California Public
Utilities Commission

Reply Comments on Draft Resolution SPD-15

January 11th, 2024

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January 11, 2024

VIA Electronic Mail

Rachel Peterson
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Re: **Reply Comments of the Coalition of California Utility Employees on Draft Resolution SPD-15**

Dear Ms. Peterson:

We write on behalf of the Coalition of California Utility Employees (CUE) to respond to comments on Draft Resolution SPD-15. The Draft Resolution proposes to adopt the *Staff Proposal for the Senate Bill (SB) 884 Program* (Staff Proposal), which would establish the process and requirements for the Commission's review of costs associated with an IOU's 10-year distribution infrastructure undergrounding plan following approval by the Office of Energy Infrastructure Safety (Energy Safety).[1] CUE's comments address stakeholder concerns regarding the proposed cost recovery mechanisms and the use of cost-benefit ratios.

A. The Draft Resolution's Approach to Cost Recovery Is Reasonable

Several stakeholders criticize the Draft Resolution's cost recovery process, which would allow IOUs to record costs up to an established cap in a one-way balancing account and to track costs that exceed the cap in a memorandum account.[2] Cal Advocates recommends that all costs be recorded in a memorandum account with an annual cap on the amount a utility can record.[3] TURN

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[1] Safety Policy Division, California Public Utilities Commission, Staff Proposal for SB 884 Program (Nov. 2023) (hereinafter "Staff Proposal").
[2] Draft Resolution at p. 7; Staff Proposal at pp. 10-11.
[3] Cal Advocates Comments at p. 7.

recommends limiting cost recovery exclusively to a one-way balancing account.[4] In addition, both Cal Advocates and TURN recommend that all recorded costs be reviewed through an application process and that potential changes to a cost cap be addressed through a petition for modification.[5] These recommendations should be rejected.

A one-way balancing account for recorded costs up to Commission-approved caps is reasonable because IOUs would be obligated to meet several conditions before obtaining recovery, including complying with an annual cost cap, an average recorded unit cost cap, an average recorded CBR cap, and using third-party funding to reduce ratepayer costs.[6] Stakeholders are also afforded an opportunity to address these caps, and any other reasonable conditions, during the Commission's review of an IOU's undergrounding plan cost application.[7]

A memorandum account for costs that exceed a Commission-approved annual cap is also reasonable because it provides a mechanism for IOUs to seek recovery of costs that could not have reasonably been foreseen at the time the undergrounding plan was approved. Without such a mechanism, the Commission would effectively require that IOUs perfectly forecast costs over a 10-year planning horizon. Indeed, the Commission routinely allows IOUs to seek recovery for unexpected costs that are not recovered through other ratemaking mechanisms. It should be no different here. Moreover, establishing a memorandum account does not guarantee cost recovery, as implied by several stakeholders,[8] as they would be afforded the opportunity to scrutinize excess costs since the Draft Resolution requires IOUs to file a separate application determine whether those costs are just and reasonable.[9] Finally, CUE concurs with PG&E that there should be an expedited nine-month review for memorandum account costs to avoid unnecessary and lengthy delays.[10]

All these guardrails adequately protect ratepayers while also ensuring an expedited review of expected costs and implementation of an undergrounding plan which Energy Safety would have already found will substantially increase reliability and substantially reduce wildfire risk.[11]

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[4] TURN Comments at p. 8.
[5] Cal Advocates Comments at pp. 7-10; TURN Comments at pp. 7, 12.
[6] Draft Resolution at p. 7.
[7] Staff Proposal at p. 10; Pub. Util. Code § 8388.5(e)(4).
[8] *See e.g.*, Cal Advocates Comments at p. 6; TURN Comments at pp. 8-12.
[9] Staff Proposal at pp. 10-11.
[10] PG&E Comments at pp. 6-7.
[11] Pub. Util. Code § 8388.5(d)(2).

B. Cost-Benefit Ratios Should Not Serve as the Sole Determinant for Selecting and Implementing Risk Mitigations

SCE recommends that the Commission clarify that CBRs would not be used as the sole determinant for selecting and implementing risk mitigation.[12] CUE agrees. 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.[13] 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).[14] 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.[15] The Draft Resolution and Staff Proposal should be revised to expressly state that CBRs are only one of many factors that may be considered when evaluating risk mitigations, and that CBRs should not serve as the sole determining factor.

C. Conclusion

We respectfully urge the Commission to approve Draft Resolution SPD-15 to ensure costs associated with Energy Safety-approved underground plans are reviewed in a timely manner. Thank you for your consideration of these comments.

Sincerely,

Andrew J. Graf

Cc: Service Lists for A.21-06-021, A.23-05-010, A.22-05-016, and SB 884 Notification List

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[12] SCE Comments at pp. 1-3; see also SDG&E Comments at p. 4.
[13] D.22-12-027 at pp. 26-27.
[14] *Id.* at p. 12.
[15] *Id.* at p. 26-27.

Via Email
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January 11, 2024

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Re: Reply Comments on Draft Resolution SPD-15

Dear Executive Director Peterson:

The California Farm Bureau (Farm Bureau) submits these reply comments on Draft Resolution SPD-15 (Draft SPD-15 or Draft Resolution) and the comments of other parties in accordance with Rule 14.5 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission) and pursuant to the November 9, 2023, cover letter accompanying Draft SPD-15.

I. Introduction

The California Farm Bureau (Farm Bureau) appreciates the opportunity to provide reply comments to other parties' positions on the Draft Resolution. The three utilities who commented Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E) and Southern California Edison Company (SCE) are very similar if not verbatim in several places with PG&E's comments being the most extensive. Farm Bureau will focus its response primarily on the confusion and potential for undermining the SB 884 Program (or Program) with several of the cost counting proposals the utilities raise as well as the request to include non-high fire threat districts (HFTD) miles within the Program. Next, Farm Bureau will focus on the overwhelming support ratepayers have for improving the Draft Resolution to make certain all of SB 884 which was the protection of ratepayers and their costs while improving wildfire risk reduction and reliability exists. As Farm Bureau pointed out in its opening comments, the Draft Resolution took an unfortunate turn away from that ratepayer and cost containment component and the comments received by the parties who do not stand to financially gain from this endeavor should guide improvements to the Draft Resolution.

II. The Utilities Proposal to Timely Recover Costs While Simultaneously Delaying Review Creates Incentives to Game the System

The utilities are seemingly requesting the Commission allow for cost recovery within a year, but not to use that same year cost recovery when reflecting on average unit cost or the annual cost caps. Farm Bureau is not opposed to evaluating the Program and progress in various ways, but when it comes to cost recovery, it is a simple formula to use the recorded cost a utility is intending to recover within a single year as the values by which the metrics for performance are calculated within that year. Any attempt to do otherwise leaves the program open to significant gamesmanship that will only hurt ratepayers.

It would seem inequitable to require ratepayers to fully fund a program, but not know whether or not the metrics that are required for evaluating the program are being met until three years down the road. PG&E uses an example of a high value project being completed on December 31 and then two very low cost projects being completed on January 1 as justification for needing to use an average. But what is absent from that proposal is the request to delay the recovery of that high value project from the end of that year over subsequent years. Thus, there is no risk to the utilities, only to ratepayers with the hope and prayer that a utility will offset high value projects with low value projects to demonstrate a more reasonable average. Further, are the three years forward looking? Or can it be one year backward and one year forward? The ability to manipulate and create perverse incentives within the program will be endless. Ratepayers deserve the dollars that are spent each year to be evaluated as such. Otherwise, no recovery should be made *until* the proposed average cycle is complete and evaluated.

If instead, the utility will not be requesting *any* recovery of cost for a project until is fully completed and operational, then it would seem reasonable to do so *only* once each year of the project's lifecycle can be properly evaluated as well as the final averages. Further, this would include the *actual* close out costs rather than a proxy that can be manipulated to meet a unit cost average, but may ultimately exceed that goal when actual costs are factored in. Should a proxy be allowed, there must be a disallowance of cost with interest returned to ratepayers should that proxy value be deemed to have been insufficient.

The utilities pitch to the Commission has always been that approving more miles means greater "economies of scale" and efficiencies that would translate into ratepayer "savings." That should be true each year even if it is spread across multiple projects. Year 3 should be less expensive than year 1 in unit cost otherwise this exercise is pointless. If "savings" are only realized within a single project in the waning months of that project, then there would be no need for a 10-year plan and funding on this scale, but rather a project by project request and evaluation.

III. The Request to Include Miles Outside the Scope of SB 884 Should be Denied

PG&E and SDG&E request to be allowed to include miles outside the HFTD areas despite the statute clearly stating that "only undergrounding projects located in tier 2 or 3 high fire-threat districts or rebuild areas may be considered and constructed as part of the program."[1] SB 884 was intended to address specific areas using a particular technology and the Commission must follow the statute. There cannot be exceptions for a half mile here and a mile there when the utilities have many other venues to address funding of these miles that are outside the HFTD area.

IV. The Commission Should Not Remove the Requirement for Utilities to be Transparent in Costs Previously Approved, Denied, or Not Yet Recovered

As the Commission is aware there are a significant number of proceedings before it and many revolving around wildfire and its related costs. The Draft Resolution correctly requires applicants to identify costs they are seeking which have been previously denied as well as those already approved or those requested and not yet recovered. This requirement could be improved and certainly should remove the opportunity for utilities to take a second bite at the apple,[2] but nevertheless provides a base level of transparency regarding what has previously been done and what the utility plans to do outside of the SB 884 Program.

A utility that utilizes the SB 884 Program will be seeking the Commission's approval to seek billions and billions of dollars in funding from ratepayers. The requirement that a utility maintain a basic accounting of where they have already asked for potentially overlapping funds or intend to do so elsewhere or have already been denied is vital to an application's evaluation. What has routinely turned into a shell game of trying to match requests across proceedings and resolving one request only to see very similar funding appear in a subsequent application can be at least partially solved before an application is ever approved. If a utility cannot keep track and cannot be transparent about where they have received funding and where those projects are occurring and not allow those two pools of money to mix within the SB 884 Program, then they have no business applying in the first place. Ratepayers deserve this basic level of transparency, accountability and protection, and the Commission should swiftly reject PG&E's recommendation. As an applicant to a *voluntary* program, the burden of proof lies with PG&E and the other utilities, and they must demonstrate that costs are contained and not overlapping outside of the Program. Otherwise, the Commission will be unable to meet its statutory burden of review of an application.

[1] PUC Section 8388.5(c)(2).
[2] Farm Bureau Opening Comments p. 2; TURN Opening Comments p. 15.

V. Ratepayers Deserve Greater Protection Within the SB 884 Program

It is clear from the opening comments on the Draft Resolution that the parties who do not stand to financially benefit from the SB 884 Program are underwhelmed by the protections provided in the Draft Resolution and disappointed in the removal or redrafting of key sections from the Staff Proposal.[3] As the parties responsible for funding this ambitious endeavor, we deserve sufficient safeguards and guarantees. Otherwise, notions of ratepayer affordability and acknowledgment of the tremendous burden facing ratepayers will be nothing more than, as TURN put it, empty rhetoric.

There are simple solutions that can improve the Draft Resolution that are supported by the non-financial beneficiaries of this Program such as removing the automatic cost recovery of the one-way balancing account and reverting it back to conditional approval with an opportunity to evaluate whether the utility has complied with specified conditions before approval.[4] Or reinstituting the one section from the Staff Proposal "Consequences for Failure to Satisfy Conditions of Approval" that demonstrated any attempt to explicitly hold utilities accountable.[5] Or removing the ability for utilities to re-litigate General Rate Case (GRC) decisions that parties and the Commission spent years determining and are often the result of Commission compromise on many parties positions.[6] Or simply requiring the utilities to stand by what they have repeatedly claimed both at the Commission and in the media as long term ratepayer "savings."[7]

The Commission must accept its role of holding utilities accountable and must provide opportunities for those burdened with funding this Program to question utility progress and seek consequences for failures.

VI. Conclusion

Farm Bureau appreciates the opportunity to provide reply comments on the Draft Resolution and reiterates that feedback on the Draft Resolution should be evaluated but a decision be delayed until the entire picture of what the Office of Energy Infrastructure Safety evaluation process has been determined. The Commission cannot fear creating too onerous of a program and thereby destroying ratepayer protection in the process. **No**

[3] Opening Comments of Farm Bureau, Cal Advocates, TURN, and MGRA (the non-utility parties).

[4] TURN Opening Comments pp. 3-5; Cal Advocates Opening Comments pp. 3-6; Farm Bureau Opening Comments p. 2.

[5] Farm Bureau Opening Comments p.4-5; TURN Opening Comments p. 12.

[6] Farm Bureau Opening Comments p. 2; TURN Opening Comments p. 15.

[7] Farm Bureau Opening Comments p. 4; TURN Opening Comments pp. 13-14; PG&E CEO Pattie Poppi repeatedly claimed, although unsupported by the record of the Phase 1 proceeding, that undergrounding 2,000 miles would save ratepayers $5.7 billion dollars, *see* https://www.kcra.com/article/pge-wants-to-bury-more-power-lines-cpuc-says-no/45525596 or https://www.pgecurrents.com/articles/3854-information-hub-pg-e-proposes-undergrounding-powerlines-reduce-wildfire-risk-save-long-term-costs.

utility is required to participate in this expedited program and the Commission must balance the tradeoff for expedited review with extreme transparency of the costs and implications of these plans and establish meaningful consequences to protect ratepayers.

Sincerely,

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- SB-884 Notification List
- Service Lists for A.21-06-021, A.23-05-010, and A.22-05-016

REPLY COMMENTS OF AT&T CALIFORNIA; THE CALIFORNIA BROADBAND AND VIDEO ASSOCIATION; CROWN CASTLE FIBER, LCC; AND SONIC TELECOM, LLC; ON DRAFT RESOLUTION SPD-15 IMPLEMENTING SB 884

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January 11, 2024

REPLY COMMENTS OF AT&T CALIFORNIA; THE CALIFORNIA BROADBAND AND VIDEO ASSOCIATION; CROWN CASTLE FIBER, LCC; AND SONIC TELECOM, LLC; ON DRAFT RESOLUTION SPD-15 IMPLEMENTING SB 884

AT&T California (U-1001-C); the California Broadband and Video Association; Crown Castle Fiber, LLC (U-6190-C); and Sonic Telecom, LLC (U-7002-C) (collectively, the "Communications Providers") respectfully submit these reply comments in response to opening comments filed by other parties on Draft Resolution SPD-15 ("Draft Resolution"), which establishes the Commission's Senate Bill ("SB") 884 program pursuant to Pub. Util. Code § 8388.5.

<u>The Commission Should Reject Recommendations to Include Undergrounding That Is Outside Tier 2 or Tier 3 High Fire-Threat Districts ("HFTDs") or Rebuild Areas</u>

SB 884 is clear concerning which geographic areas may be included in the investor-owned utilities' ("IOUs'") expedited utility distribution infrastructure undergrounding programs. Pub. Util. Code § 8388.5(c)(2) states,

> Only undergrounding projects located in tier 2 or 3 high fire-threat districts or rebuild areas may be considered and constructed as part of the program.

