California Public
Utilities Commission

# Informal Comments on Staff Proposal for SB 884 Program

September 27th, 2023

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September 27, 2023

***VIA Electronic Mail***

Safety Policy Division
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, California 94102
Email: SB884@cpuc.ca.gov

Re: **Comments of the Coalition of California Utility Employees on the Staff Proposal for SB 884 Program**

Dear Safety Policy Division:

We write on behalf of the Coalition of California Utility Employees (CUE) to comment on Safety Policy Division's Staff Proposal for the SB 884 Program.[1] If adopted, the Staff Proposal would establish the process and requirements for the Commission's review of 10-year distribution infrastructure undergrounding plans and related costs pursuant to SB 884.

CUE is a coalition of labor unions whose approximately 43,000 members work at nearly all the California electric utilities, both publicly and privately owned. CUE's coalition union members make up the on-the-ground workforces of the IOUs that would implement undergrounding plans. CUE has participated in proceedings before the Commission for more than 25 years, including as a party to general rate cases, the Order Instituting Rulemaking to Implement Electric Utility Wildfire Mitigation Plans Pursuant to Senate Bill 901 (2018), and other related proceedings.

CUE's comments focus on the Staff Proposal's use of cost-benefit ratios (CBRs), workforce development implementation costs, and timeline for disposition of cost recovery requests.

[1] California Public Utilities Commission, Safety Policy Division, Staff Proposal for SB 884 Program (Sept. 2023) (hereinafter Staff Proposal), *available at* https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/reports/staff-proposal-for-sb-884-program_091323.pdf.

**A. Recorded Costs Should Not Be Automatically Disallowed Based on Cost-Benefit Ratio Targets**

The Staff Proposal recommends that the Commission include a condition of approval requiring that the recorded CBRs for all projects completed in a year to equal or exceed the approved average target CBR for that year.[2] If an IOU falls below the CBR target, then the Staff Proposal recommends that recorded costs be disallowed for as many projects as necessary to bring the recorded CBR average up to the approved target.[3] CBRs should not be used as a basis to deny cost recovery.

The Commission has repeatedly confirmed that CBRs, like their predecessor risk-spend efficiency (RSE) scores, are only one of many factors to be considered when assessing risks mitigations.[4] In D.22-12-027, the Commission replaced the multi-value attribute function framework (which expresses risk consequences in unitless RSEs that can be compared and ranked) with a cost-benefit approach (which expresses risk consequences in dollar values that provide an indication of cost-effectiveness).[5] The Commission expressly stated that CBRs are not intended to serve as the sole determining factor for IOU proposals or Commission decisions on risk mitigations, and reiterated that mitigation selection can be influenced by other factors.[6] A condition of approval which requires IOUs to maintain an average CBR above the approved target for a particular year without consideration of other relevant factors is an inappropriate use of the metric.

Moreover, reliance on CBRs is duplicative and unnecessary given that the Staff Proposal includes conditions of approval that would disallow costs if the total annual or average unit costs exceed approved targets for a particular year plus a 10% contingency allowance for unexpected circumstances.[7] These conditions are enough to protect ratepayers from unexpected and inefficient cost overruns.

The Staff Proposal should be revised to remove the condition of approval that would disallow costs based on CBRs. To the extent the Commission utilizes CBRs as a means of disallowing costs, IOUs should be afforded an opportunity to

[2] *Id*. at p. 8.
[3] *Id*. at pp. 11-12.
[4] D.22-12-027 at pp. 26-27.
[5] *Id*. at p. 12.
[6] *Id*. at p. 26-27.
[7] Staff Proposal at pp. 8-9



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demonstrate why the recorded costs for any projects that bring the annual average CBR below the applicable target are just and reasonable.

### B. The Undergrounding Plan Application Should Include Costs Associated with Implementing the Mandatory Workforce Development Plan

SB 884 requires that an IOUs' undergrounding plan include "[a] plan for utility and contractor workforce development."[8] Cost recovery for workforce development implementation is appropriate because it ensures that IOUs recruit, train, and retain an adequately sized, qualified workforce to carry out the proposed undergrounding plan and provide safe and reliable electric service. The Staff Proposal should be revised to require that IOUs present workforce development cost forecasts for each year of the 10-year application period in the undergrounding plan application.

### C. The Staff Proposal Should Establish a Timeline for Issuing Cost Recovery Resolutions

To recover recorded costs, IOUs would initiate Phase 2 of the SB 884 process by filing a Tier 3 Advice Letter, to be disposed of by Commission resolution.[9] Commission staff will "determine whether conditions stipulated in the Commission's conditional approval of the Application (based on forecast costs) are met when evaluated using recorded costs."[10] The Commission's evaluation will be based on based on biannual progress reports submitted by the IOUs, annual compliance reports submitted by the independent monitor, relevant information in annual wildfire mitigation plan updates, and stakeholder input.[11]

While the Staff Proposal clearly articulates the timeline for review of undergrounding applications, it leaves the timeline for cost recovery open-ended. In fact, the Staff Proposal anticipates that "Phase 2 may extend over a series of periodic Advice Letter filings, as needed, to support cost recovery over the 10-year program period. The review period will be determined in the Commission's decision on the Application."[12]

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[8] Pub. Util. Code § 8388.5(c)(5).
[9] Staff Proposal at p. 9.
[10] *Ibid.*
[11] *Ibid.*
[12] *Ibid.*



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The Staff Proposal should be revised to include a more specific timeline for disposition of Advice Letters. If the Staff Proposal is adopted, disposition should be a relatively straightforward exercise since the Commission's review would be limited to a comparison of recorded costs against the annual total and unit cost caps after applying any third-party funding reductions and contingency allowances. Timely decisions are essential to the financial health of IOUs, which impacts its ability to borrow and, ultimately, impacts rates.

**D. Conclusion**

We respectfully urge the Safety Policy Division to revise the Staff Proposal to eliminate reliance on CBRs as a means of disallowing costs, to establish a timeline for issuing cost recovery resolutions, and to require presentation of workforce development implementation costs in the undergrounding plan application.

Thank you for your consideration of these comments.

Sincerely,

Andrew J. Graf

AJG:acp



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September 27, 2023

**Re: Informal Comments on SB 884 Staff Proposal**

The California Farm Bureau (Farm Bureau) appreciates the effort and thought that went into the Staff Proposal for SB 884 Program. Farm Bureau represents agricultural energy customers that are located and take service from the state's electric investor-owned utility companies and has been active throughout the process from the legislature to now regarding SB 884. There are many things the Staff Proposal gets right including the steps taken to delineate the process from the role Office of Energy Infrastructure (OEIS) will play in contrast to the role the Public Utilities Commission (PUC) will play. However, Farm Bureau still has significant concerns about how this program will impact General Rate Cases (GRCs) and the overall potential for ratepayer costs with regards to the program. Farm Bureau is hopeful there will be additional clarifying amendments to the Staff Proposal and the ability retained for both OEIS and PUC to impose additional requirements should they be deemed necessary during the Program. It cannot be lost that participation in this expedited program is entirely *voluntary*. Ratepayer protection should be at the forefront and if a large electrical corporation deems the Program too onerous then they can proceed with proposing and requesting funding for undergrounding during the normal GRC process.

To keep its comments succinct, Farm Bureau offers support for the sections it does not mention and provides constructive feedback on the sections which could use more clarity or additional requirements to ensure efforts are being made to balance the cost impacts to ratepayers from improvements to utility infrastructure.

## Phase O

The Staff Proposal introduces a high level breakdown of what the approval process is through OEIS, but there are scant details on what will transpire during the nine month review period. Based on footnote 1 on page 2, Farm Bureau will reserve comments on this part of the proceeding but is hopeful that "Phase 0" will include robust stakeholder participation as well and take heed of some of the suggestions coming from this portion of stakeholder feedback.

Farm Bureau is concerned to the degree OEIS will review or consider cost information during this phase. OEIS should not ignore cost completely, but their review should also have no precedent or bearing on what transpires in the cost review at the PUC.

## Phase 1

The Staff Proposal introduction atop page 5 is critically important.

> *This Staff Proposal understands that Plans approved by Energy Safety will have been found to show that implementation of the Plan will substantially increase reliability and substantially reduce wildfire risk, as required in Public Utilities Code, Section 8388.5(d)(2). The Commission's role is to review and conditionally approve costs as presented in the subsequent Application.*

Far too often in GRC proceedings, utilities use an approved Wildfire Mitigation Plan (WMP) as a perceived trump card that the PUC should rubberstamp despite PUC guidance to the contrary. Farm Bureau believes this language could go even farther to state that approval by OEIS *only* shows a potential to substantially increase reliability and substantially reduce wildfire risk or to explain that the showing is done without regard to cost. In addition, it should be clear that despite a showing of increased reliability and reduction of wildfire risk it does not make any portion of that Plan immune from cost consideration or changes from PUC.

Farm Bureau believes the more information required as part of the Application Requirements the greater efficiency and transparency the Program will achieve which among other things will reduce the need for additional data requests from parties. Farm Bureau makes several suggestions below of simple changes that can bring forward crucial and necessary information to assist in achieving these goals of efficiency and transparency.

### Overlap with the GRC

Section 3 on page 6 appears to address how the Program will interact with the concurrent or future GRC proceedings. However, Farm Bureau believes that it needs to be made abundantly clear that the Program is not a second bite at the apple for the large electrical corporations and that a Decision in the GRC should set the undergrounding targets for those corresponding years of the Program. Specifically, 3) c) which would allow an explanation why a different conclusion is now appropriate should be removed. The PUC would have already decided based on a much larger swath of information and parties should not be expected to relitigate an issue that has already taken significant time and resources.

### Ratepayer Impacts

Section 4 discusses ratepayer impacts but does not clarify that it is all ratepayers. Given the current propensity to provide and highlight only residential ratepayers impacts in utility Applications, Farm Bureau would appreciate an amendment to include the word *all* so there is no question that the impacts for *all* ratepayers, which will certainly exist, will be transparent.

Farm Bureau is appreciative of Section 5 regarding proposed "savings" and believes this should be included in progress reports and the annual review as a means to evaluate the program and provide necessary penalties if savings are not realized. Should the proposed "savings" from undergrounding be touted as a *future* savings outside of the 10-year plan window, the PUC must ensure that it will hold the utilities accountable should those savings not be realized.

**Affordability**

The word affordability is noticeably absent from the Staff Proposal. While undergrounding may satisfy the requirements presented by OEIS of substantially increasing reliability and substantially reducing wildfire risk, it may not be *affordable*. Undergrounding costs are significantly higher than overhead system hardening and are not the only costs that are present in rates. For example, as the state moves toward greater electrification and clean energy goals, those costs will primarily be passed on to ratepayers. It is essential that the cost evaluation and comparisons as part of this program contain a cumulative evaluation and are consistently revisited. Large electrical corporations are aware of the additional Applications they will file within a given year and beyond and what those impacts may be. It is imperative that rate analysis capture these additional ratepayers burdens so that costs are not being approved in a vacuum. Far too often a double digit increase is followed by another a few months later and looking at those individual increases will not reveal the true impact to ratepayers.

For example, in PG&E's current GRC Phase 1 proceeding (A. 21-06-021), from the time of filing on June 30, 2021, to January 1, 2022, the agricultural average rate rose 8.2% higher than in the initial application without a single change being implemented from the GRC. When PG&E provided update testimony on September 7, 2022, the average agricultural rate for January 1, 2023, surpassed the initial application's *2026* rate projection by 1.38 cents per kWh. And the new 2026 average agricultural rate in this update was 39.6% higher than the average agricultural rate at the start of that proceeding. Yet in the proceeding the update testimony was characterized as a 3% increase because it only looked back to the last set of forecasts and base rates. While technically correct, allowing this to occur obscures the pancaking effect of these increases. If undergrounding cost will not be considered in the greater context of the GRC, the cost comparisons in this proceeding must take into account rates at the start of the 10-year period and be updated continually to reflect not only the additional costs or pending costs for any given year, but also a reflection of the overall increase from when the Program began.

**<u>Phase 2</u>**

The Staff Proposal lists stakeholder engagement in the periodic review of recorded costs, which is crucial, and parties must be given sufficient time to do that review. Time should be provided to analyze what will likely be lengthy reports and to seek additional information from large electrical corporations through data requests.

**Progress Reports**

Farm Bureau is hopeful the including, but not limited to, language will include efforts to identify the total cost landscape and affordability issues that were raised above. It is also unclear from the description of the independent monitor's report that the updates to future costs, activities, etc. will be part of that report and should be included in an update section of the progress reports. At a minimum, the large electrical corporation should be updating the impact on rates of both the recorded cost as well as the additional costs that have now been approved outside of the Program to be put into rates. It is incumbent that the evaluation of the Program and its costs be repeatedly presented to the PUC to ensure the Program remains affordable in the present and nimble enough to move to less costly means of wildfire mitigation if necessary.

**Potential Off-Ramps?**

It remains unclear if a large electrical corporation or the PUC or OEIS can terminate a plan under the Program. Should new information, technologies, cost prohibitions, or other factors arise it may be valuable to insert a termination clause that reverts a large electrical corporation back to the GRC process and provides some type of time window for preventing another Application. However, Farm Bureau is appreciative of the consequences for failure to satisfy conditions of approval and believes these requirements are necessary for ratepayer protection.

**Conclusion**

Farm Bureau appreciates the opportunity to comment on the Staff Proposal and will gladly take any additional opportunities to provide further explanation or feedback and looks forward to an opportunity to comment on the OEIS proposal as well. Ratepayers have expended enormous amounts to support wildfire mitigation projects and ratepayers must be afforded the opportunity to properly address deficiencies and issues regarding these multibillion dollar plans. It is important to remember that **no utility is required to participate in this expedited program** and the tradeoff for expedited review should be extreme transparency of the costs and implications of these plans.

Sincerely,

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**David J. Miller**
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***VIA ELECTRONIC DELIVERY TO: SB884@cpuc.ca.gov***

September 27, 2023

Chirag J. Patel, P.E., Senior Utilities Engineer (Specialist)
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San Francisco, CA 94102

Mr. Patel:

In response to an e-mail notice you sent on September 13, 2023, AT&T California (U-1001-C), the California Broadband and Video Association, and Sonic Telecom, LLC (U-7002-C) (collectively, the "Communications Providers") provide informal comments on the "Staff Proposal for SB 884 Program" ("Proposal"). Overall, the Communications Providers believe the Proposal sets forth a workable and appropriate process for considering Senate Bill ("SB") 884's expedited utility distribution undergrounding plans. However, the Communications Providers respectfully request that the California Public Utilities Commission ("Commission") revise the Proposal to clarify that: (1) an undergrounding plan need not include secondary lines and service drops and (2) costs in addition to those incurred by the electric company should be included in the cost-benefit analysis.

**The Commission's Primary Role in the SB 884 Process is to Focus on Undergrounding Costs**

SB 884 requires that the costs of an undergrounding plan be fully considered and indicates that the Commission's focus should be on assessing the reasonableness of the undergrounding costs and ways to reduce them. SB 884 outlines several items that an undergrounding plan "shall address or include, at minimum…," including a "comparison of undergrounding versus aboveground hardening," which "shall emphasize risk reduction and include an analysis of the cost of each activity for reducing wildfire risk, separately and collectively, over the duration of the plan."[1] The undergrounding plan must also include "[a]n evaluation of project costs, projected economic benefits over the life of the assets, and any cost containment assumptions."[2]

[1] Pub. Util. Code § 8388.5(c)(4) (emphasis added).
[2] *Id.* § 8388.5(c)(6) (emphasis added).

The Commission's role is to "approve the plan's <u>costs</u>" including any "<u>reduction in costs</u> compared to other hardening and risk mitigation measures over the duration of the plan."[3] The Commission is also directed to consider:

- "The cost targets, at a minimum, that result in feasible and attainable <u>cost reductions</u> as compared to the large electrical corporation's historical undergrounding costs."[4]
- "How the <u>cost targets are expected to decline</u> over time due to <u>cost efficiencies and economies of scale</u>."[5]
- "A strategy for achieving <u>cost reductions over time</u>."[6]

Thus, SB 884 is clear that the Commission should primarily focus on maximizing undergrounding cost efficiencies and reductions.

**<u>The Proposal Should be Revised to Make Clear that Secondary Lines and Service Drops Are Not Required to be Undergrounded</u>**

One means of substantially reducing undergrounding costs is to underground only high voltage primary electrical lines while leaving aboveground lower voltage secondary lines and service drop lines. This is the approach Pacific Gas and Electric Company ("PG&E") describes on its website,[7] which substantially reduces undergrounding costs in part by eliminating the cost to underground the low voltage service drops that connect individual homes to the electrical grid. On the other hand, if service drops are required to be undergrounded, the costs would increase and could include:

- digging up or boring under streets to create a path from the pole line to the customer's premises;
- digging up residential and business yards, lawns, and business property, potentially including driveways and parking lots, to run underground service drops to the customer's premises; and
- replacing service panels at homes and businesses.

Moreover, similar costs would have to be incurred if communications facilities are required to be undergrounded.

