STATE OF CALIFORNIA GAVIN NEWSOM, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

Informal Comments on Joint CPUC-Energy Safety SB-884 Workshop of Feb. 24, 2023

March 10, 2023

Fred Hanes, P.E.
California Public Utilities Commission
RASA Section, Safety Policy Division
505 Van Ness Avenue
San Francisco, CA 94102

Re: Informal Comments on SB 884 Workshop

Dear Mr. Hanes:

The California Farm Bureau (Farm Bureau) appreciates the information that was provided at the February 24, 2023, SB 884 Workshop and the opportunity to provide comments and feedback to help implement SB 884. Farm Bureau represents agricultural energy customers that are located and take service from the State's electric investor-owned utility companies. Farm Bureau was active in the legislative process for SB 884 and is familiar with the elements of the legislation as well as the importance of clarifying many of the provisions of it as implementation moves forward. We still have significant concerns about the ratepayer implications from this undertaking and believe our suggestions will help to illuminate some of those concerns so actions may be taken as the process moves forward. While Farm Bureau appreciates efforts being made to reduce the devastating impacts of utility caused wildfires, efforts must be made to balance the cost impacts to ratepayers from improvements to utility infrastructure.

Given that many important comments were made during the workshop already, Farm Bureau has chosen to focus on the bolded sections of the Background and Scoping Issues first and then provide a few additional comments that we believe are critical to protecting ratepayers and promoting transparency.

Verifying Completeness

- The Office of Energy Infrastructure Safety should absolutely review the utility application for completeness prior to the commencement of the nine month review period. This important step provides ratepayers with a buffer from ever changing proposals much like those that are seen in the General Rate Case updates but will not impact the nine month deadline and unfairly burden ratepayers.
- The proposal should be submitted to the Office under penalty of perjury regarding its completeness and its contents.

Workshop Upon Submittal to the Public Utilities Commission

- The workshop should proceed a minimum of 90 days following submission to allow the Commission and interested parties a reasonable opportunity to review the basics considering current Wildfire Mitigation Plans and recent utility testimony in General Rate Cases have exceeded 1,000 pages and it is anticipated that the 10 year plan will be just as voluminous. This will make for a more productive workshop which may be the only opportunity for interested parties to ask direct questions to the utilities.
- The 90 days would also provide an opportunity for interested parties to make data requests that will be difficult to complete given their 10 day timeframe post workshop and prior to the 30 day public comment period.
- It should also be noted that the nine month review process would not begin until completion of the workshop and public comments because the Commission should have all available information from both the utility as well as interested parties when reviewing the plan for approval. Otherwise, public comment will be nothing more than a formality.

Accountability for Biannual Reports

- Interested parties should have the opportunity to raise questions and seek additional data or workpapers regarding the claims made by the utilities in the biannual reports. This should not interfere with an ongoing ability for parties to submit data requests which will allow interested parties to properly evaluate whether progress is directly changing over the life of the program.
- The biannual reports should include detailed information regarding the utilities search for additional funding including, but not limited to, the specific applications, legislative pursuits, or grants they have applied for and a publicly accessible means of verifying and reviewing these efforts.
- As energy rates significantly increase from additional proceedings unrelated to undergrounding and wildfire mitigation, the utilities should be required to update underlying cost within the program in each biannual report. This will allow the Commission and ratepayers to evaluate whether cost targets that were originally projected may have already been reached several years in advance and provide time for intervention and further investigation. For example, in PG&E's current GRC Phase 1 proceeding (A. 21-06-021) the update testimony PG&E provided on September 7, 2022, saw the average agricultural rate for January 1, 2023, surpass the initial application's *2026* rate projection by 1.38 cents. Unless the base rates are continually adjusted and compared the context of all other proceedings impacting rates will be lost.
- The biannual report should also include the bill impacts for *all* customer classes and be updated with each report so the Commission and parties will have sufficient context to adjust the affordability of continued undergrounding in light of the potentially less costly alternatives that have previously been scoped before it is too late.
- Sufficient tracking of funding the utility has received in other proceedings that may be duplicative of funding approved or requested in this process would also be helpful. This should include any potential request by utilities for additional revenue requirement in

General Rate Case proceedings and the necessity to differentiates these requests from what is already being approved in this process. This should already be being tracked and relatively simple to produce as part of this process.

IOU Disputes or Clarification on Independent Monitor's Report

- If IOUs can respond to the independent investigators report, interested parties should also have the ability to respond to the IOU assertions.

Additional Comments and Suggestions

- As discussed during the panels, it is critical that off ramps are built into the process. Whether technological advancements or unforeseen events there will likely be many changes throughout the 10 years that requires re-evaluation.
- The plan should also contain triggers for re-evaluation if spending goes over a certain cap, if promised savings are not realized, or if costs become significantly misaligned with prior forecasts. It is imperative that ratepayers be protected and IOUs who *voluntarily* chose to undertake this expedited program have sufficient "skin in the game" and remain responsible for the promises that are being made to ratepayers in these plans.

Farm Bureau, like all members of California, want to see the end to utility caused wildfires and appreciate innovative ways for doing so. However, ratepayers have expended enormous amounts to support wildfire mitigation projects and ratepayers must be afforded the opportunity to properly address deficiencies and issues regarding these multibillion dollar plans. It is important to remember that **no utility is required to participate in this expedited program** and the tradeoff for expedited review should be extreme transparency of the costs and implications of these plans.

Sincerely,

Kevin Johnston
Attorney for
California Farm Bureau
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Center for Accessible Technology
Informal Comments on SB 884 Workshop
March 8, 2023

Center for Accessible Technology (CforAT) appreciates the information provided at the SB 884 Workshop held on February 24, 2023, and offers the following feedback on behalf of our constituency of utility customers with disabilities and medical vulnerabilities. SB 884 outlines a process for large electric investor-owned utilities (IOUs) to pursue and obtain expedited review and approval of ten-year plans for undergrounding electric lines.

Process for Resolving Potentially Inconsistent Versions of Undergrounding Plans:

The procedure outlined in SB 884 requires both the Office of Electric Infrastructure Safety (OEIS) and the California Public Utilities Commission (CPUC) to approve an IOU's proposed undergrounding plan. Both agencies have the authority to order an IOU to make modifications to an undergrounding plan before approving it.[1] Because the OEIS and the CPUC approve undergrounding plans at different points in the plan development process, it is possible that the CPUC could order significant modifications to a plan that the OEIS has already approved. CforAT would appreciate more information on which version of the plan would be controlling in cases of inconsistencies or ambiguities or for tracking an IOU's progress in implementation. Or, if both agencies need to approve the same version of a plan, CforAT would appreciate more information on the process to be used to harmonize the inconsistent versions. SB 884 does not address this possibility, nor did any participant raise it at the workshop.

Electric Line Paths & Accessibility:

To the extent that SB 884 undergrounding plans will impact above-ground pedestrian rights of way, CforAT strongly encourages participating IOUs, OEIS, and the CPUC to consider the impact of proposed undergrounding projects on wheelchair accessibility. Multiple participants in the Panel Discussion 2 mentioned that underground electric lines may have to take different paths than above-ground electric lines due to on-the-ground obstacles, which presents an opportunity to improve wheelchair accessibility if underground line paths are planned appropriately.

Undergrounding is already a recognized means of enhancing wheelchair accessibility. All three major IOUs' current rules for Tariff Rule 20A undergrounding projects recognize that wheelchair accessibility compliant with the Americans with Disabilities Act is in the public interest and therefore have wheelchair access as a potential criterion for Rule 20A projects.[2]

[1] Cal. Pub. Utilities Code §§ 8388.5 (d)(2), (e)(5).

[2] Electric Rule 20 Guidebook, San Diego Gas & Electric (revised Sept. 22, 2021), at p. 8, available at https://www.sdge.com/sites/default/files/SDGE-Electric%20Rule%2020%20Guidebook_0.pdf; Electric Rule No. 20, Pacific Gas & Electric Company (revised July 6, 2021), at p. 1, available at https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_RULES_20.pdf; Electric Rule 20 Guidebook, Southern California Edison, at p. 8, available at https://www.sce.com/sites/default/files/custom-files/Web%20files/SCE%20Electric%20Rule%2020%20Guidebook.pdf.

These rules were all developed in the context of agreements with CforAT or its predecessor, Disability Rights Advocates, in conjunction with past major utility General Rate Cases. Improved wheelchair access should also be recognized as advancing the public interest in the context of SB 884.

Affordability:

CforAT echoes concerns expressed by participants in Panel 2 about the potential effects of SB 884 projects on electric rates, particularly for low-income ratepayers. Potential impacts on electric rates and on affordability (as evaluated through the affordability metrics adopted in R.18-07-006) must be an ongoing consideration during both the agency review and implementation phases of any SB 884 undergrounding plans.

CITY OF OAKLAND

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City Administrator's Office (510) 238-3301
Steven Faulk FAX (510) 238-2223
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March 10, 2023

Dear CPUC, Office of Energy Infrastructure Safety,

Thank you for your invitation to submit comments on issues related to SB884. As the City of Oakland's Chief Resilience Officer, I coordinate our Wildfire Prevention Working Group that is an interdepartmental team working to reduce the risk of wildfires in Oakland.

Oakland's Montclair Neighborhood is almost exclusively in a Very High Fire Severity Zone according to CalFIRE and due to the density of housing and narrow evacuation routes, the City is taking many precautions and appreciates a positive partnership with other public agencies in that effort including Caltrans, neighboring jurisdictions, and PG&E.

Montclair neighbors and City staff have had a number of meetings with PG&E and were told that Montclair is NOT included in the undergrounding plan of the 10,000-Miles Undergrounding Program because Montclair is not in the highest tier of fire risk. Excluding Montclair from the Undergrounding Program will fail to meet the intent and goal of SB884 to reduce wildfire risk. Pursuant to SB884, PG&E's undergrounding plan needs to be reviewed and approved by the CPUC. I would respectfully request CPUC consider the following wildfire risk factors before approving the PG&E undergrounding plan:

• Montclair is situated adjacent to the site of the 1991 firestorm in the Oakland Hills. Montclair's topography, vegetation, climate, and dense population are similar to the area in the 1991 Oakland Hills Firestorm that killed 25 people, destroyed more than 3,400 homes, and caused damages estimated at $3 billion in today's dollars. With climate change and increasingly hot and dry fire seasons, the wildfire risk in Montclair and the Oakland Hills has markedly increased in recent years.

• Shepherd Canyon is situated in the heart of Montclair. It is heavily covered with trees and vegetation. Residential houses are located all around Shepherd Canyon and PG&E's powerlines are in close proximity to the houses. In 1995, a fire in Montclair was caused by sparks falling from PG&E powerlines that were whipped by wind. The sparks ignited a fire on the slope of Shepherd Canyon below Asilomar Drive and destroyed several homes. PG&E admitted fault and accepted liability.

- Shepherd Canyon acts like a wind funnel. The strong canyon wind often sweeps through Montclair. A small spark caused by a powerline will quickly be fanned into a firestorm by the canyon wind.

- Montclair's roads are narrow and windy. Evacuation routes are very limited for a population of this size. PG&E's undergrounding plan does not take into the risks of "ingress and egress". PG&E's powerlines crisscross over Montclair's limited evacuation routes. A fallen powerline on an evacuation route will block evacuation and fire-fighting access, resulting in loss of lives.

- Although PG&E has performed some powerline "hardening", in light of the factors described above, the overhead powerlines pose an immense wildfire risk in Montclair. Undergrounding the powerlines will greatly reduce the wildfire risk in meeting the intent and goal of SB884.

The neighbors have started a petition in Montclair to collect signatures to urge the CPUC Office of Energy Infrastructure Safety to require PG&E to underground the powerlines in Montclair. This letter is in support of that effort. I understand there are many communities competing for the resources being put into wildfire prevention and would hope the CPUC will recognize the risks in Montclair, and in particular, Shepard Canyon, in reviewing PG&E's proposed plans.

I am happy to discuss this further and can be reached at jdevries@oaklandca.gov

Respectfully,

Joe DeVries
Deputy City Administrator and Chief Resilience Officer
City of Oakland

RCRC
RURAL COUNTY REPRESENTATIVES
OF CALIFORNIA

March 10, 2023

Forest Kaser
Deputy Executive Director
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Julie Alvis
Acting Deputy Director
Office of Energy Infrastructure Safety
715 P Street, 20th Floor
Sacramento, CA 95814

RE: Senate Bill 884 Workshop, Joint Implementation

Submitted via email SB 884 Notification List (last updated 3/7/23)

Dear Mr. Kaser and Ms. Alvis:

On behalf of the Rural County Representatives of California (RCRC), I am pleased to provide feedback on the Senate Bill 884 Workshop held on February 24, 2023. RCRC is an association of forty rural California counties and the RCRC Board of Directors is comprised of elected supervisors from each of those member counties.

Senate Bill 884 (Chapter 819, Statutes of 2022) provides an avenue for a large investor-owned utility (IOU) to identify specific distribution segments in Tier 2 and Tier 3 high fire-threat districts (and rebuild areas) it intends to underground in specific timetables over the next ten years along with corresponding data that demonstrates undergrounding as the most cost-effective way to reduce wildfire risk, provide greater energy reliability, *and* reduce costs. SB 884 appropriately sets a high bar for a large IOU to substantiate its desire for monumental capital expenditures. RCRC looks forward to reviewing SB 884 undergrounding plans, given they will specify exact, discreet distribution segments in particular communities that are planned for undergrounding over a longer planning horizon. This is particularly important as there may be opportunities for cross-coordination to implement local dig once policies and co-locate other infrastructure—such as broadband—to maximize safety, resilience, and overall cost efficiency benefits long-term.

RCRC appreciates the California Public Utilities Commission (CPUC) and Office of Energy Infrastructure Safety (Energy Safety) soliciting feedback from interested stakeholders early in the implementation process of SB 884. As such, we offer the following initial observations for joint implementation.

Regulatory and Approval Process

- While SB 884 specifically states the plan must reduce outages including—but not limited to—Public Safety Power Shutoffs (PSPS) and Enhanced Powerline Safety Settings (EPSS),[1] we note that PG&E has indicated that it will only underground primary (high voltage) distribution lines and leave secondary distribution lines (750 volts or less) in place for wildfire safety undergrounding.[2] It is not clear at this time whether EPSS or a similar successor program will be enabled on secondary lines that will remain aboveground. PG&E's plan must include the specific disclosure of instances where secondary lines are left in place aboveground and where the primary distribution line has been undergrounded, including reliability implications. This should include discussions about whether EPSS will be used on the secondary line, the residual risk posed by keeping the secondary line aboveground, planned vegetation management for the remaining secondary distribution line, and what, if any, system hardening will take place on those secondary lines should they continue to pose an ignition risk. In sum, there must be a direct nexus between the safety and reliability of the proposed undergrounded segment with the corresponding (or any remaining) overhead asset. Finally, if a utility's ten-year undergrounding plan notes that it will underground primary distribution lines while leaving associated secondary lines aboveground, the utility should disclose the construction costs avoided by undergrounding only the primary distribution line.

- A key tenant of Energy Safety's underlying approval is whether the plan demonstrates both energy reliability improvements and wildfire risk reductions. These plans should include a detailed analysis of the most unreliable circuits in Tier 2 and Tier 3 high fire-threat districts and whether they are proposed for undergrounding or not. Approval of the plan must, overall, weigh whether customers on the most impacted circuits for PSPS/EPSS outages stand to benefit from the IOU's plan *and* receive priority for undergrounding installation.

- While PUC § 8388.5 (f)(1) requires a progress report be filed by the IOU every six months, this will likely not account for updates needed to the underlying plan over time, such as accounting for updated risk models and assessments. As a result, RCRC urges progress reports to include updated data, such as the most recent predictive risk modeling methods presented in the IOU's most recent Wildfire Mitigation Plan filing. IOUs should use consistent calculation methods and not "cherry-pick" data that suits them at a specific point in time.

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[1] See PUC §8388.5 (d)(2)

[2] This information was provided in PG&E's presentation during a Rule 20 (R.17-05-010) workshop held on November 8, 2022. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M499/K626/499626345.PDF

Wildfire Risk and Project Assurance

- A plan must detail *quantifiable* strategies to satisfy the plan's proposed costs and cost reductions over time. This should include, at a minimum, risk spend efficiency (RSE) calculations and projected margins of error or other pertinent indicators by each circuit proposed for undergrounding. Given the plans must also include, at a minimum, projected benefits over the life of the asset, plans should detail the process and costs for conducting maintenance and repairs, including oversight and accountability mechanisms of outside contractors (when applicable).