The Commission should reject suggestions from Pacific Gas and Electric Company ("PG&E") and San Diego Gas & Electric Company ("SDG&E") to allow for the inclusion of undergrounded facilities outside of these boundaries. PG&E recommends the addition of a footnote to Resolution SPD-15 stating:

> In some cases, undergrounding projects can be located outside an HFTD and rebuild areas or a portion of the projects can be located outside HFTD and fire rebuild areas, so long as the electrical corporation explains and justifies the inclusion of these projects and/or portions of projects.[1]

PG&E provides two examples as justification for this inclusion. First, PG&E proposes to include undergrounding projects that have incremental miles outside an HFTD. Second, PG&E seeks to include undergrounding projects that meet *none* of the statutory criteria, claiming: "circuits in areas such as PG&E's High Fire Risk Areas (HFRAs) may merit undergrounding."[2] However, PG&E offers no basis for these excursions beyond the clear statutory limits, instead offering only to "explain and justify" such inclusions.

Similarly, SDG&E also seeks to include undergrounded circuit mileage that lies partially or fully outside the statutory limits.[3] In support of its proposal, SDG&E claims only that "there may be areas outside the HFTD within the wildland-urban interface or other coastal canyon areas that could benefit from undergrounding."[4] Like PG&E, SDG&E offers only to "justify" such inclusions.

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[1] PG&E Opening Comments at p. 12.
[2] *Id*.
[3] SDG&E Opening Comments at pp. 3-4.
[4] *Id*. at p. 4.

The Commission should reject these attempts to expand the express statutory geographical boundaries of the SB 884 undergrounding program. Instead, PG&E and SDG&E should seek Commission approval for such additional undergrounding via means other than the SB 884 program.

The Communications Providers Support Recommendations from Parties that the Commission Should Defer Further Consideration of Draft Resolution SPD-15 Until the Office of Energy Infrastructure Safety ("Energy Safety") Issues its 10-year Undergrounding Guidelines, and Should Coordinate Closely with Energy Safety

Several parties observe in their opening comments that under Pub. Util. Code § 8388.5, Energy Safety has the first set of obligations.[5] Energy Safety has begun the process by holding a series of Working Groups and then developing a set of 10-year Undergrounding Guidelines. These guidelines are still in development, with comments due from stakeholders later this month. Once Energy Safety's Undergrounding Guidelines are finalized, the IOUs will file their Distribution Infrastructure Undergrounding Plans for Energy Safety's review and approval.

As these parties point out, the Commission's formal review responsibilities under SB 884 do not ripen until Energy Safety has approved an IOU's Distribution Infrastructure Undergrounding Plan, and that IOU has filed an Application with the Commission to approve that Plan. Of course, it is appropriate for the Commission to establish "ground rules" for discharging its SB 884 responsibilities, as Draft Resolution SPD-15 seeks to do, in advance of such Applications. However, as these parties suggest, it is not necessary to finalize Resolution SPD-15 on the proposed date of January 25, 2024. First, the final version of Resolution SPD-15 should take Energy Safety's Undergrounding Guidelines into account. Draft Resolution SPD-15 could conceivably need to be modified to remove inconsistencies with Energy Safety's Undergrounding Guidelines. Second, the Commission should consider requesting additional comments on revisions to Draft Resolution SPD-15 that are driven by Energy Safety's Undergrounding Guidelines before finalizing Resolution SPD-15. The Communications Providers thus concur with other parties that the Commission should defer further consideration of Draft Resolution SPD-15 until Energy Safety issues its Undergrounding Guidelines.

The Communications Providers also agree with Cal Advocates that the Commission should coordinate closely with Energy Safety throughout the SB 884 processes, in addition to the areas of coordination specified in the Staff Report.[6] This further coordination should include, *inter alia*, developing a common set of terms, definitions, and cost efficiency metrics; coordinating required changes to the IOUs' Plans; and leveraging the Commission/Energy Safety Memorandum of Understanding to increase interagency collaboration.

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[5] California Farm Bureau Opening Comments at p. 2, Public Advocates Office ("Cal Advocates") Opening Comments at p. 1, TURN Opening Comments at p. 2, Mussey Grade Road Alliance ("MGRA") Opening Comments at p. 7.

[6] Cal Advocates Opening Comments at pp. 10-12.

The Commission Should Require the Inclusion of Alternatives to Undergrounding in the Cost-Benefit Analysis, Which Should be Updated Periodically

As MGRA points out in its opening comments, there are a number of cost-effective alternatives to circuit undergrounding that can reduce wildfire risk.[7] In addition to covered conductors, the major IOUs are developing and evaluating other advanced technologies, which may be far more cost-effective than undergrounding. Moreover, given the 10-year time horizon of SB 844, the relative costs and benefits of undergrounding versus other, newer technologies may shift. The Communications Providers therefore support MGRA's proposals that other technologies be included in the IOUs' cost/benefit analyses, and that such analyses be updated on a periodic basis.

The Commission Should Ensure its Cost-Benefit Analysis Covers the Appropriate Time Period and Considers the Cost and Implementation Time of Various Mitigation Measures

To ensure the greatest benefit to California and Californians, it is important for the IOUs and the Commission to identify the most cost-effective wildfire mitigation measures. Dr. Robert Johnson explains that this involves, among other things, careful selection of the appropriate time period for the cost-benefit analysis.[8] Both the cost of mitigation measures and the implementation time have a significant impact on the amount of wildfire risk reduction. For example, as Dr. Johnson shows, the high cost and long implementation time required for undergrounding may result in lower risk reduction as compared to cheaper and faster alternatives such as insulating distribution lines – both in the short run and over a 50 year-period.[9] The Communications Providers agree with Dr. Johnson that the Commission should ensure its cost-benefit analysis thoroughly and accurately identifies the most cost-effective mitigation measures.

Conclusion

The Communications Providers appreciate the opportunity to share their views with the Commission on the important role the Commission will play in implementing SB 884, via the procedures to be specified in the final version of Resolution SPD-15. We respectfully urge the Commission to make the modifications and modify the procedures as we have recommended in our opening and reply comments.

Respectfully submitted,

/ s / Stephen P. Bowen
Stephen P. Bowen
Bowen Law Group
Outside Counsel to Sonic Telecom, LLC
For the Communications Providers[10]

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[7] MGRA Opening Comments at p. 4.
[8] Dr. Robert Johnson Opening Comments at pp. 1-4.
[9] *Id*. at p. 4.
[10] 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.

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Office of Energy Infrastructure Safety Wildfire Safety Division, California Public Utility Commission	Resolution SPD-15

REPLY COMMENTS OF THE GREEN POWER INSTITUTE

ON DRAFT RESOLUTION SPD-15

January 11, 2024

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REPLY COMMENTS OF THE GREEN POWER INSTITUTE ON DRAFT RESOLUTION SPD-15

The Green Power Institute, the renewable energy program of the Pacific Institute for Studies in Development, Environment, and Security (GPI), provides these *Reply Comments of the Green Power Institute on Draft Resolution SPD-15*.

The GPI has been involved in the review and analysis of WMPs since their inception, and in a number of related issues at the OEIS, including the undergrounding of distribution lines. We participated in the development of the record at the OEIS and the Commission underlying the *Staff Proposal for SB 884 Program*, which is attached to draft Resolution SPD-15. We offer the following replies to the opening comments of the parties on draft Resolution SPD-15.

1. The 10-year Undergrounding Program is a long-term planning horizon program and therefore must include well defined regulatory mechanisms that enable Phase 1 Plan, Phase 2 Application, and evaluation criteria adjustments, as well as party input to those adjustments over the duration of the Plan.

The 10-year Undergrounding Program is, by definition, a long-term planning horizon program on multiple levels. It commits not only to 10-year plan implementation, but also to the most expensive wildfire mitigation approach that comes with a multi-decadal useful lifetime and likely a permanent shift from overhead to undergrounded distribution infrastructure. It is therefore critical to establish a well-defined Program framework that is concrete, yet sufficiently adaptable to change. This includes the ability to adapt to factors including, but not limited to updated risk modeling methodologies, environmental and system inputs, and wildfire risk mitigation technologies and capabilities.

GPI is a party in the Integrated Resources Plan Proceeding (IRP), R.20-03-005, and is engaged in the IRP Program development process. Briefly the IRP, previously the Long-Term Planning Process (LTPP), provides a relatively robust example for how long-term Utility planning frameworks can be structured. The IRP plans for and oversees multibillion-dollar capacity procurement over a 10 to 12-year planning horizon that is implemented via 2-year cycles.[1] During each cycle, load serving entities (LSEs) are required to file a procurement plan for the 10 to 12-year planning horizon that incudes updates and adjustments to their prior year's plan. The CPUC issues updated modeling inputs and assumptions every 2-years and conducts annual top-down probabilistic modeling to refresh assumptions and realign procurement planning and procurement orders to the best available inputs, assumptions, and model adjustments. Periodic modeling updates and resultant plan adjustments on reasonable 2-year timeframes over the planning horizon are critical design elements of the IRP framework that manage uncertainty associated with the long-term planning horizons. This approach iteratively guides long-term investments that incrementally converge on cumulative solutions based on the best available and up-to-date information. The Undergrounding Program does not yet have equivalent critical long-term planning horizon design elements.

Draft Resolution SPD-15 recognizes that there are: "… significant uncertainties in undergrounding electrical distribution equipment that are likely to grow over a 10-year period."[2] GPI generally agrees with this statement. However, in reference to addressing "significant uncertainties in undergrounding," SPD-15 establishes a Memorandum account to record costs above approved plan costs.[3] This is managed via Program Phase 3, which includes "Periodic reasonableness reviews of recorded costs in the memorandum account…"[4] This framework element only addresses a very narrow view of the impacts of uncertainty on 10-year Undergrounding plans. Specifically, it only assumes that Utilities may reasonably underestimate the cost of their proposed undergrounding program. This acknowledgement of and mechanism for addressing uncertainty does not adequately recognize the range and sources of uncertainty that are likely to affect an Undergrounding plan and CBRs over the long-term planning horizon.

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[1] Integrated Resource Plan and Long Term Procurement Plan https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning Accessed 1/11/2024.
[2] Draft Resolution SPD-15, p. 7.
[3] Draft Resolution SPD-15, p. 7.
[4] Draft Resolution SPD-15 Staff Proposal, p. 4.

Other mechanisms in SPD-15 and the Staff Proposal that address long-term planning horizon uncertainty include:

- Conditional Approval of the Phase 2 Applications[5]
- Phase 3 Applications
- File progress reports with the CPUC and OEIS every 6-months.[6]
- Annual Independent Monitor Reports filed on December 1.[7]
- CPUC and OEIS compliance reviews based on Utility and independent monitor reports.[8]

These long-term planning horizon uncertainty management approaches focus on alignment with the *original* Plan and/or Phase 2 Application. SPD-15 and the Staff Proposal framework fail to clearly address other sources and potential outcomes of long-term planning horizon uncertainty that can and likely will warrant material changes to the initial Plan, Phase 2 Application, or metrics against which Plan and/or Application reasonableness is weighed. Other sources of uncertainty include, but are not limited to:

1. Updated and/or overhauled risk modeling methods adopted by the OEIS and/or individual Utilities, as well as methods developed outside the WMP process such as climate change modeling requirements adopted in the Climate Adaptation Proceeding (R.18-04-019).
2. Updated risk modeling inputs, including from outside the OEIS WMP process such as climate change forecasts adopted in or informed by the Climate Adaptation Proceeding.
3. Changes to cost forecasts for raw materials, labor markets, or construction for all risk mitigation types/methods.
4. Updated effectiveness metrics for all risk mitigation approaches. This includes novel insights from completed mitigation deployments or from pilot projects and studies.
5. New technologies that provide novel solutions to risk mitigation, or advancements in existing wildfire risk mitigation technologies that improve effectiveness and/or reduce cost.

[5] Draft Resolution SPD-15, p. 2.
[6] Draft Resolution SPD-15, p. 2.
[7] Draft Resolution SPD-15 Staff Proposal, p. 3.
[8] Draft Resolution SPD-15 Staff Proposal, p. 3.

At present the 10-year Undergrounding Program framework is ill equipped to address these potential and even likely changes to wildfire risk mitigation approaches, methods, inputs, capabilities, and resulting cost-benefit ratios over the 10-year plan horizon. Namely, SPD-15 and the Staff Proposal do not adequately establish and define regulatory mechanisms that will be necessary to address the range of sources of uncertainty in 10-year Undergrounding Plans. The Undergrounding Program must have a defined mechanism for periodically updating the Phase 1 Plan and Phase 2 Application, accompanied by a stakeholder review and agency approval process. Updates should minimally capture substantive changes to underlying assumptions, inputs, and models.

GPI generally supports opening comments by MGRA that call for on/off ramp policies, and by CalAdvocates and TURN that recommend using the Petition for Modification (PFM) as the regulatory vehicle for changes to Utility plans over the 10-year implementation duration. GPI further contributes to this issue by recommending the following additional, specific use cases for PFMs in the 10-year Undergrounding Program. Specific modeling methods, inputs, and assumptions governing utility Undergrounding Plans and Applications should be formally approved in CPUC decisions and utilities subsequently should be required to file a PFM if/when:

1. Changes are made to wildfire risk planning model inputs, including those used in the WMPs, that are relevant to the modeling approaches required for 10-year Undergrounding Plans, and that alter granular risk scores and risk rankings (e.g. by a defined threshold). This should also include any future relevant decisions or recommendations made in the Climate Adaptation Proceeding.
2. Changes are made to wildfire risk planning model methods in the WMP, by a Utility, or by the OEIS, that are relevant to the modeling approaches required for 10-year Undergrounding Plans and that alter granular risk scores and risk rankings (e.g. by a defined threshold). This should also include any future relevant decisions or recommendations made in the Climate Adaptation Proceeding.
3. Changes to cost forecasts, resource availability, or other implementation factors that impact cost estimates (or feasibility) for Undergrounding or alternative risk mitigation types/methods.

4. Updated effectiveness metrics change for wildfire mitigations, including Undergrounding or any alternative mitigation approach, inclusive of novel risk mitigation approaches. This includes updated effectiveness metrics resulting from WMP-based mitigation deployments, studies, or pilot projects.

These PFM requirements will provide an opportunity to iteratively update and preemptively approve or reject material changes to Utility Phase 1 *Plans* and Phase 2 Applications including granular project on/off ramp requests, costs, and CBR adjustments.

Qualifying PFM conditions 1 and 2 are especially critical to updating Undergrounding Plans over the long-term planning horizon since utility and third-party wildfire risk planning models are still maturing and actively undergoing material updates and findings. For example, PG&E recently included their custom egress model into their wildfire risk planning model, though we expect that the model it will not enter the formal and public WMP record for review until the next WMP Update is filed in 2024. Future model adjustments could materially alter the absolute risk values and resulting risk rankings for individual projects, although the Program is currently incapable of capturing these changes and also fails to provide a pathway for updates, stakeholder comment, and agency approval.

Qualifying conditions 3 and 4 (cost forecasts, resource availability, and mitigation effectiveness) could change substantially over time and with increased deployment across California. For example, SCE's Program-level adoption of REFLC and other Utility REFLC pilot programs may influence its cost, regional availability, and provide updated insights on its effectiveness. These inputs and assumptions should be periodically reviewed, and their impacts assessed in order to right-size Utility Phase 1 Plans, Phase 2 Applications, and qualifying CBR thresholds.

