Revised March 2023

Decision _________________

FILED
01/29/26
04:59 PM
A2601025

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of The Utility Reform Network for Award of Intervenor Compensation for Substantial Contributions to Resolution SPD-37	Application 26-01-___ (Filed January 29, 2026)

INTERVENOR COMPENSATION CLAIM OF THE UTILITY REFORM NETWORK AND DECISION ON INTERVENOR COMPENSATION CLAIM OF THE UTILITY REFORM NETWORK

NOTE: After electronically filing a PDF copy of this Intervenor Compensation Claim (Request), please email the document in an MS WORD and supporting EXCEL spreadsheet to the Intervenor Compensation Program Coordinator at Icompcoordinator@cpuc.ca.gov.

Intervenor: The Utility Reform Network (TURN)		**For contribution to Resolution** Safety Policy Division (SPD)-37
Claimed: $161.232.50		**Awarded: $**
Assigned Commissioner: N/A		**Assigned ALJ: N/A**
I hereby certify that the information I have set forth in Parts I, II, and III of this Claim is true to my best knowledge, information and belief. I further certify that, in conformance with the Rules of Practice and Procedure, this Claim has been served this day upon all required persons (as set forth in the Certificate of Service attached as Attachment 1).		
	Signature:	/s/ *Thomas J. Long*
Date: 1/29/26	**Printed Name:**	Thomas J. Long

PART I: PROCEDURAL ISSUES

(to be completed by Intervenor except where indicated)

A. Brief description of Decision:	SPD-37 builds on earlier Resolution SPD-15, which established a CPUC program and program guidelines to implement Senate Bill (SB) 884 relating to the Commission's review of any large electrical corporation's 10-year distribution infrastructure undergrounding plan and its related costs. SPD-37 adopted outcomes include: (1) Updating and adding Phase 2 application requirements;

	(2) Explaining a process for ensuring costs recovered via the memorandum account are capped and not excessive; (3) Adopting primary and secondary objectives for an audit of costs recorded to the one-way balancing account; and (4) Establishing a joint Phase 1 application process to resolved certain issues not resolved in SPD-37.

B. Intervenor must satisfy intervenor compensation requirements set forth in Pub. Util. Code §§ 1801-1812[1]:

	Intervenor	CPUC Verification
Timely filing of notice of intent to claim compensation (NOI) (§ 1804(a)):		
1. Date of Prehearing Conference:	N/A	
2. Other specified date for NOI:	N/A	
3. Date NOI filed:	N/A (see comments)	
4. Was the NOI timely filed?		
Showing of eligible customer status (§ 1802(b)) or eligible local government entity status (§§ 1802(d), 1802.4):		
5. Based on ALJ ruling issued in proceeding number:	A.21-12-007	
6. Date of ALJ ruling:	5/31/22	
7. Based on another CPUC determination (specify):		
8. Has the Intervenor demonstrated customer status or eligible government entity status?		
Showing of "significant financial hardship" (§1802(h) or §1803.1(b)):		
9. Based on ALJ ruling issued in proceeding number:	A.21-12-007	
10. Date of ALJ ruling:	5/31/22	
11. Based on another CPUC determination (specify):		
12. Has the Intervenor demonstrated significant financial hardship?		

[1] All statutory references are to California Public Utilities Code unless indicated otherwise.

	Intervenor	CPUC Verification
Timely request for compensation (§ 1804(c)):		
13. Identify Final Decision:	SPD-37	
14. Date of issuance of Final Order or Decision:	12/10/25	
15. File date of compensation request:	1/29/26	
16. Was the request for compensation timely?		

C. Additional Comments on Part I: ***use line reference # as appropriate)***

#	Intervenor's Comment(s)	CPUC Discussion
I.B.3	In D.98-11-049, the Commission determined that an NOI incorporated in the timely-filed Request for Compensation for work on an advice letter is itself timely filed. TURN has attached to this compensation request our NOI for this proceeding. The approach TURN is following here is consistent with the instructions in the CPUC's Intervenor Compensation Program Guide (Revised 4/17), p. 27.	
II.B.5, 6, 9, 10	The cited ALJ Ruling was issued within one year prior to the commencement of this informal proceeding with the November 17, 2022 joint letter from the CPUC and OEIS announcing the start of the SB 884 implementation process.	

PART II: SUBSTANTIAL CONTRIBUTION

(to be completed by Intervenor except where indicated)

A. Did the Intervenor substantially contribute to the final decision (*see* § 1802(j), § 1803(a), 1803.1(a) and D.98-04-059): ***(For each contribution, support with specific reference to the record.)***

Intervenor's Claimed Contribution(s)	Specific References to Intervenor's Claimed Contribution(s)	CPUC Discussion

TURN recommended, as a new Phase 2 Application requirement, that the application include the latest data associated with the list of projects from Office of Energy Infrastructure Safety (OEIS) Screen 2. TURN 4/25/25 Comments in Response to April 11, 2025 Post-Workshop Questions from CPUC Staff (TURN 4/25/25 Comments), p. 13.	SPD-37 adopted this new requirement, consistent with TURN's recommendation. SPD-37, p. 13.	
TURN recommended, as a new Phase 2 Application requirement, that the application include a detailed explanation of the need for any spans that extend beyond the HFTD boundary for any project included in the application. TURN 4/25/25 Comments, pp. 13-14.	SPD-37 adopted this new requirement, consistent with TURN's recommendation. SPD-37, p. 13.	
TURN recommended, as a new Phase 2 Application requirement, that the application include the same Key Decision-Making Metrics (KDMMs) data as was provided in the plan approved by OEIS TURN 4/25/25 Comments, pp. 16.	SPD-37 adopted this new requirement, consistent with TURN's recommendation. SPD-37, p. 13 and p. 15, citing TURN's comments.	
TURN recommended that the Commission require all projects to have a Benefit Cost Ratio (BCR) in excess of a threshold, the value of	SPD-37 adopted, as a new Phase 2 Application condition, that all included projects have a BCR in excess of the threshold value of 1.0, a partial adoption of	

which should be determined in the Phase 2 proceeding. TURN 4/25/25 Comments, pp. 9-10.	TURN's recommendation (See Part II.C, Note 1 below). SPD-37, pp. 13, 16.	
TURN recommended a cap on memorandum account cost recovery set at 10% of the total ten-year costs approved in the Phase 2 decision. TURN 4/25/25 Comments, pp. 3, 16.	Consistent with TURN's recommendation, SPD-37 adopted a cap on memorandum account cost recovery to be based on a percentage of the total ten-year costs approved for one-way balancing account recovery, which is the same approach TURN recommended for applying the cap. However, SPD-37 deferred a determination of the percentage of the cap to the Phase 2 decision. (See Part II.C, Note 1 below regarding partial adopting of an intervenor recommendation). SPD-37, p. 18, citing TURN's comments at fn. 43.	
TURN recommended, as a key objective of the audit, that the Commission determine that all Phase 2 conditions – those established in SPD-15 and in the Phase 2 Decision – have been satisfied. TURN 4/25/25 Comments, pp. 19-20.	Consistent with TURN's recommendation, SPD-37 determined that the primary objective for the audit of the one-way balancing account is to determine whether all Phase 2 conditions have been satisfied. SPD-37, p. 22.	
TURN recommended additional audit objectives, including determining that the projects for which costs are	Consistent with TURN' recommendation, SPD-37 adopted, as secondary objectives of the audit of the	

recorded are used and useful and that the recorded costs are incremental. TURN 4/25/25 Comments, pp. 19-20.	one-way balancing account, verifying that the projects are used and useful and determining whether the recorded costs are incremental. SPD-37, pp. 22-23 and p. 21 (agreeing with TURN regarding the need for audit objectives advocated by TURN that are included in SPD-37's secondary objectives).	
TURN recommended, in comments on Draft SPD-37, that the comment period for opening and reply comments on the audit report be changed from 20 days (opening) and 5 days (reply) to 42 days (opening) and 7 days (reply). TURN 9/4/25 Comments on Draft SPD-37, p. 7.	SPD-37 adopted TURN's recommendation. SPD-37, p. 31, stating that the Commission adopts TURN's recommended comment periods.	
TURN's comments on Draft SPD-37 criticized as unfair and unduly burdensome the provision of SPD-37 that would place the burden on intervenors to file a petition for modification (PFM) of the Phase 2 Decision to seek refunds of costs found to have violated the Phase 2 conditions. TURN instead recommended an Audit Refund Resolution process.	In response to TURN's objection, SPD-37 removed the language regarding intervenors filing a PFM, while noting that intervenors always have this right. SPD-37 stated that after the receipt of comments, the Commission would decide whether refunds are needed, without addressing TURN's recommended Audit Refund Resolution process. (See Part II.C, below regarding partial adopting of an intervenor recommendation).	

TURN 9/4/25 Comments on Draft SPD-37, pp. 6-7.	SPD-37, pp. 23, 31, noting that this change was made in response to TURN's comments.	
TURN recommended that costs that do not meet applicable conditions and requirements not be recoverable at any time. TURN 4/25/25 Comments, p. 23.	SPD-37 stated that, if the Commission directs a utility to issue refunds, the refund amounts many not be recovered through any other means, which is partially in accord with TURN's position. (See Part II.C, Note 1 below regarding partial adopting of an intervenor recommendation). SPD-37, p. 23.	
TURN recommended that the audit be performed by an entity that is independent of the utility. TURN 12/12/24 Comments in Response to 10/14/24 Staff Questions (12/12/24 TURN Comments), p. 8.	Similar to TURN's recommendation, SPD-37 adopted provisions indicating that the auditor must be independent of the utility, including that the utility shall not have input into the direction, focus, or output of the audit that goes beyond the opportunity afforded to other parties. SPD-37, p. 23.	
TURN recommended that BCRs be calculated using the year a project becomes used and useful as year zero.	Consistent with TURN's recommendation, SPD-37 directed that the year a project becomes used and useful serve as year zero in the BCR calculation.	

TURN 4/25/25 Comments, p. 29.	SPD-37, p. 27, citing TURN's comments in footnote 72.	
TURN's comments pointed out the complexity and potential controversy related to BCR calculations, which would be difficult to resolve in a timely fashion in the context of an audit. TURN supported addressing issues related to BCR calculation methodology in advance and offered recommendations on various methodology issues. TURN 12/12/24 Comments, p. 3, 5-6; TURN 4/25/25 Comments, pp. 21, 24-29.	Consistent with TURN's comments, SPD-37 determined that BCR calculation methodology should be addressed in the Phase 1 application and specified several issues that TURN addressed as issues that should be considered in the Phase 1 application. SPD-37, pp. 25-28.	
TURN recommended that the response period for discovery requests be changed from five business days to three business days. TURN 4/25/25 Comments, p. 12; TURN 9/4/25 Comments on Draft SPD-37, p. 9.	In response to TURN's comments, SPD-37 changed the response period to five days (not five *business* days), which moved closer to TURN's recommendation. SPD-37, p. 5 (which changed the period to five days from 5 *business* days in Draft SPD-37, p. 5) and p. 32, noting that conforming changes were made in response to TURN's comments.	
TURN recommended a new Phase 2 condition that would require the forecasted BCR of each project to exceed the forecasted BCR of all alternative mitigations.	Similar to TURN's recommendation, Draft SPD-37 would have adopted a new Phase 2 Condition that the forecasted BCR of the project exceed the forecasted BCR of alternative mitigations by a certain threshold value, which would be determined in the Phase 2 decision. (See Part	

TURN 4/25/25 Comments, p. 7; TURN 12/12/24 Comments, p. 2.	II.C, a below regarding substantial contribution based on intervenor success in a proposed decision). Draft SPD-37, p. 19.	
TURN recommended a new Phase 2 condition that the actual recorded BCR of a project may not be lower than the forecasted BCR in the Phase 2 application by more than a prescribed percentage, which would be determined in the Phase 2 decision. TURN 4/25/25 Comments, p. 9.	Consistent with TURN's recommendation, Draft SPD-37 would have adopted a new Phase 2 Condition that the actual recorded BCR of a project may not be lower than the forecasted BCR in the Phase 2 application by more than a prescribed percentage, which would be determined in the Phase 2 decision. (See Part II.C, Note 2 below regarding substantial contribution based on intervenor success in a proposed decision). Draft SPD-37, p. 19.	
TURN recommended a new Phase 2 condition that the actual recorded unit cost of a project may not be higher than the forecasted unit cost in the Phase 2 application by more than a prescribed percentage, which would be determined in the Phase 2 decision.	Consistent with TURN's recommendation, Draft SPD-37 would have adopted a new Phase 2 Condition that the actual recorded unit cost of a project may not be higher than the forecasted unit cost in the Phase 2 application by more than a prescribed percentage, which would be determined in the Phase 2 decision. (See Part II.C, Note 2 below regarding substantial contribution based on	

TURN 4/25/25 Comments, p. 9.	intervenor success in a proposed decision). Draft SPD-37, p. 19.	
TURN recommended that the BCR calculations in the Phase 2 application should include calculations based on a risk neutral scaling function. TURN 4/25/25 Comments, p. 28.	Similar to TURN's recommendation, Draft SPD-37 would have required BCRs to be calculated using risk-neutral values. (See Part II.C, Note 2 below regarding substantial contribution based on intervenor success in a proposed decision). Draft SPD-37, pp. 31, 33.	
TURN recommended, when calculating reliability risks in the BCR using the ICE calculator, that the calculations be disaggregated across four HFTD/non-HFTD categories and across three customer classes. TURN 4/25/25 Comments, p. 26.	Similar to TURN's recommendation, Draft SPD-37 would have required that calculations of the reliability component of BCRs be disaggregated across two HFTD/non-HFTD categories and across two customer classes. (See Part II.C, Note 2 below regarding substantial contribution based on intervenor success in a proposed decision). Draft SPD-37, p. 34.	
TURN recommended that the benefits in the BCR calculation should include reductions to both ignition and outage risk.	Consistent with TURN's recommendation, Draft SPD-37 would have specified that the benefits in the BCR calculation should include reductions to both ignition and outage risk. (See Part II.C, Note 2 below regarding substantial contribution based	

TURN 4/25/25 Comments, p. 29.	on intervenor success in a proposed decision). Draft SPD-37, p. 31.	

B. Duplication of Effort (§ 1801.3(f) and § 1802.5):

	Intervenor's Assertion	CPUC Discussion
a. Was the Public Advocate's Office of the Public Utilities Commission (Cal Advocates) a party to the proceeding?[2]	Yes.	
b. Were there other parties to the proceeding with positions similar to yours?	Yes.	
c. If so, provide name of other parties: Mussey Grade Road Alliance (MGRA) and Cal Advocates.		
d. Intervenor's claim of non-duplication: TURN, Cal Advocates and MGRA coordinated with respect to the preparation of comments in this post-SPD 15 phase of the CPUC's SB 884 implementation. While the parties were generally in alignment on positions, the coordination consisted of choosing areas of emphasis and development of positions in comments. For example, MGRA took a lead role in supporting the need for use of a risk neutral scaling function in calculating BCR, whereas Cal Advocates took a lead role on issues relating to Phase 2 application data requirements. As a result, TURN was able to focus more of its efforts on developing and presenting its detailed proposals on other issues, such as Phase 2 conditions, audit processes and requirements, memorandum account issues, and other aspects of the BCR calculation. TURN believes these coordination efforts were successful in making TURN's participation more efficient and impactful, as reflected in the numerous substantial contributions identified above. For these reasons, TURN submits that the Commission should find no undue duplication between TURN's participation and that of other parties.		

[2] The Office of Ratepayer Advocates was renamed the Public Advocate's Office of the Public Utilities Commission pursuant to Senate Bill No. 854, which the Governor approved on June 27, 2018.

C. Additional Comments on Part II: ***<u>(use line reference # or letter as appropriate)</u>***

#	Intervenor's Comment	CPUC Discussion
1	<u>Partial success</u>. Although TURN was not successful on all issues and recommendations it presented in its comments to the CPUC, TURN's partial success satisfies the definition of "substantial contribution" under PU Code Sec. 1802(j) ("in the judgment of the commission, the customer's presentation has substantially assisted the commission in the making of its order or decision because the order or decision has adopted in whole or in part one or more factual contentions, legal contentions, or specific policy or procedural recommendations presented by the customer."). The for an award of intervenor compensation is whether TURN made a substantial contribution to the Commission's decision, not whether TURN prevailed on a particular issue or recommendation. For example, the Commission has recognized that it "may benefit from an intervenor's participation even where the Commission did not adopt any of the intervenor's positions or recommendations." D.08-04-004 (in the review of SCE's contract with Long Beach Generation, A.06-11- 007), pp. 5-6. Similarly, in D.09-04-027, awarding intervenor compensation for TURN's efforts in the SCE AMI proceeding (A.07-07- 026), the Commission found TURN to have made a substantial contribution even on issues where TURN did not prevail, as TURN's efforts	

#	Intervenor's Comment	CPUC Discussion
	"contributed to the inclusion of these issues in the Commission's deliberation" and caused the Commission to "add more discussion on the issue, in part to address TURN's comments." D.09-04-027, p. 4. Here, as discussed in Section II.A above, TURN achieved at least partial success on recommendations related to a BCR threshold requirement, a cap on memorandum account cost recovery, use of a PFM for audit refunds, and non-recoverability of refunded amounts.	
2	<u>Contributions to Draft SPD-37</u>. The Commission has repeatedly held that an intervenor's contribution to a final decision may be supported by contributions to a proposed decision, even where the Commission's final decision does not adopt the proposed decision's position on a particular issue. See, for example, D.92-08-030, mimeo. at 4; D.96-08-023, mimeo. at 4; D.96-09-024, mimeo. at 19; D.99-11-006, pp. 9-10 (citing D.99-04-004 and D.96-08-023); D.01-06-063, pp. 6-7; D.06-08-007 ("Commission precedent clearly supports awarding TURN compensation related to positions adopted by the PD even if the Commission rejects those positions"). Here, as discussed in Section II.A above, Draft SPD-37 adopted, in whole or in part, TURN's positions regarding: a condition	

#	Intervenor’s Comment	CPUC Discussion
	requiring BCR comparison with alternative mitigations; a condition requiring comparison with forecasted BCRs and unit costs; use of a risk neutral scaling function when calculating BCR; and other aspects of calculating BCR.	

PART III: REASONABLENESS OF REQUESTED COMPENSATION

(to be completed by Intervenor except where indicated)

A. General Claim of Reasonableness (§ 1801 and § 1806):

	CPUC Discussion
a. Intervenor's claim of cost reasonableness: This request seeks an award of $161,232.50 as the reasonable cost of our participation in this important proceeding. These costs are reasonable in light of the quality of TURN's work and the contributions of TURN to SPD-37. This statutory implementation proceeding does not determine cost recovery, so it is difficult for TURN to identify with any precision the monetary benefit of TURN's participation in this proceeding. The 10-year undergrounding programs that may be submitted pursuant to SPD-37 are likely to have proposed costs in the tens of *billions* of dollars. Promoting a robust process for review of the utility plans and their associated costs is key to ensuring that the ratepayer dollars provide a benefit sufficient to justify their impact on customer bills. While the dollar value of TURN's substantial contributions is uncertain, TURN submits that our participation should result in significant benefits to ratepayers far exceeding the costs of TURN's participation. In sum, the Commission should conclude that TURN's request is reasonable given the cost of the undergrounding programs at issue and the adopted outcomes.	
b. Reasonableness of hours claimed: Description of TURN's Work Claimed in this Request TURN requests compensation for 199 hours of substantive work related to the CPUC's post SPD-15 implementation of SB 884 and the adoption of SPD-37. TURN's efforts consisted of work to inform SPD's preparation of Draft SPD-37, including: meetings with SPD to discuss technical issues, such as depreciation and results of operation models, and the details of TURN's recommendations; preparation of two rounds of detailed comments (11/12/24 and 4/25/25) in response to complex questions from SPD; and participation in a 4/8/25 workshop. TURN's work also included analysis of Draft SPD-37, including a meeting with SPD-37 to understand the details of the SPD proposal, and the preparation of two rounds of comments (9/4/25 and 9/9/25) in response to Draft SPD-37. TURN also prepared for and participated in meetings with Commission offices to discuss TURN's recommended changes to	

	CPUC Discussion
Draft SPD-37 and to revisions to that draft that were circulated prior to the final voting meeting. TURN is not claiming here any hours specifically devoted to OEIS's parallel proceeding to implement SB 884. TURN's team was led by its attorney, Director of Regulatory Strategy (and beginning in July 2025 Outside Counsel) Thomas Long, who has over 35 years of experience in CPUC regulatory matters and more than ten years of experience related to quantitative risk analysis and utility wildfire mitigation efforts, both in CPUC and OEIS proceedings. Because of Mr. Long's in-depth experience with respect to the relevant issues, he was able to effectively serve both as TURN's subject matter expert and attorney. Mr. Long prepared or supervised the preparation of all of TURN's written submissions and led TURN's participation in the workshop and in meetings with CPUC staff. After his retirement from full-time work as TURN's Director of Regulatory Strategy in June 2025, Mr. Long continued his lead role in this case in the capacity of TURN Outside Counsel. Anticipating Mr. Long's retirement, in April 2025, TURN Assistant Managing Attorney Elise Torres and TURN Staff Attorney A Mireille Fall joined TURN's SB 884 Implementation team. With 15 years of advocacy experience in CPUC energy ratemaking matters, Ms. Torres brought significant ratemaking expertise to the development of TURN's strategy and recommendations in the April 25, 2025 comments and the two rounds of comments on Draft SPD-37. In addition, Ms. Torres led TURN's presentations in two of the three Commissioner office meetings regarding Draft SPD-37. Ms. Fall, who joined TURN's staff in January 2025, brought 20 years of legal and litigation experience to the team, including work on utility regulatory issues for Florida's counterpart to the CPUC's Public Advocates Office. She provided strategic input and drafting assistance to TURN's 4/25/25 comments and its comments on Draft SPD-37, assisted in preparing TURN's written materials for its meetings with Commissioner offices, and led TURN's presentation in one of those meetings when Ms. Torres was unavailable. TURN General Counsel Robert Finkelstein consulted with Mr. Long on technical issues related to depreciation and shared his expertise in a meeting with SPD staff. TURN Managing Attorney Hayley Goodson provided useful information to Mr. Long regarding results of operation and depreciation issues (when Mr. Finkelstein was unavailable) to inform TURN's 11/12/24 comments to SPD. Mr. Finkelstein and Ms. Goodson each have decades of experience on complex ratemaking issues.	