- RCRC agrees with suggestions mentioned by panelists that the plan "track and trace" overhead lines proposed for removal, given those lines are the source of the safety risks. RCRC would add that, in the case of PG&E, this also include any overhead lines being partially left in place, such as purported lower risk secondary lines of 750 volts or less.

- Given these plans span a ten-year period, it is imperative that 6-month progress reports be data-driven documents that will equip an independent monitor to produce a robust analysis. We also urge the independent monitor to conduct field inspections as one method to confirm reported information.

Accountability

- In the event a utility does not correct deficiencies identified by their respective independent monitor, the CPUC should explore how that affects the underlying status of the plan or, in the case of PG&E, if it would trigger the Enhanced Oversight and Enforcement Process pursuant to Commission Decision D.20-05-053 given the nexus to the safety performance of PG&E.[3] Penalties must be substantive and effectual to successfully deter non-compliance.

- Regarding workforce development, the plan should detail protocols for consistency amongst contracted labor, along with accountability mechanisms. This should include, for example, on-the-ground oversight of communication practices with customers, as well as quality assurance and quality control of work performed.

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[3] Step 1, Triggering Event ii: "PG&E fails to comply with, or has shown insufficient progress toward, any of the metrics (i) set forth in its approved wildfire mitigation plan including Public Safety Power Shutoffs (PSPS) protocols, (ii) resulting from its on- going safety culture assessment, (iii) contained within the approved Safety and Operational Metrics, or (iv) related to other specified safety performance goals." [Emphasis added]

Step 2, Triggering Event ii: "PG&E fails to comply with electric reliability performance metrics, including standards to be developed for intentional de-energization events (i.e., PSPS) and any that may be contained within the approved Safety and Operational Metrics." [Emphasis added]

Next Steps

- IOUs must connect the objectives of an approved plan into complementary processes, such as General Rate Case proceedings and Wildfire Mitigation Plans. This will also provide an added benefit for parties and stakeholders alike to provide feedback in a public process on an ongoing basis.

RCRC would additionally like to point out that SB 884 undergrounding plans should in no way be treated by an IOU as an aspirational document or an otherwise unactionable plan with aggregated information. These ten-year plans should be a detailed blueprint by circuit with supporting evidence and data subject to robust review and analysis on an ongoing basis to ensure it serves the public's interest.

Finally, while we recognize the wildfire risk reduction focus on many undergrounding efforts, we cannot overstate the importance of energy reliability as the State continues to mandate building and vehicle electrification to achieve its air quality goals, as well as serve disadvantaged and vulnerable populations. It is imperative that discreet outages, such as those utilized by IOUs through PSPS and EPSS, be eliminated over time as investments to safeguard infrastructure are deployed. While undergrounding is *one* option to reduce risk (and an even more important option where it provides greater and more durable benefits than alternatives), it is essential for IOUs to execute it in a way that will holistically provide energy reliability, and be achieved in a safe, affordable manner. Nothing in SB 884 compels Energy Safety or the CPUC to approve such an ambitious plan. Should IOUs pursue expensive capital investment projects with limited benefits to customers, it will chill greater electrification objectives that are the backbone of the State's Scoping Plan.

Thank you for your consideration of our comments. Should you have any questions, please do not hesitate to contact me at lkammerich@rcrcnet.org.

Sincerely,

LEIGH KAMMERICH
Policy Advocate

cc: The Honorable Mike McGuire, Member of the California State Senate

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March 09, 2023

Via Electronic Mail

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California Public Utilities Commission
RASA Section, Safety Policy Division
505 Van Ness Avenue
San Francisco, CA 94102

Re: Informal Comments on SB 884 Workshop

Dear Mr. Hanes,

I am writing to on behalf of ExteNet Systems, LLC (U-7367-C) and ExteNet Systems (California) LLC (U-6959-C) (collectively "ExteNet") to submit informal comments about the SB 884 workshop held on February 23, 2023 regarding preparation of ten-year undergrounding plans for the major electric utilities in California. As requested, ExteNet has organized its comments first to respond to specific workshop panel questions and then to identify additional issues it believes are critical to be addressed during the implementation of undergrounding plans.

I. INTRODUCTION AND BACKGROUND

ExteNet was certified by the Commission as a full facilities-based competitive local exchange carrier ("CLC") in California in 2006.[1] The Commission authorized ExteNet to attach to utility poles or other aerial support structures in the public rights-of-way ("ROW") and to construct its own facilities in or near the ROW.[2]

In California, ExteNet provides non-switched dedicated Point-To-Point Private Virtual Circuit ("PVC") Transport Service on a wholesale basis to other carriers via small cell and Distributed Antenna System ("DAS") networks. Additionally, ExteNet provides dark and lit fiber services to enterprise end-user customers. In order to provide wholesale DAS and fiber-based services, ExteNet must place equipment, including fiber optic cable, wireless antennas and radios on utility poles located in the public rights-of-way.

[1] D. 06-04-063 issued April 27, 2006. At that time, ExteNet operated under the name Clearlinx Network Corporation.
[2] *Id.*, at p.2-3.

ExteNet places its equipment on jointly owned utility poles through membership in the Northern and Southern Joint Pole Associations, and through bi-lateral pole attachment agreements with electric utilities ("IOUs"). In addition, ExteNet occasionally places its own poles in the public rights-of-way when there are no existing utility poles are available or usable. ExteNet's solely-owned utility poles do not typically have equipment from other CLCs or power lines.

Because ExteNet must place its wireless equipment above ground, any undergrounding plan that removes vertical infrastructure such as utility poles from large geographic areas in California will significantly affect its ability to support broadband and emergency 911, among other services. Therefore, it is critical that the Commission exercise its dual authority over both electric and communications facilities to ensure that sufficient provisions are made for access to vertical infrastructure necessary for communications services in the IOUs ten-year undergrounding plans.

II. WORKSHOP PANEL QUESTIONS ON REGULATORY AND APPROVAL PROCESS ISSUES

As noted during the workshop, SB 884 is intended to expedite undergrounding of the largest electric utilities' distribution infrastructure in Tiers 2 and 3 of the High Fire Threat Districts established previously by the Commission. The Commission will share joint responsibility with the Office of Energy Infrastructure Safety ("Energy Safety") to review and approve large IOUs' ten-year undergrounding plans for distribution facilities. The Commission is uniquely situated to take into account a comprehensive set of public interest considerations because it has regulatory authority over both electric and communications utilities and already has established decisions and proceedings related to important aspects of undergrounding.

The workshop panel questions seek comment on how the Commission should align its implementation of SB 884 with other related proceedings such as the Wildfire Mitigation Plan and/or IOU General Rate Cases ("GRCs"). The questions also ask commenters to identify other considerations or potential complexities the Commission should consider as it implements the IOUs' ten-year undergrounding plans called for in SB 884.

It is important for the Commission to coordinate examination of undergrounding plans with existing proceedings such as wildfire safety and IOU general rate cases, but it is urgent for the Commission to consider more broadly the operational and financial effects of undergrounding on communications carriers with equipment attached to existing vertical infrastructure.

No existing proceeding is examining such issues on a comprehensive basis. ExteNet requests the Commission to open a rulemaking on SB 884 implementation and to include issues related to the effects of undergrounding on communications attachments. ExteNet submits that a rulemaking will ensure a full and complete record, as well as the opportunity for cross-industry participation. While informal workshops may provide useful input to the process, the staggering costs and loss of infrastructure needed to support wireless communications should be fully analyzed and mitigated in a formal proceeding with an assigned administrative law judge, commissioner and full due process.

Opening an immediate rulemaking to establish rules for addressing communications provider issues is especially important because the Commission will have only nine months to review proposed undergrounding plans after they have been reviewed by Energy Safety. With such a compressed time frame, it is unlikely that the Commission would be able to adequately consider effects of undergrounding on communications providers without an already-established set of rules, protocols and procedures.

The Commission has administered IOU undergrounding pursuant to Rule 20 in IOUs' tariffs for decades. In 2000, the Commission opened R.00-01-005 to implement Assembly Bill (AB) 1149[3] which. required the Commission to study ways to amend, revise, and improve the rules for the conversion of existing overhead electric and communications lines to underground.[4] Tariff Rule 20 governs both when and where a utility may remove overhead lines and replace them with new underground service in particular cities, and who will bear the cost of the conversion – entirely borne by ratepayers, partially borne by ratepayers or fully born by electric customers with no ratepayer contribution.[5]

A number of "controversial" issues in R.00-01-005 were postponed to a second phase of the proceeding to enable the Commission to organize and staff a hearing.[6] Among those controversial issues were recovery of undergrounding costs by communications providers.[7] The Commission expressly stated that its intention was "the creation of a fair, equitable, and competitively neutral recovery mechanism for telecommunications carriers and cable companies to recover their undergrounding costs."[8] R.00-01-005 was closed in 2005 without completing Phase 2 of the proceeding.[9]

III. ADDITIONAL ISSUES TO BE ADDRESSED

Although the Commission has not proceeded with a general rulemaking, the thorny issues related to undergrounding effects on communications providers have already been previewed in PG&E's Grate case (A.21-06-021). PG&E announced a highly controversial proposal to underground 10,000 miles of distribution facilities,[10] about a third of which would be undertaken during the GRC period of 2023 to 2026.[11] PG&E subsequently decreased the total miles of undergrounding to 2,000,[12] but its proposal revealed a number of critical issues related to communications carriers that have equipment (some of which cannot be undergrounded) attached to existing IOU vertical infrastructure.[13]

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[3] (Aroner) (Stats. 1999, Ch. 844).
[4] D.01-12-009, 2001 Cal. PUC LEXIS 1067, at *3 (Dec. 11, 2001).
[5] *Id.*, at *4-5.
[6] Decision 05-04-038, at p. 2 (Apr. 21, 2005) (mimeo).
[7] D.01-12-009, at *49.
[8] *Id.*, at *37.
[9] Decision 05-04-038 (Apr. 21, 2005).
[10] A.21-01-016, PG&E Amended 2023 GRC Application Chapter 4.3 (Mar. 10, 2022); *see also* PG&E News Release, July 21, 2021: "PG&E Announces Major New Electric Infrastructure Safety Initiative to Protect Communities from Wildfire Threat; Undergrounding 10,000 Miles of Power Lines in Highest Fire-Threat Areas," available at https://www.pge.com/en/about/newsroom/newsdetails/index.page?title=20210721_pge_announces_major_new_electric_infrastructure_safety_initiative_to_protect_communities_from_wildfire_threat_undergrounding_10000_miles_of_power_lines_in_highest_fire-threat_areas.
[11] A.21-06-021, PG&E Reply Brief at 352.
[12] *Id.*
[13] Disputed issues such as PG&E's undergrounding proposal remain unresolved.

Some of the issues revealed in PG&E's rate case proceeding include whether PG&E's vertical infrastructure would remain for use by communications carriers after electrical facilities are undergrounded and how the substantial costs for undergrounding will be borne and by whom. Carriers such as ExteNet are not regulated under a rate of return regime that would enable them to pass on costs of undergrounding to customers through a rate base proceeding, so the costs of undergrounding could be crippling if placed on communications carriers.[14]

All of the issues related to communications providers in the PG&E General Rate Case should be examined, but other issues not specifically raised in that proceeding should be examined as part of the Commission's implementation of SB 884. Such issues include:

- If the Commission requires IOUs to leave in place vertical infrastructure, what entities would assume ownership and/or be responsible for maintenance and replacement of poles;
- If IOUs are allowed to remove vertical infrastructure after undergrounding their electrical facilities, how will communications carriers be accommodated if their equipment cannot be placed underground;
- If IOUs intend to remove vertical infrastructure after undergrounding, communications carriers should be authorized to file expedited petitions to stop such removal and take ownership themselves;
- If IOUs intend to remove vertical infrastructure after undergrounding their electrical facilities, communications carriers should be authorized to file expedited petitions to delay such removal until they can install their own vertical infrastructure to accommodate facilities that cannot be undergrounded;
- If IOUs are allowed to remove vertical infrastructure they should be required to install an extra conduit for communications facilities simultaneously with conduit installed for their electrical facilities;

The legislative history of SB 884 makes clear that the implementing agencies may consider the effect of IOU undergrounding on communications providers. The legislative history notes that the bill "may require the removal of electric utility poles across large geographic regions" and that "[u]ndergrounding may increase costs for wireline deployment proposals, and the absence of poles may limit the locations where wireless infrastructure can be installed."[15] The history states that if the Commission approves an IOU's undergrounding plan, communications providers must cooperate with that plan to underground **non-wireless** telecommunications infrastructure on utility poles that will be removed as part of an undergrounding project."[16] The Commission has

[14] *See*, A. 21-21-06-021, AT&T Sur-reply Brief, at p. 3 n.10 (Jan. 23, 2023). AT&T estimated that just 2,000 miles of undergrounding (assuming an average of 35 poles per mile) would affect 70,000 poles and would cost $70 million if AT&T had to buy those poles at an average cost of $1,000 each. Alternatively, AT&T estimated it would cost $1 million per mile to underground its facilities currently attached to PG&E utility poles. The cost for 2,000 miles of undergrounding was estimated at $2 billion. Similarly, PacifiCorp estimates distribution undergrounding projects would cost between $1million and $6 million per line mile. Resolution SPD-12, 2023 CAL. PUC LEXIS 61, at *74 (Feb. 23, 2023).
[15] 2021 Legis. Bill Hist. CA S.B. 884.
[16] *Id.*

the authority and unique expertise to balance the important goals of wireless broadband, voice and emergency communications with the important goals of undergrounding in SB 884.

ExteNet respectfully requests that the Commission open a rulemaking on implementation of SB 884 and expressly include consideration of the issues identified in these comments. ExteNet appreciates the opportunity to submit these comments and looks forward to participating in the implementation of SB 884.

Sincerely,

Counsel for ExteNet Systems, LLC and ExteNet Systems (California) LLC

cc: SB884@cpuc.ca.gov
fred.hanes@cpuc.ca.gov
Service List

CERTIFICATE OF SERVICE

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

ExteNet Systems, LLC (U-7367-C) and ExteNet Systems (California) LLC (U-6959-C) Informal Comments on SB 884 Workshop

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Dated: March 09, 2023

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

INFORMAL COMMENTS OF THE GREEN POWER INSTITUTE ON SB 884 IMPLEMENTATION

March 10, 2023

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INFORMAL COMMENTS OF THE GREEN POWER INSTITUTE
ON SB 884 IMPLEMENTATION

The Green Power Institute (GPI), the renewable energy program of the Pacific Institute for Studies in Development, Environment, and Security, provides these *informal Comments of the Green Power Institute on SB 884 Implementation.* GPI has been an active participant in the Wildfire Mitigation Plan design and review process since 2018, with its inception in R.18-10-007, the now closed CPUC **Order Instituting rulemaking to Implement Electric Utility Wildfire Mitigation Plans Pursuant to Senate Bill 901 (2018)**. Utility wildfire mitigation planning and implementation marks the nexus between many utility and environmental factors such as the criticality of robust distribution planning and design required to serve all Californians in a high-electrification future. GPI is invested in advancing these and other aspects of utility planning and operations that are necessary to support state environmental, emission reduction, and electrification goals.

GPI addresses the following concerns regarding the implementation of SB 884 and the need for additional guiding information regarding Underground plan design and elements:

Regulatory and Approval Process Issues

- SB 884 plan requirements are too vague to produce 10-year undergrounding plans with adequate information and clarity required to evaluate plan efficacy and reasonableness.
- The requirement to apply for external funding is vague and could lead to no outside monies received.
- SB 884 plans must be coordinated with the WMP filing and review process.

Wildfire Risk and Project Assurance Issues

- Utility planning, including distribution planning, has substantial and increasing uncertainty in the mid- to long-term planning horizon (5-10 years) making static expedited 10-year undergrounding plans a high-risk and uncertain investment.
- SB884 outlines a static 10-year plan to determine costly upgrades for a system that is undergoing relatively rapid environmental changes as well as distribution system needs.

Dynamic plans and review processes are necessary to adapt to changing conditions, especially given the high uncertainty over the course of the planning horizon.

- Wildfire risk models are in an early stage of development that equates to relatively unstable results. This is further exacerbated by efforts to model a changing system that is responding to climate change impacts.

- A ratemaking proceeding is the appropriate vehicle to address the issues described above.

These deficits should by no means be interpreted as a complete list of issues regarding what is required to effectively implement SB 884.

Comments

Regulatory and Approval Process Issues

SB 884 plan requirements are too vague to produce 10-year undergrounding plans with adequate information and clarity required to evaluate plan efficacy and reasonableness.

