters.

E. Working Group 5: Cost containment and economies of scale

The electrical corporation must:

1. Provide full and transparent information about project costs, including but not limited to:
   a. Engineering, design, permitting, and construction phases of the project,
   b. Materials and labor, capital costs, and operations and maintenance (O&M) costs,
   c. Costs to remove the overhead line,
   d. Costs for future vegetation management,
   e. Costs to sell or dispose of existing rights-of-way and utility assets,
   f. In sum, all the costs associated with the project life cycle: all costs of putting together a project from planning to permitting to implementation, construction and energization.

2. Provide a life cycle analysis for every alternative plan strategy i.e., business as usual and overhead, to the same level of detail as provided for the undergrounding plan as described in Section E.1 above.
3. Provide workpapers, methods employed, assumptions, and all information needed to evaluate and implement a cost cap and a cost-benefit ratio cap.
4. Provide sufficient documentation of models and methods for benchmarking project costs to enable thorough agency and stakeholder review.
5. Provide full details of economic benefits, such as:
    a. Avoided costs, including:
        i. Vegetation management costs that are minimized or obviated when an overhead circuit is undergrounded,
        ii. Inspection costs (labor and materials) that are no longer required when a circuit is undergrounded,
        iii. Maintenance costs, as above,
        iv. Costs associated with utility management of a public safety power shutoff (PSPS), such as staffing an emergency operations center, providing community resource centers during PSPS, etc.
    b. Reliability benefits,
    c. Stranded assets,
    d. Sold or disposed assets.
6. Capture all costs and benefits in the alternatives analysis.
7. Identify all truly new cost containment strategies and economies of scale.

VIII. CONCLUSION

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

Respectfully submitted,

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January 8, 2024