	CPUC Discussion
As noted, TURN seeks compensation for a combined total of 199 hours for TURN's team of advocates to analyze, develop and present TURN's positions on the many complex issues addressed in this post-SPD phase of the proceeding, over a 19-month period. In light of the complexity and novelty of the issues to implement this new statutory program and the numerous substantial contributions enumerated in section II.A above, TURN submits that all of the claimed hours are reasonable and warrant compensation. <u>Meetings or Discussions Involving More Than One TURN Advocate</u> Some of TURN's time entries reflect meetings or phone calls involving more than one TURN advocate. TURN submits that these hours do not reflect internal duplication. Rather, such participation was essential to TURN's development and implementation of its strategy for this proceeding. Attendance by multiple staff at internal meetings, such as those to prepare the 4/25/25 comments and the comments on Draft SPD-37, was necessary to develop a coordinated strategy and to coordinate drafting assignments. Likewise, participation by multiple team members at certain meetings with SPD and Commissioner offices was necessary in order to address questions that arose at those meetings, because of the different areas of issue expertise developed by TURN's advocates in the course of preparing comments. Intervenor compensation can and should be awarded for the time of all participants where, as here, each participant was needed to advance advocacy efforts. <u>Time Spent on Meetings With Commissioner Offices</u> TURN's request includes time devoted to meetings with three CPUC Commissioner offices regarding Draft SPD-37. These hours include time spent preparing for the meetings including drafting written materials, participating in the meetings, and in the case of one office, providing written follow-up responses to questions raised at the meeting. These meetings were an important opportunity for TURN to explain its positions and to answer questions from the Commissioner offices. The Commission should find that hours spent on these communications represent the "reasonable costs of preparation for and participation in a hearing or proceeding." (Cal. Pub. Util. Code §1803) and that hours spent by advocates reflect costs "incurred by the customer in preparing or presenting" (§1802(j)) TURN's arguments to the Commission. The Commission has routinely approved compensation for ex parte activities by intervenors, including meetings with Commissioner offices,	

	CPUC Discussion
in decisions dating back for more than 25 years. A sampling of prior decisions awarding compensation for time devoted to ex parte communications include (but are not limited to) D.25-10-059, D.24-09-049, D.24-01-024, D.23-10-013, D.23-06-045, D.22-08-050, D.22-08-010, D.22-06-018, D.21-12-051, D.21-08-033, D.21-06-016, D.21-07-017, D.21-04-013, D.19-10-020, D.19-10-018, D.19-08-032, D.19-07-020, D.19-03-005, D.18-11-043, D.18-04-021, D.15-08-023, and D.12-08-041. <u>Preparation of Compensation Request</u> TURN is requesting compensation for 18.5 hours that it devoted to preparation of this request for compensation, including the associated Application and Notice of Intent to Claim Compensation. This is a reasonable number of hours for preparing a compensation request of this magnitude with numerous and detailed substantial contributions requiring specification and documentation. Mr. Long prepared this request because of his involvement in most aspects of the work for which compensation is requested. <u>Summary</u> In sum, the Commission should find that the number of hours claimed is fully reasonable in light of the substantial contributions TURN made in this proceeding.	
c. Allocation of hours by issue: TURN has allocated all of our attorney time by issue area or activity, as is evident on our attached timesheets. The following codes relate to the issue and activity areas addressed by TURN in this proceeding.	

Code	Description	Allocation (other than "Comp" time)	Hours
Staff Proposal	Work related to informing SPD's post-SPD-15 development of updated proposed guidelines, including development of TURN's overall positions and strategy, and work on technical issues such as depreciation, RO model, and addressing changes to utility plans.	28.89%	57.50

				CPUC Discussion
Memo	Work related to issues concerning the memorandum account.	5.15%	10.25	
Audit	Work related to issues associated with the audit of costs recorded to the one-way balancing account, including recovery of costs that do not satisfy conditions.	19.85%	39.50	
Conditions	Work related to issues associated with new Phase 2 conditions.	8.79%	17.50	
Application	Issues related to new Phase 2 Application requirements	2.14%	4.25	
BCR	Work related to the issue of calculation of BCR values.	10.05%	20.00	
Proc	Work related to the procedure for this proceeding and to procedures for review of utility undergrounding plans.	0.88%	1.75	
Coord	Work related to the development and presentation of coordinated positions with Cal Advocates and MGRA.	1.01%	2.00	
Draft SPD-37	Work related to strategy and overall analysis regarding Draft SPD-37, including in connection with responding to other party comments	23.24%	46.25	
Comp	Time devoted to compensation-related pleadings.	n/a		

TURN submits that under the circumstances this information should suffice to address the allocation requirement under the Commission's rules. Should the Commission wish to see additional or different information on this point, TURN requests that the Commission so inform TURN and provide a reasonable opportunity for TURN to supplement this showing accordingly.

B. Specific Claim:*

CLAIMED						CPUC AWARD		
ATTORNEY, EXPERT, AND ADVOCATE FEES								
Item	**Year**	**Hours**	**Rate $**	**Basis for Rate***	**Total $**	**Hours**	**Rate $**	**Total $**
Thomas Long, TURN Dir. of Legal Strategy	2024	25.50	$860	D.24-09-016	21,930.00			
T. Long, Dir. of Legal Strategy	2025	49.50	$885	Res. ALJ-393, 2024 rate plus 3.46% COLA. See Comment #1	43,807.50			
T. Long, Outside Counsel	2025	39.25	$885	Res. ALJ-393, 2024 rate plus 3.46% COLA See Comment #1	34,736.25			
Elise Torres, TURN Asst. Managing Attorney	2025	55.75	$600	Res. ALJ-393,2024 rate plus 3.46% COLA and additional increase for move to Attorney -Level IV experience tier. See Comment #2.	33,450.00			
A Mireille Fall	2025	23.50	$600	Res. ALJ-393 – New Rate; See Comment #3	14,100.00			
Robert Finkelstein, TURN General Counsel	2024	4.0	$875	D.24-07-033	3,500.00			
Robert Finkelstein, TURN General Counsel	2025	1.0	$905	Res ALJ-393, 2024 rate plus 3.5% COLA; See Comment #4	905.00			

CLAIMED						CPUC AWARD		
Hayley Goodson, TURN Managing Attorney	2024	0.50	$680	D.24-09-017	340.00			
					Subtotal: $152,768.75			***Subtotal: $***
OTHER FEES **Describe here what OTHER HOURLY FEES you are Claiming (paralegal, travel **, etc.):**								
Item	**Year**	**Hours**	**Rate $**	**Basis for Rate***	**Total $**	**Hours**	**Rate $**	**Total $**
					Subtotal:			***Subtotal: $***
INTERVENOR COMPENSATION CLAIM PREPARATION **								
Item	**Year**	**Hours**	**Rate $**	**Basis for Rate***	**Total $**	**Hours**	**Rate $**	**Total $**
T. Long	2026	18.50	$457.50	Placeholder rate, Res. ALJ-393, 2025 rate plus estimated COLA (See Comment #1)	8,463.75			
					Subtotal: $8,463.75			***Subtotal: $***

COSTS				
#	**Item**	**Detail**	**Amount**	**Amount**
1.				
2.				
			Subtotal: $	***Subtotal: $***
			TOTAL REQUEST: $161,232.50	***TOTAL AWARD: $***

*We remind all intervenors that Commission staff may audit the records and books of the intervenors to the extent necessary to verify the basis for the award (§1804(d)). Intervenors must make and retain adequate accounting and other documentation to support all claims for intervenor compensation. Intervenor's records should identify specific issues for which it seeks compensation, the actual time spent by each employee or consultant, the applicable hourly rates, fees paid to consultants and any other costs for which compensation was claimed. The records pertaining to an award of compensation shall be retained for at least three years from the date of the final decision making the award.

**Travel and Reasonable Claim preparation time are typically compensated at ½ of preparer's normal hourly rate

Claimed			CPUC Award
ATTORNEY INFORMATION			
Attorney	**Date Admitted to CA BAR[3]**	**Member Number**	**Actions Affecting Eligibility (Yes/No?) If "Yes", attach explanation**
Thomas Long	December 1986	124776	No
Elise Torres	December 2011	280443	No
A Mireille Fall	FL Bar Admission September 2004	FL Bar 758841	No
Robert Finkelstein	June 1990	146391	No
Hayley Goodson	December 2003	228535	No

C. Attachments Documenting Specific Claim and Comments on Part III:
(Intervenor completes; attachments not attached to final Decision)

Attachment or Comment #	Description/Comment
Attachment 1	Certificate of Service
Attachment 2	Timesheets for TURN Attorneys/Experts
Attachment 3	TURN hours allocated by issue
Attachment 4	Notice of Intent to Claim Intervenor Compensation
Attachment 5	SPD Questions for Stakeholders Regarding the CPUC SB 884 Guidelines, October 14, 2024
Attachment 6	November 12, 2024 Informal Comments of TURN in Response to October 14, 2024 Questions from CPUC Staff Regarding SB 884 Implementation
Attachment 7	SPD Slides for the 4/8/25 SB 884 Workshop
Attachment 8	SPD Post-Workshop Questions for Stakeholders Regarding the SB 884 Guidelines, 4/11/2025
Attachment 9	Comments of TURN in Response to April 11, 2025 Post-Workshop Questions From CPUC Staff Regarding SB 884 Implementation
Attachment 10	Draft Resolution SPD-37 (issued 8/15/25)
Attachment 11	TURN's Opening Comments on Draft SPD-37 (9/4/25)
Attachment 12	TURN's Reply Comments on Draft SPD-37 (9/9/25)

[3] This information may be obtained through the State Bar of California's website at http://members.calbar.ca.gov/fal/MemberSearch/QuickSearch.

Attachment or Comment #	Description/Comment
Attachment 13	Documentation of hourly rate billed by Outside Counsel Thomas Long in 2025 and 2026
Comment #1	**2025 Hourly Rate for Thomas Long** For Mr. Long's work in this case as a TURN employee (through early June 2025), TURN requests an hourly rate of $885. TURN requests that the Commission adjust his authorized 2024 rate of $860 (D.24-09-016) by applying the annual escalation adjustment authorized by Resolution ALJ-393 for 2025 of 3.46%. TURN uses a 2025 rate of $885 to prepare this claim. In June 2025, Mr. Long retired from his role as TURN's Director of Regulatory Strategy. After Draft SPD-37 was issued, he continued his work in this case in the role of Outside Counsel. TURN requests the same $885 rate for his work in that role, which is the rate that Mr. Long charged to TURN (as shown by an attached invoice). The legal work and the development and execution of TURN's strategy in this case did not change when Mr. Long became Outside Counsel. Mr. Long continued to steer TURN's efforts in this case based on his prior experience regarding the implementation of SB 884, and his more than a decade of experience leading TURN's work regarding wildfire mitigation and grid hardening programs and the development of the Risk-Informed Decision-Making Framework (RDF). That knowledge and experience should be reflected in Mr. Long's hourly rate. In addition, Mr. Long continued to effectively perform the role of a Legal Director in this case, taking on a complex matter implementing a novel statute, and charting case strategy in responding to Draft SPD-37. For these reasons, and in light of Mr. Long's 39 years of experience as an attorney specializing in public utilities regulatory matters before the CPUC, TURN believes that the same hourly rate should apply for Mr. Long's work on this case after he transitioned to an Outside Counsel role. TURN requested this same $885 hourly rate for Mr. Long's in house and outside counsel work in 2025 in a compensation request in R.20-07-013 filed on October 27, 2025. **2026 Hourly Rate for Thomas Long** For Mr. Long's work in this case in 2026, TURN requests an hourly rate of $915. To calculate this 2026 rate, TURN applied a *placeholder* of 3.3% for the forthcoming 2026 escalation rate to his requested 2025 rate of $885 (discussed above). $885 x (1 + 0.033) = $914.21.

Attachment or Comment #	Description/Comment
	TURN used an estimated 2025 escalation rate because the 2025 COLA is not yet available, as the Bureau of Labor Statistics' last update is the percent change for the 12-months ended September 2025 (3.3%). See https://www.bls.gov/news.release/eci.t05.htm (Bureau of Labor Statistics Employment Cost Index, Table 5, for the Occupational Group "Management, Professional, and Related excluding Incentive Paid Occupations"). TURN asks the Commission to apply the adopted escalation rate to set Mr. Long's 2026 hourly rate.
Comment #2	**2025 Hourly Rate for Elise Torres** For Ms. Torres's work in 2025, TURN requests that the Commission adjust her 2024 rate of $555, authorized in D.25-03-022, in two regards: (1) by applying the annual escalation adjustment authorized by Resolution ALJ-393, 3.46%; and (2) further adjusting Ms. Torres's hourly rate by 5% to recognize her move from Attorney - Level III (5-10 years) to Attorney - Level IV (10-15 years). In D.08-04-010, the Commission recognized moving to a higher experience tier as one of the circumstances that qualifies an intervenor representative for a rate increase, apart from annual COLA adjustments and "step" increases. (D.08-04-010, p. 8). The requested rate adjustment for Ms. Torres's change in experience tier is consistent with the Commission's adoption of a similar adjustment in setting TURN Attorney David Cheng's 2024 hourly rate in D.24-07-030. (D.24-07-030, p. 11). Ms. Torres was admitted to the CA bar in December 2011. In D.21-12-049, which authorized the first rate for Ms. Torres pursuant to Resolution ALJ-393, the Commission recognized that Ms. Torres had worked in utility regulation for 9 years and practiced as an attorney for 7 ½ years in setting her 2021 rate in the Attorney – Level III labor role. (D.21-12-049, p. 25). By 2025, Ms. Torres has four more years of experience, putting her squarely in the Attorney – Level IV labor role, with 11 ½ years practicing law and 13 ½ years of directly relevant experience working in utility regulation. TURN has not previously requested a rate that recognizes this change in Ms. Torres' experience. Consistent with prior decisions, the Commission should continue to recognize that "professional experience gained by a practitioner … while employed in a role other than an attorney can nonetheless confer directly relevant skills and expertise which warrant consideration in determining

Attachment or Comment #	Description/Comment
	hourly rates for purposes of the Intervenor Compensation Program." (D.24-07-030, p. 11, citing D.19-04-035, p. 13). TURN accordingly requests a 2025 rate for Ms. Torres of $600. Calculation: $555 x [1.0346 (COLA) + 0.05 (move to higher tier)] = $601.95, rounded to $600. TURN requested this same hourly rate in a compensation request filed in A.25-04-015 on January 5, 2026.
Comment #3	**2025 Hourly Rate for A Mireille Fall** TURN requested a 2025 hourly rate for Ms. Fall of $600 in A.21-09-008 in a compensation request filed November 18, 2025. TURN refers the Commission to that submission for the basis for this hourly rate under ALJ-393.
Comment #4	**2025 Hourly Rate for Robert Finkelstein** TURN requests an hourly rate of $905 for work conducted by TURN General Counsel Robert Finkelstein in 2025. The requested rate is equal to the rate authorized by the Commission in D.24-07-033 for Mr. Finkelstein's work in 2024, $875, adjusted by the 2025 escalation rate of 3.46%. Calculation: $875 x [1.0346 (COLA)] = $905.28, rounded to $905. TURN requested this same hourly rate in a compensation request filed in A.22-12-009 on 11/21/2025.

D. CPUC Comments, Disallowances, and Adjustments *(CPUC completes)*

Item	Reason

PART IV: OPPOSITIONS AND COMMENTS
Within 30 days after service of this Claim, Commission Staff or any other party may file a response to the Claim (*see* § 1804(c))

A. Opposition: Did any party oppose the Claim?	

If so:

Party	Reason for Opposition	CPUC Discussion

B. Comment Period: Was the 30-day comment period waived (*see* Rule 14.6(c)(6))?	

If not:

Party	Comment	CPUC Discussion

(Green items to be completed by Intervenor)

FINDINGS OF FACT

1. **The Utility Reform Network** [has/has not] made a substantial contribution to **SPD-37.**

2. The requested hourly rates for **The Utility Reform Network**'s representatives [, as adjusted herein,] are comparable to market rates paid to experts and advocates having comparable training and experience and offering similar services.

3. The claimed costs and expenses [, as adjusted herein,] are reasonable and commensurate with the work performed.

4. The total of reasonable compensation is $___________.

CONCLUSION OF LAW

1. The Claim, with any adjustment set forth above, [satisfies/fails to satisfy] all requirements of Pub. Util. Code §§ 1801-1812.

ORDER

1. **The Utility Reform Network** is awarded $____________.

2. Within 30 days of the effective date of this decision, _____ shall pay **The Utility Reform Network** the total award. [for multiple utilities: "Within 30 days of the effective date of this decision, ^, ^, and ^ shall pay **The Utility Reform Network** their respective shares of the award, based on their California-jurisdictional [industry type, for example, electric] revenues for the ^ calendar year, to reflect the year in which the proceeding was primarily litigated. If such data are unavailable, the most recent [industry type, for example, electric] revenue data shall be used."] Payment of the award shall include compound interest at the rate earned on prime, three-month non-financial commercial paper as reported in Federal Reserve Statistical Release H.15, beginning [date], the 75th day after the filing of **The Utility Reform Network**'s request, and continuing until full payment is made.

3. The comment period for today's decision [is/is not] waived.

This decision is effective today.

Dated _____________, at San Francisco, California.

APPENDIX

Compensation Decision Summary Information

Compensation Decision:		**Modifies Decision?**	
Contribution Decision(s):	SPD-37		
Proceeding(s):	A.26-01-XXX		
Author:			
Payer(s):			

Intervenor Information

Intervenor	Date Claim Filed	Amount Requested	Amount Awarded	Multiplier?	Reason Change/Disallowance
The Utility Reform Network	January 29, 2026	$161,232.50		N/A	

Hourly Fee Information

First Name	Last Name	Attorney, Expert, or Advocate	Hourly Fee Requested	Year Hourly Fee Requested	Hourly Fee Adopted
Thomas	Long	Attorney	$860	2024	
Thomas	Long	Attorney	$885	2025	
Thomas	Long	Attorney	$915	2026	
Elise	Torres	Attorney	$600	2025	
Hayley	Goodson	Attorney	$680	2024	
A Mireille	Fall	Attorney	$600	2025	
Robert	Finkelstein	Attorney	$875	2024	
Robert	Finkelstein	Attorney	$905	2025	

(END OF APPENDIX)

Attachment 1
Certificate of Service
(Filed electronically as a separate document pursuant to Rule 1.13(b)(iii))
(Served electronically as a separate document pursuant to Rule 1.10(c))