SB 884 provides limited direction on IOU 10-year undergrounding plan elements. Plan elements are distilled down to six elements in SB 884 Section 8388.5(c). Notably, the wildfire mitigation plan process and evaluation guidelines are now 34 pages long. Additional detail was necessary to improve plan quality, reduce the occurrence of missing information, and establish clear expectations that are essential to the plan review and approval process. Gaps in SB 884 plan requirements include but are not limited to:

- "Plan" and "Project" are not defined. A plan often covers the entirety of deliverables, high-level methods and overall timeline. Projects are a subset of each plan and are typically defined as having concrete implementation parameters, such as a completed design, specific location, start and end dates, granular risk-spend efficiency etc.
- Specific reporting elements required for each undergrounding *project* for each year of the plan.

- Specific metrics, calculations, and any ancillary considerations required to substantiate project location, scope, design, prioritization, risk spend efficiency, and other necessary evaluation components.
- A clear definition for risk-spend-efficiency (e.g. lifecycle benefits, repair costs, distribution system upgrade costs) specific to undergrounding projects and alternative mitigations that are necessary to capture all costs and compare mitigations.
- Whether each project design must incorporate and account for known and potential future distribution grid needs.
- Six-month progress reporting specifics that include reassessing whether mid- and long-term scoped projects are still necessary and cost-effective nearer the date of implementation.
- Project on- and off-ramp provisions and reporting.
- Stakeholder input and review of progress reports over the plan.
- The parameters and requirements that determine plan approval, conditional approval, or denial by the OEIS and CPUC.
- The specific elements and requirements for the independent monitor report.
- A defined and transparent penalty structure and basis, including specific parameters that define whether an IOUs is "substantially" complying with a commission decision.
- A measurable metric that determines whether each IOU has made an adequate effort to secure non-ratepayer moneys to reduce ratepayer costs.
- No requirement to report on a plan for seeking nonratepayer funding support, or reporting on progress.

The requirement to apply for external funding is vague and could lead to no outside monies received.

SB884 states:

> Each large electrical corporation participating in the program shall apply for available federal, state, and other nonratepayer moneys throughout the duration of its approved undergrounding plan, and any moneys received as a result of those applications shall be used to reduce the program's costs on the large electrical corporation's ratepayers.

External funding should be secured to the maximum extent possible in order to reduce ratepayer costs. However, as written this provision could be satisfied by submitting just a few low-quality funding applications for nonratepayer money over the 10-year planning horizon. Seeking federal, state, or other ratepayer funding through grants and other programs for a 10-year plan with costs in the billions is a substantial undertaking that would likely require dedicated personnel. GPI strongly recommends that each 10-year undergrounding plan require a clear and comprehensive external funding plan that minimally includes where the utility will seek funding, specific funding opportunities the utility has identified, an estimated total dollar amount that could be offset through external funding, and a resource allocation plan that ensures the effort will be adequately staffed and timely implemented. Without a comprehensive plan and regular updates, GPI is concerned that Utilities can, and will, easily circumvent this important provision. Ratepayers need to be protected from this outcome.

SB 884 plans must be coordinated with the WMP filing and review process.

Undergrounding is one of many wildfire risk mitigation strategies, and is therefore a core element in the 3-year Wildfire Mitigation Plans and interim annual updates. Any and all aspects of a 10-year undergrounding plan must be included in each WMP filing, including 10-year plan changes. Consequently, the CPUC and OEIS must coordinate all WMP and 10-year undergrounding plan filings, reviews, and penalties. This will require careful coordination of reporting requirements, determinations for review and approvals (e.g., evaluation parameters, requirements, jurisdiction, and timing), and filing schedules by the CPUC and OEIS in order to prevent filing conflicts (e.g., information vintage and content) or excessively redundant information between the two plans. Failure to do so can and likely will result in issues such as inconsistencies between plans that affect work completed and increased workload and costs for the CPUC, OEIS, IOUs and stakeholders with no offsetting benefit to ratepayers.

These same issues currently plague other intersecting CPUC proceedings and should be taken as a cautionary example. For example, the renewable portfolio standard program (RPS) and Integrated Resource Planning (IRP) overlap such that RPS procurement is a subset of IRP procurement, much like undergrounding is a subset of wildfire risk mitigation approaches. In the past few reporting cycles the contents of RPS annual reports and IRP bi-annual reports (every 2 years) have largely converged to contain the same reporting elements but with responses generated at different times of the year and twice during the same year. Each updated report includes a plan reanalysis based on updated policy and system conditions, which effectively outdates plans reported in the parallel proceeding. This equates to substantial and inefficient use of time and costs for Utilities, the CPUC, and stakeholders. The IRP and RPS are under consideration for alignment and even consolidation. The CPUC should make every effort to avoid a similar outcome with the WMP and 10-year Undergrounding plans.

The WMP filing process, combined with SB 884 will result in the following reporting requirements:

- 3-year WMP base plan [All mitigations including undergrounding]
- WMP Annual Update [All mitigations including undergrounding]
- WMP quarterly data report, 4 total [All mitigations including undergrounding]
- WMP Change requests (on and off -ramps) [All mitigations including undergrounding]
- WMP third party reviews [OEIS specified mitigations]
- OEIS WMP Decision
- CPUC WMP Decision
- A 10-year Undergrounding plan [Undergrounding subset of all WMP filings]
- 2 annual (every 6-mo) Underground plan updates [Undergrounding subset of all WMP filings]
- Potential additional on- and off-ramp filings [Undergrounding subset of all WMP filings]
- Third-party independent monitor report [Undergrounding subset of all WMP filings]
- OEIS Underground Plan Decision [Undergrounding subset of all WMP filings]
- CPUC Underground Plan Decision [Undergrounding subset of all WMP filings]
- OEIS Underground Implementation review and penalty Decision(s) [Undergrounding subset of all WMP filings]
- CPUC Underground Implementation review and penalty Decision(s) [Undergrounding subset of all WMP filings]

The annual filing requirement increases to a minimum of 7 separate filings on wildfire mitigation planning and progress reports (1 annual plan and 6 interim reports), not including other periodically mandated reports and optional reports (e.g. change orders). GPI urges the CPUC and OEIS to invest some effort in aligning the WMP and 10-year undergrounding plans in order to produce an efficient and effective pathway for wildfire mitigation planning and project implementation.

Wildfire Risk and Project Assurance Issues

Utility planning, including distribution planning, has substantial and increasing uncertainty in the mid- to long-term planning horizon (5-10 years) making static expedited 10-year undergrounding plans a high-risk and uncertain investment.

Utility planning for all decisions at all levels, transmission and distribution, must manage and mitigate risk associated with large uncertainties stemming from many factors outside of utility control. This includes but is not limited to climate change, weather uncertainty, environmental changes, population changes including granular population density and statewide population change, energy demand sources and profiles (e.g. Electric Vehicles), energy generation sources and generation profiles (e.g. Distribute Energy Resources, DER; microgrids), markets, new technologies, customer choice and adoption patterns, and new policies.

The Integrated Resource Planning (IRP) proceeding is a prime example of a CPUC-managed IOU long-term planning approach. The IRP addresses Utility long-term procurement planning over the 5-10+ year planning horizon. In the IRP proceeding utilities tend to hedge against future uncertainty by leaving open, or short, procurement positions that allow for planning flexibility due to model and other sources of uncertainty that can later be filled as the year of need approaches and uncertainty decreases. In preparing and filing utility-specific IRP plans every 2 years, utilities often make changes to their procurement strategy and specify that the plans are subject to change due to uncertainty associated with forecasting assumptions and future conditions (e.g. market, climate change, policy, load). The IRP process is currently on a 2-year cycle, which includes updated modeling, and model inputs/assumptions, as well as Utility-specific IRP plan filings that address a rolling 10+ year planning horizon (required every two years). The IRP to date has only issued procurement orders through the mid-term planning horizon (2-5 years ahead). These orders build in procurement flexibility by specifying resource attributes, rather than specific technologies or locations (e.g. project specifics). This approach provides procurement flexibility towards least-cost-best-fit principles by supporting plan adaptations (e.g. due to changing markets) as the year-of-need approaches.

The Distributed Resources Plan proceeding (R.14-08-013, now closed) provides a good example of CPUC oversight and Utility approaches to distribution planning. In DRP distribution planning, uncertainty linked to factors such as high granularity of need, customer demand, load profiles, interconnection queues and likelihood, as well as generation profiles, leads to near and mid-term forward planning horizons that initiate near-term decisions. For example, the Distribution Investment Deferral Framework (DIDF), developed in the DRP proceeding, is a distribution planning process that identifies distribution grid needs that are eligible for deferral or replacement by DER solutions. Utilities established an eligibility filter that eliminates projects in the 0-3 year need timeframe, and subsequently rank the remaining opportunities on factors that include the likelihood of need. Utilities assume the further out a specifically defined distribution system project need (e.g. number of calls, technical requirements) the more uncertain the likelihood of the need becomes. This is in part due to the specificity of the project which includes highly granular location, generation profile, and timing requirements.

By their own determination, the IOUs identify most distribution needs in the 0–3-year planning horizon and deploy traditional wires solutions in order to ensure timely solutions to grid needs. Through this process, utility distribution planning and upgrades are most often implemented in the 0-3 year need or near-term timeframe to reduce the likelihood of stranded investments and to mitigate risk associated with forecast uncertainty. The Grid Needs Assessment (GNA) report shows the overwhelming majority of utility-identified distribution grid needs are concentrated in the near-term planning horizon. For example, in PG&Es 2020 GNA, 70 percent of PG&E distribution planning needs had a 2020 need date, and 16 percent had a 2021 need date. The 0-3 year planning horizon totaled 93 percent of all identified distribution grid needs. Distribution planning needs were only provided over a 5-year planning horizon (2020-2024) on account of increasing need uncertainty over longer forecasts. The DIDF, and GNA report therein, are modeled and filed on an annual basis to capture new grid needs (on-ramp) and/or off-ramp previously identified grid needs that are no longer necessary.

In contrast to the IRP and DRP approach, SB 884 outlines a relatively static, one-time, expedited 10-year undergrounding project plan with a single OEIS and CPUC review and approval/denial opportunity, and no periodic reassessment requirement for the duration of the 10-year plan. This inflexible approach is directly at odds with other CPUC-managed long-term planning (e.g. IRP) and distribution system (e.g. DRP) program designs and requirements. As previously described, the CPUC requires IOUs and CPUC Staff to periodically re-assess (e.g. every 1-2 years) plans that outline near, mid-, and long-term activities. This includes re-running updated models based on the most up-to-date inputs and assumptions as well as formal reporting, in order to capture and ***adapt*** to system changes with the benefit of updated information. As evidenced by the DRP and IRP, The CPUC and Utilities are both aware of inherently increasing uncertainty over mid- to long-term forecasting and planning horizons and its potential to lead to inefficient or ineffective investments, especially when specific projects (e.g. location, method, resources) are included in the plan. Both the CPUC and IOUs often elect to build in plan flexibility since plans predicated on mid- to long-term forecasts and planning horizons are the most susceptible to scope changes necessary to ensure cost-effective investments.

GPI is concerned that a 10-year undergrounding project plan that is subject to full approval at only one point in time based on currently available information will result in distribution system investments that do not follow least-cost-best-fit principles, especially in the mid- and long-term plan years (e.g. plan years 5-10). A 10-year undergrounding scope of work, with projects defined for the near- mid, and long-term planning horizons, should take into account many factors including but not limited to: wildfire risk and consequence models, model inputs and assumptions, fuels, climate change rate and modeled impacts, population density, population growth, cost of materials and other build resources (market-based), rate of build, available technology, risk reduction potential, and resultant granular and overall risk spend efficiency. Undergrounding projects also constitute changes to distribution grid topology. All distribution grid topology changes should address distribution grid needs (e.g. DIDF, GNA, Distribution

Planning Process) while also planning for the future by enabling state goals for electrification and DER adoption (e.g. customer EVs), both of which are directly linked to achieving the state greenhouse gas emission targets. Each of these plan inputs and the resultant distribution system needs is likely to change and has increased uncertainty over the 10-year plan horizon. Meaning the resultant undergrounding plans and projects in the mid to long term also have large uncertainty (e.g. need, risk spend efficiency, etc.). To remedy this, GPI strongly recommends adopting program elements that allow for plan and project-specific changes (on and off-ramp) through an iterative modeling, update reporting, and review approach.

SB884 outlines a static 10-year plan to determine costly upgrades for a system that is undergoing relatively rapid environmental changes as well as distribution system needs. Dynamic plans and review processes are necessary to adapt to changing conditions, especially given the high uncertainty over the course of the planning horizon.

California is experiencing unprecedented change in terms of climate and electricity needs. Climate change is linked to increasing energy needs associated with building cooling during heat waves, agricultural water pumping due to drought, and enabling greenhouse gas emissions reduction through statewide requirements for building and transportation electrification, as well as DER renewable energy procurement. These increased energy needs have a ripple effect throughout the entirety of California's electric infrastructure that impacts distribution and transmission system capacity and design. Climate change is also affecting wildfire likelihood and consequences due to environmental factors such as drought and fuel characteristics, among many other factors.

Undergrounding sits at the nexus of all of these factors. Undergrounding constitutes the relatively costly removal and rerouting of overhead lines. The specific location of each undergrounding project and its coverage will determine a granular risk spend efficiency. However, cost-effective undergrounding designs and topology should also take into account future grid needs associated with changing demands on the electric system. Undergrounding projects must address any identified future grid needs in the IOU's annual Grid Needs Assessment in order to prevent costly after-the-fact upgrades. Notably, IOU GNA reports largely include known location-specific projects in planning years 0-3. Utilities generally deem more distant grid needs (4+ years) as having higher uncertainty. Meaning that by in large, only undergrounding project plans in the 0-3 year timeframe can be reasonably designed to address both wildfire risk and anticipated distribution grid needs. GPI also recommends requiring undergrounding designs that enable cost-effective future and as yet unknown upgrades, but that are likely over a 10-year timeframe due to increasing energy requirements and design changes (e.g. DER and microgrids deployment) necessary to achieve state goals. Undergrounding projects that fail to address known distribution grid needs or include design elements that enable future grid upgrades will result in increased ratepayer costs, thereby reducing project and plan risk spend efficiency.

To mitigate these challenges GPI urges the CPUC to develop and adopt undergrounding plan requirements that: (1) Take into account the distribution planning process and distribution gid needs as part of every undergrounding project design; (2) Iteratively update plans (e.g. data informed on and off ramps) to capture ongoing rapid system changes; (3) Periodically review plans (CPUC, OEIS, and stakeholders) to ensure cost-effective investments are made over the entirety of a 10-year plan.

Wildfire risk models are in an early stage of development which equates to relatively unstable results. This is further exacerbated by efforts to model a changing system that is responding to climate change impacts.

The 10-year undergrounding plans will be predicated on wildfire risk and consequence models which are still maturing and are based on many inputs and assumptions that are subject to change over the 10-year implementation horizon. Utility wildfire risk models are novel approaches to capturing ignition likelihood and wildfire consequences from a wide range of sources. Substantial updates to PG&E's granular ignition likelihood planning model have resulted in major changes to circuit and asset-level wildfire risk scores. These adjustments have resulted in wildfire risk mitigation plan overhauls that increase costs to ratepayers, decrease risk spend efficiency, and slow the rate of utility wildfire risk reduction. Model stabilization is a process that understandably takes time. However, granular utility wildfire risk planning models are an important input in determining the most risk-spend efficient locations for undergrounding projects. GPI does not at this time recommend approving any 10-year undergrounding plans that are based on the still-evolving IOU wildfire risk models.

Any static model, run at one point in time, will include substantial inherent uncertainty that increases over the planning horizon. Models as well as their inputs and assumptions are all subject to uncertainty. Meaning, it is expected that over the 10-year planning horizon the models, underlying assumptions, and data inputs will change. As previously described, the IOUs continue to improve and refine their wildfire risk planning models, which are novel modeling approaches as of 2020. Model inputs are also vintaged, available data that provide a snapshot of current system conditions and forecasts. The amount and quality of data, as well as system conditions and forecasts, will most likely change over the 10-year planning horizon. For example, fuels, weather patterns, tree mortality, fuels moisture, and a plethora of other system conditions are all subject to change substantially over a 10-year planning horizon. This means any mid- and long-term plan or project scope that is based on a single model run has substantial uncertainty in terms of need and value (e.g. risk spend efficiency). Furthermore, the uncertainty associated with the wildfire risk planning model outputs for all time horizons is currently unknown and is likely large given the model complexity and its relative novelty.