The Proposal indicates that "[t]he calculated annual and total benefits must relate to the mitigation of overhead line miles <u>including secondary lines and service drops</u> …."[8] The Proposal does not indicate any basis for requiring the undergrounding of secondary lines and

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[3] *Id*. § 8388.5(d)(1)(A) (emphasis added).
[4] *Id*. § 8388.5(d)(1)(B) (emphasis added).
[5] *Id*. § 8388.5(d)(1)(C) (emphasis added).
[6] *Id*. § 8388.5(d)(1)(D) (emphasis added).
[7] *See* Attachment A, PG&E's Undergrounding Fact Sheet, which can be found at PG&E Undergrounding Fact Sheet (pge.com) (last visited Sept. 27, 2023).
[8] *See* Proposal, p. 7, paragraphs 9 and 10 (emphasis added).

service drops, even though excluding them would be an effective cost mitigation measure.[9] In this respect, the Proposal appears to be inconsistent with SB 884, which requires the Commission to focus on maximizing cost efficiencies and reductions. The Communications Providers therefore respectfully request that the Commission revise the Proposal to reserve judgment on the appropriateness of leaving secondary lines and service drops aboveground and allow the electric utilities to propose this more cost-effective undergrounding approach as appropriate.[10]

**<u>The Proposal Should be Revised to Clarify that Undergrounding Costs Incurred by Other Parties Should be Considered</u>**

The Communications Providers further request that the Proposal be revised to clarify that undergrounding costs incurred by parties other than the electric company must also be considered. Although the Proposal does not preclude consideration of such costs, it should be revised to expressly include consideration of such costs consistent with SB 884.

As noted above, undergrounding could impose substantial costs on residential households and small businesses, depending on the location and undergrounding configuration. Moreover, undergrounding that involves utility pole removal would impose severe costs on other service providers that use the poles, including the Communications Providers. The Communications Providers' costs could exceed $1 million per mile of undergrounding.[11] At that rate, PG&E's 10,000-mile undergrounding proposal alone, if adopted, would impose $10 billion in costs on the communications and broadband industry[12]—an amount that far exceeds the $6 billion allocated by the California Legislature for broadband deployment in unserved and underserved communities in SB 156.[13]

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[9] The Proposal notes that 100 miles of overhead PG&E circuits would require approximately 125 miles of underground circuits. Proposal, p. 7, n. 7. But this statement appears to reflect the fact that overhead circuits by their nature can take more direct routes than underground circuits, not the undergrounding of secondary lines and service drops.

[10] If the Commission does not revise the Proposal in this manner, it should open a rulemaking to consider and determine appropriate compensation for any resulting undergrounding of communications facilities. It is the Commission, and not the Office of Energy Infrastructure Safety, that has the jurisdiction to address and decide that issue, which is of paramount importance to the Communications Providers whose facilities are attached to such poles.

[11] *See* A.21-06-021, *Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2023*, Opening Brief of Pacific Bell Telephone Company d/b/a AT&T California at 7-9 (Nov. 4, 2022).

[12] *Id*. at 4 (citing Ex. AT&T-01 at 2).

[13] *Id*. at 12.

## Conclusion

For the reasons explained above, the Communications Providers respectfully request that the Commission revise the Proposal to clarify that: (1) an undergrounding plan need not include the undergrounding of secondary lines and service drops and (2) costs other than those incurred by the electric company must be included in the cost-benefit analysis. Specifically, the Communications Providers propose that the Commission revise page 7 of the Proposal in the following manner:

9) The Application shall present the forecasted average Cost-Benefit Ratio (CBR) across all projects expected to be completed in each of the 10 years of the Application period, broken out by year and for the total Application period. Cost and Benefits must be calculated as defined in Commission Decision (D.)22-12-0276 or its successor. The calculated annual and total benefits must relate to the mitigation of overhead line miles including any secondary lines and service drops the utility elects to propose for undergrounding, not miles of undergrounding. The forecasted average CBR must include costs projected to be incurred by parties other than the utility. [footnotes omitted]

10) The Application shall include the forecasted CBRs, broken out by year and for the total Application period, for alternative wildfire mitigation hardening methods considered, in place of undergrounding, including forecasted CBRs for combinations of non-undergrounding hardening mitigation measures. The calculated annual and total benefits must relate to the mitigation of overhead line miles including any secondary lines and service drops the utility elects to propose for undergrounding, not miles of undergrounding. The forecasted average CBR must include costs projected to be incurred by parties other than the utility.

Respectfully submitted,

/s/
David J. Miller

For the Communications Providers[14]

1 attachment

[14] In accordance with Rule 1.18(d) of the Commission's Rules, the signatory has been authorized to submit this letter on behalf of all the Communications Providers.

# Attachment A
# PG&E's Undergrounding Fact Sheet

# UNDERGROUNDING

## A Safer, Stronger and More Affordable Energy Future

FEBRUARY 2023

**To better serve our customers and communities and reduce wildfire risk, PG&E is undergrounding 10,000 miles of powerlines.**

## What is undergrounding?

Undergrounding is the process of moving sections of overhead powerlines beneath the ground. This work will benefit our customers by:

- Helping prevent wildfires caused by equipment
- Reducing power outages and improving reliability
- Driving long-term affordability
- Decreasing the need for future tree work

## Where will work take place?

We are focusing our undergrounding efforts in areas where we can have the greatest impact on reducing wildfire risk and wildfire safety outages.

**↓99%**

**reduction in ignition risk at locations with lines undergrounded.**

This makes it one of the most effective ways to reduce wildfire risk at the **lowest long-term cost to customers**.

**350**

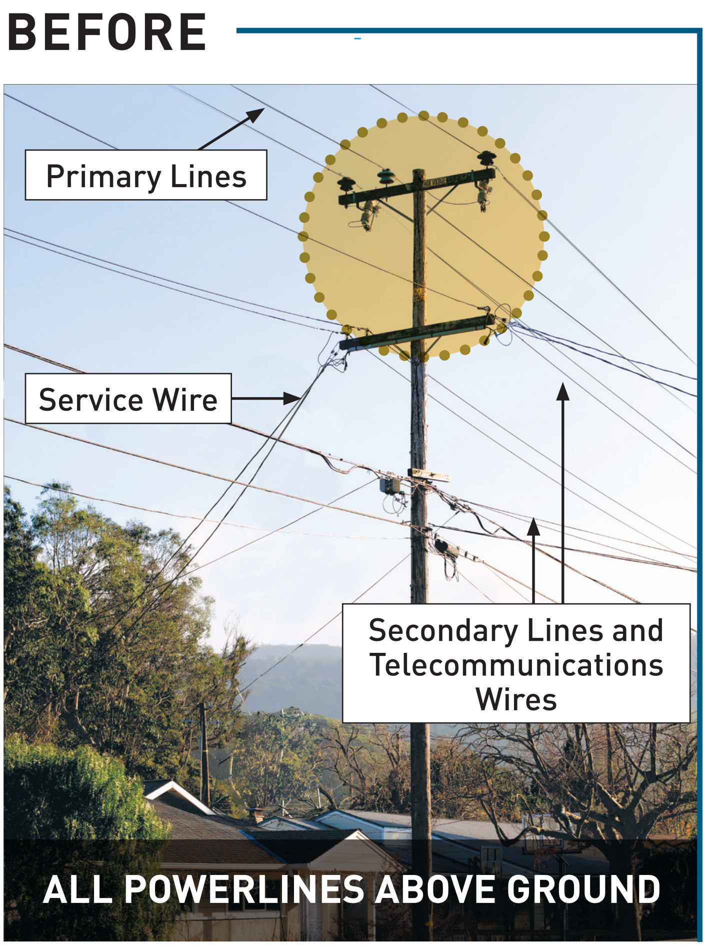
**miles planned for 2023**

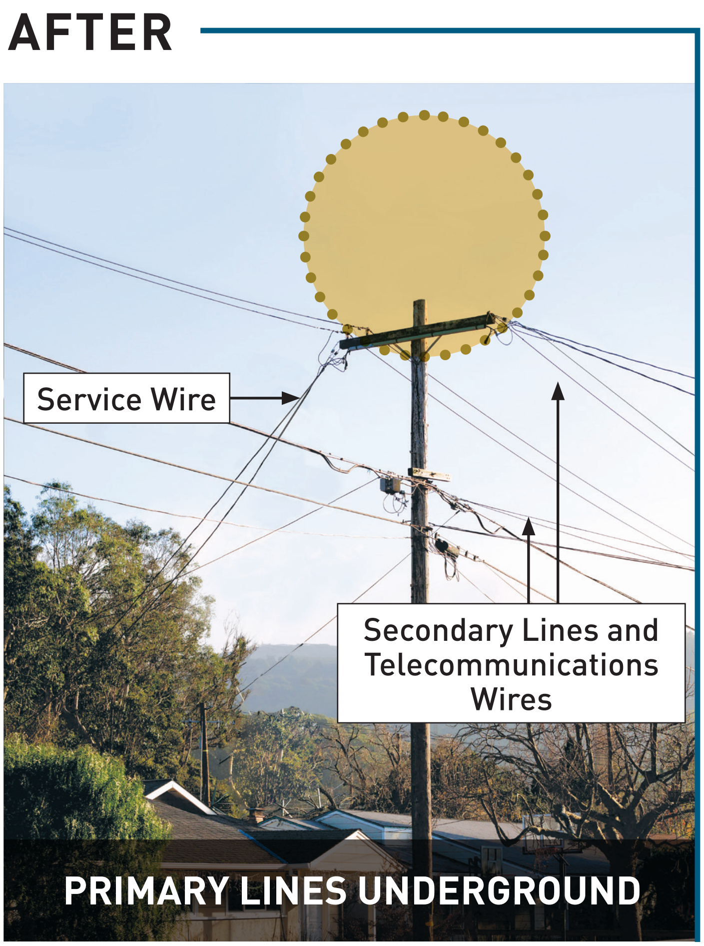
We are ramping up to underground hundreds of miles per year, to a total of approximately **2,300 miles undergrounded by 2026**.

Learn more at **pge.com/undergrounding**.

## What can you expect?

We are moving powerlines that have the highest ignition risk underground. Customers will continue to see other equipment overhead. This includes telecommunication lines or powerlines connecting to individual homes or businesses. We will continue to explore opportunities for undergrounding other equipment or hardening above ground equipment to reduce wildfire risk. This may include undergrounding all lines for some projects.




## Working together

We will keep customers and communities informed about this work, which may include providing notifications before work begins and updates until it is completed.

Some of the measures included in this document are contemplated as additional precautionary measures intended to further reduce the risk of wildfires. "PG&E" refers to Pacific Gas and Electric Company, a subsidiary of PG&E Corporation. ©2023 Pacific Gas and Electric Company. All rights reserved. CCC-0123-5886. 02/09/2023

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September 27, 2023

*Via Electronic Mail*

California Public Utilities Commission
505 Van Ness Avenue
San Francisco, California 94102

Office of Energy Infrastructure Safety
715 P Street, 20th Floor
Sacramento, California 95814

*Re: DISH Wireless, L.L.C. Response to SB 884 Staff Proposal*

DISH Wireless, L.L.C. (U 4533 C) ("DISH") hereby submits comments on the SB 884 Staff Proposal setting forth procedures for review of the major electric utilities' 10-year undergrounding plans mandated by SB 884.[1] DISH has reviewed the Staff Proposal and notes that it did not address the effect of undergrounding on telecommunications infrastructure and facilities attached to utility poles. DISH is currently constructing an advanced standalone 5G cellular network across the nation, including in California. Removal of existing electrical distribution poles would undermine this effort.

First, DISH concurs with other wireless providers' comments previously submitted on this issue and asks that the Staff Proposal be revised to include discussion of how undergrounding plans will affect the availability of distribution poles for wireless and telecommunications attachments. It is critical that the existing utility pole infrastructure in California remains available for use by telecommunications providers to attach to even after electric utilities underground their electrical facilities. SB 884 fails to consider how or whether electric utilities may dispose of utility poles after undergrounding their facilities. Rather, the Staff Proposal focuses on rate issues associated with ten-year undergrounding effort. The Commission should issue a clarification and require electric utilities to leave utility poles in place after the electrical facilities are removed as a default rule.

Second, DISH itself will be affected adversely if distribution poles are taken down after electric facilities are removed. The ten-year undergrounding plans required by SB 884 apply to Wildfire Threat Zones 2 and 3, where there are often few other vertical structures to which communications carriers may attach. Thus removing distribution poles also removes critical infrastructure to support communications equipment. DISH's 5G network will support mobile broadband and emergency 911 traffic, both of which are important for safety during emergencies. The Commission has recognized the important of wireless communications services

[1] Codified at Cal. Pub. Util. Code §388.5(e)(4).

during emergencies. "We must ensure that California's wireless customers have access to communications services during disasters or power outages, can receive emergency alerts and notifications, and access the internet for critical information during times of crises."[2] For this reason, the continued ability of telecommunications providers to deploy infrastructure must be a factor in deciding whether utility poles remain available.

DISH is committed to building out its 5G network to further the Commission's stated priority for ensuring Californians have readily available communications in emergencies and everyday situations. To that end, DISH respectfully requests that the Staff Proposal be modified to include an examination of disposition of distribution poles after the electrical facilities are removed.

Sincerely,

Anita Taff-Rice

*Counsel for DISH Wireless L.L.C.*

*cc:* SB884@cpuc.ca.gov
chirag.patel@cpuc.ca.gov
Service List

President Alice Reynolds
Commissioner Genevieve Shiroma
Commissioner Darcie Houck
Commissioner John Reynolds
Commissioner Karen Douglas
Director Robert Osborn
Director Caroline Thomas Jacobs

[2] *Id*, at p.76.

## CERTIFICATE OF SERVICE

I hereby certify that on the date below, I caused to be served the foregoing:

**DISH Wireless, L.L.C. Response to SB 884 Staff Proposal**

via electronic mail on the following recipients:

SB884@cpuc.ca.gov
chirag.patel@cpuc.ca.gov
Service List for SB 884
President Alice Reynolds
Commissioner Genevieve Shiroma
Commissioner Darcie Houck
Commissioner John Reynolds
Commissioner Karen Douglas
Director Robert Osborn
Director Caroline Thomas Jacobs

Dated: September 27, 2023

By: /s/*Aggie Hill*
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September 27, 2023

<u>*Via Electronic Mail*</u>

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Office of Energy Infrastructure Safety
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Sacramento, California 95814

*Re: ExteNet Response to SB 884 Staff Proposal*

ExteNet Systems, LLC (U-7367-C) and ExteNet Systems (California) LLC (U-6959-C) (collectively "Extenet") hereby submit comments on the Staff Proposal for Implementing SB 884 issued on September 13, 2023. Extenet previously commented on the Commission's process to implement SB 884, first by responding to questions raised at the February 23, 2023 public workshop as well as responding to other parties' correspondence to the Commissioners.

Extenet fully supports and understands SB 884's goal of reducing wildfire threats through undergrounding electric facilities. However, Extenet remains concerned that both the Commission's workshop and now the Staff Proposal have failed to address the effect undergrounding will have on communications equipment attached to poles slated for undergrounding. Communications services play a critical role in everyday life for millions of Californians. But they are even more important before and during an emergency, when wireless communications serve as vital links for Californians to seek help from first responders and to receive alerts about emergency situations and critical information on evacuations and shelters. After an emergency subsides, wireless communications provide connectivity to resources for rebuilding and even working remotely. It is important to both achieve the undergrounding goals of SB 884 and to maintain and improve wireless communications connectivity – both of which can be accomplished efficiently and expeditiously through a well-defined process.

SB 884 does not address the disposition of transmission utility poles after electric utilities remove their facilities. It does not appear that the Office of Energy Infrastructure Safety will address this issue in its examination of ten-year undergrounding plans submitted by electric utilities. Thus, the Commission is the only agency with statutory authority and expertise required to address this critical issue.

In the absence of rules from the Commission mandating that public utility poles remain in place after electrical facilities are undergrounded, Extenet and other communications carriers may be deprived of vertical infrastructure needed for their fiber cabling and wireless antennas, existing and future. Therefore, Extenet respectfully submits that the Staff Proposal be revised to include discussion of how undergrounding will affect the availability of utility poles for communications attachers.

If the Commission is not inclined to address the disposition of utility poles after undergrounding as part of its SB 884 implementation, Extenet reiterates its previous request[1] that the Commission open a rulemaking expeditiously to set rules for the disposition of transmission poles after undergrounding occurs. PG&E is the only entity to date that has opposed a rulemaking, based on its assertion that a rulemaking would take too much time. To the contrary, the issues Extenet identified for examination in a rulemaking are narrow and easily addressed on a timely basis.

Extenet previously proposed establishing a default rule that electric utilities must leave utility vertical infrastructure in place after the electrical facilities are removed. Such rule would ensure that the undergrounding of electrical facilities is not delayed, protect the status quo and ensure that communications attachers will not precipitously lose access to critical public utility poles to support their services. A rulemaking will also provide the opportunity for the electric utilities to identify any concerns about leaving utility poles in place and to determine issues such as ownership and value of poles that the electric utilities might wish to scrap after removing their electric facilities.