Attachment 2

Timesheets for TURN Attorneys/Experts

A.26-01___(SPD-37)
TURN Compensation Claim
Attorney Time Sheets

Atty	Case #	Code	Description	Date	Time
Thomas Long	SB 884	Coord	Meet w/Cal Adv re strategy post decision on SPD-15	3/27/24	0.50
Thomas Long	SB 884	Staff Proposal	Prep emails to BF re prep for mtg w/SPD re SB 884 implementation	3/29/24	0.50
Thomas Long	SB 884	Staff Proposal	Prep for mtg w/SPD re implementation issues re depreciation	4/3/24	0.25
Thomas Long	SB 884	Staff Proposal	Call w/BF re Prep for mtg w/SPD re implementation issues re depreciation	4/3/24	1.00
Thomas Long	SB 884	Staff Proposal	Meet w/SPD re depreciation issues	4/4/24	1.50
Thomas Long	SB 884	Staff Proposal	Overview of SPD questions and email to EB re same	10/26/24	0.75
Thomas Long	SB 884	Proc	Call w/SPD (E. Schmitt) re schedule re responding to q's	10/28/24	0.25
Thomas Long	SB 884	Proc	Prep extension request to SPD	10/28/24	0.50
Thomas Long	SB 884	Staff Proposal	Initial rev/analysis of SPD questions	11/6/24	3.00
Thomas Long	SB 884	Staff Proposal	Continue analysis of SPD questions	11/7/24	0.25
Thomas Long	SB 884	BCR	Technical research re CBR issue	11/7/24	1.00
Thomas Long	SB 884	Staff Proposal	Discuss SPD questions re abandoned projects and RO/depreciation with HG	11/7/24	0.50
Thomas Long	SB 884	BCR	Analysis re CBR issue	11/8/24	0.50
Thomas Long	SB 884	Conditions	Draft responses re Sec. H (alternatives)	11/8/24	0.50
Thomas Long	SB 884	Audit	Analysis re Sec. D (audit)	11/8/24	1.25
Thomas Long	SB 884	Staff Proposal	Draft response re changes to plan	11/8/24	1.25
Thomas Long	SB 884	Staff Proposal	Draft response re Secs. I and J	11/10/24	1.25
Thomas Long	SB 884	BCR	Draft response re Sec. C - CBR	11/11/24	1.75
Thomas Long	SB 884	Audit	Draft response re Sec. D (audit)	11/11/24	2.75
Thomas Long	SB 884	Staff Proposal	Draft response re Sec. F - changes to plan	11/11/24	1.25
Thomas Long	SB 884	Staff Proposal	Draft response re Secs I and J - delayed and abandoned projects	11/11/24	0.75
Thomas Long	SB 884	Audit	Draft response re Sec. J - abandoned projects	11/12/24	1.00
Thomas Long	SB 884	BCR	Draft response re Sec. E - PV	11/12/24	0.75
Thomas Long	SB 884	Staff Proposal	Draft intro to response	11/12/24	0.50
Thomas Long	SB 884	Audit	Draft response Sec. B - 3rd party	11/12/24	0.25
Thomas Long	SB 884	Staff Proposal	General editing of response	11/12/24	1.50
Thomas Long	SB 884	Staff Proposal	Overview of party responses	11/13/24	0.25
Thomas Long	SB 884	Staff Proposal	Initial review of SPD question re updating SPD-15	3/27/25	0.25
Thomas Long	SB 884	Staff Proposal	Analysis re Staff questions for workshop	4/1/25	1.00
Thomas Long	SB 884	Staff Proposal	Discuss strategy re depreciation question w/BF	4/3/25	0.50
Thomas Long	SB 884	Staff Proposal	Analysis of staff questions for workshop	4/7/25	1.75
Thomas Long	SB 884	Staff Proposal	Rev OEIS guidelines referenced in staff questions	4/7/25	1.00
Thomas Long	SB 884	Staff Proposal	Analysis re Staff questions to prep for workshop	4/8/25	1.50
Thomas Long	SB 884	Staff Proposal	Participate in workshop	4/8/25	3.00
Thomas Long	SB 884	Staff Proposal	Follow up analysis of key issues in workshop	4/8/25	0.25
Thomas Long	SB 884	Staff Proposal	Prep for call w/ET	4/9/25	0.25
Thomas Long	SB 884	Staff Proposal	Call w/ET re workshop and key issues for comments	4/9/25	0.75
Thomas Long	SB 884	Staff Proposal	Analysis for cmts	4/11/25	3.00
Thomas Long	SB 884	Staff Proposal	Analysis of staff questions	4/14/25	2.00
Thomas Long	SB 884	Coord	Coordination meeting with PAO re cmts	4/14/25	0.75
Thomas Long	SB 884	Proc	Prep extenstion request to CPUC staff	4/14/25	0.25
Thomas Long	SB 884	Staff Proposal	Meet with ET and MFF re strategy re cmts	4/15/25	1.00
Thomas Long	SB 884	Staff Proposal	Analysis of staff questions and OEIS rules cited therein	4/16/25	0.75
Thomas Long	SB 884	Staff Proposal	Outline cmts	4/16/25	1.25
Thomas Long	SB 884	Staff Proposal	Outline cmts	4/17/25	0.50
Thomas Long	SB 884	Audit	Draft cmts (Phase 2/audit process)	4/17/25	2.25
Thomas Long	SB 884	Conditions	Research PGE WMP re comparable alternatives for grid hardening ignition risk	4/17/25	0.50
Thomas Long	SB 884	Conditions	Call w/EB re same	4/17/25	0.25
Thomas Long	SB 884	Conditions	Draft cmts (Sec. 4.2)	4/18/25	1.75
Thomas Long	SB 884	Audit	Draft cmts (Sec. 5)	4/18/25	3.00
Thomas Long	SB 884	Audit	Draft cmts (Sec. 5)	4/20/25	0.25
Thomas Long	SB 884	Staff Proposal	Outline cmts (Sec 6)	4/20/25	0.75
Thomas Long	SB 884	Audit	Draft cmts (Sec. C questions)	4/21/25	3.25
Thomas Long	SB 884	Staff Proposal	Meet with ET and MFF re strategy re cmts	4/21/25	1.00
Thomas Long	SB 884	Memo	Draft cmts (Sec. 3 - cost containment)	4/22/25	3.00
Thomas Long	SB 884	Application	Draft cmts (Q A1)	4/22/25	0.25
Thomas Long	SB 884	Conditions	Draft cmts (Q B1, B2, B4)	4/22/25	1.25
Thomas Long	SB 884	Staff Proposal	Prep email to ET and MFF re seeking feedback re draft cmts on key issues	4/22/25	0.25
Thomas Long	SB 884	BCR	Prep email to Jalal re Q E1	4/23/25	0.25
Thomas Long	SB 884	Memo	Revise draft cmts (Sec. 3)	4/23/25	0.50
Thomas Long	SB 884	Application	Draft cmts (Q A3, A4)	4/23/25	0.75
Thomas Long	SB 884	Conditions	Draft cmts (Sec. B questions)	4/23/25	0.50
Thomas Long	SB 884	BCR	Analysis re Q's E1 and E5, including email to Jalal re same	4/23/25	1.00
Thomas Long	SB 884	Coord	Rev MGRA, PAO drafts for coordination	4/24/25	0.50
Thomas Long	SB 884	Application	Revise draft cmts (Q A4)	4/24/25	0.50
Thomas Long	SB 884	Audit	Draft cmts (Q C2, C3)	4/24/25	0.50
Thomas Long	SB 884	Staff Proposal	Draft cmts (Q D1)	4/24/25	0.50
Thomas Long	SB 884	Memo	Revise draft cmts (Sec. 3)	4/24/25	0.75
Thomas Long	SB 884	BCR	Rev/revise Jalal draft response to Q E1	4/24/25	0.75

Atty	Case #	Code	Description	Date	Time
Thomas Long	SB 884	BCR	Draft cmts (Q E5)	4/24/25	0.25
Thomas Long	SB 884	BCR	Draft cmts (Sec. E questions)	4/25/25	2.50
Thomas Long	SB 884	Application	Draft cmts (Q A6, B5)	4/25/25	0.50
Thomas Long	SB 884	Application	Draft cmts (Q A2)	4/25/25	0.25
Thomas Long	SB 884	Staff Proposal	General editing/revision of draft cmts	4/25/25	1.00
Thomas Long	SB 884	Staff Proposal	Overview of PGE cmts	4/25/25	0.50
Thomas Long	SB 884	Proc	Rev notice re Data WG and email to HG, ET re same	5/20/25	0.25
Thomas Long	SB 884	Coord	Coordination Emails w/PAO re Data WG process	5/22/25	0.25
Thomas Long, Outside Counsel	SB 884	Draft SPD-37	Initial analysis of Draft SPD-37 including memo reflecting analysis	8/20/25	3.00
Thomas Long, Outside Counsel	SB 884	Draft SPD-37	Prep email to SPD staff identifying questions and requesting meeting	8/20/25	0.25
Thomas Long, Outside Counsel	SB 884	Draft SPD-37	Meeting with ET and MFF re analysis of SPD-37 and coordinating re comments	8/21/25	1.00
Thomas Long, Outside Counsel	SB 884	Draft SPD-37	Prep for meeting with SPD	8/21/25	0.25
Thomas Long, Outside Counsel	SB 884	Draft SPD-37	Meeting with SPD re questions re SPD-37 (cost recovery, memo account, audit, refunds)	8/21/25	0.75
Thomas Long, Outside Counsel	SB 884	Draft SPD-37	Follow up call with ET re SPD meeting	8/21/25	0.25
Thomas Long, Outside Counsel	SB 884	Audit	Research prior utility comments re cost recovery procedure and audit process	8/22/25	0.75
Thomas Long, Outside Counsel	SB 884	Audit	Research CPUC decisions, tariffs re balancing account rate recovery	8/22/25	0.50
Thomas Long, Outside Counsel	SB 884	Audit	Analysis re cost recovery provisions of SPD-37	8/22/25	1.00
Thomas Long, Outside Counsel	SB 884	Audit	Prep memo to ET/MFF re cost recovery issues/recommendations for comments	8/22/25	1.25
Thomas Long, Outside Counsel	SB 884	Audit	Rev/edit ET outline re audit/refund process, including alternative recommendations	8/28/25	0.75
Thomas Long, Outside Counsel	SB 884	Conditions	Rev/edit ET outline re Phase 2 conditions	8/28/25	0.5
Thomas Long, Outside Counsel	SB 884	Audit	Prep redline revisions to App. A re enforcing conditions/audits/refund issues	8/29/25	1.75
Thomas Long, Outside Counsel	SB 884	Audit	Prep table summarizing revisions re enforcing conditions/audits/refund issues	8/29/25	1.00
Thomas Long, Outside Counsel	SB 884	BCR	Prep memo to ET/MFF re my analysis of CBR App. 2	8/29/25	1.50
Thomas Long, Outside Counsel	SB 884	Draft SPD-37	Prep email to ET/MFF summaring key changes in draft redline and flagging decision points for TURN	8/31/25	0.50
Thomas Long, Outside Counsel	SB 884	Audit	Prep for call with ET/MFF re audit/refund issues and next steps	9/2/25	0.25
Thomas Long, Outside Counsel	SB 884	Audit	Call with ET/MFF re audit/refund issues and next steps	9/2/25	0.75
Thomas Long, Outside Counsel	SB 884	Audit	Draft comments re audit/refund process	9/2/25	2.50
Thomas Long, Outside Counsel	SB 884	Audit	Draft comments re audit/refund process	9/3/25	1.50
Thomas Long, Outside Counsel	SB 884	Audit	Draft revisions to Findings and Summary of Changes re audit/refund process	9/3/25	0.75
Thomas Long, Outside Counsel	SB 884	Audit	Prep email to ET/MFF re explanations regarding my draft sections re audit/refund process	9/3/25	0.25
Thomas Long, Outside Counsel	SB 884	Audit	Revise my draft sections per ET edits/comments	9/3/25	0.25
Thomas Long, Outside Counsel	SB 884	Application	Review/edit MFF draft sections re new conditions and new application requirements	9/3/25	1.00
Thomas Long, Outside Counsel	SB 884	Audit	Review/edit ET draft sections re no recovery of costs that violate conditions	9/4/25	2.25
Thomas Long, Outside Counsel	SB 884	Audit	Call with ET re my suggested revisions	9/4/25	0.25
Thomas Long, Outside Counsel	SB 884	Memo	Review/edit ET draft section re cap on memo account	9/4/25	0.50
Thomas Long, Outside Counsel	SB 884	Conditions	Review/edit revised MFF sections re new conditions and application requirements	9/4/25	1.50
Thomas Long, Outside Counsel	SB 884	Audit	Prep revised summary of recommended changes re Section 2 (non-recoverable costs)	9/4/25	0.25
Thomas Long, Outside Counsel	SB 884	Draft SPD-37	Overview of other party comments	9/4/25	0.25
Thomas Long, Outside Counsel	SB 884	Draft SPD-37	Review/analysis of PG&E comments (summary of changes, intro sections)	9/5/25	1.25
Thomas Long, Outside Counsel	SB 884	Draft SPD-37	Prep email to ET re workplan for reply cmts	9/5/25	0.25
Thomas Long, Outside Counsel	SB 884	BCR	Review/analysis of PG&E comments (Crit Issue 1 - CBR Appendix)	9/5/25	0.50
Thomas Long, Outside Counsel	SB 884	Conditions	Review/analysis of PG&E comments (Crit Issue 2 - Condition 5 - comparative CBR)	9/5/25	0.50
Thomas Long, Outside Counsel	SB 884	Conditions	Review/analysis of PG&E comments (Crit Issue 3,4 - variance conditions)	9/5/25	0.50
Thomas Long, Outside Counsel	SB 884	Audit	Review/analysis of PG&E comments (Crit Issue 6 - Audit)	9/5/25	0.25
Thomas Long, Outside Counsel	SB 884	Audit	Review/analysis of PG&E comments (Crit Issue 7 - Rebuild costs)	9/5/25	0.25
Thomas Long, Outside Counsel	SB 884	Draft SPD-37	Meet w/ET re TURN positions, key issues for reply cmts	9/5/25	0.75
Thomas Long, Outside Counsel	SB 884	Draft SPD-37	Rev/analysis of SDG&E cmts	9/5/25	0.50
Thomas Long, Outside Counsel	SB 884	Audit	Draft revised recommendations re non-recovery of costs that violate conditions	9/7/25	0.50
Thomas Long, Outside Counsel	SB 884	Draft SPD-37	Outline reply comments	9/8/25	1.00
Thomas Long, Outside Counsel	SB 884	Conditions	Draft reply comments (Condition 5 - comparative CBR)	9/8/25	1.00
Thomas Long, Outside Counsel	SB 884	Conditions	Draft reply comments (Variance Conditions 6, 7)	9/8/25	1.00
Thomas Long, Outside Counsel	SB 884	BCR	Draft reply comments (CBR Guidelines)	9/8/25	1.25
Thomas Long, Outside Counsel	SB 884	Audit	Draft reply comments (Audit process)	9/8/25	0.75
Thomas Long, Outside Counsel	SB 884	Audit	Draft reply comments (Rebuild costs)	9/8/25	0.50
Thomas Long, Outside Counsel	SB 884	Draft SPD-37	Draft reply comments (PGE claims re overall impact of SPD-37)	9/8/25	0.50
Thomas Long, Outside Counsel	SB 884	Draft SPD-37	General editing of draft reply comments	9/8/25	0.25
Thomas Long, Outside Counsel	SB 884	Draft SPD-37	Revise draft per ET/MFF edits/comments	9/9/25	0.50
Thomas Long, Outside Counsel	SB 884	Comp	Prepare comp request	1/5/26	2.75
Thomas Long, Outside Counsel	SB 884	Comp	Prepare comp request	1/6/26	1.25
Thomas Long, Outside Counsel	SB 884	Comp	Prepare comp request	1/7/26	2.50
Thomas Long, Outside Counsel	SB 884	Comp	Prepare comp request	1/8/26	3.00

Atty	Case #	Code	Description	Date	Time
Thomas Long, Outside Counsel	SB 884	Comp	Prepare comp request	1/9/26	1.75
Thomas Long, Outside Counsel	SB 884	Comp	Prepare comp request	1/12/26	2.25
Thomas Long, Outside Counsel	SB 884	Comp	Prepare comp request	1/15/26	1.00
Thomas Long, Outside Counsel	SB 884	Comp	Prepare comp request	1/16/26	1.50
Thomas Long, Outside Counsel	SB 884	Comp	Prepare comp request	1/20/26	1.00
Thomas Long, Outside Counsel	SB 884	Comp	Prepare comp request	1/21/26	1.50
Elise Torres	SB 884	Staff Proposal	correspond with TL RE SB 884 issues & Resolution SPD-15	4/8/25	0.25
Elise Torres	SB 884	Staff Proposal	meet with TL to discuss 4/8 workshop and issues for comments	4/9/25	0.75
Elise Torres	SB 884	Staff Proposal	meet with TL & MF RE issues to address in comments on updates to SPD-15	4/15/25	1.00
Elise Torres	SB 884	Staff Proposal	meet with TL & MF RE comments on draft SPD-15 updates & responses to questions	4/21/25	1.00
Elise Torres	SB 884	Staff Proposal	review TL draft of comments on draft SPD-15 updates & responses to questions & revise and give feedback	4/22/25	2.50
Elise Torres	SB 884	Conditions	review TL draft of responses to questions in Sections B & C and give feedback	4/23/25	1.25
Elise Torres	SB 884	Memo	coorespond with TL RE recommendations for process for cost overruns; review draft of section 3 & 5 and revise	4/23/25	0.50
Elise Torres	SB 884	Audit	review TL revisions to Section 3, 4.2.3 and 5.3 & give feedback	4/23/25	1.00
Elise Torres	SB 884	Memo	research and draft affordability paragraph for Section 3 of comments	4/24/25	0.50
Elise Torres	SB 884	Staff Proposal	review & analyze Mussey Grade comments and take notes	4/29/25	1.50
Elise Torres	SB 884	Staff Proposal	review & analyze PAO comments and take notes	5/14/25	1.25
Elise Torres	SB 884	Staff Proposal	review & analyze PG&E comments and take notes	5/15/25	2.50
Elise Torres	SB 884	Staff Proposal	meet with TL RE PG&E's comments and next steps for proceeding	5/15/25	1.00
Elise Torres	SB 884	Proc	review TL notes RE TWG and evaluate TURN participation	5/22/25	0.50
Elise Torres	SB 884	Draft SPD-37	call with MF & TL to discuss Draft Resolution SPD-37	8/21/25	1.00
Elise Torres	SB 884	Draft SPD-37	review & analyze Draft Resolution SPD-37 (41 pages) and take notes for comments	8/21/25	2.00
Elise Torres	SB 884	Draft SPD-37	call with SPD, MF & TL to discuss questions re Draft Resolution SPD-37	8/21/25	0.75
Elise Torres	SB 884	Draft SPD-37	review TL's memo analyzing Draft Resolution SPD-37 & take notes for comments	8/25/25	1.00
Elise Torres	SB 884	Draft SPD-37	review & analyze Draft Resolution SPD-37 Attachment A- Program Guidelines and take notes for comments	8/26/25	1.00
Elise Torres	SB 884	Audit	research and draft outline for comments on SPD-37	8/26/25	0.75
Elise Torres	SB 884	Conditions	research and draft outline for comments on SPD-37	8/26/25	0.75
Elise Torres	SB 884	Draft SPD-37	call with MF to discuss issues to address in comments on DR SPD-37	8/26/25	0.50
Elise Torres	SB 884	Application	review & analyze Draft Resolution SPD-37 Attach A, Appendix 2: SB 884 Project List	8/27/25	1.00
Elise Torres	SB 884	Audit	begin researching and drafting comments on DR SPD-37 RE cost recovery	8/28/25	1.50
Elise Torres	SB 884	Audit	review & analyze TL proposed additions to program guidelines and take notes RE BA	9/2/25	1.25
Elise Torres	SB 884	Audit	call with TL and MF RE program guidelines, CBR guidance and BA vs memo account costs	9/2/25	0.75
Elise Torres	SB 884	Draft SPD-37	revise comment outline in response to call and divide issues	9/2/25	0.50
Elise Torres	SB 884	Conditions	research and draft comments on DR SPD-37 RE Ph.2 conditions and balancing account recovery	9/2/25	1.00
Elise Torres	SB 884	Memo	research and draft comments on DR SPD-37 RE problems with the memo account	9/2/25	1.25
Elise Torres	SB 884	Audit	review and edit TL draft of comments on DR SPD-37 RE audit & refund process and need for CPUC resolution for refunds	9/3/25	1.00
Elise Torres	SB 884	Conditions	research and draft comments on DR SPD-37 RE Ph.2 conditions & memo account	9/3/25	1.25
Elise Torres	SB 884	Memo	review CPUC decisions RE cost recovery of incremental costs & memo accounts, take notes for comments and add to memo account section	9/3/25	0.75
Elise Torres	SB 884	Draft SPD-37	research and draft comments on DR SPD-37 intro & summary of recommendations	9/4/25	1.00
Elise Torres	SB 884	Draft SPD-37	review & revise TL draft redlines to SDP-37 Attach. A: SB 884 CPUC Guidelines & summary of revisions	9/4/25	1.00
Elise Torres	SB 884	BCR	review TL revisions to MF draft of sections addressing CBRs and make additional revisions	9/4/25	0.75
Elise Torres	SB 884	Memo	review TL revisions to my draft of sections addressing the memorandum account and balancing account and make additional revisions	9/4/25	1.25
Elise Torres	SB 884	Draft SPD-37	revise summary of recommendations and appendix A	9/4/25	0.75
Elise Torres	SB 884	Draft SPD-37	review & analyze PG&E comments on DR SPD-37, take notes for reply comments	9/5/25	1.75
Elise Torres	SB 884	Draft SPD-37	review & analyze MGRA comments on DR SPD-37, take notes for reply comments	9/5/25	0.75
Elise Torres	SB 884	Draft SPD-37	call with T.Long to discuss PG&E comments and issues to address in work plan	9/5/25	0.75
Elise Torres	SB 884	BCR	discuss PG&E comments with MF re CBR issues	9/5/25	0.25
Elise Torres	SB 884	Draft SPD-37	review & analyze Appendix A (FOFs & OPs Revisions) to PG&E comments on DR SPD-37, take notes for reply comments	9/8/25	1.50
Elise Torres	SB 884	Draft SPD-37	review & analyze SDG&E comments on DR SPD-37, take notes for reply comments	9/8/25	1.00
Elise Torres	SB 884	Draft SPD-37	review & analyze Cal Advocates comments on DR SPD-37, take notes for reply	9/8/25	0.75
Elise Torres	SB 884	Conditions	review & Revise TL draft of reply comments RE SPD-37	9/9/25	0.50
Elise Torres	SB 884	Audit	review & Revise TL draft of reply comments RE SPD-37	9/9/25	0.50
Elise Torres	SB 884	BCR	review & Revise TL draft of reply comments RE SPD-37	9/9/25	0.50
Elise Torres	SB 884	Memo	call with MF to discuss TL's proposal RE memo account for reply comments	9/9/25	0.25
Elise Torres	SB 884	Memo	further revise comments in response to feedback from MF	9/9/25	0.25
Elise Torres	SB 884	Draft SPD-37	review 9/18 revised version Draft Resolution-37	9/23/25	0.75
Elise Torres	SB 884	Draft SPD-37	call with T.Long to discuss revisions to SPD-37 & need for commissioner meetings	9/23/25	0.50
Elise Torres	SB 884	Draft SPD-37	research & develop bullet points of key issues with resolution for commissioner meetings	9/24/25	1.50