Implementing SB 884 as is would result in a 10-year undergrounding plan that leads to the long-term approval of projects and ratepayer costs based on model inputs and assumptions from one point in time. This is contrary to other CPUC-designed and approved distribution and long-term planning and implementation processes. Rather, iterative modeling as a guide for utility investments is a standard approach for both CPUC and Utility designed programs. The CPUC and IOUs typically mitigate inherent uncertainty in model outputs, especially over mid and long-term planning horizons, by periodically updating model inputs and assumptions and generating updated outputs over a rolling planning horizon. As mid- and long-term plan years approach the near- and mid-term timeframes, respectively, updated model outputs, based on the most up-to-date inputs and assumptions, are used to confirm or adjust previous plans prior to implementation. For example, IOU 0-5 year Grid Needs Assessment models are reanalyzed on an annual basis. IRP 0-12-year procurement planning model inputs, assumptions, and outputs are updated every 2 years.

GPI strongly recommends that the 10-year undergrounding plan evaluation process include a requirement that utilities periodically re-run wildfire risk planning models over the plan horizon using updated models, inputs, and assumptions. Iterative model runs are necessary to reflect the most up-to-date guidance on cost-effective undergrounding locations. These updated model outputs should inform plan adjustments (e.g. on and off-ramps) and should be made publicly available for CPUC and stakeholder review in regular updates for on and off-ramp approval and perhaps penalty assessment.

A ratemaking proceeding is the appropriate vehicle to address the issues described above.

GPI strongly recommends opening a ratemaking proceeding to implement SB 884, given the design deficits and loopholes identified above. A ratemaking proceeding would provide the platform required to: (1) Coordinate and delineate CPUC and OEIS roles; (2) Establish clearer and more comprehensive plan and reporting requirements; (3) Establish better-defined bases for plan evaluation, approval, and penalties; (4) Develop a program that supports iterative plan evaluation and project on- and -off ramps in order to avoid stranded, sub-optimal, or ineffective investments; (5) Explicitly require that distribution system rebuilds for the purpose of wildfire mitigation also address distribution planning needs (ancillary benefits); (6) Reduce to the maximum extent possible, redundant or conflicting information, schedules, and/or decisions between the WMP and Undergrounding plans. The benefits of this approach include protecting ratepayers from costly inefficiencies that include both a financial burden and wildfire risk exposure that could result from poor program implementation and plan outcomes.

Conclusion

We urge the Commission to adopt our recommendations herein.

Dated March 10, 2023

INFORMAL COMMENTS OF THE PUBLIC ADVOCATES OFFICE ON WORKSHOP REGARDING SENATE BILL 884

I. INTRODUCTION AND DISCUSSION

The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) provides these informal comments regarding the Senate Bill (SB) 884[1] workshop in response to the invitation to do so from the California Public Utilities Commission's (Commission) Safety Policy Division (SPD). SPD limited comments to no more than 10 pages.

Each utility that submits a plan under SB 884 should be held accountable for executing its plan in a timely and cost-effective manner. If a utility fails to do so, it risks wasting ratepayer resources, failing to meet their risk reduction targets, exacerbating the affordability problem for its ratepayers, and not meeting the Commission's affordability principle.[2] Accountability is vital to affordability for ratepayers.

The following list of proposed actions is intended to help implement SB 884. Each action includes discussion of the pertinent codified portion of SB 884.[3] By addressing the listed actions, the Commission will help ensure the effective implementation SB 884.[4]

To ensure that each utility follows its own SB 884 plan, the Commission should:

1) Instruct when SB 884 applications will be accepted.

Instruction as to the timing can ensure the SB 884 application harmonizes with other related proceedings, such as Wildfire Mitigation Plans (WMPs) and General Rate Cases; and will help accommodate Commission staff availability for SB 884 plan review.

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[1] SB-884 Electricity: expedited utility distribution infrastructure undergrounding program.

[2] See https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/affordability

["The California Public Utilities Commission (CPUC) recognizes that consumers need affordable utility services to ensure health, safety, and participation in society."]

[3] Points 12 and 18 are exceptions. Point 12 talks about SB 884's silence on an issue, so there is nothing to reference. Point 18 does not reference SB 884.

[4] Cal. Pub. Util. Code Section 8388.5(e)(5) requires the Commission to review or deny the electric corporation's application. Cal. Pub. Util. Code Section 8388.5(i)(2) allows the Commission to assess penalties for failure to substantially comply with a decision approving the plan.

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Pursuant to Cal. Pub. Util. Code[5] Sections 8388.5(d)(2) and 8388.5(e)(5), the Office of Energy Infrastructure Safety (OEIS) and the Commission each have nine months to approve or deny the electrical corporation's submitted plan. Section 8388.5(e)(1) directs that the electrical corporation submit a copy of the plan and an application to the Commission within 60 days of OEIS approving the plan. However, the statute is silent as to when that corporation shall initially file the plan to OEIS. Also, where an electric corporation, such as PG&E, has already proposed distribution undergrounding work and requested related ratepayer recovery in its GRC or another proceeding, SB 884 is unclear regarding whether an SB 884 application should be postponed until the Commission has had the opportunity to resolve the open proceeding(s).

2) Create a public comment process for SB 884 plans once they are submitted.

Section 8388.5(d)(1) requires OEIS to publish the plan for public comment, while Section 8388.5(d)(4) requires the Commission to facilitate a public workshop for presentation of the plan and to take public comment for at least 30 days. However, neither of these provisions provides processes for the agencies to respond to public comment.

3) Identify issues that require interagency coordination between the Commission and Office of Energy and Infrastructure Safety (OEIS).[6]

Section 8388.5(d)(2) requires OEIS to approve or deny each application, while Section 8388.5(e)(5) directs the Commission to approve or deny each application. However, the requirements do not instruct whether or how the two agencies must coordinate with one another in their review of an SB 884 application. Without coordination, it is possible that the two agencies could reach different conclusions about the completeness or acceptability of an SB 884 plan; the statute does not address what happens in this scenario.

4) Identify the relationships between SB 884 and other potentially overlapping or similar requirements.[7]

There is a need to identify relationships between SB 884 and other overlapping or similar requirements. For example, Section 8386(c)(14) requires utility Wildfire Mitigation Plans discuss "hardening and modernizing its infrastructure… such as undergrounding." Section 8386(c)(15) similarly requires Wildfire Mitigation Plans to include "A description of where and how the electrical corporation considered undergrounding electrical distribution lines…"[8]

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[5] Unless otherwise stated, all section references are to Cal. Pub. Util. Code.

[6] Many of the issues raised in these informal comments also apply to OEIS.

[7] At this time, PG&E's GRC Opening Brief (A.21-06-021, PG&E Opening Brief, November 4, 2022, pp. 378-427) has proposed wildfire system hardening and overhead system hardening. SB 884 is silent about how to avoid the potential for double recovery, inconsistent findings or other issues arising from overlapping proposals between the GRC and an SB 884 application.

[8] See also, e.g., PG&E's TY 2023 General Rate Case (A.21-06-021), in which PG&E proposes undergrounding approximately 2,100 miles during the period from 2023 through 2026. PG&E's

5) Consider how the utility will demonstrate that it has made a sufficient effort to obtain all available non-ratepayer funds.

Section 8388.5(j) directs that, "[e]ach large electrical corporation participating in the program shall apply for available federal, state, and other non-ratepayer moneys throughout the duration of its approved undergrounding plan… ." The statute is silent on how the Commission can determine that a utility has made an adequate effort to obtain such funds. This is important because regulated utilities earn profits by using ratepayer funds for capital projects and therefore have a strong disincentive to obtain any non-ratepayer funds.

6) Establish appropriate mechanism(s) for cost recovery, if non-ratepayer funds are insufficient.

Section 8388.5(e)(1) provides that the electrical corporation may request the Commission conditionally approve costs, but does not specify the mechanism(s) by which those costs will be recovered.

7) Explore a designated lead agency can comply with the California Environmental Quality Act (CEQA), while also meeting SB 884's allotted time for review.

Section 8388.5(e)(5) requires the Commission to review and approve or deny the application on or before nine months, and that the Commission may require the corporation to modify and resubmit application before approving. Similarly, Section 8388.5(d)(2) requires OEIS to review and approve or deny the electric corporation plan within nine months. However, while Agencies have noted that environmental review and preparation can be a long process,[9] SB 884 is silent on

Reply Brief, December 12, 2022, p. 9 and pp. 327-329. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M499/K888/499888041.PDF

[9] *See eg.* City of Walnut Creek Environmental Review page. Available at: https://www.walnut-creek.org/departments/community-development-department/entitlements/environmental-review ["Depending upon the complexity of the project, preparation of an EIR (Environmental Impact Report) can be a long process. It requires a 45 to 60-day public review and comment. After the public comment period, the City must respond to all correspondence received and conduct additional studies as necessary."]

See also San Francisco Planning Department Environmental Review Process Summary. ["A minimum timeline for the EIR process is 18 months; the period is variable, however, based on factors such as changes in the proposed project, MEA caseload, supplemental data 6 requirements, quality of work submitted to the Department, and whether the FEIR is appealed."] Available at: https://sfpl.org/pdf/about/commission/eirprocess.pdf how to comply with CEQA within the nine-month time requirement. Both requirements will apply to the agency designated as "lead agency" under CEQA.[10], [11]

8) Identify the appropriate level of specificity that each of the SB 884 plan elements must include.

Section 8388.5(c) requires that the electrical corporation plan submitted to OEIS include a 10-year plan, that identifies undergrounding projects, timelines for project completion, comparison of undergrounding versus aboveground hardening, plan for workforce, and evaluation of project costs and economic benefits. Section 8388.5(e)(1) requires that the electrical corporation plan to the Commission include improvements in safety risk and reduction in costs, cost targets, and strategies for reducing cost. However, neither of these provisions includes a metric for quantifying risk, a fact-based means for proposing cost targets, a methodology for evaluating economic benefits, or the level of specificity with which each project must be described.

9) Articulate the specific type of analysis that utilities must perform to compare undergrounding with other wildfire ignition mitigating options.

Section 8388.5(c) requires the electrical corporation's plan to OEIS include a 10-year plan that compares undergrounding versus aboveground hardening, but does not specify the metrics or methods to be used in those comparisons. Moreover, the statute does not specify which overhead hardening alternatives the utility must examine, nor whether the utility may, must, or should consider combinations of mitigations.

10) Quantify and compare the total revenue requirements, and rate and bill impacts of undergrounding versus overhead hardening all the projects in each electric corporation's SB 884 plan.

Section 8388.5(c) requires a comparison of undergrounding with aboveground hardening costs, but is silent about the electrical corporation's revenue requirement that would result from such costs. Notably absent is a comparison of the total return on equity, or profit, that would result from undergrounding versus aboveground hardening.

The Commission has an obligation to ensure that utility service is affordable for all customers. Section 8388.5(e)(1) requires the applicant utility to describe cost targets, cost efficiencies, and a strategy for reducing costs over time. Section 8388.5(e)(4) requires the Commission to take public input. However, the statute does not require either the utility or the Commission to present

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[10] 14 CCR Section 15367 ["The Lead Agency, as defined by CEQA, is the public agency that has the primary responsibility for carrying out or approving a project."]

[11] 14 CCR Section 15051(b) ["Where two or more public agencies will be involved with a project, the determination of which agency will be the lead agency shall be governed by the following criteria: If the project is to be carried out by a nongovernmental person or entity, the lead agency shall be the public agency with the greatest responsibility for supervising or approving the project as a whole."]

cost information in a format that would be readily understandable and meaningful to the public. Requiring an analysis of rate and bill impacts would improve public understanding of SB 884 plans.

11) Quantify risk, and clarify what degree of wildfire reduction risk an SB 884 plan is required to achieve.

Section 8388.5 requires the use of risk to prioritize, compare, evaluate, and reduce wildfire risk, but is silent about how risk should be quantified. This leaves stakeholders with no clear guidance about whether risk is measured consistently, or the criteria used for measuring. Cal Advocates is aware of the classic definition of risk, which is the probability of an event occurring times its consequence if it occurs. However, neither probability nor consequence is quantified in SB 884. SB 884 further does not specify how or if utilities should establish a risk baseline against which to measure risk reduction throughout the 10 years of the plan.

12) Set forth a process for utilities to request updates or revisions to SB 884 plans, including the frequency of such updates and the process for review and approval.

SB 884 neither prescribes nor precludes a process for updating SB 884 plans after approval. Occasional updates will be necessary to adjust to changing circumstances, such as the utilities' evolving understanding of wildfire risk, the development of new technologies, and the emergence of new rebuild areas due to future wildfires. However, overly frequent updates could waste money and utility staff time on planning or partially implementing projects that are never completed, and would burden the staff of the Commission, OEIS, and all stakeholders.

13) Define the review and approval process for the progress reports that a utility must file every six months after a plan is approved.

Section 8388.5(f) requires that if the plan is approved, progress reports must be filed, including ongoing work plans and progress in annual wildfire mitigation plan filings, and assessment of compliance with the plan by an independent monitor. However, it does not explain how progress shall be measured, whether milestones must be met, or what consequences will pertain if a utility fails to make satisfactory progress on its plan. The statute also does not state whether there will be opportunities for public comment on the progress reports.

14) Identify metrics to tell whether an SB 884 plan will allow the utility successfully mitigate risk.

Section 8388.5(f) is also silent as to what metrics shall apply to measure whether an SB 884 plan is successfully identifying the areas most at risk of wildfires, and prioritizing projects at those areas.

15) Set criteria or requirements to determine whether an electrical corporation is complying with its own plan in each semi-annual progress report.

Section 8388.5(f)(1) requires that if OEIS and the Commission approve a plan, the electrical corporation must file a progress report with both agencies every six months, include ongoing work plans and progress in annual wildfire mitigation plan filings, and hire an independent monitor to review and assess compliance with the plan. However, this provision lacks criteria and/or requirements that an independent monitor can apply to analyze whether the electrical corporation is compliant with its plan.

16) Define appropriate accountability measures (including penalties) in case a large electrical corporation fails to meet the requirement to "substantially comply" with a Commission decision approving its SB 884 plan.

Section 8388.5(i)(2) provides that the Commission may assess penalties on a large electrical corporation that fails to *substantially* comply with a commission decision approving its plan. (Emphasis added.) The bill does not say how the term "substantially" will be defined. For example, what penalties are appropriate for a given amount of failure to comply with a plan? Should completing 98% of the plan be viewed differently than only completing 90%?

17) Clarify how a utility should identify projects to rebuild from wildfires in its forward-looking SB 884 plan.

Section 8388.5(2) says in part, "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 (SB 884) program." However, this provision does not provide guidance on what areas qualify as being a "rebuild area," or how such areas compare in risk against other areas. It also does not explain how an electric corporation can provide a ten-year plan to rebuild from wildfires that have not yet occurred.

18) Establish key facts and findings that are needed to evaluate SB 884 plans.

The presentations at the February 24, 2023 public workshop included unsupported and speculative assertions on a number of issues, including construction costs for undergrounding, the lifespan of underground conductors,[12] operations and maintenance costs, available technology to improve the effectiveness of undergrounding projects, and the willingness of utility customers to pay for undergrounding.

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[12] While a workshop speaker asserted that underground distribution conductors have a service life of 100 years, recent rate cases at the CPUC have found that underground conductors have an expected useful life of about 50 years.

Certain entities have presented claims that have not been tested and are subject to dispute. For example, at the SPD and OEIS workshop on February 24, 2023, PDI2 referred to three separate undergrounding initiatives across the nation, each of which was estimated to cost less than $1 million per mile ($500 million for 2,200 miles by WEC Energy, $2 billion for 4,000 miles in Virginia, and $20 billion for 27,000 miles in Florida). By contrast, in 2021, PG&E undergrounded 40 miles at a cost of approximately $4 million per mile.[13]

19) Because certain facts need to be established, an evidentiary record should be created to support Commission findings on the policy issues identified above.

Section 8388.5(e) has several provisions about steps that the Commission should take in reviewing an electric corporation's application. However, there are likely to be material disputed factual issues related to that application, such that an evidentiary hearing will be needed so that facts can be tested. Section 8388.5 is silent about the process that would allow for evidentiary hearings.

II. CONCLUSION

SB 884 plans will be highly consequential with a long duration and costs that are likely to be multiple tens of billions of dollars. Given these facts, it is crucial to make sure that the plans are cost-effective, that they show an accurate understanding of risk, and that utilities are accountable for results.

In these comments, Cal Advocates has identified actions that the Commission should address to effectively implement SB 884 in order to achieve good outcomes.

The Commission should issue direction to the electric utilities on each of these issues before any SB 884 plans are submitted. The best way to develop such guidance would be to open a rulemaking on SB 884. A rulemaking would develop an evidentiary record and support an informed decision. As noted in the attached memo, a well-planned rulemaking can be timely and efficient.