The IOU's Opening Comments request to recover costs for abandoned undergrounding projects.[9] GPI strongly recommends adding additional programmatic guardrails that will require pre-approval of project off ramps and abandonment decisions to reduce the

[9] PG&E Comments on Draft Resolution SPD-15, p. 7.

occurrence of stranded ratepayer-funded investments. PFM qualifying criteria 1-4, plus specific on and off ramp request criteria, could preemptively address and provide a formal pre-approval process for project on and off ramp changes that include reviewing the drivers of these changes. This would shift project on and off ramps from the existing static, after-the-fact Phase 3 Application reasonableness review, to a pre-approval process by the CPUC that is informed by OEIS and stakeholder review and comment.

The PFM also allows for a stakeholder comment period prior to issuing a Decision regarding the PFM request. OEIS should also be eligible to weigh in on all PFM decisions, especially those that would alter any element of a Utility Phase 1 Undergrounding Plan. Notably, the IRP sets a recent precedence for using PFMs as the regulatory vehicle for change requests in a proceeding that oversees billion-dollar annual investments with long lifetimes (10+ years) that are implemented over long-term planning horizons (10+ years), and that are subject to CPUC established compliance requirements.[10,11] It is therefore reasonable and prudent to formally establish PFM filings as part of the 10-year Undergrounding Program.

1.1 Wildfire risk planning models are still subject to substantive changes that are likely to impact granular wildfire risk rankings over the 10-year Plan horizon.

To date, IOU wildfire risk planning models applied in the Wildfire Mitigation Plans use three disparate model frameworks that include a range of sub-models and quantitative approaches. The breadth of approaches includes high-level design discrepancies. For example, in 2023 PG&E and SDG&E were employing combined probability of ignition and consequence models while SCE's planning models focus on wildfire consequence that includes ingress/egress risk. Year after year the models have undergone refinements and major changes such that relative circuit/segment risk rankings continue to change, and sometime dramatically so. For example, PG&E recently developed a new ingress/egress

[10] PETITION FOR MODIFICATION OF DECISIONS 23-02-040 AND 21-06-035 OF THE CALIFORNIA ENERGY STORAGE ALLIANCE AND THE WESTERN POWER TRADING FORUM TO ADDRESS LONG LEAD-TIME RESOURCE COMPLIANCE DEADLINES.

[11] SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) AND PACIFIC GAS AND ELECTRIC COMPANY'S (U 39-E) JOINT EXPEDITED PETITION FOR MODIFICATION OF DECISION 21-06-035.

model that will presumably be presented in the formal public record for the first time in the 2024 WMP Updates. The ingress/egress sub-model could alter relative risk rankings, may undergo additional refinements, and should be subject to external review prior to approval for application, including for use in undergrounding project selection.

The IOUs are not the only ones adjusting their wildfire risk planning models. OEIS WMP Decisions issued in 2023 include multiple ACIs that will impact utility risk planning model methods and outputs, may alter risk rankings, and may inform future risk planning standards and/or CBR requirements.[see e.g.12] This is in addition to a variety of stakeholder comments addressing utility risk model methods and calls for model alignment within the public WMP and CPUC records.[e.g.13] Furthermore, an OEIS-specific risk mitigation approach is as yet undetermined and should be made public for external review prior to formalizing a 10-year Undergrounding Program framework. Given the level of both existing and anticipated uncertainty surrounding wildfire risk planning model methods and changing inputs, it would be imprudent to adopt Draft Resolution SPD-15 without the OEIS Plan and risk modeling guidelines, and without a mechanism for updating Phase 1 Plans, Phase 2 Applications, and evaluation criteria (e.g. CBR thresholds) in accordance with model updates. The IRP, for example, engages in comprehensive model input and assumption updates and model refinements every 1-2 years that are made available for stakeholder review and informal comment.[e.g.14] These are applied via annually-updated model outputs that iteratively guide billion-dollar annual investment plans and activities.[e.g.15] GPI strongly recommends withdrawing Draft Resolution SPD-15 and further improving the Undergrounding Program framework to include similarly critical Plan, Application, and evaluation criteria update capabilities.

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[12] TN13264_20231024T134139_SCE_20232025_WMP_Decision_and_Cover_Letter
[13] Public Workshop on Safety Requirements to Address Increasing Wildfire Risk from Climate Change and Aging Infrastructure. July 13-14, 2023

[14] Inputs & Assumptions 2022-2023 Integrated Resource Planning (IRP) June 2023
[15] 2023 Proposed PSP and 2024-25 TPP Supplemental Analysis. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-

2. Draft Resolution SPD-15 should be withdrawn, and the Staff Proposal reevaluated after OEIS Plan criteria and Project definitions are proposed.

GPI supports opening comments by CalAdvocates and TURN regarding withdrawing SPD-15 until OEIS completes its Plan proposal.[16,17] We also support Advocates recommendation to define "Project" in the context of the Undergrounding Program.[18] GPI materially adds to these recommendations here and replies to IOU Opening comment recommendations.

2.1 Consideration of the IOUs' request for 3-year rolling average unit cost caps should only be considered after a Project definition is proposed.

PG&E's comments on Draft Resolution SPD-15 state:

> Moreover, small timing issues can have a considerable impact on unit cost evaluation. For example, if a project with a high unit cost is completed on December 31st and a project with a low unit cost is completed one day later, on January 1st, under the current Staff Proposal only the high unit cost project would be considered and the high and low unit costs projects, completed one day apart, would not be averaged. To address this problem, PG&E proposes that the cost cap be calculated on a three-year rolling basis.[19]

PG&E's example takes a very narrow snapshot of Project completion dates at year's end without considering all the preceding completed projects over the course of the plan year. That is, if PG&E is completing hundreds of line miles amounting to tens or even hundreds of completed Projects each year, the impact of 1 or 2 projects completed on either end of the December 31/January 1 cusp may make a relatively small difference in the annual average unit cost caps.

The significance of roll-over projects on the average annual unit cost cap will depend on how Undergrounding Projects are defined. For example, whether Projects are defined on

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ltpp/2023-irp-cycle-events-and-materials/2023-10-20-supplemental_ruling_slides.pdf Accessed 1/11/2024

16 Public Advocates Office's Comments on Draft Resolution SPD-15 and the Staff Proposal for the SB 884 Program, p. 2.

17 COMMENTS OF THE UTILITY REFORM NETWORK (TURN) ON DRAFT RESOLUTION SPD-15 IMPLEMENTING SB 884, p. 2.

18 Public Advocates Office's Comments on Draft Resolution SPD-15 and the Staff Proposal for the SB 884 Program, pp 10-11.

a circuit segment, or circuit level granularity will affect the chunkiness of project completion as well as the annual unit cost and CBR average. A more granular definition of Undergrounding Projects, such as the circuit segment level could produce the same or similar annual average unit cost, but with a higher standard deviation that is less affected by Project completion roll-overs into future years on account of more Projects completed each year.

In contrast, a lower granularity Project definition, such as the circuit level, may allow utilities to roll more lower CBR circuit segments into each Undergrounding Project, Project unit costs may be more uniform (lower standard deviation) due to spatial averaging effects, and completion dates may have a greater impact on annual average unit cost. This may tip the scales towards adopting a 3-year rolling average if projects completed on a Q4/Q1 cusp comprise a relatively larger proportion of annual costs and CBRs. GPI is concerned that applying a temporal 3-year rolling average in addition to spatial averaging could negatively affect the prioritization of infrastructure hardening in high wildfire risk locations that are more difficult to implement. The multiple and compounding pathways for averaging within the Undergrounding Program could have a smoothing effect that influences when locations are prioritized for mitigation.

2.2 It is critical to develop a definition of Project to consider the affects of spatially based threshold CBR values and CBR averages.

GPI supports CalAdvocates request that the CPUC develop a definition of Project and include it in the Staff Proposal and Resolution.[20] GPI further contributes to the justification for this request. Defining Project granularly is critical to evaluating risk rank-informed prioritization in the 10-year Undergrounding Plans. A more granular definition of an Undergrounding Project (e.g. circuit segment) would provide more insight into how utilities are temporally prioritizing work on the highest risk ranked distribution infrastructure via Undergrounding in the 10-year Plans. A lower-granularity Project definition (e.g. circuit level) could smooth out high risk circuit segments that are grouped

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[19] PG&E Comments on Draft Resolution SPD-15, p. 3.
[20] Public Advocates Office's Comments on Draft Resolution SPD-15 and the Staff Proposal for the SB 884 Program, pp 10-11.

with lower-risk segments. This could allow Utilities to prioritize across-the-board moderate risk locations ahead of harder-to-implement, higher-risk locations. For example, a hypothetical "Circuit A" with across-the-board moderate risk ranked circuit segments versus "Circuit B" that includes relatively low- to very high-risk circuit segments, could both have the same average risk score at the circuit-level. The same effect could occur for Project unit costs. How a Project is defined will affect spatial risk averaging, and could smooth out localized wildfire risk peaks (and risk mitigation costs). The drawbacks of averaging are discussed in many contexts and comments in the WMP public record.[e.g.21] SPD-15 should be withdrawn and a definition for an Undergrounding Project should be proposed, either by the OEIS, the CPUC, or both agencies in coordination, prior to committing to any Program evaluation approach that is predicated on temporal and/or spatial averages or rolling-averages.

2.3 The IOU's request that CBRs not be the sole determinate of qualifying Undergrounding Projects is misleading and should only be considered after (1) issuing for comment the OEIS proposed Phase 1 Plan requirements, (2) establishing concrete definitions of a Project as well as minimum and/or average CBR thresholds, and (3) considering definitions for qualifying ancillary benefits.

PG&E Comments on Draft Resolution SPD-15 state:

> Finally, SPD's final guidelines for cost recovery should align with a framework in which utilities consider factors in addition to CBR when selecting sites for undergrounding in their Plans. As PG&E articulated in its earlier comments on the Staff Proposal, CBR should not be the "sole determinant" of risk mitigation strategies. Additional considerations like net benefits that incorporate reliability and public safety will be considered when selecting undergrounding projects to meet SB 884's goals of substantially increasing reliability while also substantially reducing wildfire risk.[22]

SDG&E and SCE provide similar arguments.[23,24]

CBR averaging within SPD-15 and the Staff Proposal will already create openings for utilities to consider ancillary benefits without having to justify those benefits. There are

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[21] COMMENTS OF THE GREEN POWER INSTITUTE ON THE SMALL AND MULTI-JURISDICTIONAL UTILITY 2023-2025 BASE WILDFIRE MITIGATION PLANS.
[22] PG&E Comments on Draft Resolution SPD-15, p. 9.
[23] SCE Comments on Draft Resolution SPD-15, p. 2.

currently two conditions where CBRs are, or will be, averaged: spatial averaging within Projects, and annual averaging across Projects. The latitude that spatial averaging within Projects provides to consider ancillary benefits will depend on the formal definition of a Project. For example, a circuit-level definition of a Project would average over multiple circuit segments, creating opportunity for Utilities to encapsulate and average in proximal high and low CBR circuit segments into one Project. In contrast, if a Project is defined at the circuit segment level this will limit the ability to include lower CBR Projects through Project-based averaging. Averaging CBRs across projects (e.g. annual scope of work) will allow Utilities to encapsulate lower CBR projects in any given year by averaging them with higher CBR Projects. The combination of a low granularity Project definition and annual averaged Project CBR thresholds could provide utilities with substantial latitude and opportunity to scope relatively low CBR circuit segments in any given year of the plan. That is, spatial averaging of CBRs within projects and annually across projects will likely already give Utilities the opportunity to consider and include locations based on *ancillary benefits*, not just CBRs, when developing their 10-year undergrounding plan.

The latitude that spatial CBR averaging provides to include ancillary benefits will also depend on whether and how SPD-15 and the Staff Proposal define annual CBR thresholds. SPD-15 and the Staff proposal include the following provisions:

- Establishing an annual minimum cost-benefit ratio (CBR) threshold for projects completed and booked to the one-way balancing account.[25]
- Because a threshold CBR value must be achieved, on average, for cost recovery of completed projects, this encourages large electrical corporations to prioritize projects that provide the greatest risk reduction benefits.[26]
- The average recorded CBR for all projects completed in any given year must equal or exceed the threshold CBR value for that year.[27]

The first provision requires that Projects in each year achieve a minimum CBR. It's not entirely clear if this refers to the total of or individual Project CBRs in each year. The

[24] SDG&E Comments on Draft Resolution SPD-15, p. 4.
[25] SPD-15, p. 9.
[26] SPD-15, p. 10.
[27] SPD-15 Staff Proposal, p. 10.

latter two statements suggest the threshold CBR is an average of all projects completed in that year. These amount to two different annual CBR thresholds. Utilities' latitude to include lower CBR circuit segments and therefore consider ancillary benefits in their annual undergrounding plans may depend on which threshold approach is adopted, and will depend on the absolute value of the CBR threshold.

Spatial averaging and/or annual project summations already allow utilities to include lower CBR circuit segments, and can be utilized to consider ancillary benefits within their 10-year Undergrounding Plans. Permitting additional unspecified ancillary benefit allowances will further loosen the already ill-defined criteria for reasonable undergrounding projects, and may reduce the wildfire risk reduction potential and cost effectiveness of 10-year Plans.

The methods proposed in SPD-15 and the staff proposal do not adequately inform how much latitude utilities will have, nor are they able to identify and constrain the types of ancillary benefits that utilities may consider when selecting Projects for undergrounding. GPI recommends withdrawing SPD-15 and taking the following actions to improve the Undergrounding Program framework:

- Develop a formal definition of an Undergrounding Project, including its spatial granularity.
- Provide a method for assessing and quantifying Undergrounding benefits and reevaluate the Undergrounding Program proposal as a whole.
- Clarify whether the Undergrounding Program will evaluate annual scope of work based on an annual minimum CBR threshold or an annual average CBR threshold.
- Provide a quantitative definition of or guidelines for defining an annual CBR threshold.
- Consider the latitude Utilities already have, based on the quantitative interactions of multiple averages, for including ancillary benefits when scoping circuit segments with relatively lower CBRs. Subsequently consider whether including additional ancillary benefits is acceptable for justifying undergrounding; what, if any, eligible benefits include; how approved ancillary benefits will be included, either quantitatively or qualitatively, in

CBR evaluations, Utility Plans and Applications; and how the CPUC will evaluate whether ancillary benefits are achieved.
- Re-issue the Staff Proposal for stakeholder and OEIS review after addressing the above action items.

Unless and until these actions are taken, Draft Resolution SPD-15 and the Staff Proposal already include an unknowable degree of CBR latitude that inherently allows some degree of ancillary benefit consideration, contrary to IOU claims in Opening Comments.

2.4 Incrementally releasing and adding critical Program filings and methods is imprudent.

GPI recommends withdrawing Draft Resolution SPD-15 until the OEIS proposal for 10-year Undergrounding Plans and a method for determining undergrounding benefit is provided for comment. In addition to the justifications provided above, SPD-15 does not go far enough to synchronize the OEIS and CPUC filings and their interactions. GPI appreciates that Phase 3 includes CPUC and OEIS coordination. However, SPD-15 falls well short of achieving true alignment between the OEIS and CPUC roles in the 10-year Undergrounding Program.