Atty	Case #	Code	Description	Date	Time
Elise Torres	SB 884	Draft SPD-37	review & analyze PG&E GRC testimony RE undergrounding costs (Ex. PG&E-04, Ch.7) and add to talking points	9/25/25	0.75
Elise Torres	SB 884	BCR	review & revise MF draft of bullet points of key BCR calculation issues with resolution for commissioner meetings	9/25/25	0.50
Elise Torres	SB 884	Draft SPD-37	meet with MF to prepare for meetng with Comm. Baker's office	9/29/25	0.50
Elise Torres	SB 884	Draft SPD-37	call with MF & MT to discuss key points to address during meeting with Comm. Baker's office	9/29/25	0.50
Elise Torres	SB 884	Draft SPD-37	draft handout for meeting with Comm. Baker's office	9/29/25	0.75
Elise Torres	SB 884	Draft SPD-37	meet with Comm. Baker and advisors RE SPD-37	9/29/25	0.50
Elise Torres	SB 884	Draft SPD-37	meet with Pres Reynolds and advisors RE SPD-37	9/30/25	0.50
Elise Torres	SB 884	Draft SPD-37	discuss meeting with Comm. Reynolds with MF RE talking points for my issues	10/2/25	0.25
Elise Torres	SB 884	BCR	review & revise MF draft of revised response to Pres Reynold's advisor RE BCR	10/2/25	0.25
Elise Torres	SB 884	Draft SPD-37	correspond with SPD RE potential revisions to SPD-37	10/22/25	0.25
Elise Torres	SB 884	Draft SPD-37	call with SPD to discuss revisions to SPD-37	10/23/25	0.50
Elise Torres	SB 884	Draft SPD-37	review & analyze revisions to draft SPD-37	10/28/25	0.75
A Mireille Fall	SB 884	Staff Proposal	Review and analyze postworkshop questions	4/14/25	0.50
A Mireille Fall	SB 884	Staff Proposal	Meeting with TL and ET re strategy and key issues for comments	4/15/25	1.00
A Mireille Fall	SB 884	Staff Proposal	meet with TL & ET RE comments on draft SPD-15 updates & responses to questions	4/21/25	1.00
A Mireille Fall	SB 884	Staff Proposal	Review TURN draft Comments on SB 884 & give feedback to ET/TL	4/22/25	0.50
A Mireille Fall	SB 884	Draft SPD-37	Confer with ET and TL re responding to DR SPD-37	8/21/25	1.00
A Mireille Fall	SB 884	Draft SPD-37	Review Tom's memo re analysis of DR SPD-37	8/28/25	0.50
A Mireille Fall	SB 884	Conditions	Analyze DR SPD-37 to take notes in order to prepare comments	8/28/25	0.75
A Mireille Fall	SB 884	Conditions	Analyzing SB 884 Project Requirment Guidelines and Program Guidelines and taking notes in order to prepare comments	8/29/25	1.00
A Mireille Fall	SB 884	BCR	Reviewing TL's notes on CBR to incorporate into comments	8/30/25	0.50
A Mireille Fall	SB 884	BCR	Draft CBR portion of Comments	8/30/25	1.25
A Mireille Fall	SB 884	BCR	Careful reading of App 1, CBR guidelines to make notes for comments	8/30/25	0.75
A Mireille Fall	SB 884	Conditions	Draft Comments re issues with new conditions	9/2/25	1.25
A Mireille Fall	SB 884	Memo	call with ET to discuss TL's proposal RE memo account for reply comments	9/9/25	0.25
A Mireille Fall	SB 884	Memo	Review TL's draft comments and suggest revisions	9/9/25	0.50
A Mireille Fall	SB 884	Draft SPD-37	Analyze Redline SPD-37 closely and evaluate changes and take notes	9/24/25	3.75
A Mireille Fall	SB 884	Draft SPD-37	Reviewing accuracy of numbers for undergrounding cost for talking points	9/26/25	0.25
A Mireille Fall	SB 884	Draft SPD-37	Prepare talking points for ex parte meetings	9/29/25	1.75
A Mireille Fall	SB 884	Draft SPD-37	Prepare written materials for ex parte meetings	9/29/25	1.25
A Mireille Fall	SB 884	Draft SPD-37	Confer with ET to prepare for meeting with MT re SPD-37 ex parte	9/29/25	0.50
A Mireille Fall	SB 884	Draft SPD-37	Represent TURN in ex parte meeting w/ Cmr Baker, MT, and ET	9/29/25	0.50
A Mireille Fall	SB 884	Draft SPD-37	Represent TURN at ex parte meeting with Pres. Reynolds	9/30/25	0.50
A Mireille Fall	SB 884	BCR	Analyze materials to draft clarification of response to staff question	10/1/25	1.75
A Mireille Fall	SB 884	BCR	Draft clarification of my response to staff question	10/2/25	1.50
A Mireille Fall	SB 884	Draft SPD-37	Prepare for Meeting with Cmr Reynolds	10/3/25	0.50
A Mireille Fall	SB 884	Draft SPD-37	Meeting with Cmr Reynolds	10/3/25	0.50
Robert Finkelstein	SB 884	Staff Proposal	E-mail exchange w/ TLong re: depn issues and rev req showing required in revisions to SPD-15	3/29/24	0.25
Robert Finkelstein	SB 884	Staff Proposal	Prep for upcoming call w/ SPD on depn impact on rev req't calculations, including review of materials for call w/ SPD staff and drafting e-mail to SPD staff	4/3/24	0.75
Robert Finkelstein	SB 884	Staff Proposal	Call w/T Long re same	4/3/24	1.00
Robert Finkelstein	SB 884	Staff Proposal	Further prep for call w/ SPD on depn impact issues	4/4/24	0.50
Robert Finkelstein	SB 884	Staff Proposal	Call w/SPD on depn impact issues	4/4/24	1.50
Robert Finkelstein	SB 884	Staff Proposal	Discuss depn issues in SPD questions with w/ TLong	4/3/25	0.50
Robert Finkelstein	SB 884	Staff Proposal	Review PG&E TY 2023 GRC depn materials, prepare excerpt and explanatory materials for TLong	4/3/25	0.50
Hayley Goodson	SB 884	Staff Proposal	Discuss SPD questions re abandoned projects and RO/depreciation with TL	11/7/24	0.50
Substantial Total					**199.00**
Comp Total					**18.50**
Grand Total					**217.50**

Attachment 3

TURN Hours Allocated by Issue

A.26-01___(SPD-37)
TURN Compensation Claim
TURN Hours Allocated by Issue

	Billing Period	Hourly Rate	Coord	Staff Proposal	Proc	BCR	Conditions	Audit	Memo	Application	Draft SPD-37	Substantive Hours	Substantive $$$	Comp	Compensation (iComp) 1/2 of hourly rate
A Mireille Fall	2025	$600	-	3.00	-	5.75	3.00	-	0.75	-	11.00	23.50	$ 14,100.00	-	$ -
Elise Torres	2025	$600	-	11.75	0.50	2.25	4.75	6.75	4.75	1.00	24.00	55.75	$ 33,450.00	-	$ -
Elise Torres	2026		-	-	-	-	-	-	-	-	-	-	$ -	-	$ -
Hayley Goodson	2024	$680	-	0.50	-	-	-	-	-	-	-	0.50	$ 340.00	-	$ -
Robert Finkelstein	2024	$875	-	4.00	-	-	-	-	-	-	-	4.00	$ 3,500.00	-	$ -
Robert Finkelstein	2025	$905	-	1.00	-	-	-	-	-	-	-	1.00	$ 905.00	-	$ -
Thomas Long	2024	$860	0.50	14.50	0.75	4.00	0.50	5.25	-	-	-	25.50	$ 21,930.00	-	$ -
Thomas Long	2025	$885	1.50	22.75	0.50	4.75	4.25	9.25	4.25	2.25	-	49.50	$ 43,807.50	-	$ -
Thomas Long, Outside Counsel	2025	$885	-	-	-	3.25	5.00	18.25	0.50	1.00	11.25	39.25	$ 34,736.25	-	
Thomas Long, Outside Counsel	2026	$915	-	-	-	-	-	-	-	-	-	-	$ -	18.50	$ 8,463.75
TOTAL			2.00	57.50	1.75	20.00	17.50	39.50	10.25	4.25	46.25	199.00	$ 152,768.75	18.50	$ 8,463.75
TOTAL % HOURS ALLOCATED			1.01%	28.89%	0.88%	10.05%	8.79%	19.85%	5.15%	2.14%	23.24%				

Substantial Contribution	**$ 152,768.75**
Intervenor iComp Compensation	**$ 8,463.75**
Travel Time Compensation	**$ -**
Expenses Compensation	
Grand Total	**$ 161,232.50**

Attachment 4

Notice of Intent to Claim Intervenor Compensation

FORM A: BLANK *NOTICE OF INTENT TO CLAIM INTERVENOR COMPENSATION*

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of The Utility Reform Network for Award of Intervenor Compensation for Substantial Contributions to Resolution SPD-37	Application 26-01-____ (Filed January 29, 2026)

NOTICE OF INTENT TO CLAIM INTERVENOR COMPENSATION AND, IF REQUESTED (and [ ][1] checked), ADMINISTRATIVE LAW JUDGE'S RULING ON THE UTILITY REFORM NETWORK'S SHOWING OF SIGNIFICANT FINANCIAL HARDSHIP

<u>NOTE</u>: AFTER ELECTRONICALLY FILING A PDF COPY OF THIS NOTICE OF INTENT, PLEASE EMAIL THE DOCUMENT IN AN MS WORD FORMAT TO THE INTERVENOR COMPENSATION PROGRAM COORDINATOR AT Icompcoordinator@cpuc.ca.gov.

Customer or Eligible Local Government Entity (party intending to claim intervenor compensation): The Utility Reform Network (TURN)	
Assigned Commissioner: N/A	**Administrative Law Judge:** N/A

I hereby certify that the information I have set forth in Parts I, II, III and IV of this Notice of Intent is true to my best knowledge, information and belief.

	Signature:	/s/ *Thomas J. Long*
Date: January 29, 2026	Printed Name:	Thomas J. Long

PART I: PROCEDURAL ISSUES
(To be completed by the party intending to claim intervenor compensation)

A. Status as "customer" (*see* Pub. Util. Code § 1802(b))[2] The party claims "customer" status because the party is (check one):	**Applies (check)**
1. A **Category 1** customer is an actual customer whose self-interest in the proceeding arises primarily from his/her role as a customer of the utility and, at	

[1] DO NOT CHECK THIS BOX if a finding of significant financial hardship is not needed (in cases where there is a valid rebuttable presumption of eligibility (Part III(A)(3)) or significant financial hardship showing has been deferred to the intervenor compensation claim).
[2] All statutory references are to California Public Utilities Code unless indicated otherwise.

the same time, the customer must represent the broader interests of at least some other customers. See, for example, D.08-07-019 at 5-10).	☐
2. A **Category 2** customer is a representative who has been authorized by actual customers to represent them. Category 2 involves a more formal arrangement where a customer or a group of customers selects a more skilled person to represent the customer's views in a proceeding. A customer or group of customers may also form or authorize a group to represent them, and the group, in turn, may authorize a representative such as an attorney to represent the group.	☐
3. A **Category 3** customer is a formally organized group authorized, by its articles of incorporation or bylaws to represent the interests of residential customers or small commercial customers receiving bundled electric service from an electrical corporation (§1802(b)(1)(C)). Certain environmental groups that represent residential customers with concerns for the environment may also qualify as Category 3 customers, even if the above requirement is not specifically met in the articles or bylaws. *See* D.98-04-059, footnote at 30.	☑
4. The party's detailed explanation of the selected customer category. The party's explanation of its status as a Category 1 customer. A party seeking status as a Category 1 customer must describe the party's own interest in the proceeding and show how the customer's participation goes beyond just his/her own self-interest and will benefit other customers. Supporting documents must include a copy of the utility's bill. The party's explanation of its status as a Category 2 customer. A party seeking status as a Category 2 customer must identify the residential customer(s) being represented and provide authorization from at least one customer. The party's explanation of its status as a Category 3 customer. If the party represents residential and small commercial customers receiving bundled electric service from an electrical corporation, it must include in the Notice of Intent either the percentage of group members that are residential ratepayers or the percentage of the members who are receiving bundled electric service from an electrical corporation. Supporting documentation for this customer category must include current copies of the articles of incorporation or bylaws. If current copies of the articles and bylaws have already been filed with the Commission, only a specific reference (the proceeding's docket number and the date of filing) to such filings needs to be made.	

Do you have any direct economic interest in outcomes of the proceeding? [3] If "Yes", explain:	☐Yes ☑ No
B. Conflict of Interest (§ 1802.3)	**Check**
1. Is the customer a representative of a group representing the interests of small commercial customers who receive bundled electric service from an electrical corporation?	☐Yes ☑ No
2. If the answer to the above question is "Yes", does the customer have a conflict arising from prior representation before the Commission?	☐Yes ☐No
C. Status as an Eligible Local Government Entity (§§1802(d), 1802.4, 1803.1)	
The party claims "eligible local government entity" status because the party is a city, county, or city and county that is not a publicly owned public utility that intervenes or participates in a Commission proceeding for the purpose of protecting the health and safety of the residents within the entity's jurisdiction following a catastrophic material loss suffered by its residents either in significant damage to infrastructure or loss of life and property, or both, as a direct result of public utility infrastructure.	☐Yes ☑ No
The party's explanation of its status as an eligible local government entity must include a description of (1) The relevant triggering catastrophic event; (2) The impacts of the triggering catastrophic event on the residents within the entity's jurisdiction as a result of public utility infrastructure; and (3) The entity's reason(s) to participate in this proceeding.	
D. Timely Filing of Notice of Intent to Claim Intervenor Compensation (NOI) (§ 1804(a)(1)):	
1. Is the party's NOI filed within 30 days after a Prehearing Conference? Date of Prehearing Conference: Click here to enter a date.	☐Yes ☐No
2. Is the party's NOI filed at another time (for example, because no Prehearing Conference was held, the proceeding will take less than 30 days, the schedule did not reasonably allow parties to identify issues within the timeframe normally permitted, or new issues have emerged)?	☐Yes ☐No
2a. The party's description of the reasons for filing its NOI at this other time: Because the adoption of SPD-37 happened outside of a formal proceeding, there was no prehearing conference. In accordance with the instructions in the Commission's Intervenor Compensation Program Guide (Revised 4/17), TURN is submitting this NOI in conjunction with its compensation request.	

[3] See Rule 17.1(f).

2b. The party's information on the proceeding number, date, and decision number for any Commission decision, Commissioner ruling, Administrative Law Judge's ruling, or other document authorizing the filing of NOI at that other time:

PART II: SCOPE OF ANTICIPATED PARTICIPATION
(To be completed by the party intending to claim intervenor compensation)

A. Planned Participation (§ 1804(a)(2)(A)):				
The party's statement of the issues on which it plans to participate: The party's explanation of how it plans to avoid duplication of effort with other parties: The party's description of the nature and extent of the party's planned participation in this proceeding (to the extent that it is possible to describe on the date this NOI is filed).				
B. The party's itemized estimate of the compensation that the party expects to request, based on the anticipated duration of the proceeding (§ 1804(a)(2)(A)):				
Item	**Hours**	**Rate $**	**Total $**	**#**
ATTORNEY, EXPERT, AND ADVOCATE FEES				
[Attorney 1]				
[Attorney 2]				
[Expert 1]				
[Expert 2]				
[Advocate 1]				
[Advocate 2]				
			Subtotal: $	
OTHER FEES				
[Person 1]				
[Person 2]				
			Subtotal: $	
COSTS				
[Item 1]				
[Item 2]				
			Subtotal: $	
			TOTAL ESTIMATE: $	
Estimated Budget by Issues:				
When entering items, type over bracketed text; add additional rows to table as necessary. Estimate may (but does not need to) include estimated Claim preparation time. Claim preparation time is typically compensated at ½ professional hourly rate.				

PART III: SHOWING OF SIGNIFICANT FINANCIAL HARDSHIP
(To be completed by party intending to claim intervenor compensation; see Instructions for options for providing this information)

A. The party claims that participation or intervention in this proceeding without an award of fees or costs imposes a significant financial hardship, on the following basis:	Applies (check)
1. The customer cannot afford, without undue hardship, to pay the costs of effective participation, including advocate's fees, expert witness fees, and other reasonable costs of participation. (§ 1802(h))	☐
2. In the case of a group or organization, the economic interest of the Individual members of the group or organization is small in comparison to the costs of effective participation in the proceeding. (§ 1802(h))	☐
3. The eligible local government entities' participation or intervention without an award of fees or costs imposes a significant financial hardship. (§ 1803.1(b).)	☐
4. A § 1802(h) or § 1803.1(b) finding of significant financial hardship in another proceeding, made within one year prior to the commencement of this proceeding, created a rebuttable presumption in this proceeding (§ 1804(b)(1)). Commission's finding of significant financial hardship made in proceeding number: A.21-12-007 Date of Administrative Law Judge's Ruling (or CPUC Decision) in which the finding of significant financial hardship was made: 5/31/22, which is within one year prior to the commencement of this SB 884 Implementation proceeding.	☑

B. The party's explanation of the factual basis for its claim of "significant financial hardship" (§ 1802(h) or § 1803.1(b)) (necessary documentation, if warranted, is attached to the NOI:

PART IV: ATTACHMENTS DOCUMENTING SPECIFIC ASSERTIONS MADE IN THIS NOTICE
(The party intending to claim intervenor compensation identifies and attaches documents; add rows as necessary)

Attachment No.	Description
1	Certificate of Service

ADMINISTRATIVE LAW JUDGE RULING[4]
(Administrative Law Judge completes)

	Check all that apply
1. The Notice of Intent (NOI) is rejected for the following reasons:	☐
a. The NOI has not demonstrated the party's status as a "customer" or an "eligible local government entity" for the following reason(s):	☐
b. The NOI has not demonstrated that the NOI was timely filed (Part I(B)) for the following reason(s):	☐
c. The NOI has not adequately described the scope of anticipated participation (Part II, above) for the following reason(s):	☐
2. The NOI has demonstrated significant financial hardship for the reasons set forth in Part III of the NOI (above).	☐
3. The NOI has not demonstrated significant financial hardship for the following reason(s):	☐
4. The Administrative Law Judge provides the following additional guidance (see § 1804(b)(2)):	☐

IT IS RULED that:

1. The Notice of Intent is rejected.	☐
2. The customer or eligible local government entity has satisfied the eligibility requirements of Pub. Util. Code § 1804(a).	☐
3. The customer or eligible local government entity has shown significant financial hardship.	☐
4. The customer or eligible local government entity is preliminarily determined to be eligible for intervenor compensation in this proceeding. However, a finding of significant financial hardship in no way ensures compensation.	☐
5. Additional guidance is provided to the customer or eligible local government entity as set forth above.	☐

Dated _____________, at San Francisco, California.

[4] A Ruling needs not be issued unless: (a) the NOI is deficient; (b) the Administrative Law Judge desires to address specific issues raised by the NOI (to point out similar positions, areas of potential duplication in showings, unrealistic expectations for compensation, or other matters that may affect the customer or eligible local government entity's Intervenor Compensation Claim); or (c) the NOI has included a claim of "significant financial hardship" that requires a finding under § 1802(h).

Administrative Law Judge

Attachment 5

SPD Questions for Stakeholders Regarding the CPUC SB 884 Guidelines, October 14, 2024

Questions for Stakeholders Regarding the CPUC SB-884 Guidelines

October 14 2024

Instructions:

- If any question in this document calls for a "yes" or "no" answer, please explain your answer rather than simply giving a one-word answer.
- The reference to Office of Energy Infrastructure (OEIS) Guidelines in these questions is intended to refer to the Guidelines in place at the time these questions are asked. The Guidelines are available at https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=57358&shareable=true. We acknowledge those Guidelines may change in the future.
- The Commission SB-884 Guidelines refers to Resolution SPD-15, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M526/K984/526984185.pdf. The Commission may update the Guidelines in the future.
- Each "Background" section below represents only a partial summary of the relevant context. Please refer to other resources, inlcuding the OEIS Guidelines and the Commission's SB-884 Guidelines for further context before offering any responses.

Definitions:

- **Circuit Segment**: a circuit segment refers to a specific portion of an electrical circuit that can be separated or disconnected from the rest of the system without affecting the operation of other parts of the network. This isolation is typically achieved using switches, circuit breakers, or other control mechanisms.[1]
- **Confirmed Project**: an Undergrounding Project that has completed Screen 3 (Project Risk Analysis), defined below.
- **Confirmed Project Polygon**: a special boundary generated at the beginning of Screen 3 that encompasses the entire Eligible Circuit Segment on which the Undergrounding Project is defined, except any sections already contained in another Confirmed Project Polygon.
- **Investor Owned Utility (IOU)**: Utility regulated by the Commission that seeks SB 884 cost recovery or submits an SB 884 Application or seeks OEIS approval for an SB 884 Plan.
- **Office of Energy Infrastructure (OEIS) Guidelines**: explained in "Instructions," above.
- **Plan Mitigation Objective**: the amount of change in risk (wildfire and reliability) that is necessary to meet the requirements contained in section 8388.5(d)(2).
- **Project-Level Standard**: the Risk Reduction Project Standard, the Reliability Increase Project Standard, and the Tail Risk Mitigation Project Standard.
- **Protective Equipment and Device Settings (PEDS)**: advanced safety settings implemented by electric IOUs on electric utility powerlines to reduce wildfire risk.[2]
- **Retired pole**: An electric pole that has been removed from ratebase.
- **Screen 2 (Project Information and Alternative Mitigation Comparison)**: confirms there is sufficient information available on a Circuit Segment and requires comparison of undergrounding to alternative mitigations in order to determine which Eligible Circuit Segments can be treated as Undergrounding Projects.[3]

---

[1] This concept refers to the same concept found within the OEIS Guidelines Appendix A

[2] For details see https://www.cpuc.ca.gov/industries-and-topics/wildfires/protective-equipment-device-settings

[3] For details see OEIS REVISED DRAFT 10-Year Electrical Undergrounding Plan Guidelines, Section 2.4.4 at 16-17

- **Screen 3 (Project Risk Analysis)**: the procedure for evaluating an individual Undergrounding Project in the context of the Portfolio of Undergrounding Projects and includes information obtained through the project development process.[4]
- **Screen 4 (Project Prioritization):** the Electrical Undergrounding Plan (EUP) must set forth a means of prioritization and its definition for each of the factors in section 8388.5(c)(2), i.e. wildfire risk reduction, public safety, cost efficiency and reliability benefits.[5]
- **Topped poles**: the process during an undergrounding project of cutting the top of a pole so that the communication companies can continue using the pole even after the overhead conductor has been buried.
- **Undergrounding Project**: an Eligible Circuit Segment that has completed Screen 2 including the CPUC Data Appendix 1 information completed.

A. Results of Operation (RO) Model

Background:

The Commission requires IOUs seeking rate increases to reflect the results of their requests in what are called results of operation models ("RO models"). An RO model may illustrate ~~rate~~ revenue requirement ~~impacts~~ across all of the IOU's lines of business, such as in a General Rate Case (GRC), or it may model revenue requirement ~~impacts~~ for a particular program in a "mini RO model." Both models present the utility's forecasted revenue requirement for its operations. The forecasted revenue requirement is calculated through a computer model called the RO model. The major components of the GRC RO model include:

- Rate Base
  - Includes information related to Utility Plant, Working Capital, Customer Advances, Customer Deposits, and Depreciation Reserve;
- Return on Rate Base;
- Taxes;
- Other Operating Revenues and the Rate Base component.[6]

The Commission stated in Decision (D.) 00-07-050 that RO models should be user-friendly and facilitate the Commission's ability to quickly calculate the revenue requirement for various decision scenarios and should easily be able to accomplish the following:

- Change depreciation rates;
- Move unbundled cost categories (UCCs) between major functional groups (i.e., distribution, generation, etc.);
- Calculate the lead-lag portion of working cash;
- Calculate all taxes and tax depreciation;
- Make plant adjustments, including adjustments to beginning-of-year plant; and
- Calculate a distribution Revenue Requirement and Summary of Earnings.[7]

Standalone RO models are used to generate cost recovery requests in Applications to the Commission outside of General Rate Case (GRC) Proceedings. SCE's standalone RO model is distinct and separate from the main RO model that SCE uses in its GRC Applications. ~~The Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) standalone RO model approach is completely integrated within their the main GRC RO model. SCE has used this integrated RO model approach to generate revenue requests in, for instance, a recent application to recover costs related to wildfire mitigation, vegetation management;~~

[4] For details see OEIS REVISED DRAFT 10-Year Electrical Undergrounding Plan Guidelines, Section 2.4.5 at 17
[5] For details see OEIS REVISED DRAFT 10-Year Electrical Undergrounding Plan Guidelines, Section 2.4.6 at 18
[6] For an example of how this is discussed in a GRC Decision see D.20-12-005 at 334-335.
[7] See D.00-07-050 at 11.