Importantly, a rulemaking to correctly implement SB 884 need not slow down any safety work in the field. PG&E, the only utility currently planning to participate in the SB 884 process, has already requested authorization for undergrounding projects related to wildfire safety for the 2023 to 2026 period.[14] Even if PG&E submits an SB 884 plan soon, the plan is unlikely to change the pace or scale of PG&E's wildfire safety work during the 2023-2026 GRC period, because practical resource limitations constrain what PG&E can feasibly accomplish in the near future.[15] Therefore, approval of an SB 884 plan will have no practical impact until 2027. That

[13] PG&E's response to data request CalAdvocates-PGE-2022WMP-04, question 10, February 25, 2022.

[14] PG&E's general rate case for test year 2023 (A.21-06-021) seeks authorization for 2,100 miles of distribution undergrounding related to wildfire safety.

[15] In PG&E's GRC reply brief, PG&E scaled back its proposal for wildfire-related undergrounding, partly in response to intervenor concerns about "the reasonableness of the proposed scope, pace, and costs." A.21-06-021, PG&E's Reply Brief, pp. 327-328.

allows ample time to conduct a rulemaking, which would help to clarify the legislation and ensure that necessary safety improvements are done right.

A sample timeline to accommodate a Commission rulemaking could be as follows:

- Rulemaking opens soon, wraps up by the end of 2023
- PG&E files a plan at OEIS: January 2024
- OEIS approval: October 2024
- File at the CPUC: December 2024
- CPUC approval: September 2025
- 10-year plan begins: January 2027

Cal Advocates appreciates the opportunity to provide these comments. We look forward to further discussion with OEIS and the Commission's SPD on how to implement SB 884 to achieve the best outcomes for utility customers in terms of safety and affordability.

Moreover, even if PG&E submitted an SB 884 plan that increased its undergrounding proposal after the GRC is decided (and if PG&E showed that its expanded proposal was feasible), there would be no apparent reason for the Commission to reopen a GRC and relitigate the issue.

Post-Workshop Comments of Pacific Gas and Electric Company Regarding Senate Bill 884 Implementation (March 10, 2023)

Pacific Gas and Electric Company (PG&E) appreciates the opportunity to submit these informal comments following the February 24, 2023 Senate Bill (SB) 884 Joint Workshop hosted by the California Public Utilities Commission (CPUC) and the Office of Energy Infrastructure Safety (Energy Safety) (Joint Workshop).

While several substantive issues were raised at the SB 884 Joint Workshop, perhaps the most critical issue at the outset is to confirm the importance of, and need for, a timely and expedited process for review of electrical corporation undergrounding plans, and to reflect this importance by promptly establishing the processes for Energy Safety and CPUC review. The purpose of SB 884, signed into law by Governor Newsom on September 29, 2022, is to establish an expedited program for undergrounding electric distribution infrastructure in Tier 2 or 3 High Fire Threat Districts (HFTDs) and fire rebuild areas. When the Legislature considered and ultimately approved SB 884, the need for expediency was front and center. Regarding the CPUC portion of the program, the Senate Floor Analysis noted "CPUC proceedings often take 18 months or years to resolve issues. Stakeholders have often complained about the pace of these proceedings, though stakeholders have equally expressed concerns when proceedings have been streamlined. Given the urgent need to mitigate wildfire risks, this bill requires the CPUC to resolve the proceeding within nine months."[1] The Assembly Committee on Appropriations noted that there were tradeoffs in SB 884 between speed and the typical level and timing of regulatory review. The Committee's analysis concluded that "[g]iven the ongoing risk of electrical-utility-sparked wildfires, and their potentially devastating consequences, that might be a tradeoff worth making."[2]

PG&E is fully aligned with SB 884's purpose and the Legislature's explicit recognition that it is critical to expedite the review and approval of a long-term undergrounding plan so that we can continue to maximize risk reduction in the HFTDs quickly and efficiently. Given the streamlined process, content requirements, and timelines clearly set forth in SB 884, we do not

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1 Senate Floor Analysis, issued August 30, 2022 at p. 6.

2 Assembly Committee on Appropriations Analysis dated August 2, 2022 at p. 5.

believe that additional regulatory processes, such as a potentially lengthy rulemaking, are required. PG&E and other electrical corporations should be allowed to submit their undergrounding plans without unnecessary delay to facilitate expedited review and approval.

SB 884 requires that an electrical corporation's undergrounding plan "substantially increase electrical reliability by reducing the use of public safety power shutoffs, enhanced powerline safety settings, de-energization events, and any other outage programs, and substantially reduce the risk of wildfire."[3] To achieve these important goals, PG&E plans to submit our 10-year SB 884 plan by mid-2023. Undergrounding projects are long-term efforts that require months and often years of planning and preparation. After PG&E identifies high-risk circuits for undergrounding, we begin the process of identifying project routes, acquiring land or easements, conducting environmental reviews, obtaining permits, designing and estimating projects, executing construction contracts, and ordering long lead-time materials. Given the extended time required for undergrounding projects, regulatory delays will impact our ability to quickly move forward with undergrounding, to the detriment of the people most at risk from wildfires and system outages.

The requirements and processes laid out in SB 884 are designed to ensure that undergrounding programs get started quickly, while simultaneously providing a reasonable amount of time for Energy Safety, the CPUC, and other stakeholders to thoroughly review PG&E's plan. Stakeholders will have more than a year and a half between the Energy Safety and CPUC processes to review, consider, and comment on PG&E's proposals.

We urge Energy Safety and the CPUC to expeditiously set up processes for undergrounding plan submissions and to allow electrical corporations to submit their plans to Energy Safety as soon as mid-2023. This gives Energy Safety and the CPUC more than four months to put into place initial processes for undergrounding plan review. Energy Safety will then have nine months to complete its review, and the CPUC will have nine months following Energy Safety review to conduct its review and assessment. There is more than sufficient time to get processes in place before mid-2023 so that the goals of SB 884 can begin to be realized.

There were other issues raised at the workshop in addition to timing, although the establishment of an expeditious process is critically important, as the Legislature made clear.

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3 Public Utilities Code § 8388.5(d)(2).

In the remainder of these comments, PG&E responds to issues raised at the Joint Workshop following the structure of the questions asked during the panel led discussions. Given the page limit for these comments, PG&E will not address every issue raised during the discussion, but instead focuses on key items or areas of concern. At the end of these comments, PG&E addresses issues raised in post-workshop comments that have already been submitted.

1. REGULATORY AND APPROVAL PROCESS ISSUES

1.1 Are the Requirements Established by SB 884 Sufficient or are there Additional Elements that Should be Included? Do Any of the Statutory Requirements Require Further Elaboration of Clarification?

We agree with other parties that the requirements established by SB 884 are sufficient for reviewing, approving, and monitoring electrical corporation undergrounding plans. The Public Advocates Office of the California Public Utilities Commission (Cal Advocates) noted that the legislation offers a clear roadmap about what needs to be included in the plan in terms of project prioritization, cost targets, and alternatives analysis. Both Cal Advocates and The Utility Reform Network (TURN) recommended that Energy Safety and the CPUC provide clarification around certain elements, such as accountability measures and coordination with other proceedings such as the General Rate Case (GRC) and the Wildfire Mitigation Plan (WMP). These issues are discussed more below.

1.2 Should the Expedited Undergrounding Process Align with the Wildfire Mitigation Plan and/or General Rate Case Process? If Yes, what Specific Aspects Should be Aligned and how Should Alignment be Effectuated?

PG&E agrees with parties that the 10-year undergrounding plan submitted per SB 884 should align with both the WMP and the GRC. As both TURN and Cal Advocates noted, it is important to ensure regulatory efficiency for Energy Safety, the CPUC, our customers, and other stakeholders. The legislation itself speaks to regulatory efficiency, stating that, "the Commission shall consider not revising cost or mileage completion targets approved, or pending approval, in the electrical corporation's general rate case."[4] At the workshop, Cal Advocates stated that the CPUC and Energy Safety would need to decide which of the three proceedings is the controlling proceeding and then ensure that the other two conform to it. Because each utility is on a different GRC and potentially WMP review cycle, we recommend that each participating utility

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4 Public Utilities Code § 8388.5(e)(3).

propose a specific alignment approach in its CPUC application rather than trying to adopt a "one size fits all" approach. This will allow for flexibility given that the utilities are differently situated with regard to GRC and WMP timing. It also means that the CPUC and stakeholders do not need to adopt a single approach at this point, but instead can consider the utility's proposed approach as a part of the CPUC application.

1.3 What Other Questions, Considerations, or Potential Complexities Should the Commission Consider in Establishing the Program?

PG&E is prepared to file an undergrounding plan in mid-2023. The regulatory process and timing outlined in the legislation are sufficient and, to that end, we have developed a proposed schedule for both the Energy Safety plan and the CPUC application processes. The proposed schedule is based on the expedited nine-month review process for each agency required by SB 884 and includes: (1) a pre-review period within the 9 months for completeness; (2) sufficient time for stakeholder review, discovery, and comments; (3) inclusion of statutory requirements such as workshops at the CPUC; and (4) time for Energy Safety and the CPUC to review the plans and comments and issue a final decision. We understand that Energy Safety and the CPUC are working on guidelines for their respective processes. To facilitate submission of plans by mid-2023, which would be approximately nine months after SB 884 was enacted, PG&E requests that these final guidelines be issued as soon as possible.

During the panel discussion, Cal Advocates stated that implementation of a rulemaking may be beneficial to address ambiguities in the legislation such as mechanisms for updating the plan, cost caps, the potential application of the California Environmental Quality Act (CEQA) and seeking non-ratepayer revenue sources. However, the legislation is clear in intent, content, and process for an electrical corporation's undergrounding plan. Instituting a rulemaking is unnecessary and will add years to a process that is adequately outlined in SB 884. A lengthy rulemaking would also be inconsistent with the Legislature's clear intent that the undergrounding process proceed expeditiously.

Moreover, PG&E's SB 884 plan will address the issues raised by Cal Advocates. It will include a proposed mechanism for updating the plan, cost information required by the legislation,[5] and how we will seek non-ratepayer funding. The parties will have ample opportunity to evaluate our plan as part of the established review process without having to implement a rulemaking process that could potentially double the 18-month review timeline set forth in SB 884.

Consistent with past CPUC decisions in similar contexts, CPUC approval of the costs of the SB 884 plan as called for under the legislation is not subject to CEQA.[6] With limited exceptions not applicable here, CEQA does not apply to ratemaking-related decisions such as the one the Commission is required to make under SB 884.[7] Moreover, "CEQA review is premature if the agency action in question occurs too early in the planning process to allow meaningful analysis of potential impacts."[8] PG&E has yet to conduct the detailed planning, engineering, siting, and environmental studies necessary to support permitting and associated CEQA review of the specific undergrounding projects that will ultimately be built should the Commission approve the costs of its plan. Because the detailed information required to support CEQA review does not exist at this time, any CEQA review as part of this proceeding would be entirely speculative and inconsistent with CEQA principles.

Finally, during the panel discussion some parties noted that undergrounding plans should include an adjustment mechanism to account for changes in risk modeling, wildfire technologies, and climate change. PG&E agrees with parties on this issue and will propose a mechanism for

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5 The legislation requires PG&E to: incorporate cost efficiency into its project prioritization; project unit cost targets for each year covered by the plan; compare undergrounding to other mitigations, including evaluating the cost of each activity; evaluate project costs over the life of the assets; describe economies of scale to reduce wildfire mitigation costs; demonstrate that cost targets are feasible and attainable compared to historical undergrounding costs; explain how cost targets are expected to decline over time; and provide a strategy for achieving cost reductions over time. *See* Senate Bill 884, § 8388.5(c)(2) through (c)(6) and (e)(1).

6 *See* Public Utilities Code § 8388.5(e) (requiring electrical corporation to request CPUC approval of the distribution undergrounding plan's costs), (e)(3, 5) (requiring Commission to consider specified ratemaking approaches).

7 Pub. Res. Code § 21080(b)(8) (establishing CEQA statutory exemption for establishment, modification, structuring, restructuring, or approval of rates for the purpose of, *inter alia*, obtaining funds for capital projects needed to maintain service within existing service areas).

8 *Friends of the Sierra Railroad v. Tuolumne Park and Recreation District* (2007) 147 Cal.App.4th 643, at 645-55.

adjusting elements of the plan as part of our SB 884 plan. This issue is further addressed in Section 2.3 below.

2. REGULATORY AND APPROVAL PROCESS ISSUES

2.1 What Analytical Approach and Decision-Making Framework should be Employed by the Electrical Corporations in their Plans to Justify their Undergrounding Proposals? What Level of Detail should be Provided in the Plans Comparing Undergrounding to Other System Hardening Alternatives?

PG&E and parties agree that the risk analysis framework we have already developed is sufficient and no additional framework needs to be developed. The legislation identifies the main requirements that must be included in the 10-year undergrounding plan—specifically a comparison of undergrounding versus above-ground hardening or any other alternative mitigation strategy—for achieving comparable risk reduction. The comparison should evaluate "the scope, cost, extent, and risk reduction of each activity, separately and collectively, over the duration of the plan."[9] We will provide in our 10-year undergrounding plan the information required by the legislation. In the pre-review process included in PG&E's proposed schedule, Energy Safety and the CPUC can identify any information required by statute that they believe is not included in the undergrounding plan or application.

2.2 How Can the Electrical Corporation Progress Reports and Independent Monitor Annual Reports be Maximized for Accountability? Are there Additional Accountability Tools and Procedures to Consider to Ensure Projects are Completed On-Time, On-Budget, and are Reducing Risk?

SB 884 requires electrical corporations to submit a progress report to Energy Safety and the CPUC every six months.[10] PG&E recommends that the reports include progress against approved mileage targets, cost targets, and risk reduction. We propose that the mid-year report provide a progress update and the end-of-year annual report would serve as the accountability measure to determine if we have achieved the annual targets that have been set and approved by Energy Safety and the CPUC.

9 Public Utilities Code § 8388.5(c)(4).

10 Public Utilities Code § 8388.5(f)(1).

During the panel discussion Cal Advocates raised the issue that PG&E's risk profile will change as we continue to reduce risk in the HFTD. Therefore, Cal Advocates recommends establishing a risk baseline against which risk reduction can be measured. We agree with Cal Advocates and support developing a method for measuring risk reduction as part of the 10-year undergrounding program.

There was also discussion about accountability requirements being built into the Energy Safety and CPUC agency decisions and that the progress reports should include the issues that the legislation considers important, including project prioritization and information showing that undergrounding is superior to other mitigation methods. PG&E supports having the accountability requirements be part of the decisions issued by Energy Safety and the CPUC. PG&E recommends the following measurements be included in the accountability requirements: (1) unit cost per mile; and (2) total miles complete. Project prioritization and mitigation comparison methods are required by the legislation[11] and will be included in our SB 884 plan.

TURN also raised the issue of requiring utilities to provide project level, cost-benefit analyses every six months for planned projects and projects identified for future work to ensure that projects meet a certain cost-benefit threshold to be determined at a later date. This proposal is unnecessary and inconsistent with SB 884. PG&E will conduct a cost-benefit analysis at the initiation of new projects added to the workplan and will comply with the requirement to develop a cost benefit approach established in Decision (D). 22-12-027.[12] That decision requires PG&E to apply this cost-benefit approach when we submit our 2024 Risk Assessment Mitigation Phase (RAMP) report in May 2024. Given that we expect to submit our 10-year undergrounding plan in 2023, requiring a project-level cost benefit analysis at this time is premature, would significantly delay the plan, and is not required by SB 884. Moreover, we do not believe this proposal supports the legislative intent of SB 884 to facilitate an expedited plan approval process and thus it should be rejected.

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11 Public Utilities Code § 8388.5(c)(2) (project prioritization) and § 8388.5(c)(4) (comparison of mitigation methods).

12 D.22-12-027, Phase II Decision Adopting Modifications to the Risk-Based Decision-Making Framework Adopted in D.18-12-014 and Directing Environmental and Social Justice Pilots.

2.3 How Should the Evolving Understanding of Risk and the Ever-Changing Methods for Calculating Risk be Accounted for in the Plans? Should Flexibility be Built into the Plans to Account for Uncertainty in Long-Term Risk Forecasting? Would a Mechanism to Alter an Approved Plan be Needed?

PG&E and other parties agree that flexibility needs to be built into the plan to account for both the uncertainty in long-term risk forecasting and the ever-evolving methods for calculating risk. We believe that the approved plan should be viewed as a framework for an undergrounding program and the specific projects within that framework can change as risk modeling changes and additional information about risk are obtained. The reporting mechanism in SB 884 will allow us to report on the initially selected projects as well as identify new projects over time. The intent of the legislation is to conduct work in the highest wildfire risk areas within the mileage and cost structures agreed upon. Flexibility in specific project selection based on the latest information should be incorporated into the regular progress reports while still meeting the intent of the legislation.