It is imprudent to formalize an Undergrounding Program framework via SPD-15 without defining the expectations for Phase 1. Doing so may establish and perpetuate poorly aligned and ultimately siloed OEIS and CPUC Undergrounding Program evaluation methods. This approach may also lead to unintended latitude in Project selection if the final Program evaluates scope of work based on the repeated application of averages.

GPI recommends withdrawing Draft Resolution SPD-15 and reissuing the Staff Proposal for comment after the OEIS Plan guidelines and method for determining substantial benefit are provided for comment and subsequently added to the proposal.

2.5 The Undergrounding Program is at risk of including an incongruent cost-benefit analysis approach based on the requirements for assessing mitigation costs and substantive wildfire risk reduction benefits.

Wildfire risk planning models include one or more underlying probabilistic analyses that have temporal elements. As an example, SCE's 2023 WMP planning model generates a granular wildfire consequence map using a deterministic approach based on worst-case-in-20-year conditions (e.g. wind, moisture, temperatures, etc.). Across the territory, this roughly approximates a 1-in-20-year risk event and consequence. At the asset level this may result in a patchy probabilistic basis for wildfire consequence valuation. One location could register a wildfire consequence based on 1-in-50-year event conditions, whereas a different location's maximum consequence value could reflect a 1-in-15-year event. The temporal basis (e.g. 1-in-20-year) can influence granular wildfire consequence scores, consequence severity, risk ranking, and/or threshold-based qualification for undergrounding.

It would be inappropriate to conduct a cost-benefit analysis using a 10-year mitigation capital cost analysis if, for example, a worst-case-in-20-year model were applied to determine whether substantive wildfire risk reduction is achieved. That is, it would be incongruent to base the mitigation cost-benefit assessment on 10-year capital and operating expenses relative to mitigation benefits assessed based on a 1-in-15-year or 1-in-50-year wildfire event. The potential for a temporal cost-benefit discrepancy is not specific to SCE's wildfire risk planning models, and could occur regardless of which wildfire risk model the OEIS adopts, since all granular consequence models inherently have a temporal basis. At the very least, the implications of a potential temporal cost-benefit discrepancy are not yet clear and cannot be appropriately assessed until OEIS issues Plan guidelines and a proposal for evaluating whether the Plan will substantially reduce wildfire risk and increase reliability. GPI recommends withdrawing SPD-15 and evaluating all Undergrounding Program elements holistically, including to ensure that cost-benefit ratios are temporally consistent.

GPI also generally supports the public comments filed by Robert A. Johnston and other party comments regarding the importance of considering 10-year versus asset lifetime costs. GPI urges the CPUC to pause and consider the implications of only assessing wildfire mitigation capital costs over the 10-year plan horizon.

3. The Staff proposal should include criteria for penalties.

The proposal for applying potential penalties is vague and does not clarify the basis upon which penalties can be assessed. This sets-up the Underground Program for issuing ad hoc penalties. Opaque penalty guidelines and ad hoc penalties may lead to subjective downstream application as well as uncertainty for ratepayers and the utilities. It is ineffective and perhaps even unfair to develop a penalty framework *after* a compliance threshold is "significantly" breached. An initial penalty structure should be in place to deter non-compliance, rather than relying on retroactively reacting to non-compliance.

GPI is further concerned that the provision for a one-time approval of a single 10-year Plan sets the stage for approving all downstream costs, since the Plan they are predicated on was independently deemed to substantially increase reliability and reduce wildfire risk largely independent of cost. GPI agrees with CalAdvocates and TURN that the Program's siloed approach to first reviewing and approving risk reduction impact that is largely divorced from cost, plus the creation of the memorandum account for cost overruns, seems to offer utilities a free pass to increase costs above the original Plan.[28,29] Cost overrun and/or substantive project delays, which will ultimately decrease the cost-benefit of the Plan, could be disincentivized, deterred, and managed in part through penalties. Penalties could be assessed based on measurable factors such as failure to meet annual CBR thresholds, or by complying with progress benchmarks that include defined deadlines.

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[28] Public Advocates Office's Comments on Draft Resolution SPD-15 and the Staff Proposal for the SB 884 Program, p. 6.

[29] COMMENTS OF THE UTILITY REFORM NETWORK (TURN) ON DRAFT RESOLUTION SPD-15 IMPLEMENTING SB 884, p. 3.

Establishing the basis for *at least some* penalty provisions at the outset would inform utility plan development. Failure to do so may incentivize utilities to develop a Plan that pushes the limits of what is feasible, and to subsequently push the limits of what is ultimately approved. This is especially the case since the Program proposal currently establishes a memorandum account and pathway for approving excess costs without creating a clear deterrent to cost overruns and CBR shortfalls.

4. The Program does not provide a suitable evaluation method for determining whether a Utility has "…[applied] for all available federal, state, and other non-ratepayer moneys…"

The SPD-15 Staff Proposal requires utilities to "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."[30] In order to evaluate compliance the Staff Proposal requires the Phase 2 Application to include:

> 15) The Application shall include a list of all non-ratepayer moneys (i.e., third-party funding) the large electrical corporation has applied for and/or received 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, including funding already received; e) Next steps, including timelines for processing of the funding request; and f) The amount of funding granted/authorized (if any).

This evaluation method is not capable of determining whether <u>all available</u> federal, state, and other non-ratepayer moneys are applied for.

Eligible non-ratepayer funding opportunities should be assumed to become available over the entire course of the 10-year Undergrounding Plan. However, the Phase 2 Application requirement effectively assumes that any and all eligible non-ratepayer funding applied for or received will be known by, and reported in, the Phase 2 Application filing, which appears to be a one-time filing slated for months 11-20 of the Program.[31] This assumption is not supportable. Federal, state, and other non-ratepayer funding is typically offered via

[30] Draft Resolution SPD-15 Staff Proposal, p. 3.
[31] Draft Resolution SPD-15, p. 6.

time constrained grant making cycles that may not directly align with months 1-20 of the Undergrounding Program Plan and Application development, filing, and approval process. Furthermore, the availability of eligible funding and priorities will change over the 10-year planning horizon, and might even become more favorable in forward years.

The proposed Phase 2 Application requirements are also incapable of identifying which, if any, opportunities were passed over due to qualification barriers. Grant opportunities often have qualifying factors that may require utilities to deviate from a business-as-usual approach to qualify for the funding. For example, the recent Federal grant DE-FOA-0003047: Grid Overhaul with Proactive High-speed Undergrounding for Reliability Resilience, and Security (GOPHURRS) seeks project applications for upwards of $10 Million towards undergrounding projects that advance emerging undergrounding techniques.[32] To be eligible for this funding a Utility would have to develop an eligible Undergrounding Project(s) that employs one or more specific technology categories. In another example, disaster mitigation via electrical infrastructure undergrounding qualifies for FEMA Building Resilient Infrastructure and Community (BRIC) Funds. This is evidenced by the opportunity guidelines as well as application EMD-2022-BR-001-0002 "Lincoln Electric Overhead to Underground Hazard Reduction Project," which passed the HMA requirements and was Identified for Further Review.[33,34] However, "… business owners … cannot apply directly to FMEA," rather "Eligible states, territories, and federally recognized governments can submit applications on behalf of subapplicants …,"[35] meaning a Utility would have to work with the state as a subapplicant in order to secure FEMA funding via the BRIC opportunity. These examples identify grant opportunity qualifying criteria that may lie outside the purview of business-as-usual utility

[32] ARPA-E eXCHANGE, https://arpa-e-foa.energy.gov/Default.aspx#FoaId6dc230e7-6e35-4a22-a005-7d883a9a4153 Accessed on 1/11/2024.
[33] Montana: The Lincoln County Resilient Energy and Transportation Infrastructure Project https://www.fema.gov/case-study/montana-lincoln-county-resilient-energy-and-transportation-infrastructure-project Accessed on 1/11/2024.
[34] Building Resilient Infrastructure and Communities Grant Program FY 2022 Subapplication and Selection Status and Fiscal year 2022 Subapplicant Status https://www.fema.gov/grants/mitigation/building-resilient-infrastructure-communities/after-apply/fy22-status#grant-cycle Accessed 1/11/2024.
[35] Before You Apply for Building Resilient Infrastructure and Communities (BRIC) Funds https://www.fema.gov/grants/mitigation/building-resilient-infrastructure-communities/before-apply Accessed 1/22/2024.

Undergrounding operations, and that may severely reduce the amount of non-ratepayer funding that a utility applies for if they are unwilling or unable to modify their approach. GPI is concerned that utilities may routinely pass up non-ratepayer funding opportunities on account of qualifying requirements that demand alternative approaches beyond business-as-usual methods.

Conclusion

If poorly developed, the non-ratepayer funding elements of SB 884 and the resulting Undergrounding Program runs the risk of becoming a façade that fails to have any meaningful impact on wildfire risks or ratepayer costs. GPI recommends withdrawing SPD-15 and updating the Undergrounding Program framework to bolster the non-ratepayer funding elements. GPI specifically recommends establishing external, non-ratepayer funding reporting requirements annually over the duration of the 10-year plan. These reporting requirements should stipulate that Utilities must list **all** identified opportunities eligible to fund electrical infrastructure undergrounding projects and that they must provide a summary as to why an opportunity was not applied for due to qualifying criteria. Reporting criteria should also include additional details such as Opportunity ID, deadline, and maximum funding request amount as provided by the funder.

Dated January 11, 2024
Respectfully Submitted,

Gregg Morris

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January 11, 2024

Rachel Peterson
Executive Director
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Re: **Pacific Gas and Electric Company's Reply Comments on Draft Resolution SPD-15**

Dear Executive Director Peterson:

Pacific Gas and Electric Company (PG&E) appreciates the opportunity to provide the following Reply Comments on Draft Resolution SPD-15 (Draft Resolution) adopting Safety Policy Division's (SPD) Staff Proposal for the Senate Bill 884 (SB 884) expedited undergrounding program.

PG&E reviewed opening comments on the Draft Resolution and Staff Proposal from the Public Advocates Office at the California Public Utilities Commission (Cal Advocates), Coalition of Utility Employees (CUE), the California Farm Bureau (Farm Bureau), the California Broadband and Video Association (Communications Providers), Mussey Grade Road Alliance (MGRA), San Diego Gas & Electric Company (SDG&E), Southern California Edison Company (SCE), and The Utility Reform Network (TURN). Given the limited time available, PG&E's reply comments are focused on certain key issues raised by these parties. Specifically, PG&E's reply comments address the following areas:

1. The proposed two-step approach of a balancing account and memorandum account for recovery of prudently incurred costs;
2. Cost recovery metrics;

3. The timing of a Final Resolution SPD-15 and guidelines from the Office of Energy Infrastructure Safety (Energy Safety); and,

4. Other issues including, avoided cost requirements, issues related to communications companies, recommendations regarding risk modeling and project selection, Undergrounding Plan timing, and changes to an Undergrounding Plan.

While these reply comments do not repeat all of the issues addressed in our Opening Comments, we strongly reaffirm the recommendations that we made in the areas of providing additional clarity on cost accounting and recovery processes, modifying the avoided cost requirements, and clarifying the threshold Cost-Benefit Ratio (CBR).[1] PG&E appreciates the consideration of these comments and recommendations by the Commission and its Staff as they finalize the Draft Resolution.

I. THE COMMISSION'S PROPOSED TWO-STEP PROCESS FOR COST RECOVERY IS A BALANCED APPROACH

PG&E strongly supports the two-step cost recovery process set forth in the Draft Resolution that allows electrical corporations to record costs up to an established cost cap in a one-way balancing account and to track costs that exceed the cap in a memorandum account.[2] This two-step process incentivizes electrical corporations to carefully manage their undergrounding programs to recover costs expeditiously through the balancing account. As the Draft Resolution explains, the "[o]ne-way balancing account allows participating large electrical corporations to recover the costs of undergrounding without undue delays once infrastructure is used and useful."[3] At the same time, the Draft Resolution recognizes that electrical corporations may reasonably incur unforeseeable costs during the 10-year program and provides an opportunity to recover those costs through a memorandum account subject to an application for Commission review and approval.[4]

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[1] Pacific Gas and Electric Company's Comments on Draft Resolution SPD-15, December 28, 2023 (PG&E Comments).

[2] Draft Resolution, pp. 2-3.

[3] Draft Resolution, p. 7.

[4] *Id*.

In Opening Comments, several parties proposed modifications to this two-step cost recovery process. For example, Cal Advocates recommends that all costs be recorded in a memorandum account that includes an annual cap on the amount a utility can record.[5] TURN and Farm Bureau, on the other hand, recommend eliminating the memorandum account and limiting cost recovery to a one-way balancing account.[6] Cal Advocates and TURN also recommend that recorded costs be reviewed through an application process and that potential changes to a cost cap adopted in Phase 2 be addressed through a petition for modification (PFM).[7] These proposals are inconsistent with Commission precedent and ignore the clear statutory language in SB 884 that the undergrounding program be an "expedited" program. PG&E addresses each of these proposals below.

A. The Draft Resolution Establishes Sufficient Controls for Managing Costs Recorded to the One-Way Balancing Account

The Draft Resolution and Staff Proposal establish rigorous controls for the one-way balancing account to protect ratepayers from "unexpected or inefficient cost overruns."[8] Before an electric corporation can recover costs recorded to the one-way balancing account it must meet annual cost caps, average unit cost caps, cost effectiveness limits and, where applicable, use third-party funding to reduce ratepayer costs.[9] Moreover, the undergrounding project workplan that an electrical corporation will include in its Commission application for conditional approval of plan costs will have already been evaluated and approved by Energy Safety in Phase 1 of the SB 884 Program process. Although Energy Safety has not yet completed its SB 884 guidelines, it is likely that during Phase 1, stakeholders will have ample opportunity to evaluate the proposed project selection framework, costs and benefits associated with each project, estimated wildfire risk reductions, estimated reliability improvements, execution feasibility factors, and avoided

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5 Cal Advocates Comments, p. 7.

6 TURN Comments, p. 8; Farm Bureau Comments at 3.

7 Cal Advocates Comments, pp. 7-10; TURN Comments, pp. 7, 12.

8 Draft Resolution, Staff Proposal, p. 10.

9 Draft Resolution, p. 7 and Staff Proposal, p. 10.

costs through discovery and potentially workshops. During Phase 1, stakeholders will also have an opportunity to submit comments regarding the electrical corporation's proposals as required by SB 884.[10] Stakeholders will also have ample opportunity in Phase 2 to conduct further discovery and address the appropriate annual cost caps, unit cost caps, average CBR thresholds, and any other conditions that are appropriate for the Commission to impose (*e.g.*, other metrics, such as a net benefits).

Cal Advocates proposes eliminating the balancing account and replacing it with a memorandum account that will be reviewed through an application process.[11] TURN does not oppose the use of a balancing account but recommends that the Commission establish an application process for balancing account review and that recovery of undergrounding costs incurred by an electrical corporation only occur after the application process is complete.[12] Farm Bureau recommends that the Commission review costs in the balancing account, but does not provide detail as to how the review should occur.[13] Cal Advocates and TURN both recognize that the application processes they propose will be lengthy – Cal Advocates argues for a ten (10) to thirteen (13) month process at a minimum[14] and TURN acknowledges that the application process that it proposes could take eight (8) months,[15] although this is likely an underestimate.