Note: In A.24-04-005, SCE requests to recover incremental recorded costs that exceed the GRC authorized amounts associated with wildfire mitigation activities. A standalone RO model was not needed because the authorized amounts reside in the GRC RO model.

~~catastrophic events, and wildfire liability insurance.[8]~~ In the context of wildfire mitigation investments, SDG&E has not filed a standalone cost recovery application.

PG&E utilizes what it calls a mini-RO model to generate revenue requests. This mini-RO model is distinct and separate from the main RO model that PG&E uses in its GRC Applications. In the context of wildfire mitigation investments, PG&E has used this mini-RO model approach in its 2023 cost recovery Application related to wildfire and gas safety.[9] Commission Staff understands that PG&E intends to use the mini-RO model approach to generate revenue requests for SB-884 Applications. According to PG&E, a mini-RO model is distinct from the RO models submitted to the GRC in the following ways:

- The standard mini-RO Model may be tailored for a separately funded/incremental rate case for specific types of costs and applicable income tax rules.
- The mini-RO Models used in separately funded/incremental proceedings cover a proposed revenue recovery period.
- All inputs and revenue requirement calculations are integrated within a single Excel model for simplicity and efficiency.[10]

Questions:

1. Should a standalone RO model be used for generating a revenue requirement for an SB-884 application, or is another approach more appropriate? How should each of the IOUs' approaches be harmonized to have one standard for ratemaking in this process? In your response, discuss the need to encourage transparency and stakeholder holder engagement to ensure that rate impacts are incremental to other funding granted to the IOU, accurately represented and litigated in the process of generating a revenue requirement.

2. Is the mini-RO model approach appropriate for generating revenue requests in an SB-884 Application? Why or why not?

3. Is the integrated RO model approach appropriate for generating revenue requests in an SB-884 Application? Why or why not?

4. Through data requests, PG&E has informed Commission Staff that PG&E's mini-RO model does not account for depreciation costs associated with topped poles.[11] These factors would be accounted for in PG&E's GRC RO model. According to PG&E, each of its GRC Applications includes a depreciation study which determines the depreciation rates and is the proper route to account for topped and retired poles. With the mini-RO model being distinct and separate from the main GRC RO model, what challenges might this create for ensuring that the depreciation costs of topped poles is properly accounted for within a utility's rate base? How should these challenges be addressed in the SB-884 Guidelines?

5. Assume that a Commission Decision on a utility's SB-884 Application approves Project A to underground 1 mile of overhead (OH) line that is still in the utility's ratebase.[12] In a future GRC

[8] A.24-04-005
[9] A.23-06-008
[10] PG&E response to data request EUP_DR_SPD_011_Q001-012 at 1-2
[11] Topped poles refers to the process during an undergrounding project of cutting of the top of a pole so that the communication companies can continue using the pole even after the overhead conductor has been buried. See PG&E response to data request DRU14160_Case_EUP_DR_SPD_008, Question 1 at 1.
[12] A utility's rate base is the investment upon which the utility can earn its rate of return.

Application Proceeding, how would the Commission determine that the utililty had appropriately removed the 1 mile of OH line from the ratebase if the SB-884 Application was based on the mini-RO model?

6. PG&E has informed Commission Staff that it does not submit a depreciation study as testimony in an Application where the revenue request is generated by a mini-RO model. Should the Commission require a utility to submit a depreciation study along with an SB-884 Application? If so, should the utility be required to update certain parts of the depreciation study submitted with the utility's most recent GRC, such as that related to grid hardening and other wildfire mitigations? Explain your answer.

B. Third Party Funding

1. How should the IOUs account for third-party funding they seek or receive, as required by Public Utilities Code Section 8388.5(j), for undergrounding projects to ensure the requirements of the Commission's SB-884 Guidelines and Senate Bill (SB) 884 are met?

   a. How should ratepayer savings attributable to third party funding be accounted for?
      i. Should they appear as an offset to the proposed revenue requirement in a mini-RO model?
      ii. Should they appear in the IOU's next GRC?
      iii. Should there be a reporting requirement for the utilities to report on third-party funding? If so, what information should be included in this report?

   b. Should the IOUs treat third-party funded plants as contributed plants? Why and why not?

   c. Describe the IOUs' accounting for third-party funded plants in regards to utility plant accounts, and depreciation and amortization reserves.

2. Should an IOU file an advice letter documenting which annual cost caps are reduced by third-party funding? If so, how often should it be filed and what should the advice letter include?

C. CBR Threshold

Background:

The Cost-Benefit Ratio (CBR) is described in D.24-05-064 and D.22-12-027 of Rulemaking (R.) 20-07-013. CBR is a financial metric used to evaluate the efficiency of a project by comparing the benefits it offers (in this case, wildfire risk reduction and reliability enhancement) to its associated costs (cost of undergrounding overhead lines). The greater a CBR is relative to 1.0, the more its benefits outweigh its costs. Thus, as an illustrative example, a project with a CBR of 7.0 has benefits that exceed its costs by seven times, whereas a project with a CBR of 1.0 means costs and benefits are equal, and a project with a CBR of less than 1.0 means that its costs exceed its benefits. If an IOU were allowed to deploy a project with a CBR less than 1.0, it could be due to operational constraints. For example, in order to complete a project, the IOU may be required to perform work on other circuits segments upstream or downstream from the circuit segment with a high CBR. Those upstream or downstream circuit segments may have low CBRs even though they are necessary to the project, and therefore they may bring down the total CBR of a project. Sometimes projects with a CBR of 1.0 or below would be proposed because they are associated with high-risk overhead lines that face constraints such as operational considerations or legal statutes.[13]

Questions:

1. Should IOUs be required to provide additional justifications when they want to install projects that have either:

    a. Low CBRs[14] (in comparison to other UG projects in that IOU's application);

    b. CBRs below 1.0; or

    c. Lower CBRs compared to the CBRs of alternative wildfire mitigations that do not include undergrounding (such as covered conductor, remote fault detection technologies or high impedance fault detection)?

        i. And in each case (for Questions (1) (a)-(c) above) where the answer is yes, please explain why and what those additional justifications might be.

        ii. Furthermore, if the 1.0 threshold referenced in question (1)(b) above is too low from your perspective, and if IOUs should therefore be required to provide additional justifications when they want to install projects that have CBR thresholds greater than 1.0, then at what threshold above 1.0 should the additional justifications no longer be necessary and why?

D. Audit

Background:

The Commission's SB-884 Guidelines require that costs submitted in an SB-884 Application meet certain conditions (Phase 2 Conditions) in order for Commission to authorize the recovery of those costs via a one-way balancing account.[15] That one-way balancing account is subject to audit. If the audit demonstrates that costs were incorrectly recorded or failed to meet the Phase 2 Conditions, the Commission may order a refund. The details of this audit, including who will perform it, content, frequency, venue, method for true-up and refund mechanism will be determined in a later decision or order.

Questions:

1. Please expand on what the main objectives of the audit should be, in addition to ensuring the Phase 2 Conditions have been met?

---

[13] Associated circuit segments refer to the high-risk circuit segments which might be the primary reason to hardening the Low CBR circuit in the first place.

[14] "Low CBR" can be defined as projects whose CBRs are below a certain threshold (e.g., 2 standard deviations, where the standard deviation is a measure of the amount of variation of the values of a variable about its mean) compared to the median and average CBRs of other projects offering the same type of mitigation.

[15] The Phase 2 Conditions will include, but are not limited to, a total annual cost cap, two-year rolling average recorded unit cost cap, two-year rolling average recorded CBR threshold, and applying third-party funding to reduce the cost cap. For details see SPD-15, SB-884 Program: CPUC Guidelines at 10-11.

a. What language will best ensure that the audit achieves its various goals, including determining whether the costs booked to the balancing account meet the Phase 2 Conditions?

b. Are the specific conditions and other criteria for the audit clearly outlined in the Commission's SB-884 Guidelines to help determine whether costs in question meet such criteria?

c. Should audit objectives include verifying that claimed IOU activities and projects have been completed as claimed?
   i. Would satellite imagery or other photographic evidence be sufficient to perform this verification?

d. What are the project characteristics (e.g. projects with low CBR) that the audit should address?
   i. Should the CBR stated in the Application be verified during the audit?

e. Should the auditor be required to follow professional auditing standards to meet the audit objectives; and if so, which ones?

2. In D.23-02-017, the Commission explained that costs are incremental if "in addition to completing the planned work that underlies the authorized costs, the utility had to procure additional resources, be they in labor or materials, to complete the new activity. The existence and completion of a new activity by itself does not prove the cost was incremental."[16]

   a. With this Decision in mind, how should the Guidelines ensure that the scope of the audit addresses whether the costs in an SB-884 Application are incremental to other revenue requests presented to the Commission in a GRC or other cost recovery application? Please provide suggested language.

   b. Should an IOU be required to present costs related to straight time labor, overtime labor, contracted labor or other labor-related costs in its showing of incrementality in an SB-884 Application?

   c. Should audit Guidelines address the issue of incrementality between the Balancing Account and Memo Account authorized in Resolution SPD-15 and established through a utility's SB-884 Application? If so, what language would you recommend?

   d. Should an IOU be required to document its methodology of tracking incremental costs?
      i. Should all IOUs be required to use consistent methodologies in tracking these incremental costs?
      ii. Should an IOU be required to document how the GRC-approved cost categories line up with account categories or projects claimed to provide support for its methodology of tracking incremental costs?

3. When should the audit of the balancing account occur?

   a. Should the audit begin after the Commission adopts a Decision in the utility's GRC Application proceeding; if so, when?

4. How often should the audit of the balancing account occur?

---

[16] D.23-02-017 at 27.

a. Should an audit of the balancing account be limited to once every four years to correspond with the GRC cycle?

b. If an audit of the balancing account should occur multiple times in a GRC cycle, explain how many times and the rationale for requiring multiple audits within a utility's GRC cycle?

5. The Commission's SB-884 Guidelines state that if the audit demonstrates that costs were incorrectly recorded or failed to meet the Phase 2 Conditions, the Commission may order a refund to ratepayers.

   a. Should language be added to the SB-884 Guidelines that explicitly describes the method for a refund, such as a true-up in the utility's rates after the audit has been completed? If yes, provide suggested language along with a justification. If no, explain why.

6. The Commission's SB-884 Guidelines require the utility to identify any wildfire mitigation cost savings in its Application.[17] How should the claim of cost savings be addressed by the audit?

7. Should the Commission consider other possible audits completed previously by either third parties or internal IOU auditors as part of the assessment in determining appropriateness and reasonableness of claimed costs in question?

E. Net Present Value (NPV) Calculations and Sensitivity Analyses

Background:

NPV Costs and Revenue Requirement
Because undergrounding projects take a long time to complete and have long useful lives, their CBRs are calculated in present day dollars, even if the cost will be much higher in the future. This calculation is called the NPV of costs from the revenue requirement and involves discounting future revenue requirements (which represent the utility's future costs) to their present value. Utilities need to identify and report the future revenue requirements: these are the yearly costs the utility expects to recover from ratepayers, typically including operational expenses, capital expenditures, and a return on investment. Utilities need to determine and report the discount rate(s) representing the time value of money and how NPV costs are calculated.

Sensitivity Analyses
A sensitivity analysis is a technique used to understand how different inputs into a model impact the outcome or results. For example, sensitivity analysis is often used in arriving at a CBR and shows how sensitive the projected costs, benefits or risks are to changes in the input assumptions.

AB 2847
Assembly Bill (AB) 2847 (Stats. 2024, Ch. 578) requires the following:

> Pub. Util. Code Section 739.15(a) The commission shall determine in a scoping ruling or other ruling whether an application from an electrical corporation or gas corporation requesting authorization for or recovery of capital expenditures requires the estimates described in subdivision (b).
>
> (b) An application from an electrical corporation or gas corporation requesting authorization for or recovery of capital expenditures, including an application for conditional approval of the costs of an undergrounding plan pursuant to Section 8388.5, shall include, if the commission pursuant to

[17] For details see SPD-15, SB-884 Program: CPUC Guidelines at 7.

subdivision (a) determines that the estimates are required, the electrical corporation's or gas corporation's best estimate of both of the following:

(1) The application's impact on the electrical corporation's or gas corporation's annual revenue requirement for each year that the capital expenditures described in the application are expected to remain in the application's rate base if the application is approved or conditionally approved.

(2) The net present value of the application's impact on the electrical corporation's or gas corporation's annual revenue requirement provided pursuant to paragraph (1).

(c) The commission shall require the electrical corporation or gas corporation to provide supporting workpapers and calculations for the estimates described in subdivision (b).[18]

Questions:

1. In the context of AB 2847, should the utilities calculate and report their revenue requirement and NPVs costs in an SB-884 Application using a consistent method across IOUs? Explain your answer.

2. Considering the D.24-05-064 requirement that the IOUs present the results of three discount rate scenarios for their CBR calculation,[19] should the utilities be required to present NPV Benefits, NPV Costs, and CBR using each of the three discount rates in their SB-884 Applications?

3. Given that different mitigation projects may start at different times and become used and useful[20] in different years, how should the utility incorporate these differing timeframes into the calculation of NPV Costs and NPV Benefits?

4. Should the Commission require IOUs to report and compare NPV Costs and NPV Benefits, and CBR of undergrounding in a consistent mannner across IOUs?

    a. Do the current Commission SB-884 Guidelines allow for consistent comparison between undergrounding projects and alternatives? If yes, explain why. If not, why not?

    b. Do the current Commission Guidelines allow for accurate comparison between undergrounding projects and alternatives? Explain your answer.

F. Changes to a Utility's Expedited Undergrounding Plan

Background:

OEIS' revised Electrical Undergrounding Plan (EUP) guidelines allow for changes to the IOU's undergrounding Plans to occur throughout the ten year time period of any particular Plan. For example, Guideline 2.7.5.2 provides that model version changes are "qualitative updates that substantially change the way that the risk model operates and must be accompanied by a new model report (see Section 2.7.2), the establishment of a new Baseline, and a backtest report (see Section 2.7.6)." OEIS defines "calibration changes" as "smaller changes that do not significantly impact the Model Risk Landscape and

[18] https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202320240AB2847

[19] See D.24-05-064 at 102-105. The utilities are required to calculate CBR for each mitigation using three discount rate scenarios: a) Societal Discount Rate Scenario, b) Weighted-Average Cost of Capital Discount Rate Scenario, and c) Hybrid Discount Rate Scenario.

[20] The used and useful year of a project is the year that the project is completed and energized.

only require the establishment of a new Baseline."[21] In Section 2.4.2.4 of the OEIS Guidelines, a Confirmed Project is defined by the boundaries of the Confirmed Project Polygon that encompasses the entire Circuit Segment on which the Undergrounding Project is defined.[22] If an IOU changes its project, the polygon (or other illustration of where and how the undergrounding project will occur) is not updated. However, the OEIS Guidelines in Section 2.3.4 also state that if the scope of a project changes to include sections outside of the Confirmed Project Polygon (e.g., if a portion of another Circuit Segment outside of the approved Confirmed Project Polygon is added to a project), the utility can calculate risk reduction by using the risk reduction for "the full (expanded) project" for determining the contribution towards the Plan Mitigation Objective, and yet the utility may only use "the work inside the original Confirmed Project Polygon" for determining whether the project meets the Project-Level Standard. Hence, cost and risk reduction calculations, that will provide the substantial factual basis from which the Commission will deliberate on to make its Phase 2 Decision, may be impacted by potential changes to the scope of projects after a Phase 2 Decision is issued.

Questions:

1. How should the Commission ensure and evaluate that the costs, risk reduction, and CBR of a project are accurately calculated when portions of Circuit Segments are added or modified after:

    a. an IOU submits an SB-884 Application to the CPUC?

        i. If an IOU changes its projects after obtaining OEIS approval of its EUP, how should the utility incorporate these changes in its Application for cost recovery at the CPUC?

    b. the CPUC adopts a Phase 2 Decision on an SB-884 Application?

        i. If an IOU changes a project after the adoption of a Phase 2 Decision, for example due to circuit expansion, risk model change, or operational constraints, how should any additional costs, or cost reductions, be accounted for? Explain your answer.

        ii. If an IOU changes a project after the adoption of a Phase 2 Decision, how should the CPUC require an IOU to report changes to the project's CBRs? Should there be a threshold over which CBR changes should be reported?

        iii. If an IOU changes a project after the adoption of a Phase 2 Decision, how should the CPUC address projects that no longer meet the the conditional approval stipulated in the Phase 2 Decision?

    c. an audit of the SB-884 Application has concluded?

    d. an IOU submits an Application for a just and reasonableness review of its SB-884 Memorandum Account?

[21] See OEIS REVISED DRAFT 10-Year Electrical Undergrounding Plan Guidelines, Section 2.7.5.2 at 36.
[22] OEIS REVISED DRAFT 10-Year Electrical Undergrounding Plan Guidelines, Section 2.4.2.4 at 13.

2. Considering the implications of OEIS Guidelines Section 2.3.4 described above, when the utility calculates CBRs, should the utility use the NPV Benefits calculated for the risk reduction from:

   a. "the full (expanded) project"? Why or why not?

   b. "the work inside the original Confirmed Project Polygon"? Why or why not?

   c. Would your answers to 2a. and 2b. depend on circumstances, such as when the CBR is calculated? Please describe the circumstance and explain why it would affect the answer to 2a. and 2b

3. There are limits on Commission staff's ability to make changes to a Commission Decision or Resolution pursuant to delegated authority. D.02-02-049 and GO 96-B Rule 7.6.1 describe the difference between discretionary and ministerial action.[23]

   a. If an IOU seeks to change an undergrounding project, is there any change that you believe could be deemed ministerial with approval delegated to staff? If so, describe such ministerial changes.

   b. If an IOU seeks to change an undergrounding project is it your view that a Petition for Modification (PFM) is required?[24] Does your answer depend on the type of change? If so, please explain .

4. The current OEIS guidelines allows for a Confirmed Project to change within the 10-year period of the EUP.[25] How should the Commission address an undergrounding project where the trench length exceeds the forecasted estimate submitted to the Commission in an SB-884 Application?

   a. Should there be a trench length excedence threshold that:
      i. requires the project to be audited? Explain your answer.
      ii. triggers a PFM requirement? Explain your answer.

   b. What data could be used to determine whether or not the excedence threshold has been surpassed?
      i. Would the data collected through the OEIS Guidelines be sufficient? Why or why not?

5. Are the model version changes and calibration changes described in OEIS Guidelines 2.7.5.2 relevant to how the CPUC should handle undergrounding plan changes? Explain your position.

   a. How, if at all, should an IOU report to the CPUC and stakeholders on updates to a model, including the Outage Program Risk model described in Section 2.7 of the OEIS SB-884 Guidelines,[26] which are still in development and not submitted or approved as part of an IOU's Wildfire Mititgation Plan (WMP)?

---

[23] While discretionary and ministerial actions vary based on the subject matter, they broadly mean the following. Ministerial actions are actions which are made based on pre-defined criteria. These actions can be carried out by Industry Divisions, such as Safety Policy Division and Energy Division. Agencies cannot delegate discretionary action without statutory authority.

[24] PFMs asks the Commission to make changes to an issued decision. See CPUC Rules of Practice and Procedure Rule 16.4.

[25] For details see OEIS REVISED DRAFT 10-Year Electrical Undergrounding Plan Guidelines, Section 2.4.2.4 at 13.

[26] For details see OEIS REVISED DRAFT 10-Year Electrical Undergrounding Plan Guidelines, Section 2.7 at 24-41.

6. TURN stated in its May 29, 2024 comments on the OEIS Draft Guidelines that changes of at least 20% of circuits included in the EUP should trigger a new comment period of 10-15 days.[27] Cal Advocates similarly stated in its August 9, 2024 comments on PG&E's topics for Discussion of Revised Draft Guidelines that at each semiannual progress report new thresholds and risk models be used to re-evaluate the cost-effectiveness of projects in the current EUP work plan, to ensure that the thresholds are meaningful and the project prioritization evolves to reflect current information.[28]

    a. State your position on these comments.

G. How to Address Circuit Segments and Project Polygons

Background:

Section 2.8.1 of the OEIS Guidelines requires IOUs to furnish updated tabular data with each Progress Report. Section 2.8.3 of the OEIS Guidelines requires IOUs to furnish updated information reported in geodatabase submissions in each Progress Report including the latest version of their projects in polygon form. Section 2.7.6 of the OEIS Guidelines require the IOUs to retain models and calibrations data for the lifetime of the program, but the OEIS Guidelines do not have an explicit retention policy regarding tabular data and geodatabase submission updates.

Questions:

1. Should the CPUC Guidelines include an explicit retention policy that requires the utilities to retain updates to the tabular data and geodatabase with each Progress Report for the lifetime of the program?

2. Should the polygons be updated after the Commission adopts a Decision on the utility's application? Why or why not?

H. Number of Alternatives

Background:

Undergrounding refers to the practice of placing utility infrastructure, such as power lines, underground instead of using overhead poles and wires. Covered conductor refers to overhead lines encased with material thick enough to reduce the likelihood of sparks or faults, which in turn reduces the likelihood of causing fires or outages. Protection devices are switches, reclosers or sectionalizers installed on overhead power lines to isolate faults or shut off power, minimizing the scope and impact of outages or incidents. Other mitigations include, but are not limited to, practices such as vegetation management, which involves trimming or removing vegetation near power lines, and pole enhancements such as stronger, more fire-resistant materials (e.g., steel poles instead of wooden poles).