While Cal Advocates agreed that flexibility needs to be built into the plan, it recommended caution regarding the rate of change. Cal Advocates stated that the six or twelve-month reporting cycle included in the legislation may be too frequent to fully vet the proposed changes and recommends a longer timeline—potentially three to four years—to understanding proposed changes. TURN also agreed that flexibility should be incorporated into the project plan but notes that it needs to align with the governing legislation. TURN stated that new projects need to be vetted under the same criteria as the project list approved by the agencies (Energy Safety and CPUC) and suggests that this could potentially be accomplished under the GRC process. PG&E does not support the proposed process of approving the project list, and instead re-emphasizes the need for the project selection framework to be approved by agencies under the SB 884 process, which PG&E will implement accordingly and report on in the regular progress reports. Extending the timeline as recommended by Cal Advocates and TURN to evaluate the program framework outside of the expeditious process set by SB 884 would significantly impact our ability to implement a streamlined, efficient process for identifying, scoping, and constructing underground projects.

3. NEXT STEPS

3.1 Possible Rulemakings or Resolution

As discussed above, rulemakings or resolution are not required. SB 884 went through a robust public vetting and discussion via the legislative process in 2022. The result of this process was a clearly identified goal of undergrounding California's highest risk lines as fast and cost effectively as possible in response to public interest. Rulemakings or other regulatory processes would significantly slow down the regulatory process that should be streamlined to allow electrical corporations to file an undergrounding plan as soon as reasonably possible. SB 884 created an expedited regulatory review and approval framework separate from annual WMPs and 4-year GRC cycles so that a utility can commit to, and plan for, the full and long-term infrastructure program that quickly achieves scale, cost savings, and other key efficiencies. It also ensured review of undergrounding plans is consistent with the paradigm provided in Assembly Bill 1054 in 2019, which is community safety first, and above all else, as determined by Energy Safety, followed by program financing and cost balancing by the CPUC. Any added processes outside of this SB 884 framework would run contrary to legislative intent and could delay the benefits of the statute.

3.2 Possible Workshops and/or Technical Working Groups

While PG&E believes that requirements set forth in the legislation are clear, we recognize that it is important to hold workshops to hear feedback from stakeholders and to enable public participation in this program. The draft schedule we prepared (included in Appendix A) proposes a workshop to be hosted by Energy Safety after we file our 10-year plan and a workshop hosted by the CPUC regarding our application. We are amenable to additional workshops if they do not delay either the 9-month Energy Safety review schedule or the 9-month CPUC review schedule.

During the panel discussion on risk (Question Number 2), Cal Advocates and PG&E agreed that it would be reasonable to establish a risk baseline. We support establishing a technical working group to evaluate this risk baseline but only if it does not impact our intent to file our plan in 2023. If other technical issues arise that would benefit from participation in a technical working group, we would be supportive if the working group does not delay the 18-month review process.

3.3 Response to Post-Workshop Comments

In post-workshop comments submitted on March 8, 2023, the Center for Accessible Technology (CforAT) expressed concern about harmonizing potential changes the CPUC makes to the undergrounding plan with the plan approved by Energy Safety. While ensuring consistency between the two agencies is important, this comment misunderstands the roles of Energy Safety and the CPUC under SB 884. Under SB 884, Energy Safety is responsible for reviewing and approving or denying an electrical corporation's undergrounding plan.[13] If the plan is approved, the electrical corporation then submits an application to the CPUC. The application is not an opportunity to completely re-evaluate the plan, but instead addresses the costs of the approved plan and associated cost recovery.[14] Thus, while the CPUC will address cost issues through the application process, it will not be proposing substantive changes to the plan approved by Energy Safety.

4. CONCLUSION

PG&E looks forward to working with Energy Safety, the CPUC, and other stakeholders as we develop our 10-year SB 884 undergrounding plan. It is imperative that we submit our undergrounding plan as quickly as reasonably possible based on the elements prescribed in SB 884 and that the review and approval process occur within the timeframes set forth in the legislation.

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[13] Public Utilities Code § 8388.5(d)(2).

[14] Public Utilities Code § 8388.5(e)(1).

APPENDIX A: SB 884 UNDERGROUDNING PROPOSED SCHEDULE

Proposed Schedule for Energy Safety Proceeding

Activity	Date[15]
Submission of Undergrounding Plan (Plan) for completeness review.[16] Completeness review determines that the Plan includes all of the information required by statute.	Initial Submission Date (ISD)
Energy Safety confirms Plan complete or issues notice of deficiency.	ISD + 30
Plan posted to Energy Safety website for public comment.[17]	ISD + 31 days
Discovery begins. Discovery responses provided within seven (7) days on a best efforts basis.	ISD + 31 days
Energy Safety hosts workshop on Plan	ISD + 45 days
Comments on Plan	ISD + 75 days
Reply Comments on Plan	ISD + 95 days
Energy Safety issues Draft Decision	ISD + 155 days
Comments on Draft Decision	ISD + 185 days
Reply Comments on Draft Decision	ISD + 205 days
Energy Safety issues Final Decision	ISD + 250 days

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15 All days are calendar days unless otherwise indicated. If a date falls on a weekend of federal or state holiday, the delivery date will be the next following working day. *See* CPUC Rule 1.15.

16 Public Utilities Code § 8388.5(c).

17 Public Utilities Code § 8388.5(d)(1).

Proposed Schedule for CPUC Application

Activity	Date
Submission of Undergrounding Plan Application (Application) for completeness review.[18] Completeness review determines that the Application includes all of the information required by statute and CPUC rules. Undergrounding Plan Application posted on electrical corporation website and notice provided to parties.	Initial Submission Date (ISD)
CPUC confirms Application complete or issues notice of deficiency. If Application is deemed complete, formal filing date is ISD + 30 days. CPUC issues preliminary determination of categorization (Rule 7.1(a))	ISD + 30 days
Discovery begins. Discovery responses provided within seven (7) days on a best efforts basis.	ISD + 31 days
Protests due (Rule 2.6(a))	ISD + 45 days
Notice of potential rate increase (Rule 3.2(b) and (c))	ISD + 50 days[19]
Protest Replies due (Rule 2.6(e))	ISD + 55 days
Pre-hearing Conference (Rule 7.2)	ISD + 60 days
Public Workshop on the Plan and Public Comment	ISD + 60 days[20]
Notice of mandatory settlement conference for all parties (Rule 12.1(b))	ISD + 65 days
Post-workshop comments	ISD + 70 days
Bill insert of potential rate increase (Rule 3.2(d))	ISD + 75 days

18 Public Utilities Code § 8388.5(e)(1) (submission required within 60 days of Energy Safety approval).

19 Notice of rate increase is generally due within 20 days after an application is filed. In this case, because of the preliminary completeness review, formal filing of the Application is considered to have occurred on ISD + 30 days.

20 Public Utilities Code § 8388.5(e)(4).

Activity	Date
Scoping Memo Issued (Rule 7.3)	ISD + 75 days
Mandatory Settlement Conference for all parties	ISD + 80 days
Appeal of categorization (Rule 7.6)	ISD + 80 days
Intervenor testimony (if applicable)	ISD + 95 days
Proof of compliance with notice requirements (Rule 3.2(e))	ISD + 95 days
Rebuttal testimony (if applicable)	ISD + 110 days
Hearings (if necessary)	ISD + 120 days
Motion for approval of settlement (if applicable) (Rule 12.1)	ISD + 125 days
Concurrent Opening Briefs	ISD + 150 days
Comments on settlement (if applicable) (Rule 12.2)	ISD + 155 days
Concurrent Reply Briefs	ISD + 165 days
Reply comments on settlement (if applicable) (Rule 12.2)	ISD + 170 days
Proposed Decision issued	ISD + 225 days
Opening Comments on Proposed Decision (Rule 14.3(a))	ISD + 245 days
Reply Comments on Proposed Decision (Rule 14.3(d))	ISD + 250 days
Final Decision issued	ISD + 270 days

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Senate Bill 884

MUSSEY GRADE ROAD ALLIANCE INFORMAL COMMENTS

ON THE FEBRUARY 24, 2023 SB 884 WORKSHOP

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Dated: March 10, 2023

1. INTRODUCTION

The following informal comments have been prepared for Mussey Grade Road Alliance (MGRA or Alliance) regarding the February 24, 2023 meeting led by CPUC and Energy Safety staff to discuss issues relating to the passage of Senate Bill 884 allowing for expedited undergrounding proposals.[1]

MGRA Comments have been prepared by Alliance expert Joseph W. Mitchell, Ph.D. Dr. Mitchell was a panelist for the workshop.

2. BACKGROUND

My name is Joseph Mitchell, and I have been the expert witness on wildfire issues for the Mussey Grade Road Alliance (MGRA) since 2007. Wildfire risk reduction has been a core issue for MGRA as a wildland urban interface area that was severely impacted by the 2003 Cedar fire and surrounded by the 2007 SDG&E power line fires. The Mussey Grade area is economically diverse, and since 2009 we have pushed for a cost/benefit approach to finding the most cost effective mitigations to reduce power line fire risk. Over the past two years, we've commented extensively about undergrounding proposals in our comments on the Wildfire Mitigation Plans. As undergrounding is one of the most costly mitigation measures, considerable effort needs to be made to ensure that resources are directed efficiently and wisely. There is already an affordability crisis, and the heavy-handed approach to undergrounding being undertaken by utilities threatens to greatly exacerbate this problem.

During our work analyzing the 2022 Wildfire Mitigation Plans, I analyzed how utility bill increases associated with expensive hardening programs would affect the life expectancy for the poorest quartile of Californians, and was shocked to discover that it is likely that utility bill increases will lead to a significantly greater impact on public health than wildfires.[2] For this reason, I opposed the passage of SB 884, writing a letter to Governor Newsom opposing the bill, and was

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[1] Email; From: Hanes, Fred fred.hanes@cpuc.ca.gov; Sent: February 16, 2023; Subject: SB-884 Joint Workshop Panel Questions and Agenda Update

[2] OEIS Docket 2022-WMPs; pp. 57-60.

interviewed on National Public Radio's Marketplace regarding my opposition.[3] Nevertheless, the bill is now law and it is up to us to make sure that it is implemented in such a way that minimizes harm to ratepayers while still adhering to the intention of the legislators.

3. WORKSHOP PANEL QUESTIONS

3.1. Panel-Led Discussion 1: Regulatory and Approval Process Issues

The statute establishes minimum requirements for 10-year undergrounding plans to be submitted to Energy Safety. Are these requirements sufficient, or are there additional elements that should also be included? Do any of the statutory requirements require further elaboration or clarification? Why or why not?

The statute's minimum requirements will not be sufficient to successfully create 10 year undergrounding plans that will stand the test of time in a way to provide full value and maximum wildfire protection for ratepayers and residents. The requirements as stated lead to potential conflict with OEIS and CPUC processes, and these must be resolved. Utility risk analysis capabilities are evolving very rapidly, as are alternative technologies, and a means must be found to incorporate future changes into ten year plans.

Elements that need to be added are:

- Comprehensive cost benefit analysis as per the RDF Framework for choosing undergrounding priorities that includes alternative mitigations such as covered conductor and advanced technologies, PSPS as both a risk and mitigation, wildfire smoke impacts, and potential impacts on public health and life expectancy due to potential excessive rate increases.
- "Off ramps" that provide incentives for utilities to develop alternatives that reduce equivalent or greater amount of risk at lesser cost.
- "On ramps" that allow utilities to add undergrounding programs to the scope of the existing plan if compelling cost/benefit arguments can be made.

[3] Marketplace Morning Report; California wants more utilities to bury electrical lines; Lily Jamali; September 15, 2022.
https://www.marketplace.org/2022/09/15/california-wants-more-utilities-to-bury-electrical-lines/

- Cap on rate impacts for low-income ratepayers should provide constraint on roll-out pace and rate mechanisms.

Should the expedited undergrounding program process align with the Wildfire Mitigation Plan and/or General Rate Case processes? If so, what specific aspects should be aligned, and how should the alignment be effectuated?

The expedited undergrounding program is a core component of wildfire safety and as such must be integrated tightly into the Wildfire Mitigation Plans and General Rate Case processes.

- The Undergrounding Plan should provide a high-level architecture setting yearly goals and providing an overview of how undergrounding will be implemented.
- The WMP should be the forum for assigning specific circuits or tranches for work within the next 1 to 2 years.
- Proposed changes to Plan (short and long term) should be proposed in the WMP.
- Re-validation of risk reduction and cost estimates should be detailed in the WMP.
- GRC should provide funding mechanism for 4 year cycle.

What are other questions, considerations, or potential complexities should the Commission consider in establishing the program?

- After the Plan has been approved, if another hardening or operational project for a given circuit is determined to reduce wildfire and PSPS risk more effectively at a more reasonable cost, does the Plan have sufficient flexibility to allow the utility to substitute this measure under the auspice of the Undergrounding Plan?
- Utilities are heavily incentivized to invest in capital projects, making a 10% profit on these projects. Hence, utilities are strongly motivated to make their undergrounding plans as extensive as possible. Can a mechanism be devised under this program that would provide incentives for utilities to solve the same problem at lower cost?
- In evaluating whether to approve the utility Undergrounding Plans, the CPUC should fully explore the impacts of resulting rate increases on the well-being of ratepayers, particularly lower-income and vulnerable ratepayers. Therefore in setting up the mechanism for review, the Commission should communicate clear guidelines to the utilities regarding affordability so that the utilities are able to create compliant plans.

3.2. Panel-Led Discussion 2: Wildfire Risk and Project Assurance Issues

The statute requires electrical corporations to compare undergrounding to other system hardening alternatives emphasizing both the risk reduction and the cost effectiveness of undergrounding for the projected useful life of the undergrounding project versus the alternatives.
o What analytical approach and decision-making framework should be employed by the electrical corporations in their plans to justify their undergrounding proposals?
o What level of detail should be provided in the plans and why?

- As per the S-MAP proceedings and the Risk-Based-Decision-Making Frameworks at the CPUC, the utilities have all developed highly sophisticated risk analysis mechanisms that extend down to the tranche and segment level. The results of these analyses are also presented to and accepted by the Office of Energy Infrastructure safety. There is no reason that the same models cannot be applied to the Undergrounding Plans. However, some of us have discovered serious flaws and shortcomings in some aspects of each of the utility risk models. Regardless, we're not likely to come up with better models in the curtailed time we have available for these proceedings, so we should go forward with latest and best models from the utilities with the full knowledge that these are works in progress.
- As these models should be expected to change and to improve with time, it is important that the Undergrounding Plan be regularly validated against the most recent utility risk models to ensure that the prioritization remains correct, that alternative mitigations can be substituted if appropriate, and that new segments may be added to the plan if a convincing cost/benefit argument supports this.
- Included in these analyses should be full cost/benefit analysis of all mitigations, including undergrounding, and technology-enhanced covered conductor, i.e. using additional technologies such as REFCL or SDG&E's Falling Conductor Protection. Cost of PSPS events should also be quantified, as well as their benefit as part of the plan. In some remote areas it may be more cost effective to provide backup capability to residents. Again, these plans should be detailed and derived by the latest/best analysis presented in GRCs or in WMPs.

Legislation provides for an annual report by an independent monitor and a 6-month progress report from the electrical corporation.

o How can these reports be maximized for accountability?

o Are there additional accountability tools and procedures to consider to ensure that projects are completed on-time, on-budget, and are actually reducing risk?

- There are several timescales associated with this legislation, and monitoring needs to be integrated into the appropriate timescale.
    - First, there is the ten-year timeline of the plan. Because of the rapid change in fire science, engineering, and understanding of risk, this should provide overall goals and guideposts that monitors and reports should track progress against.
    - Second, there is the four year timeline of the GRC and subsequent Accountability report. This should be analyzed by monitors to ensure that utility spending is appropriately targeted to the maximum reduction of risk and that ratepayer protections have been enforced.
    - Third, there is the annual WMP update, and the annual independent auditor report should be integrated with this process, either deriving its content from the WMP or providing input into the WMP.
    - Finally, the six month utility reports should be a detailed accounting of hardening projects in the pipeline, those in progress, and those completed, compared with original utility targets.

The undergrounding plans are 10-year plans.

o How should the evolving understanding of risk and ever-changing methods of calculating risk be accounted for in the plans?

o Should flexibility be built into the plans to account for uncertainty in long term risk forecasting?

o Would a mechanism to alter an approved plan be needed? Why and how?