If a rulemaking is opened soon, it should be completed well before electric utilities submit their ten-year plans to the Office of Energy Infrastructure Safety – the first step in the approval process. Extenet is confident that the Commission can set a narrow scope and reasonable schedule for a rulemaking to examine disposition of transmission utility poles after electrical facilities are removed. While a rulemaking will require cooperation and resources, it is a far superior option to the potential loss of vertical infrastructure for communications providers or the delay and substantial expense of attempting to locate alternative vertical infrastructure (if that is possible) or to place their own poles.

A rulemaking will also provide an opportunity for the Commission and communications industry to examine the interplay between the SB 884 mandated undergrounding and other laws that limit undergrounding in situations where communications services would be harmed. As an example, Extenet notes that the Federal Communications Commission ("FCC") has issued several orders facilitating and protecting communications providers' access to utility poles. In FCC 18-133, the FCC issued rules intended to remove unreasonable barriers that unlawfully inhibit the deployment of infrastructure necessary to support wireless communications services such as 5G. The FCC noted that state or local undergrounding requirements that materially inhibit wireless service "would be considered an effective prohibition of service" [2] contrary to Section 253.[3]

It is not yet possible to know the details of the electric utilities' ten-year undergrounding plans, but such plans could inadvertently create a significant impediment to deployment of communications infrastructure that is needed for both emergency situations and to help close the digital divide. For those reasons and because the undergrounding mandate in SB 884 has the

[1] ExteNet submitted informal comments on the informal SB 884 workshop on March 9, 2023 and on June 20, 2023 it responded to a letter submitted by PG&E regarding implementation of SB 884.

[2] *Id.*, at ¶90.

[3] 47 U.S.C. § 253.

potential to be at odds with FCC orders or federal law, opening a rulemaking to examine the effect of undergrounding on communications carriers' ability to continue using utility pole infrastructure is warranted.

Sincerely,

*Counsel ExteNet Systems, LLC (U-7367-C) and ExteNet Systems (California) LLC (U-6959-C)*

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# CERTIFICATE OF SERVICE

I hereby certify that on the date below, I caused to be served the foregoing:

**ExteNet Response to SB 884 Staff Proposal**

via electronic mail on the following recipients:

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Dated: September 27, 2023

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INCOMPAS
THE FUTURE OF COMPETITION

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September 27, 2023

*VIA ELECTRONIC DELIVERY*

California Public Utilities Commission
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Office of Energy Infrastructure Safety
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**Re: INCOMPAS Comments on SB 884 Staff Proposal**

Dear CPUC, Office of Energy Infrastructure Safety:

INCOMPAS respectfully submits comments on the Commission Staff Proposal implementing procedures for review of major electric utilities' 10-year undergrounding plans in Tier 2 and 3 Wildfire Threat Zones mandated by SB 884[1]. INCOMPAS, the internet and competitive networks association, is the preeminent national industry association advocating for competition and innovation. Our members have been at the forefront of investing in building fiber, fixed wireless, and mobile networks in urban, suburban, and rural America.

INCOMPAS has actively participated in regulatory proceedings related to the development of fast, efficient and reliable communications services. For example, INCOMPAS has filed comments at the Federal Communications Commission ("FCC") focusing on specific reforms need to reduce and accelerate the deployment of wireless facilities.[2] INCOMPAS also filed comments on urging the FCC to take additional action to remove barriers and streamline processes for fiber, fixed wireless, and mobile wireless providers.[3]

INCOMPAS is following with great interest the Commission's efforts to harden California's utility infrastructure to lessen the impact of emergencies such as wildfires. The stated purpose of the Staff Proposal is to establish procedures and requirements for the Commission's review of large electrical corporation's 10-year undergrounding plans, with a focus on related costs.[4] Undergrounding on a large scale will undoubtedly raise many

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[1] Cal. Pub. Util. Code §388.5(e)(4).
[2] *Accelerating Wireless Broadband Deployment by Removing Barriers to Infrastructure Investment*, WC Docket No. 17-79, (July 17, 2017).
[3] *Accelerating Wireless Broadband Deployment by Removing Barriers to Infrastructure Investment,* WC Docket No. 17-84 (June 29, 2022).
[4] Staff Proposal, at p. 1.

important cost issues and the Commission understandably must determine how such costs should be allocated equitably. Equally important, however, is ensuring that modifying the state's vertical infrastructure against wildfires is balanced against the need to ensure affordable and reliable broadband and wireless communications services on which Californians depend for remote work, education, health care, and access to emergency services.

The Staff Proposal does not establish a process to determine what will happen to distribution poles once an electric utility has removed its electrical facilities. INCOMPAS urges the Commission to establish rules and requirements for utility poles with attached communications equipment that prevent possible service disruptions that will almost certainly occur if electric utilities remove poles after electrical facilities are placed under ground. In such instance, communications providers would either have to place their own poles or identify and obtain access to alternative vertical infrastructure. INCOMPAS notes that many of the service areas in the Tier 2 and 3 Wildfire Threat Zones are rugged and therefore locating alternate infrastructure for communications attachments may be difficult or impossible. Without Commission oversight, INCOMPAS is concerned that communications providers may lack mechanisms to prevent the precipitous loss of utility poles to which their equipment is attached and/or they not receive sufficient notice that would enable them to either preserve utility poles or obtain the necessary entitlements to place their own poles.

INCOMPAS appreciates the opportunity to contribute to the creation of a full record that will enable the Commission to develop rules and policies that protect the public interest in protecting robust communications services in California.

Sincerely,

*/s/ Angie Kronenberg*

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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 <u>or similar means as determined in the Commission's decision on the Application</u>."[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

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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 <u>or increased</u>, deferred <u>or accelerated</u>, and avoided <u>or newly incurred</u> 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

[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.

Pacific Gas and Electric Company

**Jamie Martin**
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September 27, 2023

Danjel Bout
Director, Safety Policy Division
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Re: **Pacific Gas and Electric Company's Comments on Safety Policy Division Staff's Proposal for the Senate Bill 884 Expedited Undergrounding Program**

Dear Director Bout:

Pacific Gas and Electric Company (PG&E) provides the following comments on Safety Policy Division's (SPD) Staff Proposal for the Senate Bill 884 (SB 884) expedited underground program. The Staff Proposal details the process and requirements for the California Public Utilities Commission (Commission) to review an electrical corporation's 10-year distribution infrastructure undergrounding Plan (Plan) and its application for review and conditional approval of the Plan's costs.

PG&E's comments on the Staff Proposal are focused on the following areas: (1) the cost-accounting process, (2) the use and calculation of cost-benefit metrics, (3) opportunity to update forecast targets, and (4) a few items for clarification. PG&E hopes the Commission and its staff will consider these recommendations and provide opportunities for further stakeholder engagement as they develop final guidelines pursuant to the legislation.

## I. THE FINAL SB 884 PROGRAM GUIDELINES SHOULD REFLECT THE EXPEDITED ACCOUNTING PROCESS ENVISIONED BY THE STATUTE

As written, the Staff Proposal does not align with the intent of SB 884, which is ultimately to provide electric corporations with the tools to expeditiously implement an efficient undergrounding program. To achieve the goals of the legislation, the final SB 884 guidelines should establish a two-way balancing account with program-level cost projections and annual true-ups as part of the Commission's conditional approval of a large electrical corporation's SB 884 application. PG&E also recommends that the final guidelines clarify that only recorded costs exceeding 125% of the conditionally approved annual budgets will be reviewed as part of an expedited reasonableness review.

### A. The Commission Should Authorize a Two-Way Balancing Account for Conditionally Approved Costs

PG&E urges the Commission to revise the Staff Proposal to authorize a balancing account ratemaking mechanism that ensures customers only fund actual costs spent on the undergrounding program. In this way, the Commission will align with the intention of the SB 884 legislation in ensuring that an expedited cost recovery process is in place to support critical wildfire risk reduction mitigation efforts.

Electrical corporations should be able to use a two-way balancing account (as opposed to a memorandum account) to annually recover in rates the conditionally-approved program budget contained in their application. PG&E understands that the legislature supported the bill in large part due to a recognition of the size and scale of an undergrounding program and the need to have financial certainty to enable an electrical corporation to make the long-term commitments to vendors and suppliers that would create efficiencies and drive down costs.[1]

Following each year of the program, the electrical corporation would submit a Tier 3 Advice Letter validating their recorded costs, similar to the initial Staff Proposal, for Commission review and disposition.[2] In other words, the adopted budgets will be trued-up to actual spending on the program, as approved by the Commission. Based on this review, the electrical corporation would return in future rates any over-collection in the event the program

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[1] See August 26, 2022, Assembly Floor Analysis, Senate Third Reading, SB 884 (McGuire), As Amended August 25, 2022, Majority Vote, p. 2 and August 1, 2022, Assembly Appropriations, Assembly Committee on Appropriations, SB 884 (McGuire), As Amended June 23,2022, August 3, 2022, pp. 4-5.
[2] Staff Proposal, p. 9.

underspends. The electrical corporation would also return in rates any amounts determined to be unjust or unreasonable in the Commission's disposition of the corporation's Tier 3 Advice Letter.[3] This process would conform to SB 884, which references the continued use of balancing accounts[4], in providing expedited recovery of undergrounding costs while ensuring customers only fund recorded Plan costs that comply with conditions stipulated in the Commission's conditional approval of the application.

Two-way balancing accounts are appropriate for programs in which a forecast can be developed, but in which actual spending may be difficult to estimate due to factors beyond the utility's control, and the costs are material. These types of accounts have been used for several years for wildfire-related, and non-wildfire, utility spend and effectively deal with the uncertainty of the timing and amounts of spending. They also ensure customers pay only the costs actually incurred by PG&E and provide cash flows required to support PG&E's financing.

As written, the Staff Proposal's use of a memorandum account[5] would undermine the intent of SB 884 in establishing "an expedited utility … undergrounding program"[6] with conditional budget approval subject to a reasonableness review. SB 844 states that the Commission shall consider using a balancing account ratemaking mechanism to manage undergrounding costs.[7] Despite this language, the Staff proposal prescribes the use of a memorandum account, which is fundamentally inconsistent with the Commission's conditional approval of annual Plan costs. It also creates significant financing and debt implications for electrical corporations by requiring them to finance the entire annual costs of the undergrounding program for 18 months or more[8] while waiting for an Advice Letter disposition, before beginning

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[3] Staff Proposal, p. 9. See also section I.B. below for a discussion of what costs should be deemed just and reasonable as part of the Tier 3 Advice Letter disposition.
[4] Public Utilities Code, § 8388.5(e)(6).
[5] Memorandum accounts are established to track actual costs arising from events that are not reasonably foreseen or for which a reasonable forecast cannot be developed before the costs are incurred. Generally, the Commission has found that memorandum accounts are appropriate if the costs are not forecastable, the costs are not substantial, or the existence of the costs is speculative (D.18-06-029, p. 7). In this instance, PG&E will be providing forecast program costs as part of a required future application.
[6] Public Utilities Code, § 8388.5(a).
[7] Public Utilities Code, § 8388.5(e)(6).
[8] 18 months assumes a Tier 3 Advice Letter requires a minimum 6 months for disposition.

to enter the costs into rates. In fact, the Staff Proposal potentially contemplates a much longer time before a Tier 3 Advice Letter is dispositioned, noting that the cost recovery review "may extend over a series of periodic Advice Letter filings, as needed, to support cost recovery over the 10-year program period."[9] The following are examples of similar balancing-account approved ratemaking mechanisms currently in place:

- The Gas Storage Balancing Account (GSBA)[10] requires a showing of reasonableness of all recorded costs prior to true-up of adopted forecasted costs to actual spending, and
- The Hydro Licensing Balancing Account (HLBA)[11] that trues-up adopted forecasted costs to actual costs as part of PG&E's GRC applications.

### B. A Six-Month Reasonableness Review Should Apply to Costs in Excess of 125% of the Conditionally Approved Budget

PG&E requests the Staff Proposal be revised to explicitly define a 6-month reasonableness review process for costs that were conditionally approved by the Commission during its review of the application. PG&E believes an annual reasonableness review that takes no more than six months to review the conditionally approved costs is appropriate for the expedited Tier 3 Advice Letter process following the respective nine-month periods wherein the Plan and the Application will be evaluated by the Office of Energy Infrastructure Safety, CPUC, and other stakeholders prior to approval.

PG&E proposes that the Commission consider recorded costs up to 125% of the conditionally approved annual budget targets to be just and reasonable. To conduct a reasonableness review of all undergrounding projects and recorded costs in scope of the conditionally approved application would render the commission's conditional budget approval moot and create significant administrative workload, uncertainty, and financial risk. If recorded

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9 Staff Proposal, p. 9.
10 See Gas Preliminary Statement Part EJ: pge.com/tariffs/assets/pdf/tariffbook/GAS_PRELIM_EJ (Prelim).pdf
11 See Electric Preliminary Statement Part GL: ELEC_PRELIM_GL.pdf (pge.com)

costs exceed 100% of a proposed annual cost target, reasonableness should be considered up to 125% of the original cost target given the uncertainties of forecasting undergrounding work, evolving risk, and the considerable review of unit costs, cost targets, and risk reduction already contemplated by the proposed guidelines. This buffer allows more flexibility to invest in new, effective mitigations, while still providing clarity on the regulatory review process for any costs over the forecasted amount.

## II. COST RECOVERY SHOULD NOT BE TIED TO AVERAGE COST-BENEFIT RATIOS

The Staff Proposal ties several program requirements to average Cost-Benefit Ratios (CBR). PG&E recommends that the Commission revise the final SB 884 guidelines to (A) avoid focusing solely on CBR to determine cost recovery, (B) move away from the use of an average CBR to determine project cost recoverability, as doing so makes cost recovery for one project dependent on the performance of another, and (C) use a threshold net benefit metric rather than an average CBR to guide program management.

### A. <u>The Final Program Requirements Should Not Focus Solely on Cost-Benefit Ratio to Determine Cost Recovery</u>

The Staff Proposal conditions approval of project-level cost recovery on achievement of an average CBR.[12] PG&E supports the Commission's focus on ensuring that prudent investments are made on behalf of customers and that undergrounding programs deliver sufficient benefits relative to their costs. However, rather than focus solely on CBR as the metric by which to determine project-level cost recoverability, PG&E instead recommends that the final program requirements direct electrical corporations to propose and justify an approach to ensuring their undergrounding programs provide adequate benefits to customers, within the parameters of SB 884.

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[12] Staff Proposal, p. 9.

The staff proposal requests that an electrical corporation's SB 884 application include forecasted average full-program and annual cost-benefit ratios for undergrounding projects,[13] and states that if an electrical corporation does not achieve its approved forecast of average CBR, "cost recovery will be denied for as many projects as necessary to bring the recorded CBR average up to the approved target."[14] The CBR concept is an outcome of the Commission's Risk-Based Decision-Making Framework (RBDMF) proceeding.[15] The RBDMF requires investor-owned utilities to use a Cost-Benefit Approach to assess and rank risks and mitigations in their Risk Assessment Mitigation Phase (RAMP) and General Rate Case (GRC) filings, starting with PG&E's 2024 RAMP filing. PG&E agrees the Cost-Benefit Approach is helpful, however, PG&E notes that the Commission has stated that it does not intend CBR to be the "sole determinant" of risk mitigation strategies.[16] In a RAMP proceeding, a utility is assessing and ranking enterprise risks and mitigations whereas in an SB 884 program, an electrical corporation will be evaluating the relative merits of multiple mitigations at different project locations. Therefore, alternative approaches may be appropriate for SB 884 programs.

One alternative to CBR is a net-benefit approach, which uses the difference between the monetized benefits and costs of a project. Net benefit uses the same components as CBR, but better accounts for the absolute size of benefits—relative to cost—helping an electrical corporation optimize for total risk reduction.

PG&E agrees that it may be useful for electrical corporations to forecast and report on average cost-benefit statistics for their undergrounding portfolios and to provide an explanation if they do not achieve their forecasts. However, PG&E does not believe that cost recovery for projects should be narrowly conditioned on average CBR.

[13] Staff Proposal, p. 7.
[14] Staff Proposal, p. 9.
[15] Rulemaking (R.) 20-07-013.
[16] Decision (D.) 22-12-027, p. 26.

### B. Use of an Average CBR Inappropriately Conditions Cost Recovery for One Project on the Performance of Others

As noted above, the Staff Proposal requires electrical corporations to forecast and achieve average CBRs, and conditions cost recovery for individual projects on achievement of a program-level average CBR. In addition to believing that a different metric, such as net benefit, may be more appropriate for SB 884 programs than CBR, PG&E is particularly concerned with the reliance on *average* CBR in the Staff Proposal. This is because, by conditioning cost recovery for individual projects on program-level achievement of an average CBR, the Staff Proposal makes cost recovery for any one undergrounding project dependent on the performance of other projects. This could lead to the Commission denying cost recovery for projects that offer meaningful wildfire risk reduction, and other reliability and public safety benefits, if circumstances at the program level result in average cost-benefit targets not being achieved. This would undermine SB 884's direction to prioritize undergrounding projects based on wildfire risk reduction, public safety, cost efficiency, and reliability benefits.