These parties' proposals, which recommend an additional application process <u>after</u> the Phase 2 application process, are inconsistent with the Legislature's clear direction and are contrary to Commission precedent. The Phase 2 process established in the Draft Resolution will last nine months and involve a detailed review of an electrical corporation's cost forecasts by parties and the Commission, as well as opportunities for parties to submit comments on the electrical corporation's proposals. At the end of the Phase 2 process, the Commission will

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[10] Cal. Pub. Utilities Code (PUC) §8388.5(d)(1)

[11] Cal Advocates Comments, pp. 7-8.

[12] TURN Comments, pp. 3-7.

[13] Farm Bureau Comments, p. 2.

[14] Cal Advocates Comments, p. 8.

[15] TURN Comments, p. 5.

establish annual cost caps, unit cost caps, a CBR threshold and other conditions. Cal Advocates and TURN now want to add onto the Phase 2 process additional and unnecessary annual applications for recovery of balancing account amounts that will each likely last a year or longer. In short, these parties envision an endless series of applications after a Phase 2 decision before an electrical corporation can recover any of the funds it has expended on undergrounding. This is certainly not the "expedited" undergrounding program that the Legislature directed in SB 884.[16] Moreover, the Commission recently recognized the detrimental impacts for electrical corporations and customers resulting from lengthy delays in the ability to recover costs, including direct and indirect costs that ratepayers incur.[17] Given these impacts, there is no reason to adopt Cal Advocates' and TURN's proposal for lengthy, additional application processes before costs that have already been incurred can be recovered.

Cal Advocates and TURN justify these additional and unnecessary applications by arguing that under SB 884 the Commission conditionally approves undergrounding plan costs but must also determine that the recorded costs are just and reasonable.[18] These parties assert that the justness and reasonableness of costs should be determined in an application process. Farm Bureau makes a similar argument asserting the "Draft Resolution seemingly allows the utilities to make that determination on their own and automatically include in rates any amount *they believe* should be approved"[19] and argues instead that the balancing account costs should be subject to further review.

While these parties imply that an application process alone can determine whether costs recorded in the balancing account are just and reasonable, previous Commission decisions have instituted simpler audits for reviewing undergrounding programs. For example, in PG&E's 2017 General Rate Case (GRC), the Commission established a balancing account for undergrounding

[16] PUC § 8388.5(a).

[17] *See* Decision (D.) 23-06-004 (addressing direct and indirect ratepayer impacts in the context of an interim rate relief request).

[18] Cal Advocates Comments, p. 3; TURN Comments, pp. 3-4.

[19] Farm Bureau Comments, p. 2 (emphasis in original).

costs associated with Rule 20A. To ascertain whether the costs recorded in the balancing account were reasonable, the Commission ordered that an audit be conducted rather than an additional application process.[20] Similarly, when SBC Corporation proposed recovering certain undergrounding costs through a balancing account, the Commission established a reporting and audit process, if certain thresholds were met, to ensure that amounts recorded in the balancing account were just and reasonable.[21]

The Commission should use a similar audit approach here. The Commission has well-established audit authority under Public Utilities Code Sections 314 and 314.6 and an audit division that can perform Undergrounding Plan audits in a timely manner. In Phase 2, the Commission can provide conditional approval, consistent with Section 8388.5(e)(1)[22] of the electrical corporations cost forecasts, including the detailed requirements for average unit costs, total annual costs, and average CBR thresholds. After the costs are recorded to the balancing account and included in rates for recovery, the Commission can then ensure that the costs are just and reasonable, consistent with the requirements of Section 8388.5(e)(6) and the Phase 2 decision, by conducting an audit of the balancing account. The audit will enable the Commission to review and understand the types of costs recorded to the balancing account (e.g., costs for materials, contract labor, etc.), test a number of entries to ensure that the recorded costs are appropriately supported by documentation, and request additional information, if needed. If, after an audit, the Commission determines that any costs were unreasonable, it can direct the electrical corporation to refund those costs to customers.

It is notable that in Section 8388.5(e)(1), the Legislature specified that electrical corporations file an application for conditional approval of costs but did not include a similar requirement in Section 8388.5(e)(6) regarding the Commission's determination that undergrounding costs recorded to a balancing account are just and reasonable. Had the

[20] D.17-05-013, Conclusion of Law 6-7.

[21] D.06-12-039, Conclusions of Law 3-4 and Ordering Paragraph 6.

[22] Statutory references are to the California Public Utilities Code unless otherwise noted.

Legislature wanted to require an application process for review of the balancing account, as Cal Advocates and TURN now propose, it could have added language in Section 8388.5(e)(6) to do so, similar to the language Section 8388.5(e)(1). Importantly, the Legislature did not include an application requirement in Section 8388.5(e)(6). Accordingly, the Commission should adopt an audit process as it has done in the past to ensure that recorded costs are just, reasonable, and consistent with the Phase 2 decision rather than an impractical and unnecessary process of annual applications, which even Cal Advocates and TURN concede would be lengthy.

B. It is Reasonable to Establish a Memorandum Account to Record Unforeseen Costs

As the Draft Resolution recognizes, "there are significant uncertainties in undergrounding electrical distribution equipment that are likely to grow over a 10-year period."[23] Notably, other parties agree. For example, Cal Advocates acknowledges that "a ten-year plan carries significant uncertainty."[24] To address this undisputed uncertainty, the Draft Resolution provides an opportunity for electrical corporations to establish a memorandum account to track costs exceeding the Phase 2 annual cost caps. This is a completely reasonable approach. Electrical corporations should have the opportunity to record costs that they could not have reasonably foreseen over the course of the 10-year undergrounding program for consideration and potential cost recovery. The memorandum account proposed in the Draft Resolution is well suited to facilitate the recording and review of undergrounding program costs that are reasonably incurred but exceed approved cost caps. The Commission routinely allows electrical corporations to seek recovery in separate accounts for unexpected or new costs that are not recovered through other ratemaking mechanisms, such as the GRC.[25]

Unforeseen cost increases may arise in a variety of circumstances. For example, as a result of the COVID-19 pandemic, numerous state and county health orders were issued in 2020,

[23] Draft Resolution, p. 7.

[24] Cal Advocates Comments, p. 8.

[25] D.23-11-069, p. 750.

as well as an Emergency Regulation from the California Occupational Safety and Health Administration (Cal/OSHA), requiring utilities to purchase safety equipment for employees specifically for the pandemic. In addition, social distancing guidelines required use of separate vehicles, and additional inspection requirements in response to Cal/OSHA criteria were also necessary.[26] These unforeseen costs were reasonably incurred due to extraordinary events outside of an electrical corporation's control and thus it was entirely appropriate for PG&E and other utilities to seek recovery for these through a memorandum account.[27]

Here, the Draft Resolution allows electrical corporations to establish memorandum accounts to record costs that exceed the Commission-approved one-way balancing account cap. The fact that costs are recorded in the memorandum account does not guarantee recovery. Instead, the electrical corporation will need to demonstrate that the costs in the memorandum account were prudently incurred and that recovery from customers is just and reasonable. Parties such as TURN, Farm Bureau, and Cal Advocates will have an opportunity to conduct discovery and, if appropriate, protest or oppose the recovery of some, or all, of the memorandum account costs. Only when the Commission has determined that the memorandum account costs are just and reasonable will these costs be included in rates.

TURN, Cal Advocates, and Farm Bureau assert that the memorandum account included in the Draft Resolution should be eliminated, arguing that it is a "blank check" for the electrical corporations.[28] In part, these parties point to past situations where the utilities have incurred costs greater than an authorized amount and sought recovery for the incremental costs through a memorandum account.[29] As a preliminary matter, TURN's argument that PG&E spent substantially more than it was authorized for wildfire mitigation in 2020 does little to advance its

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[26] *See* Application (A.) 18-12-009, PG&E Testimony, p. 6-4 (describing COVID-19 requirements).

[27] In PG&E's case, these costs were recorded in the Catastrophic Emergency Memorandum Account (CEMA).

[28] Cal Advocates Comments, p. 6; TURN Comments, pp. 1, 8-12; Farm Bureau Comments, p. 3.

[29] *See e.g.* TURN Comments, pp. 9-10.

argument.[30] There is no dispute that PG&E used its own funds to finance wildfire mitigation measures intended to prevent catastrophic wildfires, with no guarantee of cost recovery. The costs that PG&E incurred were not simply passed on to ratepayers, but instead were carefully and thoroughly scrutinized by parties such as TURN and the Commission in regulatory proceedings. This is the opposite of a "blank check."

More importantly, given the uncertainty associated with a 10-year plan—a fact which is not in dispute—it is entirely reasonable for electrical corporations to track excess costs in a memorandum account and have the opportunity to seek recovery of those costs through an application process. As TURN acknowledges, the application process provides a robust opportunity for the Commission and parties to "scrutinize, test, and challenge the veracity and prudence of utilities' costs."[31] If the electrical corporation's costs in excess of the annual cap are not reasonable or prudent, the Commission can deny recovery of the costs. However, if the costs are reasonable and prudent, especially given the potential for unforeseen circumstances, then recovery is appropriate. TURN's, Cal Advocates' and Farm Bureau's proposals would effectively prevent electrical corporations from even having the opportunity to demonstrate that costs in excess of the annual cost cap are reasonable.

C. The Final Resolution Should Allow Electrical Corporations to Propose Changes to a Phase 2 Decision via an Expedited Petition for Modification

The Staff Proposal requires an electrical corporation to provide both capital and operating expense cost forecasts for each year of the 10-year Application period, the forecasted average CBR across all projects expected to be completed in each of the 10 years of the Application period, and other program and project cost information consistent with the cost targets presented in the Undergrounding Plan approved by Energy Safety.[32] The Commission will review these materials and include in a Phase 2 decision conditions for approval of plan costs such as the

[30] TURN Comments, pp. 9-10.

[31] TURN Comments, p. 7 (quoting CPUC comments on State Auditor Report).

[32] The complete list of Application Requirements is provided on pp. 6-10 of the Draft Resolution, Staff Proposal.

annual cost cap, unit cost cap, and CBR thresholds.[33] However, as Cal Advocates recognizes, "a ten-year plan carries significant uncertainty."[34] Over the course of a 10-year undergrounding program, it is entirely reasonable to expect that an electrical corporation's forecast costs or calculations in an Undergrounding Plan and Application could change.

To address uncertainty, Cal Advocates and TURN recommend that electrical corporations file a Petition for Modification (PFM) to make changes to the Phase 2 decision.[35] Cal Advocates specifically proposes an expedited PFM process.[36] Because an expedited PFM process aligns to the statutory requirement for expedited review of an undergrounding Application[37] and the Staff Proposal's objective to provide for regulatory certainty for recovering undergrounding plan costs, PG&E supports Cal Advocates' proposal with certain modifications. Specifically, PG&E agrees with the following the following aspects of Cal Advocates' expedited PFM proposal:[38]

- The Commission should approve or deny the PFM within six months;
- In the petition, the petitioner must provide all facts and evidence necessary to substantiate its request;
- Within 45 days of filing, the assigned administrative law judge (ALJ) should convene a pre-hearing conference, issue questions for parties to address in initial comments, or both;
- The assigned ALJ should issue a schedule that calls for party comments approximately three months after filing, with reply comments or rebuttal testimony one month thereafter; and
- To facilitate the expedited schedule, during the review of a PFM, parties shall respond to discovery requests within five business days.

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33 Draft Resolution, Staff Proposal, p. 10.

34 Cal Advocates Comments, p. 8.

35 Cal Advocates Comments, pp. 7-10; TURN Comments, pp. 7, 11.

36 Cal Advocates Comments, pp. 8-9.

37 PUC §8388.5(a)(5).

38 Cal Advocates Comments, p. 9.

PG&E does not support Cal Advocates' recommendation that the Commission should "reject the PFM without prejudice" if the electrical corporation does not provide all facts and evidence necessary to substantiate its request.[39] "All facts and evidence necessary" is a subjective standard that Cal Advocates does not define. Moreover, the Commission may find that a PFM is missing some limited information which would not justify rejection and/or can be provided through discovery or a supplemental filing. The Draft Resolution should not pre-judge when a PFM should be rejected or not. This determination should be made when the actual PFM is filed. Additionally, PG&E does not support Cal Advocates' recommendation that the assigned ALJ should issue a schedule that calls for testimony or rebuttal testimony.[40] Parties should address issues through written comments and discovery to minimize unnecessary delay.

II. COST RECOVERY METRICS

Cost recovery for Undergrounding Plan work is based on meeting specific metrics (*i.e.*, average CBR thresholds, cost caps, and average unit costs). While the measure of forecasted project costs is certain, the measure of forecasted benefits is not. Therefore, it is critical that the final Resolution allow flexibility for selecting and justifying mitigations and not solely base risk mitigation selection on CBRs. Additionally, to address the long-term nature of an undergrounding project, it is reasonable to evaluate these cost recovery metrics over a longer time period than currently set forth in the Draft Resolution.

A. Cost-Benefit Ratios Should Not Be the Sole Determinant for Selecting Risk Mitigations

SDG&E and SCE recommend that CBRs and additional factors be used to assess if a mitigation is reasonable. SDG&E notes that the Commission's Risk-Based Decision-Making Framework (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

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[39] Cal Advocates Comments, p. 9.

[40] Cal Advocates Comments, p. 9.

projects.[41] Similarly, SCE requests that the final Resolution and Staff Proposal clarify that CBRs are one factor among many in assessing risk mitigations, and that the resolution is not intended to supplant Commission precedent confirming that CBRs are not to be used as the sole determining factor in assessing whether a proposed mitigation selection is reasonable.[42] PG&E strongly supports these recommendations.

While it is appropriate to include a CBR based on the methodology adopted in the Rulemaking (R.) 20-07-013 proceeding in Undergrounding Plans, the Commission also stated in that proceeding that it does not intend CBR to be the "sole determinant" of risk mitigation strategies.[43] Like any single metric, CBR is limited, in that it provides information on the relationship between costs and benefits, it does not evaluate the absolute magnitude of either. To promote customers' safety, an electrical corporation should have the opportunity to explain how other factors not included in a CBR calculation impact mitigation selection. More specifically, PG&E recommends that the Draft Resolution follow the CPUC's guidance in D.22-12-027 by allowing an electrical corporation to use both a CBR and other metrics—such as a net benefit metric—for project selection in its Undergrounding Plan. Net benefit (calculated by subtracting costs from benefits at a given location) uses the same inputs as CBR but captures the absolute contribution to risk reduction in High Fire Threat Districts (HFTDs) and High Fire Risk Areas (HFRA). Absolute risk reduction benefit, represented in a metric like net benefit, is important when considering the overall Undergrounding Plan risk reduction benefits and not just the risk reduction in a single location. While project selection will be addressed in an SB 884 Plan submitted to OEIS and cost recovery will be addressed in an electrical corporation's SB 884 cost recovery application to the CPUC, guidelines for the Plan and cost recovery application need to align with each other. Thus, the conditions for approval of plan costs should include both the

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[41] SDG&E Comments, p. 4

[42] SCE Comments, p. 3.