The utility risk calculation methodologies have undergone very significant changes and improvement over the past few years, and this process is not slowing down. There are currently a number of issues regarding the accuracy of the utility risk plans being litigated in the General Rate Cases and Wildfire Mitigation Plans. Among the topics currently under discussion are:

1. Whether the utility risk models adequately account for the extreme wind events that have been responsible for the vast majority of harm to Californians,

2. How wildfire smoke impacts should be incorporated into utility risk models,

3. Whether fire simulations used by utilities are able to accurately model the extreme megafires that have been responsible for the majority of losses of life and property.

4. Also the technology question needs to be addressed. Certain technologies currently being piloted, could, in conjuction with covered conductor, result in protection approaching undergrounding at a much lower cost. Also, as consultant Ben Lanz mentioned in his presentation undergrounding itself is undergoing technological changes and innovations.

5. Finally, when we take the impacts of the costs of undergrounding on the lower income segment of California, and compare these against life expectancy versus income curves, we see that the costs of undergrounding may in fact cause harm to public health that exceeds the risk from wildfire, smoke, and power shutoff. Essentially this shifts the risk from those of us living on the Wildland Urban Interface onto the poorest segment of California society.

None of these issues is going to be settled in the time that the legislature anticipated for implementation of SB884. Therefore flexibility must be built into the plan design and execution so that ratepayers continue to get maximum value for their wildfire safety spending.

The Undergrounding Plan must therefore have mechanisms to update its targets as new information is obtained.

The Wildfire Mitigation Plan updates are an annual process that can be updated for this purpose:

1. Utilities, regulators, or stakeholders can propose changes to targets or incorporate specific analysis changes that re-prioritize circuits and segments.
2. Utilities or regulators can propose that segments allocated for undergrounding instead be hardened using other engineering and operational tools. Utilities should be incentivized to develop and deploy such life and cost saving measures.
3. Utilities should be required to periodically re-run their risk analysis to validate whether changes are warranted to the prioritization and mitigations for circuits within the Plan.

4. OTHER COMMENTS

4.1. Presentation by Consultant Ben Lanz

Ben Lanz of Power Delivery Intelligence Initiative made several observations that merit comment:

- Mitigations (of all types) should be evaluated on a full-lifecycle basis.
- New technologies need to be tailored to the special needs of the California firescape. Plasma tunneling in the WUI may be a questionable idea.
- "Customers in high risk areas want safer/more resilient grid and are willing to pay for it". While this may or may be true, all customers, not just WUI customers, will be paying for these programs. As MGRA has pointed out in its filings, regulators should not allow risk to be transferred from WUI residents onto the poorest segment of society.
- "Utility executives and Wall Street want opportunities to invest billions w/guaranteed rate of return and eliminate O&M."
  Of course they do. This clearly illustrates the conflict of interest if utilities are allowed to set mitigation priorities. There is a natural tendency for them to gravitate to expensive capital improvements for which they can receive a guaranteed rate of return.

4.2. Rulemaking

One of the questions raised and discussed by parties is whether a rulemaking is necessary in order to lay out the rules and requirements for implementation of the SB 884 provisions. As laid out in the previous sections, there are many open questions, inconsistencies, and potential conflicts with existing Commission and OEIS process. A rulemaking would likely resolve these issues more expeditiously than "making it up as we go along" and then risking devolution into procedural and potentially legal squabbling.

5. CONCLUSION

After years of wildfires and power outages, the desire of the legislature and the Governor to "git 'er done" is understandable: to write out a list of circuits and segments, attach years to them, roll out a program and audit against it.

Approaching this problem in a naive way potentially destructive. It will not optimize Californian's dollars to minimize wildfire and shutoff risk. It could spend without constraint, pulling enough from the poorest Californians to shorten their lives. And at the end of it, when we have improved our models and understanding of the wildfire problem and discover that the wrong circuits are buried, we will have to go do it all over again. This scenario would benefit only the utilities, who profit from these capital expenditures.

The goal of this legislation is to reduce PSPS and wildfire risk as rapidly as possible, and only by fully incorporating the most current information regarding wildfire, utility technologies, and impacts of utility costs can we meet that objective. This will require the Commission and Energy Safety to develop an agile and flexible approach to the rules governing the Plans. Work put out early in the process will more than pay for itself in enabling a logical and well-ordered coordination of wildfire programs.

Respectfully submitted this 10th day of March, 2023,

By: __*/s/*____***Joseph Mitchell***____________________

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March 10, 2023

VIA E-MAIL

SB884@cpuc.ca.gov

RE: SDG&E Informal Comments to California Public Utilities Commission, and Office of Energy Infrastructure Safety Joint SB-884 Pre-Rulemaking Workshop

Pursuant to guidance from the California Public Utilities Commission (CPUC) and Office of Energy Infrastructure Safety (Energy Safety) in the Joint SB-884 Pre-Rulemaking Workshop (Workshop) held on February 24, 2023, SDG&E hereby submits to the CPUC and Energy Safety these informal comments on the Workshop.

I. DISCUSSION

a. Any Future Project Requirements Should Not Include Cost-Benefit or a RSE Floor

Within the second panel on Wildfire Risk and Project Assurance Issues, TURN made a comment that a cost-benefit or risk-spend efficiency (RSE) floor requirement should be included for all projects to meet. SDG&E disagrees with this suggestion as determining a cost-benefit floor would potentially inadvertently constrain wildfire risk reduction if the floor were to be determined without consideration of unique geographic or other specific conditions.

b. Greater Clarification Around Proceeding Should Be Determined

Since this workshop was hosted both by CPUC and Energy Safety, SDG&E has a question of how this issue will proceed moving forward with two regulatory bodies. SDG&E asks that further clarification is given to participants on how this proceeding will move forward, and if the CPUC or Energy Safety will be collaborating to avoid duplication.

Conclusion

SDG&E appreciates the CPUC and Energy Safety's consideration of these comments on the Joint SB-884 Pre-Rulemaking Workshop, and requests that the CPUC and Energy Safety take these recommendations into account in further development of SB-884 implementation.

Respectfully submitted,

/s/ Laura M. Fulton

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March 10, 2023

VIA E-MAIL

Fred Hanes, P.E.
Project and Program Supervisor
RASA Section, Safety Policy Division
California Public Utilities Commission

Re: Southern California Edison Company's Informal Comments Following the February 24, 2023 Joint Workshop on Senate Bill 884

Dear Mr. Hanes:

Southern California Edison Company (SCE) appreciates the opportunity to participate in the California Public Utilities Commission (Commission) and Office of Energy Infrastructure Safety (Energy Safety) Joint Workshop on Senate Bill 884 concerning the Expedited Utility Distribution Infrastructure Undergrounding Program, which was held on February 24, 2023 (Workshop). Following the Workshop, the Commission and Energy Safety invited informal written comments.[1] SCE focuses its comments on the second panel-led discussion concerning the framework that utilities should employ to justify undergrounding proposals, and a suggestion that agencies may use cost-benefit metrics to set a "cost-benefit floor" in determining whether undergrounding proposals are reasonable. While a cost-benefit metric may be one factor to consider when evaluating risk mitigation alternatives, the suggestion of a "cost-benefit floor" to determine the reasonableness of an undergrounding proposal is inconsistent with Commission precedent and should not be endorsed.[2]

Cost-Benefit Ratios Cannot Serve as the Sole Determinant for Selecting and Implementing Risk Mitigations

Senate Bill 884 added section 8388.5 to the Public Utilities Code and required the Commission to establish an expedited electric utility distribution infrastructure undergrounding program for certain electrical corporations who choose to participate in the new statutory

[1] Pursuant to guidance in the March 1, 2023 email from the Commission, SCE is providing these comments to the e-mail addresses on the SB 884 Notification List.

[2] SCE does not necessarily agree with other comments made throughout the Workshop but has focused its comments on the "cost-benefit floor" issue, which SCE believes is important to clarify for purposes of future undergrounding proposals.

process. During the Workshop, the second panel-led discussion focused on the following topic and questions:

> The statute requires electrical corporations to compare undergrounding to other system hardening alternatives emphasizing both the risk reduction and the cost effectiveness of undergrounding for the projected useful life of the undergrounding project versus the alternatives. What analytical approach and decision-making framework should be employed by the electrical corporations in their plans to justify their undergrounding proposals? What level of detail should be provided in the plans and why?

As part of the second panel-led discussion, The Utility Reform Network (TURN) expressed its view that utilities should be required to demonstrate that undergrounding is "superior" to alternative mitigations, and that "undergrounding projects should not be approved if there are more cost-effective alternatives." TURN recommended that utilities refer to a "cost-benefit approach" that was adopted in Decision 22-12-027 in connection with certain rulemaking designed to develop a risk-based decision-making framework for evaluating risk mitigation choices (R.20-07-013 (Risk OIR)).[3] According to TURN, that decision provides a methodology "that takes into account the full range of risk reduction benefits from the programs that are being compared…and it compares those benefits to the costs." TURN suggested that cost-benefit metrics "will provide an opportunity for the agencies to set an RSE [Risk-Spend Efficiency] or cost-benefit floor that projects should meet in order to be able to go ahead."[4]

To the extent that it is TURN's position that a cost-benefit ratio may be used as a dispositive factor or "cost-benefit floor" in determining whether a proposed mitigation such as undergrounding is reasonable, such an argument is foreclosed by the express language of the decision that TURN cited during the Workshop. The Commission has repeatedly and consistently confirmed that RSEs -- or their cost-benefit ratios derivatives -- are only one of many factors that may be used in assessing risk mitigations, and that neither RSEs nor cost-benefit ratios are intended to serve as the sole determining factor in assessing whether a proposed mitigation selection is reasonable.[5] For example, the Commission stated that although it adopted "Staff's proposed Cost-Benefit Approach, we do not intend that the Cost-Benefit Ratios produced using this method must serve as the sole determinants of IOU proposals or

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[3] *See* D.22-12-027, *Phase II Decision Adopting Modifications to the Risk-Based Decision-Making Framework Adopted in Decision 18-12-014 and Directing Environmental and Social Justice Pilots* (Dec. 21, 2022).

[4] A video recording of the Workshop is available at https://www.youtube.com/watch?v=u0d_eRVJTpA and TURN's comments quoted in this paragraph begin at 2:21:40 of the video.

[5] D.22-12-027 at 26, 56.

Commission decisions on risk Mitigations."[6] The decision also provides that "[m]itigation selection can be influenced by other factors including, but not limited to, funding, labor resources, technology, planning and construction lead time, compliance requirements, Risk Tolerance thresholds, operational and execution considerations, and modeling limitations and/or uncertainties affecting the analysis."[7]

The Commission's revision and approval process in reaching a final decision in the Risk OIR is also instructive in helping discern the Commission's intent. The assigned Administrative Law Judge's initial proposed decision in the Risk OIR included language stating that cost-benefit ratios "are central to the evaluation of risk mitigations."[8] However, Revision 1 to the proposed decision, as issued by the Commission, specifically deleted the language stating that cost-benefit ratios "are central to the evaluation of risk mitigations."[9] SCE had addressed this point in written comments on the proposed decision and demonstrated that there was no evidence or precedent in the record to support the inclusion of the language in question.[10] The Commission removed the language in Revision 1, and the deletion was reflected in the final decision.

The final decision in the Risk OIR correctly recognized that RSEs or cost-benefit ratios are not and should not be the only factor used to develop a proposed risk mitigation such as targeted undergrounding. There are absolute risk issues that may not be captured by the cost-benefit ratios including the crucial topic of risk tolerance, as well as a multitude of ethical, socioeconomic, compliance, and physical and resource constraints which are not readily translatable to dollar values, but which are crucial to the sophisticated process of actually managing resources, risks, and service. Employing a "cost-benefit floor" would fail to take into account several factors that the Commission has recognized may also be considered by utilities when selecting their portfolio of wildfire mitigation initiatives.

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SCE appreciates the opportunity to provide these comments and looks forward to continuing to work with the Commission, Energy Safety, and other stakeholders on this matter.

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[6] D.22-12-027 at 26-27. ("The utility is not bound to select its Mitigation strategy based solely on the Cost-Benefit Ratios produced by the Cost-Benefit Approach.").

[7] *Id.* at 27.

[8] *See* Risk OIR Proposed Decision, as issued on November 3, 2022, pp. 24, 50 (Finding of Fact No. 11).

[9] *See* D.22-12-027 at 56, *Phase II Decision Adopting Modifications to the Risk-Based Decision-Making Framework Adopted in Decision 18-12-014 and Directing Environmental and Social Justice Pilots* (Dec. 21, 2022) (Finding of Fact No. 11).

[10] *See, e.g.*, R.20-07-013, SCE Opening Comments on Phase II Proposed Decision in Risk OIR, Nov. 23, 2022, p. 4.

Respectfully submitted,

/s/ *Peter Shakro*

Peter Shakro

TURN
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March 10, 2023

TURN Informal Comments on February 24 SB 884 Workshop

Introduction and Summary

TURN was pleased to participate in the February 24, 2023 California Public Utilities Commission (CPUC) and Office of Energy Infrastructure Safety (OEIS) workshop on implementation of SB 884 and appreciates the opportunity to provide these informal comments. TURN looks forward to continuing the conversation about the requirements of SB 884 and, ultimately, to providing both agencies its analysis of any undergrounding plans that are submitted.

Undergrounding can be a beneficial wildfire mitigation, but it comes at a high price tag. In the context of today's increasingly unaffordable electric rates, the choice to deploy this mitigation must be made strategically to ensure ratepayers receive the optimal benefit of their investment. As an initial matter, TURN recommends that a rulemaking be opened to address the complex issues that must be resolved in developing the requirements of an undergrounding plan. Without advanced coordination and fully considering the interaction of the General Rate Case, Wildfire Mitigation Plan and the new Undergrounding Plan, the CPUC and OEIS risk a misuse of administrative resources as well as ratepayer dollars.

In these comments, TURN first presents – and in some cases expands on -- the responses it gave on the workshop panels to the questions posed in advance of the workshop. Second, TURN identifies limitations to the usefulness of the presentation on national undergrounding trends at the workshop. Finally, TURN recommends that a rulemaking proceeding be opened to address the challenging issues related to the implementation of SB 884. Consistent with the informal nature of these comments, TURN reserves the right to modify the views and positions it expresses here as the SB 884 implementation process evolves.

1. **The statute establishes minimum requirements for 10-year undergrounding plans to be submitted to Energy Safety. Are these requirements sufficient, or are there additional elements that should also be included? Do any of the statutory requirements require further elaboration or clarification? Why or why not?**

The statute is specific in the requirements laid out for the undergrounding plan. A compliant undergrounding plan will include:

- An identification of the undergrounding projects that will be constructed as part of the program (PU Code Section 8388.5(c))

- A prioritization of the identified projects based on (1) wildfire risk reduction, (2) public safety, (3) cost efficiency and (4) reliability benefit. (*Id.*)

TURN notes in particular that, in several places, the statute requires that the utility present information at the "project" level of detail. This is in contrast with the less specific "program" level of detail that utilities often present in a General Rate Case (GRC). Such program-based showings typically do not identify the individual projects that comprise the proposed program. SB 884's repeated use of the word "project" makes clear that the utility must identify specific information about the circuit segments to be moved underground, such as the location, project length, cost, and timeline.

The statute also repeatedly refers to the requirement for the utility to prioritize the segments to be undergrounded. (Sections 8388.5(c)(2) - (4)). The statute is thus clear that the goal is not to encourage *any* additional undergrounding but instead to ensure that undergrounding is deployed where it is the most effective strategy for wildfire mitigation. And within the locations best suited for undergrounding, work should be completed first where it is most cost efficient. As discussed in more detail in response to question 3 below, TURN recommends that this prioritization should take advantage of the cost-effectiveness quantification now required by the CPUC and OEIS and consistent with the methodology used to inform the WMP and RAMP/GRC.

Additionally, SB 884 directs the utility to provide:

- Timelines for completions (Section 8388.5(c)(3));
- Unit cost targets and mileage targets for each year (*Id.*);
- A comparison of undergrounding against alternative mitigation measures, such as covered conductor, based on factors including risk reduction and cost (Section 8388.5(c)(4);
- A plan for workforce development (Section 8388.5(c)(5)); and
- An evaluation of project costs, economic benefits, and cost containment assumptions (Section 8388.5(c)(6)).

As required by the plain words of the statute, OEIS and the Commission should clarify that the above-described information be provided on the same project-by-project basis as is used for the identification of projects. As one example of the importance of project-level information, TURN notes that the results of the alternative analysis will vary based on the unique characteristics of a project location -- not just the wildfire risk of a particular location but the factors affecting the cost of the infrastructure in that particular location. The CPUC/OEIS should specify that project-level detail will be required before any plan is accepted for submission, let alone approved.