As the Staff Proposal is written, if one project is or is not completed in such a way that it lowers the program's average CBR, another project—which in a different portfolio would have been acceptable—will be denied cost recovery solely to bring the average CBR up to the prescribed level. Retrospectively denying cost recovery for completed undergrounding projects to achieve a target average CBR is not a meaningful evaluation of the benefits of an individual project. On the contrary, trying to achieve a certain target average CBR could require continuous adjustments to a workplan that would result in much less efficient execution.

To illustrate the issues that will arise from requiring electrical corporations to achieve a target average CBR, PG&E offers the following example in Table 1 below.

**TABLE 1**
**EXAMPLE COST RECOVERY MECHANISM BASED ON AVERAGE CBR**

| Project | Original Forecast CBR | Actual CBR | Approved for Cost Recovery? | Revised Portfolio to Achieve CBR Target |
|---|---|---|---|---|
| **Project A** | 2.0 | 2.0 | No | |
| **Project B** | 3.0 | 3.0 | Yes | 3.0 |
| **Project C** | 2.0 | 2.0 | Yes | 2.0 |
| **Project D** | 4.0 | 4.0 | Yes | 4.0 |
| **Project E** | 3.0 | 2.7 | Yes | 2.7 |
| **Average CBR** | **2.80** | **2.74** | | **2.93** |

- An electrical corporation submits a portfolio of five projects for cost recovery with an average CBR of 2.8.
- Upon completion of the work, the average CBR for the portfolio is 2.74, because the CBR for one project (Project E) was lower than forecast.
- To achieve the target CBR for the portfolio, cost recovery for project A (or C) is denied.

In this example, cost recovery for Project A is denied as a mathematical exercise and does not consider the risk reduction or other benefits the project delivered. The electrical corporation does not have the opportunity to discuss with the Commission the reasons that it did not achieve the CBR.[17] PG&E understands that there will be cost targets for the undergrounding program and will commit to meeting those targets. However, in a complex, multi-year program, there will be issues outside of an electrical corporation's control that will impact project costs. Utilities should at least be given the opportunity to recover the costs up to the unit cost targets that it records for undergrounding work that benefits customers and to submit costs in excess of the cost cap for reasonableness review.

Continuing the example in Table 1, if Project A was included in a different portfolio that achieved the CBR target, the project costs would be approved. Manipulating a portfolio to

[17] Another example not shown in Table 1 would be if Project D, the project with the highest risk reduction value in the portfolio, did not meet its target CBR. To meet the average CBR both Project A and Project C would be denied. The electrical corporation would be denied cost recovery for completing two projects that reduced system risk because one project did not meet a CBR for reasons that may be out of its control and without any recourse for recovery.

achieve a pre-determined CBR target is not in customers' best interests and will impede the efficient execution of work focused on reducing wildfire risk.

Given the nature of the average statistic,[18] the problems raised by use of a CBR will be present whether performance is measured against an annual average CBR target, if performance to date is periodically measured against a full-program CBR target, or if performance against the full-program CBR target is measured only at the completion of the entire program. The problems will be exacerbated if performance is measured before completion of the entire program—that is, if performance is measured annually against an annual average CBR target or if performance to date is periodically measured against a full-program CBR target—because the time needed to complete a project may vary from the original proposed completion date.

Furthermore, the Staff Proposal's requirement that if an electrical corporation updates its project list due to updates to its risk model, it must maintain the originally forecast average CBR,[19] will not be practical to implement for two reasons. First, the list of potential undergrounding projects is not infinite. For example, if a project with a CBR of 2.0 is removed from an electrical corporation's workplan, it may not be possible to find another project with exactly the same CBR to "replace" it to maintain the same average CBR target. Second, a program that appropriately addresses the highest-risk projects first will see year-by-year risk reduction values go down over its life, because the highest-risk projects have already been completed. Therefore, as a program progresses, the CBR of the remaining projects may be inherently less than the higher-risk projects completed earlier in the program. An appropriate remedy for these issues would be to permit electrical corporations to update their cost-benefit targets when needed throughout the program, as discussed below.

### C. <u>A Threshold Net Benefit Metric Should Be Used Rather than an Average CBR to Guide Management of the Program</u>

[18] When an average is calculated over a population, some units in the population will have a lower value than the average and some will have a higher value.
[19] Staff proposal, p. 9.

Rather than using an average CBR to determine cost recoverability, PG&E proposes the use of a minimum, per-project cost-benefit threshold (minimum net benefit) in the final SB 884 guidelines. A minimum cost-benefit threshold would make clear *in advance of project execution* what cost-benefit criteria must be met for a project to be cost recoverable, rather than delaying that determination until after projects have been executed. The Commission would still assess projects' actual relative costs and benefits after the projects are completed, but the level that a project must meet to be cost recoverable would be clear up front, and electrical corporations would have the ability to manage to it.[20]

PG&E proposes that each large electrical corporation include in its SB 884 application a minimum cost-benefit threshold for project-specific cost recovery. Electrical corporations can explain how this target was derived and justify it in their applications, and stakeholders will have the opportunity to comment on each proposal. The Commission will have the opportunity to review and approve the minimum threshold. This flexibility is important given the different challenges utilities face in different geographic regions. As discussed in the following section, PG&E also believes that electrical corporations should have the opportunity to seek Commission staff approval of updates to this forecast threshold in their semi-annual reports over the life of the undergrounding program, should conditions materially change.

## III. ELECTRICAL CORPORATIONS SHOULD HAVE THE OPPORTUNITY TO UPDATE FORECAST TARGETS FOR COMMISSION APPROVAL

Electrical corporations should have the opportunity to seek Commission approval of updates to their forecast targets (including cost, cost-benefit, mileage, unit cost, etc.) in their semi-annual reports, Tier 3 Advice Letter submissions, or another mechanism to be determined by the Commission, over the life of the undergrounding program. Over the course of the program, many relevant factors including risk models, environmental conditions, technologies,

[20] Having up-front confidence in cost recovery also will facilitate efforts to apply for available federal, state, and other non-ratepayer moneys throughout the duration of the approved Plan, as those funds are typically conditioned on advance identification of specific projects to be performed and the electrical corporation obtaining matching funds to support the proposed scope of work.

and market conditions will change. As the Staff Proposal acknowledges, an electrical corporation may update its risk model and seek to incorporate its latest understanding of risk into its future project plans.[21] Risk model changes may impact the risk mitigation benefits elements of the net benefit calculation. Project costs may be impacted by many factors such as construction timing, technologies deployed, inflation, supply chain constraints, contracting efficiencies, and economies of scale. Application forecasts for future years represent electrical corporations' best available estimates, but forecasting far into the future requires making many assumptions. PG&E requests that updates to forecast targets be allowed to ensure that the forecast annual and overall targets electrical corporations are working to meet reflect current realities, market conditions, and understanding of risk.

## IV. ITEMS FOR CLARIFICATION

Several items in the Staff Proposal require clarification before final SB 884 guidelines are issued. PG&E identifies these items below. PG&E also looks forward to commenting on the proposed final SB 884 guidelines when they are completed.

### A. The Definition of a "Project" Should Be Clarified as Different Levels of Information are Available for Future Undergrounding Work

The definition of a "Project" is unclear in the Staff Proposal. There are multiple requirements associated with the reporting and analysis at the project level including: "The Application shall present the forecasted average Cost-Benefit Ratio (CBR) across *all projects* expected to be completed in each of the 10 years of the Application period, broken out by year and for the total Application period"[22] and "the average recorded CBR for *all projects* completed in a year must equal or exceed the approved average target CBR for that year"[23] (emphasis added).

[21] Staff proposal, p. 9.
[22] Staff proposal, p. 7.
[23] Staff proposal, p. 8.

PG&E defines a "project" at the circuit segment level (also referred to as circuit protection zone (CPZ)) because its current risk model measures risk at the circuit segment level and does not have more granular risk detail. Project reporting is available at the CPZ level. When projects are scoped and planned for near-term completion (e.g., within 3 – 4 years), PG&E creates sub-projects, or jobs, which will reflect portions of a CPZ. PG&E identifies jobs based on mileage, diversity of risk ranking, dependencies (e.g., easements, environmental permitting issues) and constructability. As the risk models are periodically updated and released, projects may be added to the workplan, reprioritized, or removed.

To demonstrate the level of data available for reporting and substantiate the rationale for clarifying the definition of a "project," PG&E illustrates this issue in a sample project and sub-project-level workplan in Table 2 below (noting not all required reporting fields are included).

Table 2 shows that CPZ 1 has three sub-projects that are in various stages of construction (construction, pre-construction, and scoping). Each of the three sub-projects has a unique Project ID (Orders 1234, 1235, and 1236) to track the sub-project's associated costs. The net benefit of each of the three sub-projects is the same as the net benefit of its CPZ 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.

**TABLE 2**
**SAMPLE PROJECT LEVE 10-YEAR WORK PLAN**

| **Project ID** | **CPZ** | **Status** | **Net Benefit Forecast** | **Miles Forecasted Based on Latest Risk Model** | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | **In-flight sub-projects (jobs)** | | | | **Projects (CPZs) identified by latest Risk Model** | | | | | |
| | | | | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** |
| **CPZ 1** | **CPZ 1** | **Various** | **67.6** | **1** | **7** | **3** | **5** | | | | | | |
| Order 1234 | CPZ 1-a | Construction | N/A | 1 | 4 | | | | | | | | |
| Order 1235 | CPZ 1-b | Pre-construction | N/A | | 3 | 3 | | | | | | | |
| Order 1236 | CPZ 1-c | Scoping | N/A | | | | 5 | | | | | | |
| **CPZ 2** | **CPZ 2** | **Various** | **34.7** | **2** | **7** | **3** | | | | | | | |
| Order 2234 | CPZ 2-a | Construction | N/A | 2 | 1 | | | | | | | | |
| Order 2235 | CPZ 2-b | Permitting | N/A | | 6 | | | | | | | | |
| Order 2236 | CPZ 2-c | Scoping | N/A | | | 3 | | | | | | | |
| **CPZ 3** | **CPZ 3** | **Various** | **20.2** | | | | | **35** | | | | | |

Table 2 shows that circuit segments scheduled for later in the program (2027 in the example above) have not yet been divided into sub-projects. The number of sub-projects and miles within each sub-project will be determined closer to the planned project start date.

For the reasons described above, PG&E recommends that a "project" be defined as a circuit segment or circuit protection zone.

### B. The Commission Should Provide Examples of Triggers for Modification and Resubmission of an Application

The Staff Proposal states that "[b]efore conditionally approving or denying the Application, the Commission may require the large electrical corporation to modify or modify and resubmit the Application. An order to modify the Application would not restart the Commission's nine-month timeline for approving or denying the Application. In contrast, an order to resubmit would result in the nine-month timeline restarting upon resubmittal."[24]

PG&E asks that the Commission provide examples of scenarios that would trigger a modification requirement and examples of scenarios that would trigger a modification and resubmission requirement, assuming the electrical corporation complies with the guidelines provided. This will help electrical corporations ensure they provide the information the Commission needs to issue its decision on the application without the need for further updates.

### C. Clarify that Avoided Cost Calculations May Include Assumptions

The Staff Proposal notes that the Application "shall identify any forecast costs that would be reduced, deferred, or avoided because of implementing the proposed undergrounding plan, and the proposed disposition of the savings." It further directs electrical corporations to provide additional detail on avoided costs.[25]

Electrical corporations may not be able to provide details on avoided costs at the level of granularity the Staff Proposal appears to require. While these avoided costs can be modeled and forecasted based on the number of underground miles completed per year, providing details on

[24] Staff Proposal, p. 4
[25] Staff proposal, p. 6.

when they are avoided at the project level may be unrealistic at that level of specificity. For example, the exact timing of avoided vegetation management costs cannot be precisely known since PG&E will no longer assess trees adjacent to now-undergrounded lines to determine which would have needed trimming or removal if lines had stayed overhead. An electrical corporation will be able to provide a system-wide, annual estimate of avoided vegetation management costs, but cannot definitively report how a specific avoided cost was reallocated. Given the long-term nature of the undergrounding plan, cost savings are expected to materialize and accumulate over time as more miles are undergrounded, which makes tracking avoided costs increasingly complex.

To make a good faith effort to provide the requested cost-avoidance information, electrical corporations would need to develop a forecast of avoided costs based on assumptions. The SB 884 cost application can then support these calculations by providing relevant workpapers.

PG&E therefore suggests that the Staff Proposal's application requirement #5 be revised to read:

> The Application shall identify ***estimates of*** any forecast costs that would be ***materially*** reduced, deferred, or avoided because of implementing the proposed undergrounding plan (such as vegetation management), and ***how spending on programs or areas of work where forecast costs will be materially reduced, deferred, or avoided will be affected*** ~~the proposed disposition of the savings~~. ~~The Application shall distinguish between forecast costs already approved by the Commission for recovery, forecast costs for which the Commission previously denied a request for recovery, and forecast costs that have not yet been the subject of a request for recovery. For forecast costs already approved by the Commission for recovery, the Application shall identify any accounts used to track such costs; the amounts in each such account; and the Commission decision(s) authorizing recovery.~~

### D. <u>The Field Name "HFTD Tier" Should be Updated in Project List Data Requirements</u>

The Field Name "HFTD Tier" suggests the possible values be Tier 2 and Tier 3 in accordance with CPUC High Fire Threat District Tier per D.17-01-009.[26] PG&E recommends adding one additional field for "Fire Rebuild" in the "Category" Field.

## V. CONCLUSION

PG&E appreciates the opportunity to provide these comments and looks forward to continuing to partner with the Commission and stakeholders on this important work. If you have any questions, please do not hesitate to contact the undersigned at Jamie.Martin@pge.com.

Very truly yours,

*/s/ Jamie Martin*

Jamie Martin

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[26] Staff proposal, p. 15.

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September 27, 2023

VIA E-MAIL

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**RE: SDG&E Informal Comments to the California Public Utilities Commission's Staff Proposal for SB 884 Program**

San Diego Gas & Electric Company (SDG&E) provides the following comments on the California Public Utilities Commission (Commission) Safety Policy Division's (SPD) Staff Proposal addressing the Senate Bill (SB) 884 expedited undergrounding program. The Staff Proposal provides additional detail regarding the process and requirements for the Commission's review upon receiving an electrical corporation's ten-year distribution infrastructure undergrounding plan (Program).

SDG&E's comments to the Staff Proposal focus on the need for additional flexibility given the complexity of and long-term planning associated with a long-term undergrounding plan. Namely, both the accounting mechanisms and the overly restrictive application of the cost-benefit metrics fail to allow any adjustments based on what may be reasonable and necessary changes—some of which may be mandated through other proceedings—to risk analyses or program costs. SDG&E requests that the Commission consider these recommendations in developing final SB 884 guidelines.

## I. DISCUSSION

### a. The Staff Proposal Should Reflect Additional Coordination with the Office of Energy Infrastructure Safety Regarding the First Phase of the SB 884 Program.

The Staff Proposal notes the understanding that "Plans approved by Energy Safety will have been found to show that implementation of the Plan will substantially increase reliability and substantially reduce wildfire risk," as required by SB 884.[1] At this point in time, the process that Energy Safety intends to use to assess wildfire risk reduction and increased reliability, seek stakeholder engagement, and review a Program proposal, remains unclear. SDG&E requests that the Commission further engage with Energy Safety during this planning process to ensure the use of consistent metrics and standards and avoid duplicative or conflicting requirements. Coordination and understanding of the entirety of the Program review process will better

[1] Staff Proposal at 5.

promote efficiency and allow for the timely review of Program applications, achieving SB 884's goal of an expedited and efficient establishment of utility undergrounding programs.

**b. The Accounting Process Should Allow for Recording of Costs that Exceed the Conditional Approval**

The Commission should reconsider the overly restrictive cost accounting and annual review process to address Program cost recovery. SB 884's primary objective was to establish a means to perform an expedited review and approval of utility long-term undergrounding programs and ensure a level of financial certainty to make long-term investment commitments to vendors and suppliers. This financial certainty and the ability to enter into long-term arrangements facilitates the efficiencies necessary to drive down undergrounding costs. However, the cost caps foreseen by the Staff Proposal and the lack of any accounting mechanism to address unforeseen costs in excess of the cap leave the electrical corporations with an unreasonable amount of financial certainty in performing work that will have already been deemed reasonable to reduce wildfire risk.

First, the use of cost caps without any method to track or seek recovery of unforeseen additional costs is unwarranted and does not align with the intent of SB 884, which foresees the continued use of balancing accounts in facilitating expedited recovery of undergrounding costs.[2] By requiring the Commission to consider continued use of balancing accounts, the Legislature explicitly rejected the concept of a cost cap associated with undergrounding. But despite this clear mandate, the Staff Proposal prescribes the use of balancing treatment and fails to provide for any mechanism to address costs over a "predetermined cap," which will "not be authorized for recovery."[3] This is an overly restrictive approach that fails to recognize the many variables related to undergrounding projects.