[43] D.22-12-027, Finding of Fact 11.

CBR and other metrics (like net benefit) rather than narrowly requiring reliance on a single metric (CBR).

B. Project Metrics Should be Applied on a Three-Year Basis

PG&E recommended in our Opening Comments that the Commission apply both unit cost caps and the average CBR threshold over a longer period than one year. PG&E proposed that the cost cap be calculated on a three-year rolling basis and any average CBR thresholds required should be set for a longer time interval—for example, every three (3) years, or for the period during which a utility selects projects based on one version of its risk model.[44] Achieving unit cost caps or an average CBR on an annual basis is challenging because the timing of undergrounding projects may shift among the years of an Undergrounding Plan due to construction-related factors.

In its comments, SCE recognizes the challenges with measuring metrics on an annual basis for multi-year undergrounding projects. SCE notes that if a project is completed faster than anticipated or is delayed for any number of reasons, one year's average annual CBR or annual cost cap could be exceeded or underrun, despite no actual change in a project or the overall Plan's costs or risk buydown. SCE recommends measuring such metrics on a longer time horizon, which would allow for meaningful Undergrounding Plan oversight that is not unduly swayed by unforeseeable timing changes and allows a completed project to be evaluated in its entirety.[45] Given the many factors that can impact the timing of a long-term construction project, PG&E reaffirms our recommendation that the final Resolution allow unit cost caps and the average CBR threshold to be applied over a longer time interval, preferably a three-year rolling average.

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[44] PG&E Comments, pp. 3, 9.

[45] SCE Comments, p. 3.

III. THE COMMISSION SHOULD NOT DELAY ACTION ON THE DRAFT RESOLUTION WHILE ENERGY SAFETY COMPLETES ITS SB 884 GUIDELINES

Several parties commented on the timing and relationship between the final guidelines for review and conditional approval of 10-year undergrounding plan costs that will be issued by the Commission (Phase 2) and the final guidelines for the 10-year Undergrounding Plan evaluation that will be issued by Energy Safety (Phase 1).[46] Parties are concerned that there could be inconsistency between the two sets of guidelines if the Phase 2 guidelines are finalized before Energy Safety adopts the Phase 1 guidelines. Accordingly, the parties recommend that: (1) the Commission delay a decision on the Staff Proposal until Energy Safety completes its guidelines; or (2) the Commission finalize its guidelines but allow an additional comment period on the final Application (Phase 2) guidelines once Energy Safety's final Undergrounding Plan guidelines (Phase 1) are complete.

PG&E strongly opposes delaying Commission action on the Draft Resolution for an indefinite period. SB 884 was enacted in September 2022, more than 15 months ago. The Commission's Staff has been working diligently since that time and has developed a comprehensive proposal for implementing the Commission's responsibilities under SB 884. There is no reason to delay final adoption of the Commission's guidelines until some unspecified future date when the Energy Safety guidelines are adopted.[47] If there are conflicts between the final Commission and Energy Safety guidelines, PG&E recommends that the Commission adopt an expedited PFM process, similar to the process described above in Section I.C. If appropriate, parties can request a modification to the final Resolution to align it with Energy Safety's guidelines. To ensure an expedited process, PG&E recommends that the Commission approve or deny any such PFM within 60 days after it is filed. Given that there will be no factual issues,

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[46] Cal Advocates Comments, p. 2; Farm Bureau Comments, p. 2, MGRA Comments, p. 1, and TURN Comments, pp. 2, 12-13.

[47] PG&E believes that Energy Safety Staff has also been working diligently on developing Phase 1 guidelines. Energy Safety has hosted a number of workshops and recently asked for post-workshop comments. However, Energy Safety has not announced when it intends to issue draft Phase 1 guidelines and thus the timing of Energy Safety's final guidelines to implement SB 884 is unclear.

and a PFM will simply focus on inconsistencies between the Commission's guidelines and Energy Safety's guidelines, 60 days is reasonable to address any concerns.

IV. OTHER ISSUES

In addition to the issues discussed above, parties made several other recommendations in their Opening Comments. In this section, PG&E addresses recommendations related to: (1) avoided cost requirements; (2) communication facilities and joint poles; (3) Energy Safety addressing risk modeling issues rather than those issues being addressed in the Final Resolution; (4) SB 884 plan timing; and (5) changes to Undergrounding Plans.

A. PG&E Supports the Avoided Cost Requirements in the Draft Resolution

The Staff Proposal requires an electrical corporation to identify costs that will be reduced, deferred, or avoided because of implementing the proposed undergrounding Plan.[48] In our Opening Comments, PG&E supported the requirement to include information about avoided costs in an Undergrounding Plan and in annual updates.[49]

TURN recommends that the final Resolution restore language that had required a utility to provide "the proposed disposition of the savings" and augmented the language by requiring the Phase 2 application to include a methodology by which the Commission can ensure that the claimed cost savings will be reflected in rates.[50] This proposal is unreasonable. PG&E intends to identify the savings, or avoided costs, associated with an Undergrounding Plan by modeling or forecasting avoided costs based on the number of underground miles completed per year at the program level. Avoided costs will include forecast savings in areas such as asset inspections, maintenance, and vegetation management. However, it is unreasonable to require an electrical corporation to set up an entirely new tracking system to determine if the forecasted avoided costs occur and, if so, how any savings associated with the avoided costs are used. To the extent that savings occur in years already accounted for in rates, that money would be used to fund other

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[48] Draft Resolution, Staff Proposal, p. 7.

[49] PG&E Comments, p. 8.

[50] TURN Comments, pp. 13-14.

high priority work benefitting customers. Consistent with PG&E's responsibility and its discretion to adjust priorities to accommodate changing conditions, PG&E would fund work that is deemed necessary for safe and reliable service. To the extent savings are forecasted to occur in years not yet accounted for in rates, PG&E would not request funding for those activities. By not requesting funding for work deemed unnecessary because of undergrounding projects, the cost savings would be reflected in rates.

B. Issues Related to Communications Providers

Several parties raised issues related to the impact of undergrounding plans on communications providers. The parties recommended that the CPUC require an electrical corporation to: (1) include non-electric pole attachment and third-party costs associated with undergrounding in its application;[51] (2) describe how it will address affected shared poles; and (3) remove poles from its rate base that are transferred to a telecommunications utility.[52] PG&E does not support these recommendations.

First, it is unreasonable to require an electrical corporation to include third-party costs in its Phase 2 Application. An electrical corporation is asking to recover costs from customers that it incurs for its own undergrounding program and has no control over or authority to verify cost estimates incurred by other entities. Nor can an electrical corporation attest to the accuracy of costs forecasts provided by third-parties, especially if those third-parties decide not to participate in the Phase 2 proceeding where the costs are considered.

Second, there are established rules covering joint pole practices around ownership, maintenance, use, setting, placement, or removal.[53] These practices do not need to be repeated in a Phase 2 Application.

Third, poles that are transferred would be retired from service and would be fully depreciated when they are retired from service. These assets would no longer be in rate base after

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[51] Communication Providers Comments, p. 3.

[52] Cal Advocates Comments, pp. 14-15.

[53] *See* Northern California Joint Pole Association, Operations/Routine Handbook, 2019.

retirement, and there would be no depreciation charges related to these assets. Separately, any reimbursements[54] related to ownership transfer or removal that are received from any third party including a telecommunications company would reduce rate base. These transactions follow FERC accounting rules.

C. Recommendations Regarding Risk Modeling and Project Selection Should be Addressed in Energy Safety's Guidelines

MGRA raises issues in its Opening Comments related to the following: re-analyzing circuits and providing alternate mitigations; re-running risk analysis and mitigation prioritization every time major changes are made to risk models; optimal risk mitigation strategies; and benchmarks for deployment of advanced technologies and research and development.[55] These issues are more appropriately addressed during the Undergrounding Plan review conducted by Energy Safety (*i.e.*, Phase 1 of an SB 884 proceeding). Because the issues raised by MGRA do not specifically relate to cost recovery—the Commission's area of responsibility under SB 884 and the subject of the Draft Resolution—PG&E is not responding to them in these reply comments but will address them in the appropriate forum (*i.e.*, before Energy Safety). The Commission should not address these issues in the final Resolution as they are more appropriately addressed by Energy Safety consistent with the SB 884 statutory language.

D. The Commission Should Not Limit When an Undergrounding Plan Can Begin

Farm Bureau argues that the Commission's decision in PG&E's 2023 GRC stated that the GRC was to act as a bridge to the SB 884 Program and therefore no 10-year undergrounding program should begin until 2027.[56] PG&E does not support any limitations on when an SB 884 Undergrounding Plan can begin.

Undergrounding work performed under an approved SB 884 plan will substantially increase reliability and reduce wildfire risk in some of the highest wildfire risk areas of

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[54] *Id*.

[55] MGRA Comments, pp. 6-7.

[56] CFBF Comments, p. 2.

California. This critically important work should not be delayed by language in the Draft Resolution. SB 884 does not place any restrictions on when an Undergrounding Plan can start, and the Commission did not place any limitations on when PG&E could file an Undergrounding Plan in its 2023 GRC Decision.[57] Electrical corporations filing an SB 884 plan should decide when their 10-year programs will begin based in part on their customers' needs. Thus, PG&E recommends that the final Resolution exclude any restrictions on when an Undergrounding Plan can begin.

E. Changes to Undergrounding Plans Should be Addressed in a Subsequent Process

The Staff Proposal states that procedures for considering changes to elements of an Undergrounding Plan, including cost forecasts, project lists, and risk models, will be determined by the Commission in coordination with Energy Safety in a subsequent process.[58] As indicated above in Section I.C, changes to a Phase 2 decision should be addressed through an expedited PFM process. In Table 1 below, PG&E provides initial considerations related to how changes to elements of an Undergrounding Plan could occur including both the expedited PFM and changes to the Undergrounding Plan reviewed by Energy Safety.

Table 1 – Processes for Changing Elements of an Undergrounding Plan

Undergrounding Plan Element	Change Process
Annual Cost Cap	Expedited PFM
Average Unit Cost	Expedited PFM
Average CBR	Expedited PFM

[57] The only references to an SB 884 Undergrounding Plan in PG&E's 2023 GRC Decision are: (1) reference to potential adjustments to the content, format, and timing of undergrounding reports to ensure accuracy and consistency with the implementation of SB 884 should PG&E choose to participate in the SB 884 program; and (2) stating that an electrical corporation may pursue conditional approval of a 10-year undergrounding plan pursuant to PUC §8388.5. D. 23-11-069, p. 283 and Conclusions of Law No. 87, p. 862.

[58] Draft Resolution, Staff Proposal, p. 13.

Undergrounding Plan Element	Change Process
Minor Updates/Changes to Project Selection Framework	• Notify parties of an update in the 12-month progress report submitted to Energy Safety. • Allow for limited discovery related to the updated/changed element.
Risk Model(s)	• Notify parties of an update in the 12-month progress report submitted to Energy Safety. • Allow for limited discovery related to the updated/changed element.
Elements of a Project Selection Framework (e.g., unit costs, mitigation effectiveness, etc.)	• Notify parties of an update in the 12-month progress report submitted to Energy Safety. • Allow for limited discovery related to the updated/changed element.
New Mitigation Technologies or Construction Techniques	• Notify parties of an update in the 12-month progress report submitted to Energy Safety. • Allow for limited discovery related to the updated/changed element.
Individual Undergrounding Projects	Update in regular progress report submitted to Energy Safety
Workforce Development Strategy	Update in regular progress report submitted to Energy Safety
Sustainable Supply Chain Strategy	Update in regular progress report submitted to Energy Safety
Third Party Funding	Update in regular progress report submitted to Energy Safety

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

Cc: Service lists for A.21-06-021, A.23-05-010, and A.22-05-016 and SB 884 Notification List

The Public ADVOCATES OFFICE

January 11, 2024 **VIA ELECTRONIC FILING**

Rachel Peterson, Executive Director
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102
SB884@cpuc.ca.gov

Subject: **Public Advocates Office's Reply Comments on Draft Resolution SPD-15 and the Staff Proposal for the SB 884 Program.**

Dear Executive Director Peterson,

The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) respectfully submits the following reply comments on Draft Resolution SPD-15 for the SB 884 Program. Please contact Holly Wehrman (Holly.Wehrman@cpuc.ca.gov), Senior Utilities Engineer, Henry Burton (Henry.Burton@cpuc.ca.gov), Program and Project Supervisor, or myself with any questions relating to these comments.

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

Sincerely yours,

/s/ Nathaniel Skinner
Program Manager, Safety Branch

cc: Koko Tomassian, Safety Policy Division
Fred Hanes, Safety Policy Division
SB 884 Service List –
https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/documents/sb-884---notification-list-updated-1_8_2024.xlsx
Service Lists for A.21-06-021, A.22-05-016, and A.23-05-010
Caroline Thomas Jacobs, Office of Energy Infrastructure Safety
Kristin Ralff Douglas, Office of Energy Infrastructure Safety

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I. INTRODUCTION

Pursuant to Rule 14.5 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission), the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) hereby submits these reply comments on Draft Resolution SPD-15, which adopts the Commission's Staff Proposal for the Senate Bill (SB) 884 Program.

SB 884, codified as Public Utilities (PU) Code section 8388.5, went into effect on January 1, 2023. This statute directs the Commission to establish a program for long-term utility distribution undergrounding plans and authorizes large electrical corporations (utilities) to participate in that program.[1,2] On November 9, 2023, the Safety Policy Division (SPD) served Draft Resolution SPD-15 to adopt a Staff Proposal that establishes the process and requirements for the Commission's review of the utilities' SB 884 program applications.[3]

On December 28, 2023, Cal Advocates and other stakeholders filed opening comments on Draft Resolution SPD-15 and the Staff Proposal.[4] Draft Resolution SPD-15 invites interested persons to file reply comments by January 11, 2024.

II. DISCUSSION

A. The Commission should clarify the requirements regarding the annual unit cost caps and cost-benefit ratio thresholds.

Both Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E) correctly note a discrepancy between the language in the Staff

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

[2] PU Code section 8385 and section 8388.5.

[3] SPD, Draft Resolution SPD-15, November 9, 2023 (Draft Resolution) and Attachment 1, *Staff Proposal for SB 884 Program*, November 9, 2023 (Staff Proposal).

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

Proposal and in Draft Resolution SPD-15.[5] The Staff Proposal states that the unit cost cap and cost-benefit ratio (CBR) threshold apply to the *average* recorded unit cost and CBR, whereas Draft Resolution SPD-15 states CBR and unit cost cap apply to each project.[6] PG&E and SDG&E state that these conditions should apply to the average recorded values, rather than on a per-project basis.[7]

1. The Commission should clarify that the unit cost cap applies to the average for a given year.

Cal Advocates agrees that the unit cost cap should apply to the average unit cost, rather than the unit cost of each project. This interpretation allows utilities some flexibility to underground high-risk lines in difficult and costly locations, while constraining overall costs to protect ratepayers. The Commission should modify the language in Draft Resolution SPD-15 to clarify that the unit cost cap applies to the average unit cost of all projects completed in a given year.