Regarding statutory elements that need further elaboration or clarification, TURN nominates the phrase "conditional approval" used in Section 8388.5(e)(1). As the two agencies continue to develop the process and procedures to implement SB 884, the meaning of this phrase is a question that will need attention.

In addition, elaboration regarding how to address the evolving nature of an Undergrounding Plan will be needed before any undergrounding plans are submitted. Experience at both the CPUC and OEIS demonstrates that utility plans can change over time. General Rate Case periods are four years and the Wildfire Mitigation Plans cover three years with annual updates. It is not uncommon, however, for the utilities to adjust their WMP spending or pursue different projects than was originally requested in a GRC. Especially given SB 884's required specificity, the CPUC and OEIS should explore how modifications to an approved plan will be handled in advance of receiving any plan.

2. **Should the expedited undergrounding program process align with the Wildfire Mitigation Plan and/or General Rate Case processes? If so, what specific aspects should be aligned, and how should the alignment be effectuated?**

Yes. For purposes of administrative efficiency the three proceedings should be aligned and any previously completed review and approval should not be revisited. The language of the statute makes it clear that the proceedings are to be aligned, stating: "the Commission shall consider not revisiting cost or mileage completion targets approved, or pending approval, in the electrical corporation's general rate case."[1]

As an initial matter, TURN notes that the statute does not require a utility to submit an undergrounding plan. The existing WMP and GRC proceedings on their own are sufficient to approve the plans of the utility to underground miles in the near term. In fact, the PG&E General Rate Case for Test Year 2023 has already been submitted to the Commission for a decision. Wildfire Mitigation Plans will be submitted to OEIS for its expedited review on March 27. For PG&E, existing procedures are likely to provide a more efficient review process for undergrounding projects to be completed before the end of the 2023-2026 GRC period.

The legislation should be interpreted to charge each agency with review of the plan related to their unique missions and expertise. OEIS should be relied on to assess the plan related to the efficient promotion of wildfire safety goals with the CPUC focused on ratemaking and the balancing of safety, reliability, affordability and clean energy goals. The CPUC has perspective on the many non-wildfire areas of ratepayer-funded utility spending, giving it important context and expertise on the impact of the proposed undergrounding on ratepayer affordability and on state electrification goals.

Coordinating GRCs, WMPs and SB 884 proceedings, while avoiding conflict and duplication, will be a challenging endeavor. As discussed further in Section 8 below, opening an SB 884 implementation rulemaking proceeding would give OEIS and the CPUC an opportunity to work through the challenging issues in harmonizing the SB 884 plan with the current WMP and GRC proceedings. It would also provide an opportunity for each organization to clarify the process for its unique review to ensure that administrative resources are put to their best use while avoiding unnecessary duplication.

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[1] Cal. Pub. Util. Code § 8385.5(e)(3).

3. **The statute requires electrical corporations to compare undergrounding to other system hardening alternatives emphasizing risk reduction and including cost over the lifetime of the plan versus the alternatives. What analytical approach and decision-making framework should be employed by the electrical corporations in their plans to justify their undergrounding proposals? What level of detail should be provided in the plans and why?**

The two agencies should require utilities to use the quantitative risk modeling approach developed by the CPUC in its S-MAP proceedings. The first S-MAP case, A.15-05-002, culminated in the Risk Spend Efficiency (RSE) calculation framework adopted in D.18-12-014. The second and still pending S-MAP case, R.20-07-013, adopted in D.22-12-027 a Benefit-Cost Approach to advance the D.18-12-014 framework, under which utilities calculate Benefit-Cost Ratios that allow stand-alone estimates of a program or project's cost-effectiveness. By the time that any utility is prepared to submit an SB 884 undergrounding plan to OEIS, the utility should have fully implemented the changes required to calculate Cost-Benefit ratios required by D.22-12-027.

The value of the RSE and Benefit-Cost approaches to calculating cost-effectiveness is that they take into account all of the different risk-related considerations specified by the statute for evaluating proposed undergrounding projects, including estimated reduction to public safety (fatalities and injuries), financial (e.g, property damage incurred by the public), and reliability (including reduction of the need for PSPS outages). Those risk reduction benefits are compared to the cost of the project in question, resulting in a comprehensive measure of cost-effectiveness. Consistent with the statute's direction, the cost-effectiveness measures should be calculated on a project-by-project basis. Additionally, all potential alternatives to hardening should be assessed on the same project-by-project basis. The utility should provide workpapers, in excel format, underlying the calculations and allow for sensitivity analyses to be run on an expeditious basis, by either stakeholders or by the utility at the direction of stakeholders.

4. **The legislation provides for an annual report by an independent monitor and a 6-month progress report from the electrical corporation. How can the effectiveness of these reports for providing accountability be maximized? Are there additional accountability tools and procedures to consider to ensure that projects are completed on-time, on-budget, and are reducing risk?**

Properly designed accountability measures will incentivize the utilities to maximize the benefits of their spending and will ensure that ratepayers get the utility performance promised when the agencies approved the plan.

The accountability reports should track the required elements for the SB 884 plans themselves highlighted in response to question 1 above. The utility should show that (1) they are on track to meet all timelines identified and approved by the Commission, (2) completing the work within declining unit cost caps, and that (3) all projects completed are above a specified cost-effectiveness floor. The unit cost caps and cost-effectiveness floors should be determined by OEIS/CPUC in their decisions.

One of the goals of the statute is that a demonstrated long-term commitment to undergrounding will enable the utilities to take advantage of economies of scale that will hopefully come with the long-term commitment to undergrounding. TURN recommends that the unit cost caps should decline in 6 month increments so that the CPUC and OEIS can ensure that the promised economies of scale are being realized.

Importantly, the accountability reports must show that the work that is being completed is on the highest priority miles. Without this direction, a utility would be free to focus on easier to implement projects regardless of priority. Given the statute's emphasis on prioritization, completing only lower risk and lower priority work should be insufficient to maintain compliance with the requirements of the plan.[2] To avoid this outcome, the targets must be designed to require that a minimum cost-effectiveness threshold will be met before a project is executed.

In addition to providing the information specified above, the utility should provide detailed and specific information on any failure to meet the targets. The utility should be required to provide ***all*** material reasons for any deviation from the target even, and especially, if the reason is unflattering to the utility. As the CPUC and OEIS consider the future role of undergrounding, they will benefit from understanding if disappointing results are driven by the technology itself or by the implementation of that technology by the utility.

The Commission and OEIS should explore not only the setting of targets but also the consequences for missing any target. Depending on what target has been missed, consequences could include financial penalties for shareholders and potential removal of miles from the plan. The requirements and consequences for failure to meet the requirements should at a minimum be specified in any decision by OEIS or the CPUC approving a SB 884 plan. A rulemaking, however, could provide a forum to more fully discuss and develop the potential consequences in advance.

As experience with the GRC and WMP have shown, the utility plans can change from year to year as new lessons are learned or technologies emerge. The ten-year time frame of the plans adds considerable complexity to accountability reports. Well-designed accountability measures will highlight when a potential off ramp may be needed from the longer-term plan because the projects are not meeting their specified risk reduction or cost containment goals.

Finally, TURN recommends that the utility be required to submit accountability reports under oath by an officer.

[2] The Federal Monitor appointed in PG&E's probation found that while PG&E had technically met a mileage target for Enhanced Vegetation Management (EVM), the utility had not completed the work on the highest priority miles. Letter from Federal Monitor to U.S. District Court for the Northern District of California, (October 16, 2020), regarding update on PG&E's vegetation management and infrastructure inspection operations since 2019, p. 2: "Put another way, as the Company pushed to meet its 2,455-mile EVM target for 2019, it did not prioritize wildfire risk reduction according to its risk model."

5. **The Undergrounding Plans are 10-year plans. How should the evolving understanding of risk and changing methods of calculating risk be accounted for in the Plans? Should flexibility be built into the plans to account for uncertainty in long term risk forecasting? Would a mechanism to alter an approved plan be needed? Why and how?**

The language of SB 884 recognizes that undergrounding should only be adopted as a tool to address risk in a particular location when the utility has demonstrated its superiority to other alternatives. As time passes, new technologies may reveal themselves or the realities of undergrounding installation costs may prove more different than originally expected. As noted above, experience with GRCs and WMPs have demonstrated that the ultimate projects completed by the utility commonly vary from the original plans. This situation creates unique obstacles when attempting to approve a ten-year plan.

The agency decisions should specify a cap on the scope of the approved undergrounding mileage. In addition, as noted in response to question 4 above, the agency decisions should identify a steadily declining unit cost cap and should specify a floor for the cost effectiveness measure. The projects that are implemented should not run afoul of the adopted floors or ceilings. There should be a streamlined off ramp to remove from the plan any projects that will not meet the specified requirements.

Presenting a greater challenge is the scenario where the utility wants to substitute new projects to replace previously approved projects. To meet the statute's project-focused requirements, any new projects should undergo a similar level of review as the original projects in the plan. Balancing compliance with the statutory requirements with administrative efficiency – and the potential role of GRCs and WMPs in such balancing -- should be a question that the agencies explore in the SB 884 implementation rulemaking that TURN recommends below.

6. **To achieve a meaningful review within the nine-month period required by statute, should there be a pre-application or completeness review? Why or why not? If so, how should such a review be structured?**

Yes. TURN recommends that given the expedited pace of the proceeding, OEIS and the CPUC identify in advance all requirements of a plan in as much detail as possible. For purposes of the 2023-2025 Wildfire Mitigation Plan cycle, OEIS has developed guidelines for the submissions as well as a handbook for submission. A similar process should take place for the undergrounding plans. A rulemaking would provide a venue to develop these materials.

Once the requirements are identified and the utility submits the SB 884 plan, OEIS and the CPUC should first certify that the required information has been provided. TURN recommends that the sequential nine-month period for review only start after both OEIS and the CPUC have concluded that the utility application is complete.

7. Response to PDI2 Presentation

The workshop included a presentation on "National Undergrounding Trends" by a representative of an organization called Power Distribution Intelligence Initiative (PDi2). After the workshop, TURN had an opportunity to research PDi2 and its membership. Based on that research, it is clear that PDi2 is effectively a trade association for vendors of materials and services for the utility industry. PDi2's website describes the organization as comprised of "professionals from the North American power industry value chain including materials suppliers, cable makers, installers, equipment and accessory manufacturers and engineering firms."[3] It describes its mission as "to increase awareness about options for undergound power infrastructure."[4] Some of its members have a direct financial interest in the expansion of undergrounding throughout the United States. For example, one of the members, Imcorp, describes itself as a "provider of underground power cable reliability services."[5] Another member, Earthgrid, touts what it calls its groundbreaking underground tunnel-boring technology.[6] PDi2 is funded by firms that include vendors that would financially benefit from the expansion of undergrounding. For varying degrees of financial commitment, a company can provide advice, influence or even join the board of PDi2. According to the PDi2 website, for a minimum annual commitment of $30,000 a company can have a voting representative on the board of the organization.[7]

Given the financial interest of at least some PDi2 members in increased undergrounding and the obvious financial interest of its membership in the expansion of utility infrastructure programs, the PDi2 presentation should not be considered unbiased information about "national undergrounding trends." Broad claims in the PDi2 presentation – such as that customers are willing to pay for the increased costs of undergrounding, and optimistic assertions that technological improvements are driving costs down – need to be viewed with an understanding of the financial interest that PDi2's membership brings to its particular assessment of national trends. In short, OEIS and CPUC should not place any reliance on supposed trends identified in the PDi2 presentation.

That said, the PDi2 presentation acknowledges a very important reality of undergrounding's appeal ***to utilities***: "Utility executives & Wall Street want opportunities to invest billions w/guaranteed rate of return."[8] Expanded reliance on undergrounding would boost utility profits for several decades. Thus, monopoly utilities have a strong incentive to seize any opportunity they can find to increase the deployment of undergrounding in order to benefit their shareholders. However, a key purpose of regulation is to restrain the financial incentives of investor-owned utilities to maximize profits. Instead, regulators must ensure that utility infrastructure programs serve the public interest and the needs of utility customers, which include delivering safe and reliable service at affordable rates. Needless to say, if energy service is not affordable, it is not useful.

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[3] https://pdi2.org/about/
[4] *Id.*
[5] https://www.imcorp.com/
[6] https://earthgrid.io/
[7] https://pdi2.org/membership/
[8] PDI2 Presentation, Slide 11.

8. TURN recommends CPUC/OEIS Open a Rulemaking to Consider these Issues.

In the workshop and in these informal comments, a variety of questions have been raised, including the challenge of coordination with GRC and WMP proceedings, the specific requirements that must be met by SB 884 submissions, and how to handle plan modifications in later years. It is in the best interest of ratepayers – and indeed all stakeholders -- that these difficult questions be answered before any plan is filed. If the Commission and OEIS do not dictate in advance the requirements of a SB 884 submission the agencies will be left in the position of reacting to the utility proposals. The process will not be transparent and utilities will have an unfair advantage in shaping how the void is filled. For this reason and as noted throughout these comments, TURN recommends that the Commission and OEIS initiate a rulemaking to establish the requirements of the plan and address the other challenging procedural issues before inviting the utilities to submit a plan. A rulemaking will provide a venue for exploring these difficult questions and ensure that the process, once begun, will run smoothly and not serve to unnecessarily favor the utility.

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verizon✓

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Jane Whang
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Public Policy, Law and Security
Verizon

March 10, 2023

Via Electronic Mail

Fred Hanes, P.E.
California Public Utilities Commission
RASA Section, Safety Policy Division
505 Van Ness Avenue
San Francisco, CA 94102

Re: Verizon Comments on SB 884 Workshop/Questions

Dear Mr. Hanes,

Cellco Partnership d/b/a Verizon Wireless (U 3001 C) ("VZW") on behalf of its wireless affiliates and MCImetro Access Transmission Services Corp. d/b/a Verizon Access Transmission Services (U-5253-C) (collectively, "Verizon") respectfully submits these comments on the SB 884 questions circulated by staff on February 28, 2023.

The SB 884 workshop was convened to address implementation issues related to the establishment of an expedited electric utility distribution infrastructure undergrounding program for large electrical corporations. Verizon is a communications provider offering wireless, wireline, and broadband services in California, and is not on the service list to A.21-06-021 or the SB 884 "interest list," and consequently did not learn of the SB 884 joint workshop until only a couple of days ago. Verizon submits these limited comments on "[w]hat are other questions, considerations, or potential complexities should the Commission consider in establishing the program?"

Verizon strongly recommends that the Commission (i) consider how to ensure that electric corporation undergrounding plans do not adversely affect communications facilities attached to poles where facilities may be forced underground and (ii) open a rulemaking to address SB 884 implementation and provide notice to all potentially interested parties (including communications providers) for participation in such a proceeding.

As a communications provider, Verizon attaches its equipment (wireless antennas, fiber optic cables, radio equipment, and other facilities) to many electric utility poles as part of its communications network. A critical consideration in the undergrounding of electric facilities is how to care for and ensure that attachments such as wireless antennas on the utility pole can remain on the pole. Wireless antennas cannot be undergrounded as they will not work underground; the cost to relocate such antennas to other poles or to construct new poles for the antennas could be exorbitant, time-intensive, result in unnecessary ground disturbance and potential environmental effects, and may result in disrupted or degraded wireless service in the area of undergrounded poles.

Moreover, the Commission should consider whether non-wireless communications facilities, such as fiber optic or other wireline equipment should also remain on utility poles, as there may be technical issues related to undergrounding electric and communications lines. In addition, there are significant costs in undergrounding communications lines that will have further adverse impacts on communications service rates (including wireless service that relies on fiber lines to carry wireless traffic from antennas to switching centers), and such costs should be weighed against the benefits to undergrounding such lines that do not in themselves pose significant wildfire risk. At a minimum, electric utilities should install conduit for communications equipment at the same time that they are installing conduit for electric equipment, in order to minimize the time, expense, and work involved for undergrounding facilities on a pole. All of these factors must be considered in order to prevent degradation or disruption of communications and broadband services that serve critical needs for Califoirnians, in all aspects of their lives but especially during emergencies.

For the foregoing reasons, the Commission must consider communications and wireless issues in establishing the 10-year expedited undergrounding program. Further, as noted above and in comments filed by ExteNet, these issues are best addressed in a rulemaking in which all potentially affected parties are notified and provided opportunity to comment consistent with the Commission's rules.

Thank you for your consideration of these comments.

Sincerely,

/s/

Jane Whang

Cc: Fred Hanes
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SB 884 service list