While SDG&E anticipates ongoing achievement of undergrounding efficiencies, it is unreasonable to prescribe a cost cap without any mechanism to address unanticipated costs which may be entirely outside of the company's control. These can include supply chain issues, material shortages, and inflation. Failing to allow for utilities to record and seek review of costs in excess of a pre-determined cap for projects that reasonably reduce wildfire risk is unnecessarily punitive. Further, it could dilute the desired effect of SB 884 and reduce the financial certainty the Legislature sought to create in establishing long-term undergrounding programs.

For the above reasons, SDG&E recommends that the Commission revise the Staff Proposal to remove any statements that costs in excess of a pre-determined cap will not be eligible for recovery. To recognize the nature of the conditional approval of Program costs associated with an approved Program application, SDG&E recommends that the Staff Proposal be revised to note that upon approval of an Application, the Commission will authorize a two-way balancing account to track Program costs. SDG&E recommends that conditionally approved costs be recovered through an annual Tier 2 advice letter process with a review period not to

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[2] Pub. Util. Code Sec. 8388.5(e)(6) ("The shall consider continuing an existing commission-approved balancing account ratemaking mechanism for system hardening for the duration of a plan, as determined by the commission, and shall authorize recovery of recorded costs that are determined to be just and reasonable.")

[3] Staff Proposal at 12.

exceed six months. For costs in excess of the conditional approval, SDG&E recommends that the Commission allow utilities to submit an application for recovery through a reasonableness review, with a timeline for approval not to exceed twelve months.

**c. The Timeline for Review of the Annual Advice Letters Should Reflect the Expedited Nature of Conditional Approval**

The Staff Proposal as written currently fails to account for and provide a mechanism for expedited cost recovery as envisioned by SB 884. As written, Phase 2 of the Program (Review and Recovery of Recorded Costs) commences with the submission of a Tier 3 Advice Letter and "may extend over a series of periodic Advice Letter filings … over the 10-year Program period."[4] Further, the Staff Proposal implies that conditional approval of the cost targets laid out in the electrical corporation's Application may ultimately be revised and reduced with the benefit of hindsight.[5] Further, the Staff Proposal does not establish a timeline for these reviews. SDG&E recommends revisions to both of these elements of the Staff Proposal to better reflect the certainty that the Legislature sought to create in passing SB 884 and to address timely and efficient cost recovery.

First, SDG&E proposes that the Commission revise the Staff Proposal to establish a presumption that recorded Program costs up to 100% of the conditional approval are just and reasonable. The Staff Proposal currently establishes a secondary reasonableness review for all conditionally approved Program costs, which defeats the objectives of the original application process. Costs would have to be reviewed all over again, creating not only significant and redundant administrative workload for the Commission, the electrical corporations, and stakeholders, but also leaving the electrical corporations exposed to the uncertainty and financial risk that SB 884 was specifically enacted to reduce. A presumption of recovery of conditionally approved costs is consisted with SB 884 and reasonable in this instance.

If Program costs exceed the conditional approval, SDG&E recommends that the Commission establish an application process, as described above, to review and approve any costs determined to be just and reasonable. This buffer allows the flexibility to respond to changing times, respond to changing understanding of risk, and to invest in new technologies and effective mitigations that may arise.

Finally, the Staff Proposal should clearly establish a timeline for review of costs to promote regulatory certainty and avoid the build-up of cost recovery submissions. Annual Program costs should be reviewed and implemented in rates on an annual basis to avoid accumulated debts on the electrical corporations' balance sheet and to smooth rate impacts. As discussed previously, SDG&E recommends that costs up to 100% of the conditional approval be reviewed and authorized through a Tier 2 Advice Letter within six months, and Applications for

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[4] Staff Proposal at 9.

[5] Staff Proposal at 11.

recovery of costs in excess of conditional approval be reviewed and approved within twelve months.

**d. The Commission Should Allow for Consideration of Metrics Outside of Cost-Benefit Ratios**

The Staff Proposal requests that an electrical corporation's SB 884 application include forecasted average full-program and annual cost-benefit ratios for undergrounding projects,[6] and states that if an electrical corporation does not achieve its approved forecast of average CBR, "cost recovery will be denied for as many projects as necessary to bring the recorded CBR average up to the approved target."[7] The CBR concept is an outcome of the Commission's Risk-Based Decision-Making Framework (RBDMF) proceeding.[8] While the Cost-Benefit Approach is helpful in assessing the reasonableness of a proposal, the Commission has stated that it does not intend CBR to be the "sole determinant" of risk mitigation strategies.[9] Further, because a Program application will not be comparing risk mitigation strategies across its risk portfolio, as it would in a Risk Assessment Mitigation Phase (RAMP) filing, the Commission should remain open to alternative approaches when considering an SB 884 Application.

Additionally, the RBDMF proceeding is ongoing, and the value of benefit is not yet clearly defined. SDG&E requests that the Staff Proposal remove the overly prescriptive use of CBRs and provide additional flexibility to assess the full scope of risk reduction and benefits of undergrounding projects.

**e. The Program Should Allow for an Update or Change Order Process**

Over the course of the program, it is undeniable that many relevant Program factors, including but not limited to risk models, environmental conditions, technologies, and markets may change. While the Program Applications will inlcude a best effort to make estimates using available information, this will invariably involve the use of assumptions in setting Program targets. Due to the long-term nature of the Program targets, the Staff Proposal should allow for a process to seek Commission approval of updates to forecast targets. SDG&E recommends that this take place through the electrical corporation's semi-annual report or a Tier 3 Advice Letter submission on a cadence to be determined by the Commission. SDG&E further requests that the Commission consider aligning such a process with the WMP Change Order process in place at Energy Safety.

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[8] Rulemaking (R.) 20-07-013.

[9] Decision (D.) 22-12-027, p. 26.

## II. CONCLUSION

SDG&E appreciates the CPUC's consideration of these comments on the Staff Proposal, and requests that the CPUC take these recommendations into account in further refining the Staff Proposal.

Respectfully submitted,

*/s/ Laura M. Fulton*

Attorney for

San Diego Gas and Electric Company

**INFORMAL COMMENTS OF THE UTILITY REFORM NETWORK (TURN) ON THE CPUC STAFF PROPOSAL FOR THE SB 884 PROGRAM**

September 27, 2023

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THE UTILITY REFORM NETWORK

**Informal Comments of The Utility Reform Network (TURN)**
**On the CPUC Staff's Proposal for the SB 884 Program**

## 1. Introduction and Summary

The Utility Reform Network (TURN) appreciates this opportunity to provide these informal comments on the CPUC Staff Proposal for the SB 884 Program. The Staff Proposal is a thoughtful effort at implementing a complex statute. TURN particularly welcomes the detailed, project-specific data requirements specified in Appendix 1 to the Staff Proposal and the elements that are designed to protect ratepayers from overruns and promote accountability for utility claims that unit costs of undergrounding will diminish over time.

These comments and the accompanying mark-up of the Staff Proposal will provide TURN's initial and preliminary recommendations for improvements to the Staff Proposal, with as much specificity as possible in the time afforded for these comments. An important caveat is that the CPUC Staff Proposal relates to only one-half of the process for review and approval of undergrounding plans. TURN's recommendations may very well change once the Office of Energy Infrastructure Safety (Energy Safety) shares a proposal for the implementation of the portion of the process over which it has responsibility, and as TURN considers other parties' comments.

These comments should be read in conjunction with TURN's specific recommended modifications to the Staff Proposal attached as Appendix A. TURN appreciates the time and effort that CPUC Staff devoted to drafting its proposal and believes that this SB 884 implementation process can best be advanced by equally specific proposed modifications from the parties. Section 2 of these comments presents the key recommendations that are reflected in TURN's Appendix A modifications. Section 3 concludes by providing TURN's recommendations for next steps in this implementation process.

## 2. Key Recommendations Reflected in TURN's Appendix A Redline of the Staff Proposal

### 2.1. The Utilities Must Be Required to Show that The Deployment of Undergrounding Is Prioritized by Risk

SB 884 requires utilities to prioritize undergrounding projects "based on wildfire risk reduction, public safety, cost efficiency, and reliability benefits."[1] As a matter of statutory compliance and the sound policy of targeting grid hardening where it is most needed, utilities should be required to prioritize hardening in the highest risk locations first before hardening lower risk areas. While the requirements related to prioritizing projects based on risk appear in sections related to Energy Safety's responsibilities, project prioritization is also important to the CPUC's responsibilities to ensure that the plan costs are just and reasonable.

In particular, the efforts in the Staff Proposal to cap costs will not be meaningful unless the utilities are required to prioritize projects based on risk. Otherwise, utilities will be able to manipulate their total costs and unit costs by including in their annual plans relatively low risk and low cost projects that will improve their cost numbers. Because risk is highly concentrated in relatively few circuit segments, such a result would be contrary to the important goal and statutory requirement of prioritizing projects based on risk reduction.

Accordingly, TURN's redline in Appendix A includes several changes to ensure that projects are prioritized by risk, including:

- Application Conditional Approval, Denial, or Modification & Resubmittal – providing that an order to resubmit will be required if Application fails to prioritize projects based on risk rank.
- Application Requirements, # 14 – detailing information that must be provided in Application to demonstrate that the deployment of undergrounding will be prioritized based on risk.
- Conditions for Approval, #5 – specifying as a condition for approval that utility demonstrate that it has prioritized projects in the highest risk locations before pursuing lower risk work.
- Phase 2 – Review of Recorded Costs for Rate Recovery, Table 1 – including condition to prioritize projects from highest to lower risk locations and the data needed to satisfy that showing
- Consequences for Failure to Satisfy Conditions of Approval, #4 – stating that cost recovery will not be provided for any lower risk project completed when higher risk locations have not been hardened.

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[1] PU Code Section 8388.5(c)(2). Subsections (3) and (4) of this same provision also refer to "prioritized undergrounding projects."

TURN's redlines related to this issue recognize that the goal should be to prioritize the deployment of grid hardening mitigations, be they overhead hardening or undergrounding, based on risk. Accordingly, the utility can satisfy TURN's recommended prioritization requirements by showing that a higher risk-ranked location has been overhead hardened.

### 2.2. The Utilities Must Show that Each of their Proposed Undergrounding Projects Is the Most Cost-Effective Grid Hardening Mitigation Based on the Local Conditions at Each Project Location

SB 884 also recognizes the importance of demonstrating that undergrounding is more cost effective than other grid hardening alternatives.[2] Section 8388.5(c)(4) requires that each undergrounding project be compared with overheard hardening mitigations, including covered conductor, with and without current limiting technologies such as REFCL. This comparison shall include considerations of risk reduction and cost "separately" for each project. This statutory requirement is consistent with the record in both WMP proceedings before Energy Safety and in CPUC GRCs, which show that whether undergrounding is more cost effective than alternatives can depend significantly on which risk drivers are present in a particular location, as well as the cost and time to complete an undergrounding project, which is highly variable depending on local characteristics.

To satisfy the statutory goal of project-specific cost-effectiveness, the CPUC's assessment of whether rate recovery is warranted should include a requirement that the utility show that it is deploying undergrounding only where it is the more cost-effective alternative at a given location. TURN's Appendix A redlines recommend several changes to address this issue, including:

- Application Conditional Approval, Denial, or Modification & Resubmittal – providing that an order to resubmit will be required if Application fails to identify the most cost-effective project for each location.
- Application Requirements, ## 9, 10 – requiring utility to provide project-specific CBRs for undergrounding and all reasonable alternative grid hardening mitigations, including where appropriate covered conductor combined with current limiting technologies such as REFCL.

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[2] *E.g.* Section 8388.5(c)(2), requiring a means of prioritizing projects based on "cost efficiency"; Section 8388.5(c)(4), requiring comparison of undergrounding with aboveground hardening for each project comparing, among other things, risk reduction and cost; Section 8388.5(e)(1)(A), requiring plan submitted to CPUC to show any improvements in risk reduction and cost of undergrounding compared to alternative mitigations.

- Application Requirements, #11 – requiring utility to show that, for each proposed project, that the CBR exceeds the CBR of all reasonable grid hardening mitigations that were considered.
- Conditions for Approval, # 4 – utility must show that the updated CBR for each project exceeds the updated CBR for all reasonable grid hardening mitigations that were considered.
- Phase 2 – Review of Recorded Costs for Rate Recovery, Table 1 – including condition that project CBR exceed CBR for all alternatives, and the data needed to satisfy that showing.
- Consequences for Failure to Satisfy Conditions of Approval, #3 – stating that cost recovery will not be provided for any project where the updated CBR for a grid hardening alternative is higher than the recorded CBR for the project.

### 2.3. The Staff Proposal Would Benefit from Additional Requirements to Ensure that Utility Undergrounding Plans Are Cost-Effective

The Staff Proposal (p. 8) includes a condition that the average recorded CBR for all projects completed in a year must equal or exceed the approved CBR for that year. This provision has the potential to promote a measure of cost-effectiveness in utility undergrounding plans, but needs to be strengthened. The most important requirement that should be included relating to CBR is described in the previous section. As discussed, the key issue is whether undergrounding is more cost-effective than overhead hardening alternatives. This important comparison is addressed by TURN's recommendations discussed in the previous section, which TURN views as essential to meet statutory requirements and to ensure that ratepayer-funded undergrounding represents the most cost-effective grid hardening solution.

A problem with the Staff Proposal's CBR condition is that it is subject to manipulation by the utility. For example, a utility could manipulate the timing of completion of a project that would reduce the average CBR below the approved level by deferring completion to the next year, which for a year-end project, could mean a delay of only days or weeks. Furthermore, the use of averages allows a utility to offset low CBR projects that do not make sense to perform with high CBR projects.

TURN recommends buttressing the Staff Proposal average CBR condition with a further requirement that the CBR for each project should equal or exceed a minimum CBR specified in the CPUC's decision conditionally approving a plan. This modification is reflected in the following sections of TURN's redline of the Staff Proposal: (1) Conditions for Approval, #3; (2) Phase 2 – Review of Recorded Costs for Rate Recovery, Table 1; and (3) Consequences for Failure to Satisfy Conditions of Approval, #3.

### 2.4. In Applying Cost Caps, the Commission Should Limit the Allowance of Contingency Adders

The Staff Proposal (pp. 8-9) includes as a condition of approval cost caps for total annual costs and unit costs, "plus a 10 percent contingency allowance for unexpected circumstances." TURN recommends two changes to this provision for a contingency adder.

First, it is premature to mandate a contingency in these implementation rules. When it reviews an Application, the Commission can determine whether a contingency is warranted. A utility should be required to justify a contingency in its Application based on a showing of the reasons why its forecast cost is subject to unexpected circumstances.

Second, the inclusion of a contingency runs counter to the goal of holding utilities accountable for their claims that they will be able to achieve their forecast unit costs and that unit costs will decline significantly over time. Utilities should be expected to exercise greater control over their undergrounding costs as they gain more experience with this work. In addition, the SB 884 undergrounding plan of PG&E, for example, will likely begin in 2027, after it has had more than five years of undergrounding experience as a wildfire mitigation. Thus, TURN recommends that, if the Commission allows a contingency adder, it should be limited to the first year (or at least the early years) of the plan.

TURN's recommended changes to the Proposed Rules would thus make the addition of a contingency discretionary (zero to 10 percent) and limit any such contingency to only the first year of the plan. These changes are reflected in Appendix A in Conditions for Approval, ## 1,7.

### 2.5. Utilities Must Be Required to Demonstrate How the Commission Can Ensure that Ratepayers Will Fully Benefit from Any Claimed Cost Reductions

Section 8388.5(e)(1) requires the utility's submission to the CPUC to show cost targets that will decline over time and a strategy for cost reductions over time. Related to this showing, the Staff Proposal (p. 5) would require the utility to identify any forecast costs that would be reduced, deferred or avoided by virtue of the plan and "the proposed disposition of the savings." To ensure that utilities are held accountable for their claims that undergrounding will significantly reduce other current costs, this element of the Staff Proposal must be strengthened. Utilities should be required to include a methodology by which the Commission can ensure that these claimed cost savings will be achieved. (See Appendix A, Application Requirements, #5).

### 2.6. The Commission's Review Must Include An Analysis of All of the Factors that the CPUC Typically Examines Before Approving Cost Recovery under PU Code Section 451 and Other Statutes

SB 884 does not change the bedrock requirements of Public Utilities (PU) Code Sections 451 and 454 that, before any costs may be added to rates, the CPUC must find those costs to be just and reasonable. Thus, the CPUC is already legally obligated to carefully consider all factors affecting whether rates resulting from an approved undergrounding program would be just and reasonable, including; affordability, the competing demands on ratepayer funds, the effect of elevated electric rates on electrification goals and environmental and social justice goals. Affordability and the avoidance of disconnections must also be considered under PU Code Sections 382, 718 and 739.13 and are particularly important considerations given the extensive and costly undergrounding programs proposed by certain utilities. The SB 884 implementation process must ensure that these statutory requirements for the approval of undergrounding-related cost and rate increases are satisfied.