[27] See TURN Opening Comments on Draft 10-Year Electrical Undergrounding Plans Guidelines, May 29 2024 at 3 https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=56734&shareable=true

[28] See Corrected Comments of the Public Advocates Office on Pacific Gas and Electric Company's Topics for Discussion on Revised Draft EUP Guidelines, August 9 2024 at 2 https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=57175&shareable=true

The OEIS guidelines require an IOU to compare two alternative mitigations.[29] An alternative to this approach is the idea of requiring utilities to present an "exhaustive list" of all possible mitigations, which could offer more comprehensive risk analysis but may be resource intensive.

Questions:

1. Should the CPUC limit alternatives to those required by OEIS, or should it require additional mitigation alternatives to be presented? Explain your answer.

2. Should the CPUC allow utilities to tailor the number of alternatives analyzed based on specific circumstances, such as regional risks, or should a standard approach for all projects be required? Explain your answer.

3. How can the CPUC ensure that the analysis of alternative mitigations clearly, comprehensively and accurately compares costs and benefits of undergrounding, covered conductor, protection devices, and other mitigations?

4. Are there standards or regulations the CPUC should consider requiring for IOU projects and altenative mitigations, similar to Australia's Electricity Safety Bushfire Mitigation Regulations 2017[30]?

I. Compliance with the Application

1. If a project does not adhere to the timeline for completion included in its Application to the Commission, how should the Commission address this delay, and should delay affect cost recovery for that project?

J. How to Address Costs if an Application or Projects are Rejected or Abandoned

1. Undergrounding preparation costs could include permitting, site or right of way acquisition, labor/hiring, planning, environmental review and other operational costs incurred in planning an undergrounding project. What is your view on how the Commission should treat undergrounding preparation costs if the undergrounding project is not carried out and/or completed?

2. Does your answer to Question J.1 depend on why the project was not carried out and/or completed? For instance:

   a. Project denied by OEIS;

   b. Project funding disapproved by CPUC;

---

[29] Alternative Mitigation 1 must include covered conductor in combination with some type of PEDS. Alternative Mitigation 2 must include one other mitigation or combination of mitigations that meet or exceed the risk reduction of Alternative Mitigation 1, including but not limited to remote fault detection technologies and high impedance fault detection. For details see OEIS REVISED DRAFT 10-Year Electrical Undergrounding Plan Guidelines, Section 2.7.10 at 41.

[30] Electricity Safety (Bushfire Mitigation Duties) Regulations 2017 (legislation.vic.gov.au). These Regulations set guidelines and standards for protective devices' performance (e.g., how fast switches should close and reduce voltage on a faulted line) and for other mitigation measures.

c. Project abandoned by IOU;or

d. New legislation prevents the project from being carried out.

3. Generally, costs incurred prior to plant being placed in service and deemed used and useful are recorded as Allowance for Funds Used During Construction (AFUDC) costs. AFUDC is typically used for projects that are expected to be constructed and be placed into rate base so they can earn a rate of return.

   a. Should SB 884 undergrounding costs be treated as AFUDC if a project is rejected by OEIS or cost recovery for the project is denied by the CPUC?

   b. Should AFUDC costs related to a project that is rejected, denied or abandoned be recovered in an IOU's General Rate Case or should the CPUC solely determine cost recovery for costs of projects that are not yet completed in SB 884 project applications?

   c. How should IOUs record costs related to projects that are in progress but not yet completed to avoid retroactive ratemaking?[31] IOUs responding shall specify in which account they plan to record pre-Application costs and how they propose to seek cost recovery for those costs if a project is rejected, denied or abandoned.

4. Should the CPUC impose a requirement that if an SB-884 project reaches a certain stage it needs to be completed? Explain your answer.

5. Should the Commission develop guidelines pertinent to abandoned projects (i.e., projects the IOU opts not to complete or use)? If so, what positions should the guidelines take?

   a. Should any relate to cost recovery; and if so what positions should they take?

   b. Should any relate to removal of facilities; and if so what positions should they take?

   c. What other guidelines should there be?

6. Should the CPUC impose a requirement that a project that has remained at a particular stage for more than a certain period should be reported as abandoned?

   a. If so, what should the CPUC require regarding cost recovery and other activity on that project?

   b. If so, at what stage(s) of the project should it be reported as abandoned? How much time should elapse within that stage for the CPUC to require the utility to report the project as abandoned?

   c. If not, why not?

7. New Jersey has a rule that relates to cost recovery for abandoned projects that were part of an accelerated level of investment needed to promote the timely rehabilitation and replacement of certain non-revenue producing, critical water distribution components that enhance safety, reliability, water quality, system flows and pressure, and/or conservation.

   The rule states:

---

[31] Rates are set on the cost of doing business which the utility files in a rate case. The resulting Decision of the rate case is applied going forward and is never retroactive.

If within three years after the effective date of a Foundational Filing, a water utility has not filed a petition in accordance with the Board's rules for the setting of its base rates, all interim charges collected under the DSIC rate shall be deemed an over-recovery, and shall be credited to customers in accordance with this subchapter. A water utility may seek recovery of such projects in the ordinary course through its next base rate case. Notwithstanding the above, a water utility may continue to collect a DSIC charge during a pending rate case filed in accordance with this section.[32]

a. Should the CPUC develop a similar requirement for SB 884 undergrounding projects? Explain your answer.

[32] New Jersey Administrative Code 14:9-10.4 (e) - DSIC Foundational Filing https://casetext.com/regulation/new-jersey-administrative-code/title-14-public-utilities/chapter-9-water-and-wastewater/subchapter-10-distribution-system-improvement-charge/section-149-104-dsic-foundational-filing

Attachment 6

November 12, 2024 Informal Comments of TURN in Response to October 14, 2024 Questions from CPUC Staff Regarding SB 884 Implementation

INFORMAL COMMENTS OF THE UTILITY REFORM NETWORK (TURN)
IN RESPONSE TO OCTOBER 14, 2024 QUESTIONS
FROM CPUC STAFF REGARDING SB 884 IMPLEMENTATION

November 12, 2024

1. Introduction

The Utility Reform Network (TURN) submits these comments in response to the October 14, 2024 questions circulated by the Commission's Safety Policy Division (SPD) related to the CPUC's implementation of SB 884.

TURN appreciates the thoroughness and thoughtfulness of SPD's questions and that SPD is providing an open and transparent opportunity for all interested parties to answer these questions simultaneously. These comments reflect TURN's best efforts to respond to these important questions.

However, it should be understood that time and resource constraints limit TURN's ability to answer every question with as much detail as we would like. In addition, because it is not clear that this question and answer process will contribute to a Commission decision that is eligible for intervenor compensation, TURN has not been able to retain an outside consultant to help with responding to the questions. Furthermore, TURN does not have the benefit of knowing the nature of the utility's plans for SB 884 applications and does not have a dedicated staff who can devote most or all of their time to thinking through issues and contingencies that may arise in the SB 884 process and the detailed mechanics of SB 884 implementation. For all of these reasons, TURN's responses below should be considered preliminary and subject to change as TURN gains a more detailed understanding of the utility requests and positions.[1]

2. Section C – CBR Threshold

2.1. When Utilities Should Be Required to Provide Additional Justification for Projects

Utilities should be required to provide additional justification for projects in at least two situations (SPD Question 1).

The first is when the undergrounding project CBR for a given location is less than the CBR of one or more alternative projects to address the risk at that location. (See Section H – Number of Alternatives below). Undergrounding is the most expensive alternative, one that increases utility rate base. Thus, utilities have a financial incentive to choose undergrounding over other more reasonable alternatives – one that needs to be kept in check by the CPUC's duty to ensure just and

[1] For these reasons, TURN is not able to respond to questions in certain sections of SPD's document. The questions in Section A, regarding RO models and depreciation, are one example of questions that require the expertise of an outside consultant and would benefit from being presented in a process that is certain to contribute to a Commission decision that is eligible for intervenor compensation.

reasonable rates.[2] Thus, in the Phase 2 review process,[3] the Commission has an obligation to ensure that, for each proposed project location, undergrounding is the most reasonable alternative. The CBR is an important measure of one of the key elements of reasonableness, cost-effectiveness. The CBR is designed to comprehensively measure all relevant benefits of risk mitigation projects in the numerator and all relevant costs in the denominator. Thus, when the undergrounding CBR is less than or equal to the CBR of one or more operationally feasible alternatives, the utility should be required to make the case for why the undergrounding solution is still the most reasonable solution.

When the undergrounding CBR is less than or equal to the CBR of one or more operationally feasible alternatives, the fundamental showing the utility needs to make is why, notwithstanding this situation, the Commission should still approve the project in question. A key showing should be why the CBR, as calculated, is not sufficiently accounting for the benefits of undergrounding compared to the other alternatives for this particular location – what important factors is the CBR calculation missing or not correctly valuing? Are there risk characteristics of the location that the CBR is not sufficiently capturing or is the calculation of risk mitigation benefits of the competing alternatives not accurate in a way that undervalues undergrounding for some reason? If so, the utility needs to explain in detail why the CBR results should not be relied upon.

The second situation in which a utility should be required to provide additional justification for a proposed undergrounding project is when the CBR of the project is below a CBR threshold. It is premature to specify this threshold now. The threshold should be one of the issues determined in Phase 2, based on the CBR information submitted with the Phase 2 application. As discussed below in this section, experience has shown that utilities have different ways of calculating RSEs and the same is likely to be true for CBRs, notwithstanding Commission efforts to the contrary. For example, if utilities use different scaling functions or have different ways of addressing tail risk in their calculations, the CBR values for the same activity could differ significantly.

Once the Commission sets this threshold, which should be an early determination in the Phase 2 proceeding, the utility should be required to submit a justification for any project that falls below the threshold. The showing should again be the utility's explanation of why the CBR is not an accurate reflection of the cost-effectiveness of the project in question and why, notwithstanding the low CBR, the project should still be approved.

---

[2] PU Code Sections 451, 8388.5(e)(6).

[3] These comments use the Phase 1, Phase 2, and Phase 3 nomenclature, as those Phases are defined in SPD-15.

2.2. Robust Scrutiny of the Utility's CBR Calculations and Methodology is Necessary

As SPD knows, CBRs (and their predecessor, RSEs) are complex calculations based on complex methodologies. When determined in accordance with Commission requirements and otherwise using reasonable inputs and assumptions, they provide extremely valuable information regarding the cost-effectiveness of proposed projects and competing alternatives. However, because of their complexity, utilities also have the ability to skew the calculations in favor of their preferred outcomes. Potentially controversial elements of CBRs include, but are not limited to: whether the utility is accurately reflecting the mitigation effectiveness of competing alternatives;[4] whether the utility is using accurate costs for competing mitigations;[5] whether the utility's analysis is sufficiently granular to take into account the specific risk factors and costs at a given location; whether the utility is using reasonable values for the cost of electric reliability consequences;[6] whether the utility is reasonably valuing property damage from wildfires;[7] whether the utility is correctly modeling the impact of climate change on the wildfire risk;[8] whether the utility is correctly valuing safety consequences;[9] the reliability of CBR results based on a risk-averse scaling function as compared to a risk-neutral scaling function in the circumstances under consideration; [10] and the discount rate used to determine present values of the costs and benefits.[11]

Because of this complexity and opportunity for utility-calculated CBRs to reflect the companies' financial interest rather than the public interest, the CPUC needs to require the Phase 2 application to include comprehensive workpapers explaining the CBR calculation methodology and documenting the inputs, assumptions, and calculations.[12] If a utility has recently provided such workpapers in other submissions, the utility could provide those same workpapers but would

---

[4] In GRCs, intervenors have found that certain utilities understate the mitigation effectiveness of covered conductor based alternatives, including REFCL and other enhancements to covered conductor, compared to undergrounding.

[5] In GRCs, TURN has found that certain utilities overstate the relative cost of covered conductor based alternatives compared to undergrounding.

[6] See SPD's 11/8/24 Evaluation Report on PG&E's RAMP, A.24-05-008, p. 3, criticizing PG&E's method and noting that it inflates wildfire mitigation benefits.

[7] See SPD's 11/8/24 Evaluation Report on PG&E's RAMP, A.24-05-008, p. 56.

[8] See SPD's 11/8/24 Evaluation Report on PG&E's RAMP, A.24-05-008, p. 53.

[9] See SPD's 11/8/24 Evaluation Report on PG&E's RAMP, A.24-05-008, TURN's Informal Comments attached as Attachment 5, pp. 5-7.

[10] See SPD's 11/8/24 Evaluation Report on PG&E's RAMP, A.24-05-008, p. 4.

[11] See Section 8 below, responding to SPD's Section E questions.

[12] SPD-15, Attachment 1, p. 7.

need to clearly identify and explain any material changes. An application that fails to provide complete CBR workpapers should be rejected and a resubmission required.[13]

3. Section H – Number of Alternatives

The Commission should not limit the alternatives presented and considered to those required by OEIS (SPD Question 1). The Commission, not OEIS, has the obligation to ensure that any plan approved in Phase 2 meets the just and reasonable standard. Ensuring that each undergrounding project is needed and superior to all other alternatives is essential to meeting that standard. In addition to the alternatives noted in the preface to the SPD questions for this item, the alternatives should include remote grids and EPSS/PSPS. In some locations, it may be far less expensive to use a combination of EPSS/PSPS and utility-supplied off-grid back-up power than undergrounding.

As discussed in Section 2 above, the utility should demonstrate for each project that undergrounding is the most reasonable alternative for that location. The alternative that utilities are required to compare should include all operationally feasible options for the location. When considering covered conductor, all operationally feasible enhancements to covered conductor, such as REFCL, Fast Curve, EPSS, and other current-limiting technologies should also be considered as a menu of options, each with different effectiveness and cost attributes. If an alternative is not feasible, the utility needs to explain why. Thus, depending on which alternatives are feasible at a location, the alternatives considered may vary by location (SPD Question 2).

For TURN's response to SPD's question 3, see Section 2 above regarding how CBR should be used in the comparison of alternatives, including the need for detailed workpapers showing how the CBR was calculated, which should include comprehensive information about costs and benefits.

4. Section D – Audit

4.1. Preliminary Matters

The inclusion of an "audit" in the CPUC's process was a change to draft SPD-15 in response to comments. As a result, parties have not been given an opportunity to comment on that change. TURN appreciates the opportunity to address at least some of TURN's concerns with that aspect of SPD-15 here.

As a preliminary matter, TURN continues to take the position that the statute requires an *up-front* determination, *before cost recovery is authorized*, that the recorded costs are just and reasonable, including satisfying the Phase 2 conditions.[14] TURN's comments here do not waive

[13] *Id.*, p. 5.

[14] See TURN's 12/28/23 Comments on Draft SPD-15, pp. 3-5.

that legal contention but will assume, solely for purposes of discussion, that the CPUC can successfully defend its legal position.

As another preliminary matter, TURN notes its concern with the vague and inapposite term "audit." As will be discussed in this section, what SPD-15 describes as an "audit" needs to be a CPUC decision-making process – a post-implementation review -- that allows full participation by intervenors and results in an appealable decision made by the CPUC, not Staff. The necessary review cannot simply be outsourced to an "auditor" who makes the necessary determinations without a meaningful opportunity to participate by all interested parties and a decision by the Commission.[15]

4.2. Questions 1 and 5

As identified in SPD-15, a key objective of the review must be to ensure that the conditions of approval have been satisfied. The conditions identified in SPD-15 primarily relate to ratemaking matters that would not likely be within the expertise of a traditional auditor, nor covered by professional auditing standards. Instead, the Commission should use a process that allows meaningful participation by all interested parties (and by CPUC Staff, if the CPUC so chooses) to enable the CPUC to determine whether the information the utility supplies to support satisfaction of each condition is accurate and based on a reasonable methodology with reasonable inputs and assumptions.[16]

To the extent that the utility fails to demonstrate compliance with any of the conditions, costs of implemented projects must be removed from the balancing account as necessary to bring the completed projects into compliance with the conditions. Those costs should not be included in rate base at any point, unless and until the CPUC finds them just and reasonable and appropriate for inclusion in rates.[17]

The CPUC's review process should also assess whether factual contentions on which the Phase 2 approval was predicated proved to be accurate. If recorded costs exceed forecast costs by more than 5% for any project, the utility should be required to show that the change in cost did not change any of the CPUC's findings relating to stand-alone or relative cost-effectiveness (i.e., compared to alternatives) on which the CPUC's approval was based. If the increase in project

---

[15] Having noted its concern about the term "audit," TURN will use the term "review" in the remainder of this section.

[16] See Section 2.2 above regarding the need to carefully scrutinize the utility's calculated CBRs.

[17] It is unclear from SPD-15 whether costs that are removed in order to satisfy the Phase 2 conditions are eligible for inclusion in a Phase 3 application. To encourage cost efficiencies by the utility, TURN recommends that such costs not be eligible for recovery through Phase 3.

costs renders those findings invalid, the excess costs should be removed from the balancing account, as discussed in the prior paragraph.

In addition, the review should determine that the recorded costs were spent correctly by examining, among other things, whether: the project was completed as claimed, as supported by satellite imagery; all of the recorded costs directly related to the identified project and are properly treated as a cost of the project (not some other project); the costs were clearly described to demonstrate satisfaction of the foregoing requirements; no duplicate costs were included; if any recovery of cost overheads was allowed in the Phase 2 decision, overheads were properly calculated and reasonable; only categories of costs allowed by the CPUC in its Phase 2 decision are included in the balancing account. In contrast to the SPD-15 approval conditions, these sorts of requirements do not require ratemaking and cost analysis expertise and would benefit from review by a traditional auditor (fully independent of the utility – see Section 4.6 below) under professional auditing standards. The auditor's results should be made available to all interested parties for their comment. All recorded costs that were incorrectly assigned to approved projects must be removed from the balancing account.

The costs for any project that was included in the plan approved in the Phase 2 decision but not performed in the prescribed year should be removed and the price cap for that year reduced by the approved cost of the project. Costs should not be included in the balancing account until a project is complete. As discussed further in Section 7 below, ratepayers should not pay costs for projects that were not completed and are not attributable to a used and useful project.

It is critical that any previously recovered costs that are removed from the balancing account as a result of this review process (or any other process) be returned to ratepayers. The removed costs should include interest, to ensure that ratepayers are not made worse off by the time it may take to conclude the review process. The removed costs, plus interest, should be credited to ratepayers in the utility's annual electric true up advice letter.

The CPUC's review process must allow sufficient time and discovery opportunities for interested parties to analyze the utility information and prepare meaningful comments to inform an appealable CPUC decision that is eligible for intervenor compensation. As noted, the intent of the process is to ensure that the recorded costs are just and reasonable and appropriate for recovery in rates. Section 8388.5(e)(6) confirms that the Commission must determine that costs are just and reasonable. Intervenors have a statutory right to participate in ratemaking proceedings to assess whether costs are just and reasonable.[18] Nothing in SB 884 abridges such rights.

---

[18] *E.g.,* PU Code Sections 451, 1701.3.

4.3. Question 2

The utility should also be required to make the labor and resource incrementality showing cited in question 2. Cal Advocates has focused on this aspect of the incrementality issue in cases seeking recovery of wildfire mitigation costs, so TURN would defer to Cal Advocates on the details of the necessary showing.

If the SB 884 plan period coincides with any period in which a GRC decision has allowed cost recovery for any undergrounding costs, the review process should require an incrementality showing to make sure none of the activities covered by the GRC are included in the SB 884 balancing account recorded costs. GRC cost overruns for activities covered by the GRC authorization should not be considered incremental and should not be included in the balancing account, for reasons TURN has explained in Section 7 of its opening brief in A.23-06-008. [19]

4.4. Questions 3 and 4

The review process discussed in this Section should happen at least once per year, after the completion of each year of work authorized in the Phase 2 decision. The review for each year should be limited to only the costs of projects completed in that year, because only those costs should be included in the balancing account. The review after the first year would not be able to review Phase 2 conditions that require two years of recorded data (e.g., Conditions 3 and 4 in SPD-15, Att. 1, p. 11), but would be able to review the other conditions and other matters discussed in this response. The review for the first year of recorded costs should indicate that recovery of year 1 costs remains contingent on satisfaction of conditions 3 and 4 and any other conditions that require more than one year of information.

4.5. Question 6

Regarding how any utility claim of cost savings should be addressed by the review process, it is premature to give a definitive answer to that question. The review process may have an important role to play, but the role would likely depend on the nature of the asserted cost savings and whether the costs in question have already been approved for recovery or whether they are costs that have not been the subject of a cost recovery request. In addition, as the SPD-15 Guidelines state, the utility's Phase 2 application must explain the methodology by which the Commission can ensure that all identified savings are passed on to ratepayers. TURN would be better able to offer an answer to this question after first considering the methodology proposed by the utility.

---

[19] For a discussion of the type of showing the utility should be required to make to demonstrate incrementality compared to the GRC authorization, see, e.g., TURN's Opening Brief in A.23-06-008, found here, pp. 46-48.

4.6. Question 7

To the extent that a traditional auditor is used for any aspects of this review process, the auditor must be either on the CPUC staff or directed exclusively by the CPUC, not by the utility. The review of recorded costs is intended to fulfill the CPUC's obligation to ensure the costs are just and reasonable. As a result, any auditor should be thoroughly independent and overseen solely by the CPUC. Results from utility-retained auditors should not be considered dispositive of any issue in the review process. Prior cases have shown that utility retained auditors have missed key problems with the incrementality and reasonableness of the costs they supposedly audited.[20]

5. Section F – Changes to a Utility's Plan[21]

Under SB 884, the plan submitted to the CPUC for its Phase 2 review will be a group of proposed projects with detailed information for each project as required by the statute[22] and by the rules of the two reviewing agencies. The statute allows OEIS to require that this plan be modified,[23] but only the OEIS approved plan can be presented to the CPUC for its review and approval.[24] Thus, the statute does not allow a utility to add any new projects to the plan approved by OEIS or make material changes to projects, as the new or changed projects will not have been vetted through the mandated OEIS review process. Because each project must be reviewed by OEIS, a utility cannot attempt to add a new project after the OEIS Phase 1 decision by claiming that it is "offset" by a removed project.