2. The Commission should establish both an average CBR threshold and a per-project CBR threshold.

With respect to the cost-benefit ratio (CBR) metric, there are reasonable arguments for both an average threshold and a per-project threshold. An average CBR threshold would allow utilities some flexibility to carry out projects that would address substantial risk, even if such projects were in difficult and costly terrain. On the other hand, a per-project CBR threshold would ensure that utilities focus on the locations and projects that most efficiently reduce wildfire risks. The Commission should discourage utilities from including lower-efficiency projects in their undergrounding plans, because these projects would unduly burden ratepayers while providing less overall risk reduction than offered by alternate mitigations.

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[5] PG&E, *Pacific Gas and Electric Company's Comments on Draft Resolution SPD-15*, December 28 (PG&E's opening comments) at 3-4.

[6] PG&E's opening comments at 3-4; Staff Proposal at 10; Draft Resolution SPD-15 at 9.

[7] PG&E's opening comments at 4; SDG&E, *SDG&E Comments on Draft Resolution SPD-15*, December 28, 2023 (SDG&E's opening comments) at 2.

To make the best use of the CBR metric, the Commission should modify the Staff Proposal and Draft Resolution SPD-15 to establish both a CBR threshold that all projects must meet, and an average CBR threshold that projects completed within a given year must meet. The per-project CBR threshold should be less stringent than the annual average CBR threshold, and should act as a floor on the acceptable cost efficiency of proposed undergrounding projects. The per project CBR threshold should make sure that, at a minimum, the values of benefits each project are commensurate with the costs of that project. If not, then such a project should have an explanation as to why a valid exception should apply.

To assess compliance with the per-project CBR threshold, the Commission should examine the individual CBRs for all projects completed within a calendar year and for which the utility is requesting cost recovery. If a project falls below the per-project CBR threshold, the Commission should deny cost recovery for a portion of the costs of that project such that the remaining costs meet the per-project CBR threshold.[8]

Following the assessment of the per-project CBR threshold, the Commission should sum the remaining costs of all projects completed within a calendar year and for which the utility is requesting cost recovery, and divide that sum by the sum of the estimated benefits of the projects. If the resulting value falls below the average CBR threshold, the Commission should deny cost recovery for a portion of the total costs such that the remaining costs meet the average CBR threshold.[9]

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[8] For example, consider a theoretical project with estimated benefits of $4.0 million and a cost of $4.5 million. The actual CBR for this theoretical project would be 0.89. If the per-project CBR threshold was set at 1.0, then $0.5 million of the project costs would be denied such that the remaining CBR would meet the minimum CBR threshold ($4 million in benefits divided by $4 million in adjusted costs).

[9] For example, consider a set of two theoretical projects: one with estimated benefits of $4.0 million and a cost of $4.5 million; the other with estimated benefits of $5.0 million and a cost of $2.8 million. Assume the per-project CBR threshold is set at 1.0 and the average CBR threshold is set at 1.5. To meet the per-project CBR threshold, $0.5 million of the costs for the first project would be denied. The second project already complies with the per-project threshold, so no adjustments would be made.

The average CBR for the project set would then be 1.3 ($9 million in total estimated benefits and $6.8 million in adjusted total costs). To meet the average CBR threshold, and additional $0.8 million would be denied, leaving $9 million in benefits and $6 million in remaining costs that would be eligible for recovery.

B. The Commission should clarify that unit cost calculations will be based on the cost of completed projects.

PG&E and SDG&E state that it is unclear if only completed project costs are considered as part of the unit cost cap evaluation, or if the unit cost cap evaluation considers costs recorded in a specific year regardless of whether the project is completed in that year.[10] PG&E recommends that project costs be included in the average unit cost calculation only in the year the project is completed.[11]

Cal Advocates agrees that all project costs should be considered and recovered in the year the project is completed. Actual unit cost can only be calculated once all project costs are known. Furthermore, the Staff Proposal clearly states that a utility may only recover costs for a project once the project is used and useful.[12] A reasonable and transparent approach to the evaluation of the unit cost caps would be to apply the unit cost cap for a given year to the projects that a utility has completed in that year, and for which it is requesting cost recovery. The Commission should modify the language in the Staff Proposal and Draft Resolution SPD-15 to clarify that the average unit cost calculations will be based on completed projects: the calculation will use the entire cost of each project in the year that the project is completed.

C. The Commission should require utilities to credit forecast operational cost-savings to customers or omit them from estimated cost-benefit ratios.

Utilities have claimed in recent years that undergrounding will lead to savings in vegetation management and operational costs over the lifetime of the asset.[13] The Staff

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[10] PG&E's opening comments at 4, SDG&E's opening comments at 2-3.

[11] PG&E's opening comments at 4.

[12] Staff Proposal at 4.

[13] *See, e.g.*, PG&E, *2023-2024 Wildfire Mitigation Plan R3*, September 27, 2023 at 400: "Additional benefits of undergrounding include improved reliability, reducing PSPS and EPSS outages, fewer emergency restoration activities during winter storms, and less need for vegetation management activities."

Proposal requires utilities to forecast these estimated cost savings over the life of the undergrounding plan.[14]

The Utility Reform Network (TURN) correctly notes that neither the Staff Proposal nor Draft Resolution SPD-15 require utilities to propose a mechanism to ensure that ratepayers will receive the benefits of these forecasted cost savings.[15] TURN recommends that the Commission require a phase 2 application to include a methodology by which the Commission can ensure that claimed cost savings will be reflected in rates.[16] California Farm Bureau Federation (CFBF) makes a similar recommendation.[17]

Cal Advocates agrees with TURN and CFBF and adds that it is unclear at this point whether utilities plan to include these estimated operational savings in their CBR calculations, which would increase the estimated CBR for undergrounding. Because these cost savings are currently speculative, it is inappropriate to include them in CBR calculations unless the utility provides substantial quantitative data to support the proposed operational cost savings, and commits to returning the estimated cost savings as a credit to ratepayers.

The Commission should modify the Staff Proposal and Draft Resolution SPD-15 to state that utilities may not include speculative operational savings in estimated CBRs for undergrounding unless the utility can provide evidence to support its inclusion. Furthermore, if a utility includes such savings in its estimated CBRs, the Commission should require the utility to return the cost savings to ratepayers via a Commission-approved mechanism. To do this, a utility should forecast the operational cost savings for the lifetime of the project and calculate the present value of those savings. When the project is complete and its capital costs go into rates, the utility should be required to

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[14] Staff Proposal at 7.

[15] TURN, *Comments of the Utility Reform Network (TURN) on Draft Resolution Spd-15 Implementing SB 884*, December 28, 2023 (TURN's opening comments) at 13-14.

[16] TURN's opening comments at 14.

[17] CFBF, *Opening Comments on Draft Resolution SPD-15*, December 28, 2023 (CFBF's opening comments) at 4.

include a credit for the present value of forecasted operational savings in the annual electric true-up advice letter. This approach will hold utilities accountable for their predictions and ensure that the predicted customer savings are achievable, and ensure the utilities do not improve their undergrounding CBRs based on speculation.

D. The Commission should reinstate the consequences section of the Staff Proposal.

Both TURN and CFBF recommend that the Commission reinstate the "Consequences for Failure to Satisfy Conditions of Approval" section that was present in the first draft of the Staff Proposal but removed from the current draft.[18] Cal Advocates supports this recommendation, and proposes modifications to align those consequences with our proposed cost recovery mechanism.[19]

Under our proposal, utilities would record all SB 884 costs to a memorandum account and request recovery of the recorded costs in an expedited application. Only costs that meet the total annual cost cap, the average unit cost cap, and the CBR thresholds established in the decision on a phase 2 application would be eligible for cost recovery.[20] To establish an efficient and transparent method for review of recorded costs, the Commission should reinstate the consequences section of the original Staff Proposal, and update it to align with our proposed cost recovery mechanism.

The draft Staff Proposal's consequences section stated three times that "cost recovery will be denied for as many projects as necessary" to bring the total cost, unit cost, and average CBR in alignment with the conditions set in the decision on a phase 2 application.[21] It would be complicated for the Commission to determine which projects to remove from cost recovery in this manner. To simplify matters, the Commission should use aggregate rather than project-specific costs. That is, the Commission should sum the total costs of all projects for which the utility is requesting cost recovery, and the

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[18] TURN's opening comments at 12; CFBF's opening comments at 4-5.

[19] See, Cal Advocates' opening comments at 7-10.

[20] Cal Advocates' opening comments at 7-10.

[21] SPD, Staff Proposal for SB 884 Program, September 13, 2023 at 12.

total estimated benefit of such projects. A portion of the total cost figure can then be removed such that the total annual cost, average unit cost, and CBR threshold[22] conditions are met. Those removed costs would be ineligible for cost recovery.

This proposed method for recording and reviewing costs is reasonable. As CFBF correctly notes, the SB 884 program is voluntary.[23] If a utility's SB 884 application is approved, it will be guaranteed cost recovery of billions of dollars incurred over ten years, subject only to verification that such costs meet the conditions set in a decision on the phase 2 application. Such an expansive cost recovery authorization should be justly balanced with strict protections for ratepayers. Denial of cost recovery for costs that do not meet the conditions of approval is a reasonable way to protect ratepayers without burdening utilities through extended litigation in future cost recovery proceedings.

E. The Commission should establish a process for utilities to request cost recovery of abandoned projects, subject to reasonableness review.

Both PG&E and SDG&E request that the Commission allow utilities to record costs for projects that it begins but does not complete.[24] Cal Advocates does not object to utilities recording abandoned project costs in the memorandum account (consistent with our proposed alternate cost recovery method[25]), subject to reasonableness review.

F. The Commission should calculate average unit costs over a single year rather than a longer time horizon.

PG&E proposes that the unit cost cap be calculated on a rolling three-year basis to address possible concerns of skewed averages in the case of a high-cost project completed in late December and a low-cost project completed in early January.[26]

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[22] This should include both the average CBR threshold and the per-project CBR threshold, as discussed in section II.A of these comments.

[23] CFBF's opening comments at 1.

[24] PG&E's opening comments at 7; SDG&E's opening comments at 3.

[25] Cal Advocates' opening comments at 7-8.

[26] PG&E's opening comments at 3.

Southern California Edison Company (SCE) similarly proposes measuring the average unit cost over a longer time horizon than one year.[27]

The Commission should reject these recommendations for two reasons. Firstly, PU Code section 8388.5(e)(1) requires a utility to show how cost targets are expected to decline over time.[28] PG&E's own forecasts have shown an approximately five percent year-over-year reduction in undergrounding unit costs through 2026.[29] PG&E's proposal to average unit costs over three years would make it difficult for the Commission to assess whether average unit costs are truly declining at the pace the utility claims. Furthermore, it would allow PG&E to construct projects with a low unit cost in year one, and projects with a high unit cost in year three, and still meet the average unit cost caps. This would be contrary to the intent of SB 884 - that unit costs decline throughout the ten years of the plan.

Secondly, PG&E is likely to construct several hundred miles each year under SB 884.[30] This volume of miles will minimize the effect of the annual averaging problem that PG&E describes.[31] Historically, PG&E's wildfire mitigation undergrounding projects have been 5.4 miles or shorter. This means that any single project should have little effect on the annual average.[32] The difference in average unit cost associated with completing a high-cost project in December and a low-cost project in January will therefore likely be minimal.

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[27] SCE, *Southern California Edison Company's Opening Comments on Draft Resolution SPD-15*, December 28, 2023 (SCE's opening comments) at 3.

[28] PU Code sections 8388.5(e)(1) and 8388.5(e)(1)(C).

[29] PG&E, A.21-06-021, *Pacific Gas and Electric Company's (U39M) Reply Brief*, December 9, 2022 (PG&E's GRC reply brief) at 362.

[30] Per PG&E's GRC reply brief at 353, as of December 9, 2022, PG&E forecasted 415 miles of undergrounding in 2024, 527 miles in 2025, and 750 miles in 2026.

[31] Per PG&E's responses to data requests CalAdvocates-PGE-2022WMP-17, question 10, March 29, 2022 and CalAdvocates-PGE-2023WMP-06, question 11, March 29, 2023, the longest undergrounding project PG&E completed between 2021 and 2022 was 5.4 miles. This is roughly one percent of the mileage PG&E plans to complete in 2025, which suggests that a single project will have only a small effect on the average unit cost for projects completed in that year.

[32] *Ibid.*

The Commission should reject PG&E's and SCE's requests to calculate the average unit cost over longer time horizons than a single year. In addition to the reasons articulated above, the utilities are positing a problem that is merely speculative. If, while implementing its plan, PG&E or another utility provides quantitative data to show that the problem exists (i.e., that calculating average unit costs over a single year yields unreasonable results), then the Commission can address the issue at that time. The utility should file a petition for modification (PFM), utilizing the accelerated PFM process we proposed in our opening comments.[33]

G. The Commission should require utilities to provide a list of all undergrounding projects, regardless of funding source, to limit the possibility of gaming or double cost recovery.

The Staff Proposal includes a provision to discourage double-dipping or venue shopping, by requiring applicant utilities to identify when they are seeking authorization for costs that the Commission has previously denied. While it does not go far enough to create transparency and enable accurate cost analysis,[34] this requirement provides an important ratepayer protection.

PG&E recommends that the Commission remove the requirement to distinguish between forecast costs already approved by the Commission, 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.[35]

Utilities can receive funding for undergrounding through multiple venues, with their general rate case (GRC) being the primary such venue. PG&E notes that the funding for undergrounding in its GRC refers only to a number of miles and not to specific projects, while SB 884 will fund specific projects.[36] According to PG&E, it

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[33] Cal Advocates' opening comments at 8-9.

[34] See discussion in Cal Advocates, *Public Advocates Office's Informal Comments on the Staff Proposal for the SB 884 Program*, September 27, 2023 at 10.

[35] PG&E's opening comments at 10-11.

[36] PG&E's opening comments at 11.

would therefore "not be possible to identify forecasted projects costs included in a Phase 2 Application for which the Commission previously denied a request for recovery."[37] Rather than propose a means to address this concern while maintaining a reasonable method for preventing double cost recovery, PG&E proposes to gut the ratepayer protections. PG&E recommends the Commission remove the entire requirement to compare SB 884 plan forecasts to other proceedings.[38]

The Commission should reject PG&E's recommendation. PG&E (and all utilities) should be capable of determining which projects it will complete during the GRC-funded period, and to differentiate between the projects requested as part of SB 884, and the projects it expects to fund as a result of the GRC decision. For example, PG&E has already provided a detailed list containing 2,100 miles of proposed undergrounding projects as part of its 2023-2025 WMP.[39, 40] This list was identified prior to the most recent GRC decision that approved 1,230 miles of undergrounding projects.[41] PG&E should be prioritizing which projects to take forward under the GRC decision and those that may be part of an SB 884 undergrounding plan.[42]

The Commission, therefore, should modify the Staff Proposal to require utilities to include a complete list of *all* undergrounding projects it currently plans to complete, including those approved through a venue other than an SB 884 application. This list should note the approved or requested funding source for each project and be updated annually throughout the duration of the undergrounding plan.[43]

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[37] PG&E's opening comments at 11.