TURN's redline includes changes to make clear that the Commission's role includes finding that all of the requirements associated with Section 451 have been satisfied (see Phase 1 – Application Submission and Review, first paragraph) and that the utility's submission must include all showings necessary to satisfy Section 451 and other requirements applicable to requests to add new costs to rates (see Application Requirements, #1).

In addition, in order for the CPUC to make a better informed determination of the full impact of the utility's proposed plan on customer rates and bills, TURN recommends that utilities be required to provide information about the incremental effect of the plan on revenue requirements and bills, *for each year that proposed undergrounding costs would be included in rate base.* (see Appendix A, Application Requirements, #4) Undergrounding will have a long-term impact on customer rates for decades and the CPUC should be aware of that full impact before conditionally approving any plan. The utility should present those long-term impacts in both nominal and present value terms, provided that the present value numbers disclose the discount rate that was applied.

### 2.7. SB 884 Should Not Allow Utilities to Re-Litigate Prior CPUC Decisions Regarding the Appropriate Scope and Cost of Undergrounding

The Staff Proposal includes an asymmetric and unfair provision that would allow the utility to re-litigate undergrounding targets and cost forecasts that were previously disallowed by the CPUC, but prohibit other parties from re-litigating the CPUC's prior approvals of undergrounding targets and costs.[3] Nothing in SB 884 requires such one-sided rules. In fact, SB 884 directs the CPUC to consider not revising such previous determinations.[4]

To fairly implement the statute and to avoid undue demands on CPUC and party resources, the Staff Proposal should be modified to bar any party from re-litigating the CPUC's prior undergrounding determinations, as reflected in TURN's edits to the Application Requirements, #3(a) and (c). If the Commission nevertheless wishes to invite utilities to engage in such re-litigation, then other parties should be given the same opportunity to re-litigate prior approved undergrounding targets and costs.

### 2.8. The Proposed Procedures Should Be Clarified and Modified to Ensure Sufficient Opportunity for Analysis and Informed Comment by Interested Parties

TURN recommends changes to the Staff Proposal's procedures regarding modification and resubmittal of the initial Application and regarding Phase 2 requests for recovery of recorded costs. In addition, in light of the accelerated timeframe for decisions, TURN recommends a three business day turnaround for discovery requests.

Regarding the initial Application, in light of the accelerated nine-month process, TURN recommends changes to ensure that utilities do not gain an unfair advantage in by withholding significant information from their Applications. TURN's edits (to Application Conditional Approval, Denial, or Modification & Resubmittal, second paragraph) would require re-submittal whenever the utility fails to provide information that the CPUC deems important to process the Application, and would specify that information showing the most cost-effective grid hardening alternative for each proposed location and the risk ranking of project locations is important information that must be supplied to avoid a re-submittal. In addition, TURN recommends another option for the CPUC, pausing of the decision-making clock when the utility is required to submit additional material information that falls short of being important to the processing of the Application.

With respect to Phase 2, TURN strongly objects to the proposal that determinations allowing recovery of recorded costs be made via Tier 3 Advice Letter submissions. Advice letters are not designed to accommodate decisions approving cost recovery, particularly decisions such as are required here -- that would require review and analysis of significant volumes of updated information regarding recorded costs, unit costs, compliance with cost caps, re-calculated CBRs based on updated information, to name just some of the many categories that would need to be reviewed. As is the case with all advice letters, interested persons would have

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[3] Staff Proposal, p. 6, Application Requirements, #3.

[4] PU Code Section 8388.5(e)(3).

only 20 days to submit comments, which is plainly insufficient for parties to provide meaningful comments to the CPUC. TURN's redline (Phase 2- Review of Recorded Costs for Rate Recovery) recommends that cost recovery requests be made by application, with clearly prescribed data requirements for the applications in order to facilitate timely processing.

With respect to both the initial and subsequent Phase 2 applications, TURN recommends that utilities be required to respond to data requests within three business days, consistent with the procedures that Energy Safety prescribes for WMP proceedings.

### 2.9. Risk Model Changes that Would Modify the List of Conditionally Approved Projects Should Be Reviewed Via a Petition for Modification

The Staff Proposal (p. 12) appropriately considers the likely possibility that, during the duration of the plan, the utility's risk model will change and that the changes would affect the list of projects included in the utility's plan. However, under the Staff Proposal, there would be no formal opportunity for parties to review the modified model and the resulting changes to the list of projects.

As an initial matter, TURN supports updating project plans based on improved models and updated information regarding costs and risk reduction benefits. TURN has made edits throughout the Staff Proposal to ensure that projects that proceed with undergrounding actually meet the prescribed conditions when they are performed, not just based on forecasts.

TURN disagrees with the absence of any formal process for reviewing risk model changes that affect the conditionally approved projects. Risk models are complex and can be controversial. Utility changes should not be accepted without an opportunity for scrutiny by the parties. In addition, a risk model change could justify reducing the scope of undergrounding projects in favor of other grid hardening alternatives. Cost and CBR caps do not protect ratepayers from the deployment of undergrounding where risk models show it to no longer be cost-effective.

To afford adequate scrutiny to risk model changes and resulting impacts on conditionally approved projects, TURN recommends using the well-established petition for modification procedure,[5] which applies when a party is seeking to modify a CPUC decision (see Appendix A, Conditions for Approval, #6 and Consequences Section #5). The rules governing petitions for modifications afford the CPUC ample discretion to tailor the process and procedures for resolving the petition based on the situation presented.

[5] CPUC Rules of Practice and Procedure, Rule 16.4.

### 2.10. Appendix 1 Should Require Corresponding Project-Specific Information Regarding All Reasonable Grid Hardening Alternatives

Appendix 1 to the Staff Proposal appropriately requires the utility to submit project-specific information regarding the proposed undergrounding project and overhead system hardening. TURN recommends that Appendix 1 be clarified to require this information for each overhead hardening alternative that is reasonable to consider for the location. For example, in many locations, the utility should consider covered conductor by itself as one mitigation and covered conductor coupled with a current limiting technology as a separate overhead hardening mitigation. The cost, risk reduction, and CBR results will differ under these two alternatives and should be separately considered.

### 2.11. Phase 2 Applications Should Include Updated Appendix 1 Information

Utilities should be required to submit updated information in their Phase 2 Applications (not Tier 3 advice letters – see Section 2.8 above) to demonstrate that they have complied with the conditions in the decision granting conditional approval. To this end, utility applications should include the complete updated project-specific information specified in Appendix 1. This information should be updated as of no earlier than three months before the date of submitting the Phase 2 application.

## 3. Conclusion and Recommended Next Steps

TURN appreciates the opportunity to submit these informal comments and looks forward to reviewing the comments of other interested stakeholders.

TURN recommends that the CPUC host a workshop to allow discussion of the Staff Proposal and parties' comments, followed by an opportunity to submit follow-up comments. The workshop and comments would be most productive if took place after Energy Safety shares its proposal for implementing its responsibilities under SB 884, to help parties better understand how the two parts fit together.

Dated: September 27, 2023

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**THE UTILITY REFORM NETWORK**

**Appendix A - TURN Redline of Recommended Changes to Staff Proposal**

California Public
Utilities Commission

# Staff Proposal for SB 884 Program

S A F E T Y P O L I C Y D I V I S I O N

September 2023

# Table of Contents

# Purpose:

This Staff Proposal, if adopted, will satisfy the Commission's statutory obligation, pursuant to Public Utilities Code Section 8388.5(a), to establish an expedited utility distribution undergrounding program consistent with Senate Bill No. 884 (SB 884). This Staff Proposal addresses the process and requirements for the Commission's review of any large electrical corporation's 10-year distribution infrastructure undergrounding Plan (as defined below) and its related costs.

# Background:

SB 884, enacted September 29, 2022, authorizes only those electrical corporations with 250,000 or more customer accounts (i.e., large electrical corporations) within the state to participate in the expedited program.

To participate in the program, the large electrical corporation must submit a 10-year distribution infrastructure undergrounding plan (hereafter, "Plan"), including, among other requirements, the undergrounding projects that it will construct as part of the Plan, to the Office of Energy Infrastructure Safety (Energy Safety). Energy Safety is required to review and approve or deny the Plan within nine months of submission. Before approving the Plan, Energy Safety may require the large electrical corporation to modify the Plan. Energy Safety may only approve the Plan if it finds that the electrical corporation's Plan will achieve, at the least, both of the following:[1]

1) Substantially increase reliability by reducing use of public safety power shutoffs, enhanced powerline safety settings, de-energization events, and other outage programs.
2) Substantially reduce wildfire risk.

If Energy Safety approves the large electrical corporation's Plan, the large electrical corporation must submit to the Commission, within 60 days of Energy Safety's approval, a copy of the Plan and an application requesting review and conditional approval of the plan's costs (hereafter, "Application"). The Commission must approve or deny the Application within nine months of submission. The Commission may, however, require the large electrical corporation to modify or modify and resubmit the Application prior to approval. An order to modify the Application would not restart the Commission's nine-month timeline for approving or denying the Application. In contrast, an order to resubmit would result in the nine-month timeline restarting upon resubmittal.

If the Plan is approved by Energy Safety and the Application is conditionally approved by the Commission, the large electrical corporation must file progress reports with the Commission and Energy Safety every six months, include ongoing work plans and progress in its annual wildfire mitigation plan submissions, hire an independent monitor (selected by Energy Safety) to review and assess its compliance with the Plan, apply for all available federal, state, and other non-ratepayer moneys throughout the duration of the approved Plan, and use those non-ratepayer moneys to reduce the Plan's costs to its ratepayers.

The independent monitor must annually produce and submit a report to Energy Safety no later than December 1 over the course of the Plan.[2] The independent monitor's report will identify any failure, delays, or shortcomings in the large electrical corporation's compliance with the Plan and provide recommendations for improvements. After consideration of the independent monitor's report and whether the large electrical corporation has cured the deficiencies identified therein, Energy Safety may recommend penalties to the Commission. The Commission may assess penalties on a large electrical corporation that

[1] Energy Safety plans to separately issue guidelines detailing the requirements for submission and review of undergrounding Plans.

[2] Pursuant to Public Utilities Code, Section 8388.5(h), Energy Safety is required to publish these reports on its website.

fails to substantially comply with the Commission decision approving its Plan pursuant to Public Utilities Code, Section 8388.5(i)(2).

Figure 1 below shows an overview of the timelines, events, and responsible parties for implementation of the SB 884 program.

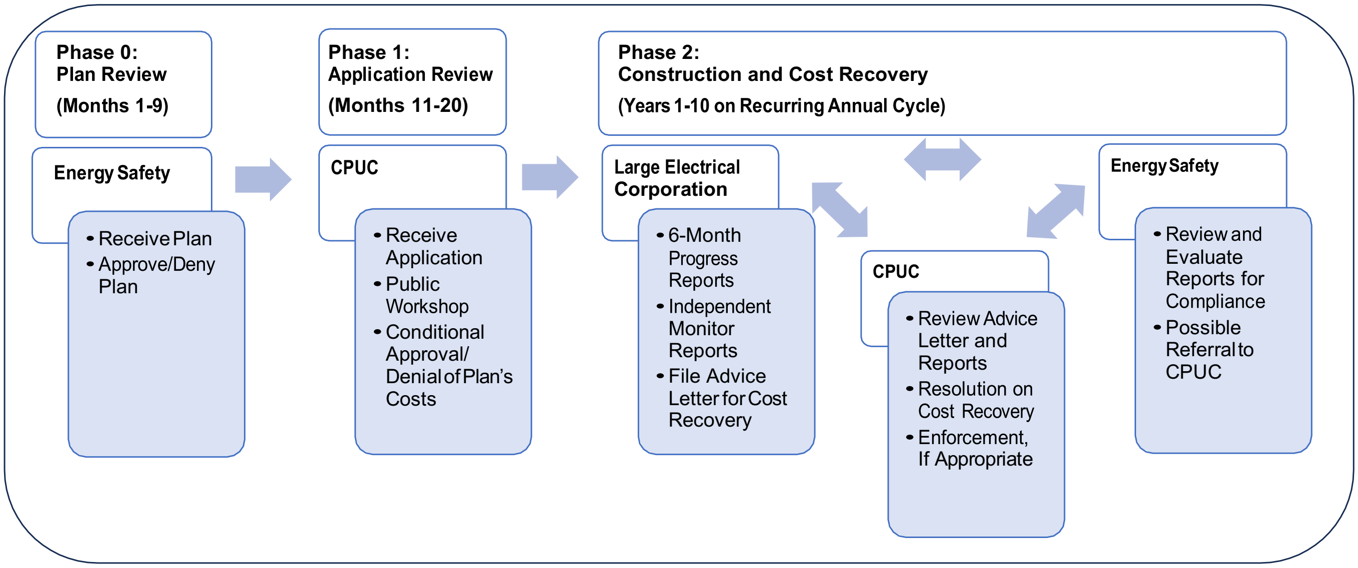


*Figure 1: SB 884 Plan, Application, Reporting, and Cost Recovery Timeline*

# SB 884 Program Process and Requirements:

Staff proposes the following process for review and conditional approval of the Application be executed in two phases:

1) Phase 1: Application submission and review for conditional approval.
2) Phase 2: Periodic reviews of recorded costs and compliance with conditions.

Phase 1 will commence with the submission of an Application for Commission consideration and conclude with the Commission's disposition of such Application (i.e., conditional approval or denial). If conditionally approved in Phase 1, the Commission's conditional approval of the Application will allow the large electrical corporation to record costs related to execution of the Plan with the presumption that the large electrical corporation may collect those revenues in rates if and only if it satisfies the conditions stipulated in the Commission's conditional approval. The Phase 1 conditional approval process will determine whether all ~~necessary~~ required information was provided in the Application, consider whether the Application needs to be modified or modified and resubmitted, consider testimony or ~~testimony~~ comments of parties in a proceeding, whether all or part of the Application's forecasted costs of the Plan should be conditionally approved, and the conditions upon which that approval will be stipulated. The conditions placed on the Commission's Phase 1 approval will consist of the stipulations that the Commission determines are necessary to justify that Plan costs are just and reasonable costs, based on the cost targets and forecasts provided in the Application.

Phase 2 will commence with the submission of an ~~Tier 3 Advice Letter~~Application requesting recovery of costs recorded in connection with the execution of any conditionally approved Plan. Phase 2 will conclude with the Commission's disposition of the last of such ~~cost recovery advice letters~~Applications associated with the Plan. In Phase 2, the Commission will annually, or at such interval determined in the Phase 1 Application proceeding, review recorded costs to determine whether recorded costs were just, reasonable, and satisfied the conditions specified by the Commission in the conditional approval of the Phase 1 Application.

## Application Conditional Approval, Denial, or Modification & Resubmittal:

On or before nine months from its filing date, the Commission shall review and conditionally approve or deny the Application. Before conditionally approving or denying the Application, the Commission may require the large electrical corporation to modify or modify and resubmit the Application.[3] An~~n~~ order to modify the Application would not restart the Commission's nine-month timeline for approving or denying the Application, but an order to make material modifications would pause the timeline. In contrast, an order to resubmit would result in the nine-month timeline restarting upon resubmittal.

An order to resubmit will be made if -the utility fails to provide important information required to process the Application, including the Cost Benefit Ratio of the proposed and alternative mitigations for each project. An order to resubmit will also be required if the utility fails to identify the most cost-effective grid hardening alternative mitigation for each location and to prioritize projects based on risk rank.

An order for modification will be issued for a failure to provide other required information that is not essential to timely processing of the Application.

[3] Public Utilities Code, Section 8388.5(e)(5).

# Phase 1 – Application Submission and Review:

This Staff Proposal understands that Plans approved by Energy Safety will have been found by that Agency to show that implementation of the Plan will substantially increase reliability and substantially reduce wildfire risk, as required in Public Utilities Code, Section 8388.5(d)(2). The Commission's role is to review and conditionally approve costs that the ~~as presented in the subsequent~~ Application demonstrates to meet the just and reasonable requirement of PU Code Section 451. In addition, PU Code Section 8388.5(e(1)(A) requires the Commission to independently find "substantial improvement in safety risk and reduction in costs compared to other hardening and risk mitigation measures over the duration of the plan." Additionally, the Commission will ensure that the Utility is achieving the cost reductions for undergrounding promised and required to justify expanded investment in undergrounding.

## Application Submission Requirements:

Applications submitted to the Commission for consideration of conditional approval of Plan costs requirements.

### Submission Deadline:

Applications for Commission review, and conditional approval or denial of the Plan's costs, as such conditional approval is described herein, must be submitted to the Commission within 60 days following Energy Safety's approval of the Plan.

### Application Type:

Applications shall be submitted according to the Commission's Rules of Practice and Procedure.[4] Applications shall be supported by sworn testimony and detailed workpapers justifying the utility request.