However, after OEIS approval and up to a certain point in the CPUC's Phase 2 review process, a utility should be allowed to *remove* any projects and all associated costs from its plan. If a utility no longer wishes to pursue a project, there is no reason to require continued inclusion of the project in the plan and the attendant use of CPUC and party resources to review a dropped project. Of course, the cost of the plan should be reduced by the cost of any dropped projects. However, at some "point of no return", when the CPUC needs to draft its final Phase 2 decision and identify the approved projects, the CPUC should make clear that no more projects can be dropped. The costs of those removed projects should be removed through the review process discussed in Section 4 above.

A utility that wishes to add projects to its approved SB 884 plan after the OEIS decision can seek funding for such additional projects through its GRC process. However, the utility

---

[20] See, e.g., TURN's Opening Brief in A.23-06-008, found here, p. 66.

[21] This section responds to some, but not all, of questions 1, 3 and 4 in Section F of SPD's questions.

[22] PU Code Section 8388.5(c)(2), (3), (4) and (6).

[23] *Id.*, Section 8388.5(d)(2).

[24] *Id.*, Section 8388.5(e)(1).

should be aware that if it seeking cost recovery for undergrounding activities via both the SB 884 and GRC processes, it will be subject to a rigorous requirement that only the cost of incremental activities will be funded via whichever cost recovery vehicle turns out to be secondary to the primary vehicle (see Section 4.3 above regarding incrementality).

The statutory requirement that SB 884 plans that are reviewed by the CPUC must be the same group of projects approved by OEIS is a wise and necessary one. It comports with the need for the Commission to have a defined set of projects to review under the just and reasonable requirements. For the ratemaking process to be manageable, the list of projects cannot be a moving target that is augmented during or after the CPUC's Phase 2 process. The CPUC should discourage OEIS from adopting rules that are contrary to the statutory scheme. In any event, the CPUC is responsible for the approval of plan costs and is obligated to follow the statute and not allow utilities to add projects that were not included in OEIS's approved plan.

If, in implementation of its approved plan, the utility finds that it needs to add a small amount of contiguous miles to a project (no more than 5-10% of total miles for a project), such minor changes could be allowed, in order to accommodate the minor increase in mileage, provided that such minor modifications do not increase the cost cap. But this accommodation should be kept limited (to no more than 5-10% of miles for a project, as described above) in order to prevent a utility from moving ahead with projects that are materially different from what has been vetted and approved by OEIS and the CPUC.

6. Section I – Delayed Implementation of Approved Projects

If a project is completed in the year after it was scheduled to be completed in the Phase 2 application (say, in Year 2 instead of Year 1), the general approach should be that the cost cap for Year 1 should be reduced by the forecast cost for the project and the forecast for year 2 increased by the cost of the project.

However, the CPUC should be aware of the possibility that a utility could game the timing of project completion in order to manipulate the results of the calculations for the CBR and unit cost Phase 2 conditions. This would serve the utility's financial interests but undermine the ratepayer protective purposes of the Phase 2 conditions that SPD-15 touts at length.[25]

To discourage such gaming, the Commission should, first, not allow any escalation of the cost of the approved project costs because of the delay. And if the approved plan called for unit costs of undergrounding to decline from year to year, the delayed project costs that are added to the price cap in year 2 should be determined by the lower approved unit cost for year 2. In addition, the Commission should require the utility to explain why the delay was outside the

[25] SPD-15, pp. 9-12.

company's control and reserve the right to remove the costs of delayed projects from the cost cap entirely if the Commission finds that gaming is occurring.

7. Section J – Rejected or Abandoned Projects[26]

As discussed in Sections 4.2 and 4.4 above, only costs associated with a completed project should be recorded to the balancing account, and the costs of any project approved in the Phase 2 decision that is not completed should be removed. Those costs should be subtracted from the price cap for the applicable year as soon as the utility decides not to complete the project.

TURN agrees with Cal Advocates that both the longstanding "used and useful" requirement[27] and SB 884 do not allow recovery for costs of work that is not associated with a completed project, as there would be no undergrounded facilities providing the benefits that are supposed to be obtained from approved projects. Utilities should not be allowed to evade these requirements by including costs related to uncompleted projects, including costs recorded as AFUDC, in any GRC account.

In addition, if a project is rejected in the Phase 1 or Phase 2 review processes, costs incurred for denied projects should not be recovered from ratepayers for the same reason.[28] The Commission should recognize that the utility's approved cost of capital includes compensation for such known risks. Ratepayers should not be required to pay additional compensation for those risks. In addition, the Commission should not reduce the utility's incentive to select undergrounding only where such a project is likely to succeed.[29] Moreover, it should be remembered that the SB 884 process is voluntary and that the GRC process is an alternative means of seeking funding for undergrounding projects.

---

[26] This response addresses SPD questions 1-3 in Section J. As noted below, questions 4-7 are mooted by TURN's response to these prior questions.

[27] *See, e.g.,* D.18-12-021, p. 154; D.84-09-055, 16 CPUC 2d 205, 228.

[28] D.84-09-055 contains a good discussion of the policy reasons for not approving recovery of planning, permitting, and other preliminary costs for projects that are not completed. The exception to the rule that costs of projects that are not used and useful are not recoverable – for projects that are prudently pursued "during a period of great uncertainty" (16 CPUC 2d at 229)– does not apply here. At this point in California's journey with respect to utility-caused wildfires, there is no significant uncertainty about the importance of prudent and cost-effective wildfire mitigation strategies. Nor is there any uncertainty that, in appropriate locations, undergrounding can be the superior wildfire mitigation choice. Managerial acumen is needed to propose undergrounding where it is the best use of limited ratepayer funds and not to attempt an excessive deployment of undergrounding to further shareholders' interests.

[29] D.84-09-055, 16 CPUC 2d at 229.

The challenges and complications posed by SPD questions 4 through 7 are mooted by following the clear rule that costs of projects that are not completed are not recoverable.

8. Section E – Present Value Calculations[30]

TURN appreciates that SPD is attentive to the requirements of recently enacted AB 2847. The Commission should make clear in a decision or ruling in advance of the submission of Phase 2 applications that those applications must include both nominal and present value (PV) lifetime calculations for the capital costs of their proposed plans. To account for the fact that different projects will start at different times over the duration of the proposed plan, the utility should include workpapers showing the lifetime costs for each proposed project.

Consistent with D.24-05-064,[31] the utility's Phase 2 application should provide CBRs and PV of lifetime revenue requirement values using the three discount rate scenarios identified in that decision.

9. Section B – Third Party Funding

Unfortunately, TURN does not expect utilities to obtain third party funding for a meaningful portion of undergrounding costs. However, if any such funding is obtained, it must be deducted from plan costs that are included in the balancing account. Utilities should not be allowed to include in rates or rate base any costs that were covered by third party funding. In GRCs, a utility would be able to seek recovery of any reasonable maintenance costs for third party funded underground plant to the extent that such maintenance costs are not covered by the third party funding source.

10. Conclusion

TURN appreciates the opportunity to respond to SPD's questions – and to see other parties' responses – in an open and transparent process. Please contact the undersigned with any questions about TURN's responses.

---

[30] TURN believes "present value" not "net present value" is the correct term in this context (costs and benefits are not netted against each other in CBRs and revenue requirement calculations) so TURN uses the former term. This section addresses questions 1-3 in Section E. Question 4 is addressed to some extent in Sections 2.1 and 2.2 above, which point out that utilities have, to date, used different methodologies for calculating RSEs, which make these cost-effectiveness measures not comparable among utilities.

[31] D.24-05-064, pp. 102-105.

Dated: November 12, 2024 Prepared by:

/s/ *Thomas J. Long*

Thomas Long, Director of Regulatory Strategy
tlong@turn.org

THE UTILITY REFORM NETWORK
360 Grand Avenue, # 150
Oakland, CA 94610
Telephone: (415) 929-8876 x303

Attachment 7

SPD Slides for the 4/8/25 SB 884 Workshop

California Public Utility Commission's SB 884 Guidelines: April 8, 2025

Potential Updates

Safety Policy Division and Energy Division

Ladder Safety

- “over 130,000 emergency room visits related to ladders each year" - ANSI
- Choose the right ladder for the task at hand and inspect before using.
- Put ladder on a stable surface and maintain three points of contact.

Agenda

Introductions	1:00 – 1:05 pm
Purpose and Expected Outcomes of Workshop	1:05 – 1:10 pm
Potential Update to CPUC Guidelines: Safety Policy Division (SPD)	1:10 – 1:40 pm
Potential CPUC Guidelines Update Q&A: SPD	1:40 – 2:20 pm
Break	2:20 – 2:30 pm
General Discussion	2:30-4:00 pm

Background

SB 884 Basics

- Requires CPUC to establish a new expedited utility distribution infrastructure undergrounding program
- Only PG&E, SCE, or SDG&E can participate in the program
  - Participation is optional
- Program requires submission of a 10-year undergrounding plan
- Plan requires review and approval by Energy Safety before cost consideration by CPUC
- Each agency allotted 9 months to complete respective portions
- Program costs considered in stand alone Application in addition to amounts approved in a GRC

SPD-15: SB 884 Program CPUC Guideline Basics

- Satisfies Commission's **PU Code § 8388.5(a)** requirement
- Implements a **3-phased approach** for implementation of CPUC and Energy Safety responsibilities under SB 884 Program:
  - ***Phase 1*** – Energy Safety Plan review and approval/denial
  - ***Phase 2*** - Application Submission and Review for Conditional Approval
  - ***Phase 3*** - Construction and potential recovery of costs not meeting Phase 2 conditions in Memo Account
- Interprets "conditional approval" as the set of requirements necessary to determine that Plan's forecasted costs are just and reasonable (up to a cost cap)
- Establishes a 1-way balancing account (BA) to record costs meeting "conditions" in the Phase 2 Decision
- Establishes a memo account to record costs that don't meet conditions
  - Requires filing of separate application to examine memo acct. costs

SPD-15 Phase 2 Conditions

1. Total annual cost cap
2. Third party funding
3. Rolling average recorded unit cost
4. Rolling average recorded cost-benefit ratio
5. Any further reasonable condition adopted by Phase 2 Decision

Roles and Responsibilities

Phase 1:
Plan Review
(Months 1-9)

Energy Safety

- Receive Plan
- Public Comments and Workshop
- Approve/Deny Plan

Phase 2:
Application Review
(Months 11-20)

CPUC

- Receive Application
- Public Comments and Workshop
- Conditional Approval/ Denial of Plan’s Costs

Phase 3:
Construction and Monitoring
(Years 1-10 on Recurring Annual Cycle)

Large Electrical Corporation

- 6-Month Progress Reports
- If Justified, File Application(s) for Recovery of Costs in Memorandum Account

CPUC

- Review 6 & 12 Month Reports
- Periodic Audits of Recorded Costs
- Enforcement, If Appropriate
- Reasonableness Review of Memo Accounts, If Needed

Energy Safety

- Select & oversee Independent Monitor (IM) who assesses Plan compliance
- Review and Evaluate annual IM Reports
- Possible Referral to CPUC

Energy Safety Project Acceptance Framework

Screen	Screen Name	Screen Objective	Screen Output
1	Circuit Segment Eligibility	Identify all circuit segments that are potentially eligible for the SB 884 program (location & risk score criteria)	Eligible Circuit Segments List
2	Project Information & Alt. Mitigation Comparison	Specifies minimum info required for "eligible circuit segments" to be considered for UGing & comparison to two alternative mitigations	UG Project List (i.e., potential UG projects)
3	Project Risk Analysis	UG Projects further scoped, compared to baseline and alt. mitigations, and IOU applies "Key Decision Making Metrics" (KDMMs) to identify fixed areas where UG work will occur (i.e., Confirmed Project Polygons)	Confirmed Project List
4	Project Prioritization & Finalization	IOU details its basis (e.g., wildfire risk, public safety, cost efficiency, reliability benefits, etc.) for prioritization for UG projects	Prioritized Projects List

Topics for Potential Update to CPUC Guidelines

Guideline Section	Topic to Update
Phase 2 Application Requirements	Additional Requirements
	HFTD
	Full Lifecycle Costs and Depreciation
	Data Retention
	Calculation of Present Value
Conditions for Approval of Plan Costs	Cap on MA/Data Variance
	CBR/KDMM Threshold
	Alternatives Comparison CBR
Phase 3	Audits and/or Review Procedure
Changes to the Plan	New Costs Added to Projects
Appendix	CBR Calculation

Potential Application Requirements to SPD-15

Should the Commission consider supplementing the Phase 2 Application Requirements?

Phase 2

- Include the data associated with the list of all projects (SB 884 Project List Data Requirements) as required by Screen 2 of the Energy Safety Guidelines.
- Require the utilities to provide a detailed explanation for any spans that extend beyond the HFTD for any project included in the Underground Project List from Screen 2 of the Energy Safety Guidelines.
- Require utility to submit a depreciation study with updated information of assets that are impacted by an SB-884 Application.
- Require both nominal and present value lifetime calculations for the capital expenditures of each project in the Undergrounding Project List from Screen 2 of the Energy Safety Guidelines .
- Require data retention policy for lifetime of EUP for tabular and geodatabase data. This should be required for both the initial application and any of the data updated through the six-month progress reports.

Potential Additional Phase 2 Conditions

Phase 2

Should the Commission consider imposing conditions on the Memorandum Account (MA)?

- Maximum total cap for MA condition
  - MA maximum total cap cannot exceed 25% the sum of the ten annual caps established for the balancing account
- Others?

Phase 2

Should the Commission consider the variance between the forecast data in the Application with updated data in the 6-month progress report as a Condition?

- If the variance between the forecasted CBRs and unit cost of a project presented in an Application compared to the updated CBRs and unit cost of a project presented in a six-month Progress Report (after a project passes Energy Safety's Screen 4) exceeds a certain threshold, then all costs for that project must be recorded in the MA.

- Others?

Phase 2

Should the Commission consider adopting a CBR Threshold Condition, and if so, what should the criteria be?

- Require all projects to have a CBR greater than a specified value.
- If a project's recorded CBR is less than a specified value, the utility must provide a detailed justification for this project.
- After Screen 2, any project ranked below a certain CBR percentile threshold is ineligible for cost recovery via the BA.
- Others?

Should the Commission consider applying Key Decision-Making Metrics (KDMMs) to the Commission consideration of projects?

Phase 2

- Require utilities to submit the same data for Commission review as provided for in Energy Safety's KDMMs after the Energy Safety approves the utility's Plan.
- After Screen 3, if the reduction in Ignition Risk and/or Outage Program Risk does not meet the required Project Level Standard set in the approved Plan, the project will not be eligible for cost recovery via the one-way balancing account.
- Others?

Should the Commission consider requiring a comparative CBR analysis of project alternatives?

Phase 2

- If an Undergrounding Project has a CBR above a specified value but the Alternative(s) has a CBR that is a specified amount greater than the Undergrounding Project's CBR, then the undergrounding project should not move forward.

- Others?

Potential Review Process for Costs

Should the Commission consider adopting the following review structure of the costs associated with an EUP?

Phase 3

- Annual post-implementation review process with intervenor participation.
- Objectives of the review should include verifying project completion, cost overheads, CBR methodology and an incrementality showing.
- Once deemed "used and useful" in a progress report, a project's costs may be included in rate base via an Advice Letter that must be disposed via Commission Resolution.
- Commission Resolution will determine whether recorded costs met the Phase 2 Conditions and other objectives of the review.
- Approved costs would enter rates via Annual True-up.

Should the Commission consider adopting this alternative review structure of the costs associated with an EUP?

Phase 3

- Annual audit by independent auditor with CPUC oversight
- Objective of the audit should include verifying project completion, cost overheads, and an incrementality showing
- Once deemed "used and useful" in a progress report, a project's costs may be included in rates via annual True-up and become subject to audit
- If the audit finds that project costs were incorrectly recorded to the Balancing Account, then the utility must issue a refund to ratepayers

Phase 3

Supporting Cost Review Questions

- How should the timing of the Independent Monitor’s (IM) review and the utility’s right to correct a deficiency found by the IM within 180 days (PUC 8838.5 (g)(2)) interact with the review of the costs of a project?

Additional Questions

Should the Commission consider requiring new costs added after the Phase 2 Decision to be booked to the Memo Account?

Phase 3

- If the updated rolling average CBR falls below the Phase 2 Condition threshold, should all new costs be deemed non-recoverable?

- Should certain categories of cost overruns (e.g., inflation-driven, safety-driven, etc.) be treated differently from discretionary cost increases?

Should the Commission consider including a CBR Calculation Appendix?

Appendix

- What level of granularity should the utility use when applying the Interruption Cost Estimator (ICE) Calculator to generate a Monetized Value of Electric Reliability?
- How should the utility calculations of CBR be presented when using the three discount rate scenarios (Weighted Average Cost of Capital, Social and Hybrid) required by D.24-05-064?
- If the utility applies a convex risk scaling function to the calculation of CBR, how should the utility also present calculations that do not apply a convex risk scaling function, as required by D.24-05-064?

Next Steps

Next Steps

- Issue Postworkshop Questions: April 11, 2025
- Parties provide written responses: April 22, 2025
- Draft Resolution: Q2-Q3 2025

Questions?

California Public
Utilities Commission

Attachment 8

SPD Post-Workshop Questions for Stakeholders Regarding the SB 884 Guidelines, 4/11/2025

Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines

April 11, 2025

Instructions:

- If any question in this document calls for a "yes" or "no" answer, please explain your answer rather than simply providing a one-word answer.
- The reference to Office of Energy Infrastructure Safety (Energy Safety) Guidelines are available at https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=58006&shareable=true.
- The Commission SB-884 Guidelines refers to Resolution SPD-15, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M526/K984/526984185.pdf

Definitions:

- **Cost Benefit Ratio (CBR**): calculated by dividing the dollar value of Mitigation Benefit by the Mitigation cost estimate.[1]
- **Circuit Segment**: refers to a specific portion of an electrical circuit that can be separated or disconnected from the rest of the system without affecting the operation of other parts of the network. This isolation is typically achieved using switches, circuit breakers, or other control mechanisms.[2]
- **Electric Undergrounding Program (EUP):** an expedited utility distribution infrastructure undergrounding program established by the CPUC pursuant to section 8388.5(a).[3]
- **Investor Owned Utility (IOU)**: Utility regulated by the Commission that seeks SB 884 cost recovery or submits an SB 884 Application or seeks Energy Safety approval for an SB 884 Plan.
- **Key Decision-Making Metric (KDMM):** Energy Safety's 10-Year Electrical Undergrounding Plan Guidelines describe Key Decision-Making Metrics as a collection of top-level metrics that the Large Electrical Corporation is allowed to use to evaluate the efficacy of an Undergrounding Project. They do not reflect financial considerations. The utility must report on seven mandatory KDMMs, and may include 5 additional KDMMs of its choice. The mandatory KDMMs include Ignition Risk and Outage Program Risk.[4]
- **Memorandum Account (MA):** In the context of Senate Bill (SB) 884 Program: CPUC Guidelines, the Memorandum Account refers an account where a large electrical corporation may record implementation costs that do not meet the Phase 2 Conditions. In Phase 3, the large electrical corporation may file an application and request rate recovery for these costs.
- **Office of Energy Infrastructure Safety (Energy Safety) Guidelines**: explained in "Instructions," above.
- **Phase 2 Conditions (Conditions):** The Phase 2 Conditions will include, but are not limited to, a total annual cost cap, two-year rolling average recorded unit cost cap, two-year rolling average recorded CBR threshold, and applying third-party funding to reduce the cost cap.[5]

---

[1] D.24-05-064, Appendix A at A-3. A higher CBR means more risk reduction is achieved for the same amount of cost, indicating greater cost-efficiency. For example, if Project A has a CBR of 2.0 and Project B has a CBR of 1.0, Project A delivers twice the risk reduction benefit per dollar spent compared to Project B.

[2] This concept refers to the same concept found within the Energy Safety Guidelines Appendix A.

[3] Energy Safety 10-Year Electrical Undergrounding Plan Guidelines, A-1.

[4] For details see Energy Safety 10-Year Electrical Undergrounding Plan Guidelines, Section 2.7.3 at 31-32.

[5] For details see SPD-15, SB-884 Program: CPUC Guidelines at 10-11.

- **Protective Equipment and Device Settings (PEDS)**: advanced safety settings implemented by electric IOUs on electric utility powerlines to reduce wildfire risk.[6]
- **SB 884 Project List Data Requirements**: the list of data fields that the utility must complete for each project the utility includes in its EUP cost recovery Application. This data set must be submitted with the initial cost recovery Application and updated in the six-month progress reports. The detailed requirements are listed in Appendix 1 of SPD-15 or any future update to Appendix 1.
- **Screen 2 (Project Information and Alternative Mitigation Comparison)**: confirms there is sufficient information available on a Circuit Segment and requires comparison of undergrounding to alternative mitigations in order to determine which Eligible Circuit Segments can be treated as Undergrounding Projects.[7]
- **Screen 3 (Project Risk Analysis)**: the procedure for evaluating an individual Undergrounding Project in the context of the Portfolio of Undergrounding Projects and includes information obtained through the project development process resulting in a list of Confirmed Projects.[8]
- **Screen 4 (Project Prioritization and Finalization):** the procedure for prioritizing Confirmed Projects using the means of prioritization approved by Energy Safety in the Electrical Undergrounding Plan (EUP).[9]
- **Undergrounding Project**: an Eligible Circuit Segment that has completed Screen 2 including the SB 884 Project List Data Requirements from Appendix 1 of SPD-15 or any future update to Appendix 1.

A. Should the Commission Consider Supplementing the Phase 2 Application Requirements?

Background:

SPD-15 included a list of 20 requirements that must be included in any Application submitted to the Commission seeking conditional approval of Plan costs. Would it be appropriate for the Commission to consider adding the following requirements?:

1. Include the data associated with the list of all projects (SB 884 Project List Data Requirements) as required by Screen 2 of the Energy Safety Guidelines
    a. Require the utility to provide us with a forecasted scope of all projects for the ten-year plan, with the expectation that projects far in the future would change.
    b. This requirement would make it explicit that the Underground Project List, which is an output from Screen 2 in the Energy Safety Guidelines, must be ready for the Commission to review before an Application can be submitted.
2. Require the utilities to provide a detailed explanation for any spans that extend beyond the HFTD for any project included in the Underground Project List from Screen 2 of the Energy Safety Guidelines.[10]
    a. The Energy Safety Guidelines allow for undergrounding circuit segments with assets inside the HFTD, then each span that crosses the Tier 2 or 3 HFTD boundary and up to two adjacent spans outside of a Tier 2 or 3 HFTD may also be included in a project.
    b. This requirement would ask the utilities to provide a detailed explanation regarding why they must include any spans that extend beyond the HFTD.