[38] PG&E's opening comments at 11.

[39] PG&E, *2023-2025 Wildfire Mitigation Plan*, March 27, 2023 at 346.

[40] PG&E provided its 2023-2026 undergrounding workplan as confidential attachment "2023-03-27_PGE_2023_WMP_R0_Appendix D ACI PG&E-22-16_Atch01_CONF.xlsx" to its 2023-2025 Wildfire Mitigation Plan, March 27, 2003.

[41] D.23-11-069 at 273, November 17, 2023.

[42] If PG&E is not doing this work, it risks confusion and uncertainty in the funding of projects.

[43] See discussion in Cal Advocates, *Public Advocates Office's Informal Comments on the Staff Proposal for the SB 884 Program*, September 27, 2023 at 10.

This complete project list would: a) provide the Commission, Office of Energy Infrastructure Safety, and stakeholders a transparent view into which projects are to be funded and approved under various proceedings, b) prevent a utility from seeking double recovery either intentionally or inadvertently, and c) ensure that projects are not moved between funding streams to render meaningless the cost caps in each proceeding or decision.[44]

H. The Commission should not allow utilities to include miles outside the high fire-threat districts (HFTD) in SB 884 undergrounding plans.

PG&E and SDG&E both request that the Commission modify the Draft Resolution to allow utilities to include miles outside the high fire-threat districts (HFTD) in their undergrounding plans.[45] Contrary to this request, the plain language of the statute directs that "only undergrounding projects located in tier 2 or 3 high fire-threat districts or rebuild areas may be considered and constructed as part of the program."[46]

Fortunately, utilities have multiple venues to address the wildfire risks of lines that are not within the HFTDs or that need to be rebuilt. . A utility could request funding through its GRC to perform undergrounding outside the HFTDs. A utility could also file a PFM to request that the Commission modify the HFTD designations to better align with the utility's understanding of high-risk locations. Indeed, in April 2023, Cal Advocates filed a Petition for Modification that requests the Commission update high fire threat district mapping.[47]

The Commission must comply with the law and not adopt utility requests to allow undergrounding mileage outside the HFTDs and rebuild areas. The Commission should, however, revisit the HFTD designations to ensure they reflect the most current

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[44] 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.

[45] PG&E's opening comments at 12; SDG&E's opening comments at 3-4.

[46] PU Code section 8388.5(c)(2).

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

understanding of wildfire risk.[48] Additionally, the Commission should commit to promptly considering and resolving any PFMs that would modify the HFTD designations.

I. The Commission should require utilities to provide geospatial data on all poles which communications companies lease from, or jointly own with, the electric companies.

PG&E recommends that the Commission modify the requirement for utilities to provide geospatial data for poles shared with communications companies, so that the requirement would only apply to poles where lease agreements have been digitized.[49] PG&E does not state what percentage of its lease agreements have been digitized, nor provide any other information that would allow the Commission to evaluate the reasonableness of this request.

It is reasonable for the Commission to require data on all poles that are shared with communications companies, particularly as those companies have noted that removal of such poles by the electric company in the course of undergrounding could impose substantial difficulties for communications companies.[50] The Commission should evaluate the additional costs these difficulties could impose on communications companies, which may then be passed to consumers as an incremental and indirect cost impact of electric undergrounding.[51] It is impossible for the Commission to effectively

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

[49] "Not all lease agreements are digitized, and GIS data can only be provided where digitized lease agreements are available." PG&E's opening comments at 11-12.

[50] "If an IOU removes its poles as part of an undergrounding project, some communications providers may face the prospect of having to either underground their overhead facilities at the same time as the IOU or discontinue service in that area. Moreover, certain communications equipment, such as Wi-Fi devices, cellular radios, and antennas that provide hotspots and wireless broadband, cannot operate below ground." Opening comments from AT&T California; the California Broadband and Video Association; Crown Castle Fiber, LLC; and Sonic Telecom, LLC (collectively, Communications Providers), December 28, 2023 at 1-2.

[51] Discussed further in section II.J of these comments.

evaluate this potential impact of SB 884 plans on ratepayers without complete information regarding shared poles.

The Commission should not adopt PG&E's recommendation to require information on shared poles only "where available." PG&E should have such information available, and should already be working on digitizing these records where it has not already done so. This is doubly so since PG&E is well aware of how its deficient recordkeeping practices contributed to the San Bruno disaster.[52] The Commission should modify Draft Resolution SPD-15 to clarify that the utilities are required to maintain data on lease agreements in an appropriate format to allow full compliance with the application requirements established in the Staff Proposal.

J. The Commission should require electric utilities and communications providers to file sufficient information in a phase 2 application for the Commission to consider the total cost of undergrounding plans to consumers.

A coalition of communications providers[53] requested that the Commission modify Draft Resolution SPD-15 to expressly consider the costs that would be incurred by parties other than electric utilities, including communications providers, as a result of SB 884 undergrounding plans.[54] They further requested that electric utilities be required to provide detailed information for each project, such as shapefiles.[55] Cal Advocates agrees with the communications providers that electric utilities should include more detailed information regarding their undergrounding projects, including shapefiles.[56] As it relates to costs incurred by communications providers, it is unclear how that information will be utilized in the Commission's decision-making during its review of a phase 2 application.

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[52] See Commission D.15-04-024, Appendix C, Table of Violations for Investigation 11-02-016, (Recordkeeping OII).

[53] Opening comments from AT&T California; the California Broadband and Video Association; Crown Castle Fiber, LLC; and Sonic Telecom, LLC (collectively, Communications Providers), December 28, 2023.

[54] Opening comments from Communications Providers, December 28, 2023 at 2.

[55] Opening comments from Communications Providers, December 28, 2023 at 2-3.

[56] Opening comments from Communications Providers, December 28, 2023 at 2-3.

The Commission should modify the Staff Proposal and Draft Resolution SPD-15 to require the communications providers to supply additional information to identify at a more granular level the costs they claim they will face. Communications providers should file that information as testimony in the phase 2 application proceeding. Information to be filed by communications providers on the record should include:

1. Pictorial drawings of the proposed distribution and service drop architectures for both the electric assets and the communications providers' access network facilities.
2. Design drawings of the proposed distribution and service drop architectures for both the electric assets and the communications providers' access network facilities.
3. Cost estimates for undergrounding of electric and communications providers' assets, based on these designed architectures. Cost estimates are to be derived from the engineered drawings and bills of materials, based on "takeoff"[57] inventories of the drawings.
4. Comparative cost reporting which specifically documents: a) the claimed incremental cost increases which are incurred by communications providers when participating in joint undergrounding projects with electric providers, vs. b) the costs incurred by the communications providers when constructing their own outside plant facilities (i.e., cables, wires, pole-mounted equipment) which are deployed via utility pole attachments by themselves without participation in a "joint trench" project with an energy provider. This comparative cost reporting will allow the Commission to evaluate the actual increased cost which may be incurred by communication providers should they participate in possible undergrounding projects with electricity providers.

[57] In construction cost estimating, "takeoff" is the practice of writing the cost estimate for a construction project based on a bill of materials that is composed of the designed elements of the project. Those designed elements as drawn on engineering drawings are subsequently recorded from the drawing or "taken off" to be items listed on the bill of materials. Costs are then determined based on the items and unit quantities which are listed on the bill of materials.

To facilitate communications providers in developing documentation of the costs they may face, the Commission should first require the electric utilities and other major pole owners[58] to address several fundamental questions with information on the record. The Commission should modify the Staff Proposal and Draft Resolution SPD-15 to require electric utilities to provide the following as part of their phase 2 applications:

1. Identification of those utility poles designated for undergrounding that contain telecommunications attachments, and a statement that answers: Whether the attached telecommunications facilities shall be undergrounded along with the electric infrastructure?
2. In each instance of such electric asset undergrounding, if the answer to question 1 is "no," will the poles with remaining telecommunications attachments be left as a monopole with only telecommunications assets on it?
3. If the answer to question 2 is "yes," are these remaining poles going to be sold, leased, or otherwise be made available to communications providers?
4. In answer to question 3, if the remaining poles are sold, leased, or otherwise made available to communications providers, how and in what accounts will this income be recorded?
5. Will the electric utilities and other major pole owners continue to have the responsibility to maintain, service, and replace the poles as necessary?
6. If an electric utility has removed their equipment, what justification shows why ratepayers should justly and reasonably bear any costs in addition to income received from entities attaching equipment to the pole.

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[58] The term "major pole owners" is a term of reference that has been utilized by the Commission in pole attachment proceedings dating back to 1998, when the Commission amended the right of way rules to apply to Southern California Edison, PG&E, AT&T, Frontier, Consolidated Communications, or their predecessor entities. This term has been utilized in each subsequent proceeding to identify the major pole owners at that given time.

These requirements will provide clarity on the total consumer cost of electric undergrounding plans and allow the Commission to consider a holistic cost-benefit analysis.

III. CONCLUSION

Cal Advocates respectfully requests that the Commission adopt the recommendations discussed herein.

Respectfully submitted,

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January 11, 2024

REPLY COMMENTS OF THE UTILITY REFORM NETWORK (TURN) ON DRAFT RESOLUTION SPD-15 IMPLEMENTING SB 884

Reply Comments of The Utility Reform Network (TURN)
On Draft Resolution SPD-15 Implementing SB 884

The Utility Reform Network (TURN) submits these reply comments on Draft Resolution SPD-15 (Draft SPD-15) pursuant to the November 9, 2023 cover letter accompanying Draft SPD-15. These reply comments focus on issues raised in opening comments by Pacific Gas and Electric Company (PG&E), which were echoed to some extent by San Diego Gas and Electric Company (SDG&E) and Southern California Edison Company (SCE). For the most part, these utility comments focus on specific details relating to the Commission's implementation of Senate Bill (SB) 884.

Before responding to the utility comments, TURN notes that the opening comments of other parties – including the Commission's Public Advocates Office (Cal Advocates), the California Farm Bureau Federation (CFBF), and Mussey Grade Road Alliance (MGRA) – agreed with TURN that there are ***fundamental*** problems with Draft SPD-15 that need to be corrected. The key problems are: (1) the "Phase 2" process allows automatic recovery of undergrounding costs without any CPUC determination that cost control and cost-effectiveness conditions have been satisfied, contrary to SB 884; and (2) the "Phase 3" process grants utilities an opportunity to recover unlimited cost overruns above the supposed Phase 2 cost caps, which is not required by SB 884 and would defeat the legislation's goal of driving cost efficiencies and reductions for undergrounding work. TURN's opening comments presented solutions to these fundamental and grave concerns with Draft SPD-15, including a redline showing how the Staff Proposal should be modified. TURN and the other intervenors identified above also agreed that, in light of the fact that Energy Safety has not presented its proposal to implement its responsibilities under SB 884, the Commission should allow parties a final opportunity to comment on the CPUC's implementation plan given the obvious interrelation of the work of the two agencies. In TURN's view, the Commission's revisions should prioritize addressing these ***fundamental*** problems.

TURN responds as follows relating to the implementation details raised by the utilities' opening comments.

Issue	TURN Recommendation
Should the unit cost cap and cost benefit ratio (CBR) conditions apply to annual costs or to three-year rolling costs?[1]	Annual costs, in order to further the statutory goal of achieving year-over-year cost efficiencies.
Should the unit cost cap apply to costs of completed projects or to all costs completed in a given year?[2]	Completed projects, as unit costs are best determined for completed projects.
Should the unit cost cap apply on an average basis or as a per-project cap?[3]	It should apply to the average unit costs for all projects completed in the year. If average costs exceed the unit cost cap, cost recovery should be permanently disallowed for the costs necessary to bring the average unit costs into conformance with the cap.[4]
Should the CBR condition apply on an average basis or as a per-project threshold?[5]	Both, with a lower per-project threshold that acts as a cost-effectiveness floor that all completed projects must meet.[6] Cost recovery should be permanently disallowed as necessary to bring the average

[1] PG&E Op. Cmts., p. 3.

[2] PG&E Op. Cmts., p. 4; SDG&E Op. Cmts, p. 2.

[3] PG&E Op. Cmts, p. 4; SDG&E Op. Cmts., p. 2.

[4] TURN notes that this remedy for costs in excess of the unit cost caps is slightly different from item 5 in the proposed "Consequences for Failure to Satisfy Conditions of Approval" that TURN included in the Appendix A Redline to its opening comments. That item 5 should be reworded to read: "Cost recovery will be denied for the costs necessary to bring the average unit costs down to the approved target."

[5] PG&E Op. Cmts., pp. 8-9.

[6] This recommendation requires the following modification to TURN's Appendix A Redline of the Staff Proposal. Item 3 in the "Conditions for Approval of Plan Costs" should be modified to read: "The average recorded CBR for all projects completed in any given year must equal or exceed the threshold *average* CBR value for that year*, and the recorded CBR for each project must exceed the threshold per-project CBR.*"

	and per-project CBRs into conformance with these conditions.[7]
Should the utility be allowed to seek recovery of costs of abandoned projects, and, if so, how should they make such requests?[8]	If not barred entirely, requests for rate recovery of costs that are not related to used and useful utility plant should be strongly discouraged. If such requests are permitted, they should be made by separate application. Any costs of abandoned projects for which rate recovery is allowed should be counted toward the annual aggregate cost caps.
Should the utility be allowed to seek recovery of undergrounding costs outside of High Fire Threat District (HFTD) areas?[9]	No, Section 8388.5(c)(2) is clear that only undergrounding projects located in HFTD areas may be considered and constructed as part of the program.

In addition, because TURN strongly opposes any opportunity in Phase 3 for utilities to book costs above the Phase 2 cost caps to memorandum accounts,[10] TURN equally strongly opposes PG&E's request (pp. 6-7) to require that recovery of such cost overruns be addressed in *expedited* applications. If the Commission were nevertheless to retain the opportunity to recover cost overruns, such applications should not be expedited, as prudence review cases are highly complex and require intensive analysis of utility records and documents, which is incompatible with an expedited application process. The fact that such reasonableness review requests are complex and would inevitably result in decision-making backlogs is another reason to modify Draft SPD-15 to remove the opportunity to recover cost overruns.

Finally, PG&E's criticism (pp. 9-10) of Draft SPD-15's inclusion of a CBR condition[11] is based on a mistaken premise. Contrary to PG&E's statements, the benefits in the cost benefit ratio already take into account the full range of benefits from the mitigation in question, including any

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[7] TURN notes that this remedy for non-compliance with the CBR condition is different from item 3 in the proposed "Consequences for Failure to Satisfy Conditions of Approval" that TURN included in the Appendix A Redline to its opening comments. That item 3 should be reworded to read: "Cost recovery will be denied as necessary to bring the average CBR and per-project CBR into compliance with the CBR condition."

[8] PG&E Op. Cmts, p. 7.

[9] PG&E Op. Cmts., p. 12; SDG&E Op. Cmts., pp. 3-4.

[10] TURN 12/28/23 Opening Comments, pp. 8-12.

[11] SCE makes a similar argument. SCE Op. Cmts, pp. 1-3.

reliability and public safety benefits. Accordingly, CBR is an appropriate measure to assess whether the full range of benefits from undergrounding projects justify the costs.

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THE UTILITY REFORM NETWORK