### Application Submission:

The Application shall be filed and served with Commission's Docket Office, with a copy to the Commission's Chief Administrative Law Judge, the service list for large electrical corporation's most recent general rate case (GRC), the SB 884 notification list linked here, as updated, SB884@cpuc.ca.gov, and any other service lists, as determined by the Commission and the large electrical corporation, to broadly reach interested parties.

## Application Requirements:

For the purposes of this Staff Proposal, all program and project costs reported in the Application shall include the standard costs associated with a system hardening conversion project including, but not limited to, program management, project execution, design, estimating, mapping, construction, internal labor, contracted labor, parts, tools, materials, overhead, and permitting.

The following is a list of required content in Applications submitted pursuant to Public Utilities Code, Section 8388.5(e):

1) The Application shall provide all documentation necessary to evaluate the proposed costs and to demonstrate the reasonableness of those costs consistent with PU Code Section 451, other applicable statutes governing the affordability of essential energy services, Commission decisions, and the

Commission's standard Rules of Practice and Procedure.[5]

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4 Rules of Practice and Procedure: California Code of Regulations Title 20, Division 1, Chapter 1. Article 3, Rule 3.2.

5 Rule of Practice and Procedure: California Code of Regulations Title 20, Division 1, Chapter 1. Articles 2-3.

2) The Application shall present cost forecasts for each year of the 10-year Application period, no higher than ~~consistent with~~ the cost targets presented in the Plan approved by Energy Safety.
3) The Application shall clearly identify all undergrounding targets (i.e., miles to underground) and cost targets in the approved Plan that overlap with undergrounding targets and cost forecasts either approved or under consideration in the large electrical corporation's most recent GRC or other cost recovery venues.
    a) Where undergrounding targets and cost targets in the Application overlap with undergrounding targets and cost forecasts either approved or disallowed in the most recent GRC or other cost recovery venue, such undergrounding targets and costs shall be clearly identified and associated costs will be excluded from consideration in the Application.
    b) Where undergrounding targets and cost targets in the Application overlap with undergrounding targets and cost forecasts still under consideration in a GRC or other cost recovery venue, the Application shall specify which overlapping targets and costs are under consideration and identify the proceeding or advice letter in which the Commission is considering them. The Application shall propose in which venue the Commission should consider the overlapping costs. Both costs and the corresponding mileage must be paired and presented for consideration in a single venue.
    ~~c) For undergrounding targets and cost forecasts which were previously disallowed by the Commission, the large electrical corporation shall identify the proceeding or advice letter in which the Commission made such determination, when that determination was made, and explain why a different conclusion is now appropriate.~~
    ~~d)~~c) The Application shall include a detailed description of the controls the large electrical corporation will implement to ensure that undergrounding costs related to execution of the Plan are not duplicative of any other costs approved by the Commission.
4) The Application shall include annual incremental revenue requirements for each year that proposed undergrounding costs will be in rate base and associated incremental ratepayer bill impacts (including impacts on CARE and non-CARE customer bills) necessary for rate recovery of the Application's forecasted costs.
5) The Application shall identify any forecast costs that would be reduced, deferred, or avoided because of implementing the proposed undergrounding plan (such as vegetation management), and the proposed disposition of the savings. The Application shall include a methodology by which the Commission can ensure that such cost savings will be achieved. The Application shall distinguish between forecast costs already approved by the Commission for recovery, forecast costs for which the Commission previously denied a request for recovery, and forecast costs that have not yet been the subject of a request for recovery. For forecast costs already approved by the Commission for recovery, the Application shall identify any accounts used to track such costs; the amounts in each such account; and the Commission decision(s) authorizing recovery.
6) The Application shall include cost targets that, at a minimum, result in feasible and attainable cost reductions as compared to the large electrical corporation's historical undergrounding costs.
    a) Cost targets shall be provided for each projected year in the 10-year Plan on a total basis and on an average cost per mile of overhead mile replaced.
    b) Annual historical undergrounding unit costs shall be provided for the previous 10 years, with separate categories for Rule 20 projects, wildfire re-build projects and wildfire mitigation

projects, as available.

c) Comparisons between the Plan's unit cost targets and historical undergrounding unit costs (both on the basis of overhead miles replaced) shall be provided using the average historical wildfire mitigation undergrounding costs for the previous three years (before the Plan's first year). The comparison shall include a statement of how the targeted cost reductions are feasible and attainable compared to historical costs.

7) The Application shall include an explanation of how the cost targets on a per overhead mile basis are expected to decline over time due to cost efficiencies and economies of scale.
8) The Application shall include a description of the ~~a~~ strategy for achieving unit cost reductions over time per 8388.5(e), which may include factors other than cost efficiencies or economies of scale such as, but not limited to identifying, developing, and deploying new technologies.
9) The Application shall present the forecasted average Cost-Benefit Ratio (CBR) on an annual average basis in each of the 10 years of the Application period, broken out by year and for the total Application period. The Application shall also include the separate CBR for each project expected to be completed. Cost and Benefits must be calculated as defined in Commission Decision (D.)22-12-027[6] or its successor. The calculated annual and total benefits must relate to the mitigation of overhead line miles including secondary lines and service drops, not miles of undergrounding.[7]
10) The Application shall include the forecasted CBRs, broken out by year and for the total Application period, for alternative wildfire mitigation hardening methods considered, in place of undergrounding, including forecasted CBRs for combinations of non-undergrounding hardening mitigation measures. To promote comparability, these forecasted CBRs for alternative mitigations should be provided assuming the alternative mitigations are performed in the same locations as in the proposed plan. In addition, for each project expected to be completed, the Application shall show that all reasonable grid hardening mitigations were considered and include the separate CBR for each alternative mitigation or combination of mitigations considered. The calculated ~~annual and total~~ benefits must relate to the mitigation of overhead line miles including secondary lines and service drops, not miles of undergrounding.

~~11)~~ The Application shall identify the projects that will be pursued in each year of the ten year period. For each project,

~~12)~~11) t~~T~~he Application shall include a description of ~~any~~ the substantial improvements in safety risk and reduction in costs of undergrounding compared to other hardening and risk mitigation measures over the duration of the Plan.

   a) Substantial improvements in safety risks shall be substantiated by providing CBRs using the above required benefits calculations ~~by comparing~~for both undergrounding benefits and ~~to~~ alternative wildfire mitigation measures, including combinations of alternative measures on the same circuit protection zones or circuit segments. The calculated benefits must relate to the mitigation of overhead line miles including secondary lines and service drops, not miles of undergrounding.
   b) Reduction in costs shall be substantiated using the same cost calculations as required above by comparing undergrounding costs to alternative wildfire mitigation measures, including combinations of alternative measures.
   c) For each project, the utility shall identify any undergrounding execution challenges and address whether alternative mitigations or combination of mitigations will face the same challenges.
   d) For each proposed project, the utility shall show that the CBR exceeds the CBR of all alternative grid hardening mitigations considered.
   ~~b)~~

~~13)~~12) For each project included in the proposed ~~approved~~ Plan the large electrical corporation shall provide, at a minimum, all data listed in Appendix 1 in tabular format.[8] This information shall be provided as both a Microsoft Excel file and searchable pdf file[9] to supplement the

Application. The data listed in Appendix 1 is the minimum required information~~preliminary~~, and may be augmented ~~will be refined~~ in consultation with Energy Safety, as it develops Plan requirements, to support uniformity where possible.

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[6] CBR is calculated by dividing the dollar value of Mitigation Benefit by the Mitigation cost estimate. See D.22-12-027 Phase II Decision Adopting Modifications, Risk-Based Decision-Making Framework, Appendix A, p. A-3.

[7] Based on information provided in PG&E's wildfire mitigation plans and current general rate case, the overhead to underground conversion rate is approximately 1.25. This means that it would require PG&E approximately 125 miles of underground circuit miles to convert 100 miles of overhead infrastructure to underground. As such, calculated benefits would relate to the 100 miles of overhead infrastructure undergrounded and not the 125 miles of undergrounding required to do so. The underground conversion rate will vary per large electrical corporation.

[8] The data requirements in Appendix 1 will be aligned with data submission requirements for the Plan, as developed by Energy Safety.

[9] See Rules of Practice and Procedure: California Code of Regulations Title 20, Division 1, Chapter 1. Article 1, Rule 1.3(b) for complete submission requirements of pdf files.

13) For each project included in the approved Plan, the large electrical corporation shall provide GIS data for all project boundaries in a Geodatabases or other suitable format.[10]
14) The Application shall include a demonstration that the deployment of undergrounding will be prioritized based on risk, including a demonstration that proposed undergrounding projects will first be completed in the highest risk locations before being deployed in lower risk locations. To support this showing, the Application shall include the calculated risk score for the location of each proposed project and the order in which the proposed projects will be initiated and completed.
15) The Application shall include a list of all non-ratepayer moneys (third-party funding) the large electrical corporation has applied for to minimize the Plan's costs on ratepayers. At a minimum, for each potential source of third-party funding, the list shall include:
    a) The source of third-party funding;
    b) The date when third-party funds were requested;
    c) The amount of funding requested;
    d) The status of the request;
    e) Next steps, including timelines, for processing of the funding request; and
    f) The amount of funding granted/authorized (if any).
16) The Application shall include a description of how any net tax benefits associated with the third-party funding will be disposed of to the benefit of ratepayers.
17) The Application shall include a statement affirming costs, tax benefits, and tax liabilities associated with federal funding sources used to fund projects included in the Plan are being tracked consistent with Resolution E-5254.[11]
18) The Application shall include an attestation that the utility will continue to search for and apply to third party funding to reduce the cost of the Plan to ratepayers throughout the duration of the Plan.
19) A copy of the Plan approved by Energy Safety.

## Public Workshop & Comments:

The Commission will facilitate a public workshop for presentation of the Application. Parties will have an opportunity to submit discovery on the Application and utilities will provide response within three business days. Formal written comments or testimony from parties will be solicited by a ruling in the proceeding after discussion of the schedule and procedure for the proceeding at a prehearing conference. Other interested persons will be afforded the opportunity to submit comments on the proposed plan at any time during the pendency of the proceeding. ~~public comment for at least 30 days per Public Utilities Code, Section 8388.5(e)(4). Formal comments from the workshop will be solicited by a ruling in the proceeding, such as a workshop report provided by a committee of parties who participated in the workshop.~~

## Conditions for Approval:

Public Utilities Code, Section 8388.5(e)(1) specifies that an Application may request "conditional approval of the plan's costs…" In this context, conditional approval shall mean that the Commission has approved the proposed projects at forecast costs but has not given final approval to those projects and has not approved cost recovery. The CPUC will only approve cost recovery if the utility complies with the conditions prescribed in the conditional approval decision.

The Commission establishes the following conditions for such Application to protect ratepayers from unexpected and inefficient cost overruns:

1) Total annual costs must not exceed a cap based on the approved cost target for that year plus a zero to 10 percent contingency allowance for unexpected circumstances, which shall apply only in the first year of the plan .
2) Third-party funding, if any, shall be deducted from the maximum conditionally approved forecasted costs, so that ratepayers receive the benefit. The third-party funding must be applied to reduce the cost cap.
3) The average recorded CBR for all projects completed in a year must equal or exceed the approved average target CBR for that year. In addition, for each of the ten years in the plan, each project must equal or exceed the approved minimum CBR for that year.
4) The updated CBR for each approved project must exceed the updated CBR for all grid hardening alternatives considered. Updated CBRs shall be presented in the applications for cost recovery.
5) The utility must demonstrate that it has prioritized and completed projects first in the highest risk locations before pursuing lower priority work. To the extent that the utility pursues lower risk work before the higher risk work is completed, the utility must demonstrate an alternative grid hardening mitigation measure was deployed in the higher risk location.

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10 Further details on GIS data submission requirements are expected to be issued by Energy Safety in the establishment of Plan guidelines. This requirement for Application submission details will align with such GIS data requirements established by Energy Safety.

11 Resolution E-5254 is available on the Commission's website at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M506/K016/506016078.PDF.

~~3)~~6) If the large electrical corporation changes its risk model during the 10-year period and chooses to change the list of remaining projects, the utility must submit a Petition for Modification to the Commission seeking approval of the risk model changes. The Petition for Modification shall include an explanation and demonstration of how the risk model changes affect the CBRs presented in the Application and why it changes the list of remaining projects. The Petition for Modification should demonstrate that the utility only intends to complete projects that exceed the minimum CBR adopted by the Commission for each remaining year of the ten-year plan and that, for each year, the average CBR will exceed the CPUC's adopted average CBR. Additionally, the utility must demonstrate that its proposed projects have the highest CBR compared to all grid hardening ~~based on the highest CBR and that the CBR of undergrounding for each project reflects substantial improvement over the CBR of~~ alternatives considered and that its revised list of projects continues to comply with the requirement to prioritize proposed projects based on risk. ~~the average CBR of the updated project list must be maintained at equal to or better than the approved CBR. If not, r~~Recovery will not be allowed for as many projects as necessary to bring the recorded CBR average down to the approved target, and for any project with a CBR below the adopted minimum CBR.

~~4)~~7) Average unit cost per mile must not exceed the approved cost for that year, plus a zero to 10 percent contingency, which shall apply only to the approved average unit cost for the first year of the plan. Unit costs must be compared to historical undergrounding costs from the three years prior to the start of the Application period. This condition will inform whether the cost targets resulted in feasible and attainable cost reductions as required in Public Utilities Code, Section 8388.5(e)(6). The unit costs are per mile of ~~undergrounding performed, rather than per mile of~~ overhead replaced~~, to focus on reduction of construction costs~~.

~~5)~~8) Any further reasonable conditions supported by the record of the proceeding and adopted by the Commission.

# Phase 2 – Review of Recorded Costs for Rate Recovery:

The elements of Recorded Costs must be consistent with the elements included in the costs presented in the Application, defined as the standard costs associated with a system hardening conversion project including but not limited to program management, project execution, design, estimating, mapping, construction, internal labor, contracted labor, parts, tools, materials, overhead, and permitting.

Following the Commission's conditional approval of an Application, large electrical corporations are required to file progress reports every six months and a third-party independent monitor is required to produce an annual compliance report by December 1.[12] Public Utilities Code, Section 8388.5(e)(6) states in part that, "[t]he Commission shall… authorize recovery of ***recorded costs*** that are determined to be just and reasonable." [Emphasis added]

Phase 2 of the program will be initiated by a large electrical corporation filing ~~a Tier 3 Advice Letter~~a Phase 2 Application seeking recovery of recorded costs~~, to be disposed of by Commission Resolution~~. With the application for recorded costs, the utility shall serve Testimony and Workpapers supporting the request including all data listed in Appendix 1 in tabular format for every project completed, updated to no earlier than three months before the date of the Phase 2 Application. The Application shall be filed and served with Commission's Docket Office, with a copy to the Commission's Chief Administrative Law Judge, the service list for large electrical corporation's most recent general rate case (GRC), the SB 884 notification list linked here, as updated, SB884@cpuc.ca.gov, and any other service lists, as determined by the Commission and the large electrical corporation, to broadly reach interested parties.

Consistent with CPUC Practice, intervenors will have an opportunity to obtain discovery and submit ~~file~~ comments or testimony on the recorded costs. ~~E~~Evaluation of the Phase 2 ~~advice letters~~Application will ~~rely on the~~be informed by the biannual progress reports submitted by the large electrical corporation, the annual compliance report submitted by the independent monitor, and relevant information in annual wildfire mitigation plan updates. Review of the projects for which cost recovery is requested and the recorded costs will include an assessment of ~~, and stakeholder input to conduct a periodic review of recorded costs and determine~~ whether conditions stipulated in the Commission's conditional approval of the Application (based on forecasted costs and CBRs) ~~are~~ were met ~~met when evaluated using recorded costs~~by the Utility. Phase 2 may extend over a series of Phase 2 ~~periodic Advice Letter filings~~Applications, as needed, to support cost recovery over the 10-year program period. The review period will be determined in the Commission's decision ~~on the Application~~setting out conditional approval of the plan.

In addition to the updated data in Appendix 1, ~~T~~the Phase 2 ~~Advice Letter~~Application must include the following data presented in Table 1 for the requested recovery period[13]. The Project Data that supports the program recorded cost values shall be provided in tabular format in a sortable Excel spreadsheet.

*Table 1: Conditionally Approved Target and Actual Recorded Cost Data*

[12] See Public Utilities Code, Sections 8388.5(f)(1) and 8388.5(f)(3).

[13] The review period under the most recent ~~Advice Letter filing~~Application~~.~~

| Conditionally Approved Targets for the Recovery Period | Actual Recorded ~~Costs~~ Data in the Recovery Period |
|---|---|
| Average Annual Program Cost | Average Annual Program Cost |
| Average Annual Program CBR | Average Annual Program CBR |
| Average Annual Program Unit Cost | Average Annual Program Unit Cost |
| Minimum Project CBR | Each project updated CBR exceeds approved minimum CBR |
| Project CBR exceeds CBR for all alternative mitigations | Updated CBR for each project compared to updated CBR for each mitigation alternative |
| Projects prioritized from highest risk locations to lower risk locations | Updated risk ranking for each HFTD location, including showing that any higher priority location not addressed by undergrounding is addressed by a grid hardening alternative |
| | Project Data for the Recorded Projects |

## Progress Reports:

Public Utilities Code, Section 8388.5(f)(1) requires large electrical corporations with approved Plans and conditionally approved Applications to file progress reports every six months with both Energy Safety and the Commission. Because the progress reports are filed with multiple agencies and at the same time, Staff propose that Energy Safety and the Commission collaborate to develop a singular set of requirements for these reports. Aligning the requirements for these progress reports will eliminate any unnecessary duplication of effort and optimize efficiency of available resources. However, it is possible that each agency may require distinct information in the progress report which may not be of discrete interest to the other. Staff understand that Energy Safety plans to detail its requirements in a forthcoming set of guidelines. Accordingly, without affecting the required progress report elements specified by Energy Safety, Staff propose that the 6-month progress reports shall include, but are not limited to, the following:[14]

1) Total recorded costs to date;
2) Third-party funds received;
    a) Explanation of how third-party funding was used to reduce fiscal burden on ratepayers.
3) All data listed in Appendix 1 in tabular format for every project completed.
~~3)~~4) A ranking of all HFTD circuit protection zones based on risk and, where applicable, identification of completed grid hardening project, including date of completion, for each circuit protection zone.
~~4)~~5) Average recorded CBR for completed projects;
6) Average recorded unit cost per mile of undergrounding for completed projects;
~~5)~~7) Total Miles of overhead replaced by undergrounding;
~~6)~~8) Total Miles of undergrounding completed;
~~7)~~9) GIS data showing location and status of each project (in Geodatabases or other suitable format);[15] and
~~8)~~10) An updated list of all third-party funding the large electrical corporation has applied for, as

specified in Application Requirements 14-16.

~~9)~~11) Total and average avoided costs and workpapers showing calculation of avoided costs.

## Wildfire Mitigation Plan Integration:

Public Utilities Code, Section 8388.5(f)(2) requires large electrical corporations to include ongoing work plans and progress relating to their undergrounding plans in annual wildfire mitigation plan filings. Further

[14] Staff reserve the right to amend the below listed progress report requirements following consultation and coordination with Energy Safety.

[15] Data requirements to be aligned with those specified in Energy Safety guidelines.

guidance on incorporating this information into annual wildfire mitigation plan filings will be provided by Energy Safety.

## Compliance Reports:

Public Utilities Code, Section 8388.5(f)(3) requires a large electrical corporation with an approved Plan and conditionally approved Application to hire an independent monitor selected by Energy Safety. The independent monitor must assess whether the large electrical corporation's progress on undergrounding work is consistent with the objectives identified in its approved Plan and the conditions in any CPUC conditional approval.[16] For each year the Plan is in effect, the independent monitor must annually produce a compliance report detailing its assessment by December. [17] The independent monitor's compliance report must also specify any failure, delays, or shortcomings of the large electrical corporation and provide recommendations for improvements to accomplish the objectives set forth in the approved Plan.[18]

## Periodic Reviews for Authorization of Rate Recovery:

The Application seeking Commission review and conditional approval focuses on the Plan's costs and the cost effectiveness of the proposed projects. All the costs in the Plan are reported as ~~targets (i.e., cost~~ forecasts~~)~~.[19] In addition, other metrics that are included in the conditions for Application approval also rely on these cost forecasts ~~targets~~ for calculation (i.e., CBRs are expected to be calculated using cost-forecast~~targets~~). However, Public Utilities Code, Section 8388.5(e)(6) clearly states that authorization of rate recovery is related to recorded costs that are determined to be just and reasonable. Given that recorded costs are not known until after the undergrounding work approved in the Plan is implemented, periodic reviews of those recorded costs are required.

Because the statute requires an Application seeking conditional approval of cost targets in the Plan, the determination of just and reasonable costs should include determination that the recorded costs have met the conditions imposed by a Commission decision that conditionally approves the Application. The goal of these periodic reviews is to determine whether the conditions placed on the Commission's approval of the Application, based on forecasted costs and CBRs ~~targets~~, have been satisfied when evaluated using the recorded costs. Recorded costs will be tracked in a memorandum account or similar means as determined in the Commission's decision on the Application. The reviews will be conducted on an annual basis, or as determined in the Commission's decision on the Application. The review process will be initiated by the utility filing an ~~Tier 3 Advice Letter, subject to disposition by Resolution,~~Application requesting that the Commission find that the conditions under which cost recovery was approved have been met and that the total costs and the cost of each project are just and reasonable.

## Consequences for Failure to Satisfy Conditions of Approval

Earlier in this proposal, Staff outline a set of requirements for an Application seeking conditional approval of Plan costs. Detailed below are the consequences related to a large electrical corporation's failure to satisfy

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[16] Public Utilities Code, Section 8388.5(g)(1).

[17] Public Utilities Code, Section 8388.5(g)(3).

[18] Public Utilities Code, Section 8388.5(g)(1).

[19] See Public Utilities Code, Section 8388.5(c).

those conditions for approval upon the conclusion of the periodic reviews for authorization of rate recovery.

1) COST CAP. Recorded costs above the predetermined cap placed on annual total costs ~~cost target for a projects~~ in the conditionally approved Application, adjusted for third-party funds received, will not be authorized for recovery.
2) THIRD-PARTY FUNDING. If non-ratepayer, third-party funding has not been deducted from the approved cost target, that portion of the costs will not be authorized for recovery.
3) COST BENEFIT RATIO. Cost recovery will be denied for ~~as many~~any project~~s~~ where the recorded CBR is less than the updated CBR for a grid hardening alternative for that location or above the approved minimum CBR. In addition, cost recovery will be denied for as many projects as necessary to bring the recorded CBR average up to the approved target.
4) RISK PRIORITIZATION. Utility must show that it prioritized projects from highest risk locations to lower risk locations, based on the updated risk ranking for each HFTD location, including showing that any higher priority location not addressed by undergrounding is addressed by a grid hardening alternative. Recovery will not be provided for any lower risk project completed when higher risk- locations have not been not hardened.

~~3)~~

~~4)~~5) RISK MODEL CHANGE. If the large electrical corporation changes its risk model during the 10- year period and chooses to change the list of remaining projects, ~~20~~20 the utility must comply with items 3) and 4) above based on the changed risk model.~~every project must exceed the minimum CBR set by the Commission for each year of the plan. Additionally, the utility must demonstrate it prioritized highest risk work first. Cost recovery will be denied for as many projects as necessary to bring the recorded average up to the approved target.~~

~~5)~~6) UNIT COSTS. Cost recovery will be denied for as many projects as necessary to bring the recorded annual unit cost average down to the approved target.

# Penalties:

Pursuant to Public Utilities Code, Section 8388.5(h)(2), the Commission may assess penalties on a large electrical corporation that fails to substantially comply with a Commission decision approving its Plan.

[20] As used in this context, "remaining projects" mean those projects which were included in the 10-year undergrounding Plan, but the large electrical corporation has not yet expended meaningful resources to execute.

# Appendix 1: SB 884 Project List Data Requirements

| Field Name | Field Description |
|---|---|
| **Order** | Unique Project Order Number. |
| **Category** | Work Category Type. Possible values:<br>• Base System Hardening<br>• Community Rebuild<br>• Fire Rebuild<br>• Targeted UG<br>• Other, see comment |
| **Category Comment** | Category type not listed in the options above. This field is required if Category is “Other, see comment”. |
| **Project Identification Code** | A unique Internal Project Identification code associated with the project and consistent with codes used in GRC and WMP filings (e.g., Maintenance Activity Type Code, Business Planning Element, etc.). |
| **Status** | Possible Values:<br>• <u>Scoping:</u> Identifying the proposed route of undergrounding the electric distribution lines, which includes gathering base map data (i.e., Light Detection and Ranging (LiDAR) and survey data of the expected route) and identifying any long lead time dependencies (i.e., land acquisitions, environmental sensitivities and permits). Scoping includes breaking out planned circuit segments into smaller, more manageable projects. Scoping is the first step to providing visibility to the construction feasibility and possible execution timing.<br>• <u>Designing/Estimating:</u> Designing the specific project to determine trench location, connection points, equipment details, materials needed, and related details, such as circuitry and pull boxes. The design also provides information about the land rights needed and produces the drawings that are submitted for permits. The project cost, including expected labor and materials, is calculated at this stage.<br>• <u>Permitting/Dependency:</u> During this stage the large |

| Field Name | Field Description |
| --- | --- |
| | electrical corporation may need to obtain land rights, environmental permits, construction contracts, encroachment permits from local counties, state and/or federal agencies, order long-lead materials, finalize construction cost estimates, and determine the construction schedule. The two longest lead dependencies often include obtaining land rights and environmental permits.<br>• Ready for Construction: Undergrounding project is ready for construction.<br>• Construction: Executing the undergrounding takes place in two phases: (1) civil construction and (2) electric construction. Project schedules may be significantly impacted during civil construction due to unanticipated weather, discovery of hard rock, and/or detection of unmarked existing utility infrastructure. Once civil construction is complete with conduit and boxes installed, then electric construction resources pull the cable through the conduit, splice segments together and re-connect the customers to the new underground system. Customer input regarding the timing of re-connection, material availability, weather, and other risks can impact the electric construction schedule as well. |
| **Division** | Division of the service territory in which the project will take place. |
| **Region** | Region of the service territory in which the project will take place. |
| **City** | The city in which the project will take place. |
| **County** | The county in which the project will take place. |
| **Applicable Risk Model** | Name and Version of Project Risk Model used to calculate Cost-Benefit Ratio. |
| **Circuit Protection Zone(s) or Isolated Circuit Segment(s)** | All Circuit Protection Zone(s)[21] or Isolatable Circuit Segment(s) included in the project scope. |
| **Project Risk Rank**[22] | Results of the applicable risk model where Projects are |

[21] A Circuit Protection Zone is a segment of distribution circuit between two protection devices.

~~[22] This information is optional pending whether the large electrical corporation has the necessary data.~~

| Field Name | Field Description |
|---|---|
| | ranked on a 1 to N basis, where 1 is the highest risk Project, and N is the lowest risk. |
| **Project Mean Risk**[22] | Summation of the total risk of all pixels (100-meter x 100-meter cell) linked to a Project, divided by the total number of pixels. |
| **HFTD Tier** | CPUC High Fire Threat District Tier per D.17-01-009. Possible Values: <br>• Tier 2 <br>• Tier 3 |
| **Feasibility Score by Project**[22] | Cost multiplier indicating the difficulty of undergrounding the Project based on presence of hard rock, water crossing, and gradient. The scale ranges from 1 to 3, with 3 being most challenging. The utility Application for conditional approval will define each level of the scale. |
| **Cost-Benefit Ratio** | Cost-Benefit Ratio of the Project per D.22-12-027. Benefits must relate to the mitigation of overhead line miles including secondary lines and service drops, not miles of undergrounding. ~~The calculated benefits must relate to the mitigation of overhead line miles including secondary lines and service drops, not miles of undergrounding~~ |
| **Risk Reduction** | Risk Reduction of the Project per D.22-12-027. |
| **Unit Cost Per Underground Mile** | Project Unit Cost per Mile of Undergrounding. |
| **Unit Cost per Overhead Mile** | Project Unit Cost per Mile of Overhead Exposure. |
| **Total Cost** | Total Project Cost. |
| **Risk Tranche(s)** | Risk tranches include a group of assets, a geographic region, or other grouping that is intended to have a similar risk profile such as having the same likelihood or consequence of risk events. |
| **Overhead System Hardening - Cost Benefit Ratio (separate line for each alternative mitigation or combination of mitigations)**[23] | Overhead System Hardening – Cost Benefit Ratio for all alternative grid hardening mitigations or combinations of mitigations to the undergrounding project scored per D.22- 12-027. Calculated for each alternative mitigation or combination of mitigations that is reasonable for the project location. The calculated benefits must relate to the mitigation of overhead line miles including secondary lines and service drops, not miles of undergrounding. |
| **Overhead System Hardening - Risk Reduction (separate line for each alternative mitigation or combination of mitigations)**[23] | Overhead System Hardening – Risk Reduction for all alternative grid hardening mitigations or combinations of mitigations to the undergrounding project scored per D.22-12- 027. Calculated for each alternative mitigation |

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| | or combination of mitigations that is reasonable for the project location. The calculated benefits must relate to the mitigation of overhead line miles including secondary lines and service drops, not miles of undergrounding. |
| **Overhead System Hardening - Unit Cost per Mile (separate line for each alternative mitigation or combination of mitigations)**[23] | Overhead System Hardening Project Unit Cost per Circuit Mile. Calculated for all alternative grid hardening mitigations or combinations of mitigations to the undergrounding project. Calculated for each alternative mitigation or combination of mitigations that is reasonable for the project location. |
| **Overhead System Hardening - Total Cost (separate line for each alternative mitigation or combination of mitigations)**[23] | Overhead System Hardening Total Project Cost. Calculated for each alternative mitigation or combination of mitigations that is reasonable for the project location. The calculated benefits must relate to the mitigation of overhead line miles including secondary lines and service drops, not miles of undergrounding. |
| **Customer Count** | Number of customers served by project. |

[23] Related to item 10 of the "Application Requirements" section.

| Field Name | Field Description |
|---|---|
| **Total Planned UG Miles** | Total Planned UG miles for the project. |
| **UG 20XX Complete** | Total UG miles completed for the project at the time the SB 884 Application is filed. |
| **UG Year 1 Forecast** | UG miles for Year 1 of Project. |
| **UG Year 2 Forecast** | UG miles for Year 2 of Project. |
| **UG Year 3 Forecast** | UG miles for Year 3 of Project. |
| **UG Year 4 Forecast** | UG miles for Year 4 of Project. |
| **UG Year 5 Forecast** | UG miles for Year 5 of Project. |
| **UG Year 6 Forecast** | UG miles for Year 6 of Project. |
| **UG Year 7 Forecast** | UG miles for Year 7 of Project. |
| **UG Year 8 Forecast** | UG miles for Year 8 of Project. |
| **UG Year 9 Forecast** | UG miles for Year 9 of Project. |
| **UG Year 10 Forecast** | UG miles for Year 10 of Project. |

# Appendix 2: Statutory Requirements Cross-Reference

| Code Section | Statutory Language | Staff Proposal Section (Page Number) |
|---|---|---|
| 8388.5(a) | The commission shall establish an expedited utility distribution infrastructure undergrounding program consistent with this section. | Purpose (p. 1) |
| 8388.5(e)(1) | Upon the office approving a plan pursuant to paragraph (2) of subdivision (d), the large electrical corporation shall, within 60 days, submit to the commission a copy of the plan and an application requesting review and conditional approval of the plan's costs and including all of the following: | Conditions for Approval (p. 7-8) |
| 8388.5(e)(1)(A) | Any substantial improvements in safety risk and reduction in costs compared to other hardening and risk mitigation measures over the duration of the plan. | Application Requirements (p. 6) |
| 8388.5(e)(1)(B) | The cost targets, at a minimum, that result in feasible and attainable cost reductions as compared to the large electrical corporation's historical undergrounding costs. | Application Requirements (p. 6)<br><br>Conditions for Approval (p. 8) |
| 8388.5(e)(1)(C) | How the cost targets are expected to decline over time due to cost efficiencies and economies of scale. | Application Requirements (p. 6) |
| 8388.5(e)(1)(D) | A strategy for achieving cost reductions over time. | Application Requirements (p. 6) |
| 8388.5(e)(3) | In reviewing an application submitted to the commission pursuant to paragraph (1), the commission shall consider not revisiting cost or mileage completion targets approved, or pending approval, in the electrical corporation's general rate case or a commission-approved balancing account ratemaking mechanism for system hardening. | Application Requirements (p. 5) |
| 8388.5(e)(4) | Upon the commission receiving an application pursuant to paragraph (1), the commission shall facilitate a public workshop for presentation of the plan and take public comment for at least 30 days. | Public Workshop & Comments (p. 7) |
| 8388.5(e)(5) | On or before nine months, the commission shall review and approve or deny the application. Before approving the | Application Conditional Approval, |

| Code Section | Statutory Language | Staff Proposal Section (Page Number) |
|---|---|---|
| | application, the commission may require the large electrical corporation to modify or modify and resubmit the application. | Denial, or Modification & Resubmittal (p. 4) |
| 8388.5(e)(6) | The commission shall consider continuing an existing commission-approved balancing account ratemaking mechanism for system hardening for the duration of a plan, as determined by the commission, and shall authorize recovery of recorded costs that are determined to be just and reasonable. | Conditions for Approval (p. 8)<br><br>Periodic Reviews for Authorization of Rate Recovery (p. 9) |
| 8388.5(i)(2) | The commission may assess penalties on a large electrical corporation that fails to substantially comply with a commission decision approving its plan. | Background (p. 3)<br><br>Penalties (p. 12) |
| 8388.5(j) | Each large electrical corporation participating in the program shall apply for available federal, state, and other no ratepayer 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. | Background (p. 3)<br><br>Application Requirements (p. 8)<br><br>Progress Report (p. 11) |