[6] For details see https://www.cpuc.ca.gov/industries-and-topics/wildfires/protective-equipment-device-settings
[7] For details see Energy Safety 10-Year Electrical Undergrounding Plan Guidelines, Section 2.4.4 at 18-19
[8] For details see Energy Safety 10-Year Electrical Undergrounding Plan Guidelines, Section 2.4.5 at 19-20
[9] For details see Energy Safety 10-Year Electrical Undergrounding Plan Guidelines, Section 2.4.6 at 20
[10] For details see PUC 8388.5(c)(2) and Energy Safety 10-Year Electrical Undergrounding Plan Guidelines, Section 2.4.3.1 at 16.

3. Require utility to submit a depreciation study with updated information of the type of assets that are impacted by an SB-884 Application
    a. Depreciation studies are typically updated when a utility files its GRC.
    b. Because undergrounding projects have large capital expenditures, there is a potential that depreciation and salvage costs may be contested in an EUP cost recovery Application.
    c. This would require a depreciation study be included in the record, but it should be a depreciation study with updated information since an EUP cost recovery Application will not necessarily be submitted in the same time frame as a GRC.
4. Require both nominal and present value lifetime calculations for the capital expenditures for each project included in the Undergrounding Project List from Screen 2 of the Energy Safety Guidelines [11]
    a. PUC 739.15 specifically calls out the need for greater clarity on the lifetime cost and benefit of a capital expenditure project such as those submitted in an EUP cost recovery Application.
    b. This would require both nominal and present value lifetime calculations for the capital expenditure of each undergrounding project.
5. Require data retention policy for lifetime of EUP for tabular and geodatabase data. This should be required for both the initial application and any of the data updated through the six-month progress reports.
    a. Since there are no additional requirements for data retention related to an EUP, this will require the utility to retain all tabular and geodatabase information submitted as part of the EUP and any data included in six-month progress reports.
    b. Staff intend to hold data template working groups later in the spring.
6. Require utilities to submit the same Key Decision-Making Metrics (KDMM) data for Commission review as provided for in the submission to Energy Safety.

B. What, if Any, Additional Phase 2 Conditions Should the Commission Consider?

Background:

SPD-15 listed five Phase 2 Conditions that must be met for the costs of any project to be booked to a one-way balancing account. The parameters or threshold values of the Conditions will be established in the Phase 2 Decision based on the forecasted numbers presented in the cost recovery Application. As explained in the Instructions above, the five Conditions listed in SPD-15 include a total annual cost cap, a two-year rolling average recorded unit cost cap, a two-year rolling average recorded CBR threshold, a requirement to apply third-party funding to reduce the cost cap, and any further reasonable Conditions supported by the record of the proceeding and adopted by the Commission in the Phase 2 Decision.[12]

1. Should the Commission consider imposing Conditions on the Memorandum Account (MA)? If so, what Conditions should be considered?
    a. Option 1: Establish a maximum total cap for the MA, limiting it to no more than 25% of the total sum of the ten-year annual caps established for the balancing account.
    b. Others?
2. Should the Commission consider assessing the variance between the forecast data submitted according to the SB 884 Project List Data Requirements in the initial cost-recovery Application to

[11] See also PUC 739.15

[12] For details see SPD-15, SB-884 Program: CPUC Guidelines at 10-11.

the Commission and the updated data submitted according to the SB 884 Project List Data Requirements in a six-month progress report and if so how?

   a. Option 1: If the variance between the forecasted CBRs and unit cost of a project presented in an Application compared to the updated CBRs and unit cost of a project presented in a six month Progress Report (after a project passes Energy Safety's Screen 4) exceeds a certain threshold, then all costs for that project must be recorded in the MA.
   b. Others?

3. Should the Commission consider adopting a CBR Threshold, and if so, what should the criteria be?
   a. Option 1: Require all projects to have a CBR greater than a specified value.
   b. Option 2: If a project's recorded CBR is less than a specified value, the utility must provide a detailed justification for this project.
   c. Option 3: After Screen 2, any project ranked below a certain CBR percentile threshold is ineligible for cost recovery via the BA.
   d. Others?
4. Should the Commission consider requiring a comparative CBR analysis of project alternatives? If so, how should this analysis be conducted?
   a. Option 1: If an Undergrounding Project has a CBR above a specified CBR Threshold but the Alternative(s) has a CBR that is a specified amount greater than the Undergrounding Project's CBR, then the undergrounding project should not move forward.
   b. Others?
5. Should the Commission consider applying some of Energy Safety's KDMMs to the Commission's consideration of whether to grant cost recovery for projects and if so, how?
   a. Option 1: After Screen 3, if the reduction in Ignition Risk and/or Outage Program Risk does not meet the required Project Level Standard set in the approved Plan, the project will not be eligible for cost recovery via the one-way balancing account.
   b. Others?

C. What methods could the Commission use to address the Audits and/or Review Procedure?

Background:

The Commission's SB-884 Guidelines require that costs submitted in an SB-884 Application meet certain Conditions (Phase 2 Conditions) before they can be authorized for recovery via a one-way balancing account.[13] That one-way balancing account is subject to audit. If the audit finds that costs were incorrectly recorded or failed to meet the Phase 2 Conditions, the Commission may order a refund. SPD-15 stated that the details of this audit would be determined in a later decision or order. The questions below explore two potential structures for determining whether costs were appropriately recorded to the balancing account:

Questions:

1. Should the Commission consider adopting the following review structure to ensure a rigorous review of the costs associated with an EUP?
   a. Annual post-implementation review process with intervenor participation.
   b. Objectives of the review should include verifying project completion, cost overheads, CBR methodology and an incrementality showing.

[13] The Phase 2 Conditions will include, but are not limited to, a total annual cost cap, two-year rolling average recorded unit cost cap, two-year rolling average recorded CBR threshold, and applying third-party funding to reduce the cost cap. For details see SPD-15, SB-884 Program: CPUC Guidelines at 10-11.

   c. Once deemed "used and useful" in a progress report, a project's costs may be included in rate base via an Advice Letter that must be disposed via Commission Resolution.
   d. Commission Resolution will determine whether recorded costs met the Phase 2 Conditions and other objectives of the review.
   e. Approved costs would enter rates via Annual True-up.
2. Should the Commission instead consider adopting the following review structure to audit the costs associated with an EUP?
   a. Annual audit by independent auditor with CPUC oversight.
   b. Objective of the audit should include verifying project completion, cost overheads, and an incrementality showing.
   c. Once deemed "used and useful" in a progress report, a project's costs may be included in rates via annual True-up and become subject to audit.
   d. If the audit finds that project costs were incorrectly recorded to the Balancing Account, then the utility must issue a refund to ratepayers.
3. Supporting Questions:
   a. How should the timing of the Independent Monitor's (IM) review and the utility's right to correct a deficiency found by the IM within 180 days (PUC 8838.5 (g)(2)) interact with the annual review of the costs of a project?
   b. How should projects that fail to meet key criteria be treated vis-a-vis cost recovery? What key criteria should be considered?
   c. Should intervenors participate in Options 1 and 2 above? If so, how and where?
   d. Should the Commission consider using a different option than 1 or 2 above? If so, explain each step in the proposed process. How and where would intervenor participation be accounted for in the proposed option?

D. How could the Commission address changes to approved projects?

Background:

Changes to project costs and implementation status can impact cost recovery under the SB-884 framework. Except for 25 projects that Energy Safety's Guidelines will require to pass through all four Screens, cost and risk data (including CBR calculations) presented will be associated with projects having passed Screen 2 at the time of Application submittal. However, it isn't until after projects have passed Screen 4 that their full scope is determined and more accurate data associated with project cost and risk (including CBR calculations) are provided. These updated data are expected to be received throughout the life of the 10-year Plans and submitted via the six-month progress reports. Accordingly, how should the Commission handle new costs added to projects after the Phase 2 Decision is issued, based primarily on Screen 2 data? How should the Commission treat costs from abandoned or incomplete projects? The following questions explore potential approaches for managing these changes.

1. Should new costs added to approved projects after the Phase 2 Decision be booked to the Memo Account?
   a. If the updated rolling average CBR falls below the Phase 2 Condition threshold, should all new costs be deemed non-recoverable?
2. Should certain categories of cost overruns (e.g., inflation-driven, safety-driven) be treated differently from discretionary cost increases?

E. Should the Commission include an Appendix with guidance for calculating the CBR of an undergrounding project?

Background:

The calculation of the CBR for undergrounding and alternative projects is a critical factor in determining project eligibility for cost recovery. In addition, the selection of CBR Year Zero[14] plays a pivotal role in accounting for the time value aspect of CBR calculations. Notably, the Energy Safety Guidelines define Total Utility Risk as the sum of Ignition Risk and Outage Program Risk.[15] The following questions explore how utilities should apply existing methodologies and present their results.

1. What level of granularity[16] should the utility use when applying the Interruption Cost Estimator (ICE) Calculator to generate a Monetized Value of Electric Reliability? Should the analysis be based on:
    a. HFTD and PEDS-activated circuits
    b. Operational Region and HFTD[17]
    c. Others?
2. How should the utility calculations of CBR be presented when using the three discount rate scenarios (Weighted Average Cost of Capital, Social and Hybrid) required by D.24-05-064?[18]
3. Since the Energy Safety Guidelines allow the utility to consider an Ignition Tail Risk Threshold and High Frequency Outage Program Threshold,[19] if the utility applies a convex risk scaling function to the calculation of CBR, how should the utility also present calculations that do not apply a convex risk scaling function, as required by D.24-05-064?[20]
4. How should the Commission consider the combined CBR benefits of Ignition Risk reduction and Outage Program Risk reduction, given that a proposed mitigation may also reduce outage program risk?
    a. Option 1: Calculate the CBR benefit based on the Ignition Risk reduction only.
    b. Option 2: Calculate the CBR benefit based on a combination of Ignition Risk reduction and Outage Program Risk reduction?
        i. Should the CPUC assume mutual exclusivity between Ignition Risk and Outage Program Risk when aggregating the CBR benefits? If not, how should these risks be comibined?
5. What is the appropriate point in time for utilities to use as CBR Year Zero in CBR calculations?
    a. Option 1: The first year of application cycle.
    b. Option 2 : The year the project is expected to become used and useful.

---

[14] The year that all Costs and Risk Reductions are discounted to for the purpose of CBR calculations.

[15] For details see Energy Safety 10-Year Electrical Undergrounding Plan Guidelines, Section 2.7.3 at 31.

[16] "Level of granularity," as used in this context, refers to the spatial scale at which it is expected the utility will organize data inputs for use with the ICE Calculator.

[17] For details see R.20-07-013, ALJ Ruling Entering Phase 4 Technical Working Group Materials and Related Staff Proposal into the Record and Setting Comment Schedule, Attachment 2: Proposed Data Template Guideline for RAMP and GRC Applications, February 7 at 5 and 18-19. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M556/K602/556602764.PDF

[18] See the requirement in D.24-05-064 at 102-105 and D.24-05-064, Appendix A, Row 25.

[19] For details see Energy Safety 10-Year Electrical Undergrounding Plan Guidelines, Section 2.7.9.1 at 42.

[20] See the requirement in D.24-05-064 at 97-98 and D.24-05-064, Appendix A, Row 7.

Attachment 9

Comments of TURN in Response to April 11, 2025 Post-Workshop Questions From CPUC Staff Regarding SB 884 Implementation

COMMENTS OF THE UTILITY REFORM NETWORK (TURN) IN RESPONSE TO APRIL 11, 2025 POST-WORKSHIP QUESTIONS FROM CPUC STAFF REGARDING SB 884 IMPLEMENTATION

TURN
THE UTILITY REFORM NETWORK
Lower bills. Livable planet.

Thomas J. Long
Director of Regulatory Strategy

Elise Torres
Assistant Managing Attorney

THE UTILITY REFORM NETWORK
360 Grand Ave., #150
Oakland, CA 94610
(415) 929-8876 (office)

TLong@turn.org
ETorres@turn.org

April 25, 2025

TABLE OF CONTENTS

1. Introduction

The Utility Reform Network (TURN) submits these comments in response to the April 11, 2025 questions circulated by the Commission's Staff related to the CPUC's guidelines for implementation of SB 884.

TURN appreciates the thoughtfulness of Staff's questions and that Staff is providing an open and transparent opportunity for all interested parties to answer these questions simultaneously. Before directly addressing the questions, TURN's comments will address in Sections 2 through 5 below, thematic issues raised by the April 8, 2025 workshop and by the April 11, 2025 questions. These sections are intended to provide a coherent explanation of the processes and conditions that TURN is advocating and the reasons for TURN's positions that might not otherwise come across in response to the questions. Following these sections, in Section 6, TURN directly responds to the Staff's questions.

2. The Utility Must Demonstrate that Each Proposed Undergrounding Project Is Superior to the Alternatives

Question B4 asks whether the updated guidelines should include a condition that requires a comparison of Cost Benefit Ratios (CBR) between undergrounding and overhead hardening alternatives. TURN wholeheartedly supports this comparison as a key condition to approval and funding of an undergrounding project, as such a condition is compelled by both the statute and sound policy.

SB 884 recognizes the importance of demonstrating that undergrounding is more cost-effective than other grid hardening alternatives. Section 8388.5(c)(4) requires the utility's application to Energy Safety to include a comparison of undergrounding with aboveground hardening for each project, comparing, among other things, risk reduction and cost – which are the two elements of the Cost Benefit Ratio (CBR) calculation. This cost-effectiveness comparison is to be made "separately" for each project.[1] SB 884 reiterates this requirement for the application presented to the CPUC. Section 8388.5(e)(1)(A) requires the plan submitted to the Commission to show substantial improvements in risk reduction and cost of undergrounding *compared to alternative mitigations*.

These statutory requirements are consistent with the record in both WMP proceedings before Energy Safety and in CPUC General Rate Cases, which show that whether undergrounding is more cost-effective than alternatives can depend significantly on which risk drivers are present

[1] Public Utilities Code Section 8388.5(c)(4).

in a particular location, as well as the cost and time to complete an undergrounding project, which is highly variable depending on local characteristics.

For these reasons, TURN recommends in these comments that the Commission's updated guidelines include an explicit condition that an undergrounding project may only move forward if the undergrounding CBR is higher than the CBR of any feasible alternatives (or combination of alternatives) providing comparable reduction of ignition risk. Such a condition is necessary to counter the utility's financial incentive to choose the mitigation that will cause the largest increase in rate base, which in most cases will be undergrounding.

See TURN's further discussion of this recommended condition in Section 4.2.1 and in the response to Question B4, found in Section 6.2.

3. As Required by SB 884, the Commission Must Ensure that the Utility Has a Strong Incentive to Constrain and Reduce Costs; the CPUC Should Therefore Either Eliminate the Memorandum Account or Impose a Tight Cap on It

Question B1 asks whether the Commission should impose conditions on the memorandum account allowed by SPD-15. TURN welcomes this question, as this issue warrants revisiting.

TURN continues to urge its previously expressed position that no memorandum account should be allowed because creating such an opportunity to recover cost overruns defeats the cost reduction and containment goals that are central to SB 884.[2] Limiting such opportunities is vital to the CPUC's efforts to regain control of runaway electric rates. In Executive Order N-5-24, the Governor calls for "decisive action to rein in" California's rapidly increasing utility rates.[3] The Executive Order further directs OEIS and the CPUC to:

> consult with each other on adjustments to utility wildfire safety oversight processes, procedures, and practices that would yield administrative efficiencies and focus utility investments and activities on cost-effective wildfire mitigation measures that reduce wildfire ignition risk while managing costs to electric ratepayers."[4]

Managing costs imposed on ratepayers is especially important as electric rates have risen significantly for all IOUs over the past five years. For example, between January 1, 2020 and

---

[2] TURN's Comments on Draft Resolution SPD-15, pp. 8-12.

[3] The Executive Order is available at: https://www.gov.ca.gov/wp-content/uploads/2024/10/energy-EO-10-30-24.pdf.

[4] Executive Order N-5-24, Ordering Paragraph #5.

January 1, 2025, PG&E residential electric rates have risen by 74% for bundled non-CARE customers and 78% for bundled CARE customers.[5]

Moreover, as discussed below in this section, there are other ways to address the uncertainties related to ten-year undergrounding plans that do not require creating another memorandum account.[6] If any memorandum account is allowed, it should be capped at no more than 10% of a utility's total Plan costs.[7]

3.1. Allowing a Memorandum Account Undermines the Cost Control Requirements of SB 884 and, As Experience Has Shown, Invites Runaway Spending

SB 884 makes clear that achieving efficiencies and reductions in undergrounding costs must be a key condition of the CPUC's cost approval process. Section 8388.5(e)(6) shows that the Legislature was highly focused on cost control by requiring that the utility's application for conditional approval of plan's costs address the following:

> (A) Any substantial improvements in . . . *reduction in costs* compared to other hardening and risk mitigation measures over the duration of the plan.
>
> (B) The *cost reductions, at a minimum, that result in feasible and attainable cost reductions* as compared to the large electrical corporation's historical undergrounding costs.
>
> (C) How the cost targets are expected to *decline over time* due to *cost efficiencies and economies of scale*.
>
> (D) A strategy for *achieving cost reductions* over time.[8]

The Legislature's emphasis on the achievement of cost reductions is thus reflected in its specification of *four separate requirements* for the utility to achieve cost reductions – both as compared to alternative mitigations and historical undergrounding costs, and as a demonstration

---

[5] TURN analysis based on PG&E Annual Electric True-Up (AET) submissions, including: PG&E Advice Letter 6805-E (2023 AET filing effective 1/1/2023), PG&E Advice Letter 7116-E (2024 AET filing effective 1/1/2024), and PG&E Supplemental Advice Letter 7426-E-A (2025 AET filing effective 1/1/2025).

[6] See also Sections 4.2.2 and Section 5.3

[7] This recommendation is further discussed in response to Question B1 in Section 6.2.

[8] Section 8388.5(e)(1) (emphasis added).

that utilities will deliver on their claims of realizing cost efficiencies with the benefit of time and economies of scale.

Allowing utilities to seek recovery of recorded cost overruns defeats the purpose of these requirements. SB 884 clearly intends for the Commission to require utilities to achieve more efficient implementation, *i.e.,* declining unit cost caps over time. Utility incentives to actually achieve this statutory requirement will be dulled, if not eviscerated, if utilities know that will have the opportunity to recover cost overruns in later applications.

By now, the Commission is well aware that memorandum accounts create a disincentive to utility cost control and causes the Commission to lose control over utility rates. The Commission has had several years of recent experience with a ratemaking model, pursuant to AB 1054, that allows utilities to record wildfire mitigation plan (WMP) costs in excess of authorized GRC amounts to memorandum accounts, and then seek recovery of those costs.[9] Despite admonitions in the statute and Commission decisions that only just and reasonable costs will be allowed to be included in rates and that unreasonable costs will be disallowed, the utilities have engaged in wildfire mitigation spending that dwarfs the forecast amounts authorized in their GRCs.

For example, PG&E's 2020 GRC decision authorized forecast costs for wildfire mitigation in 2020-2022 of $4.7 billion.[10] During that period, PG&E *actually* spent $11.7 billion related to CPUC-jurisdictional activities, more than double its GRC authorization.[11] As of the end of 2023, this excess spending had already resulted in PG&E applications and advice letters seeking to recover an additional $5.2 billion in rates, a significant portion of which is still pending authorization for rate recovery.[12]

The lesson is that utilities show no reluctance to incur costs above authorized forecast levels if they can be booked to a memorandum account for future potential recovery. In the context of SB 884, utilities would continue to expect that the Commission will find it difficult to disallow a significant portion of costs once they have been spent on infrastructure that is serving customers, even if that money could and should have been better spent.

---

[9] Section 8386.4(a) and (b).

[10] TURN Opening Brief in A.23-06-008, Nov. 5, 2024, p. 30. Found at: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M545/K343/545343978.PDF

[11] *Id.*

[12] *Id.*, pp. 30-31.

3.2. The Uncertainties in a Ten-Year Plan Horizon Can Be Addressed Without Resorting to a Memorandum Account

SPD-15 stated that a memorandum account was warranted because of "significant uncertainties in undergrounding . . . that are likely to grow over a 10-year period."[13] But the SB 884 statute that created the 10-year undergrounding plan opportunity, unlike AB 1054, did not find the 10-year horizon a reason to direct the CPUC to allow a memorandum account for cost overruns in an Undergrounding Plan. Instead, as noted, SB 884 makes clear that the purpose of the 10-year period was to *reduce* unit costs through economies of scale and scope.

Importantly, there are other ways to address the uncertainty of a 10-year time horizon that do not require extending a blank check to the utilities. In these comments, as discussed in Section 4.2.2 and in response to Question B2, TURN recommends the adoption of a variance condition that would require the utility to seek re-review of a project when project costs or CBRs vary by more than a prescribed percentage from the values on which original project approval was based. In this way, the Commission can ensure that a project whose economic metrics have changed is still worth funding, *before the utility begins construction of the project.* The result is a win-win for utilities, which gain the certainty of pre-approval of a changed project (and the terms attached to that pre-approval), and ratepayers, who gain an opportunity to present their concerns about the reasonableness of a modified project before the funds are spent.

In addition, as discussed in response to Question D1 in Section 6.4, the utility can, if warranted, submit a petition for modification (PFM) of the Phase 2 decision to seek changes to adopted conditions. This is another available vehicle to gain an advance determination from the CPUC of the costs that would be eligible for ratepayer funding, thereby avoiding the need for a memorandum account. As noted in response to Question D2, such a PFM would need to show, at a minimum, that the changed conditions that prompt the PFM are wholly outside of the utility's control.

In sum, TURN urges the Commission to resist the impulse to defer costs that fail to satisfy the Phase 2 conditions to a memorandum account. Such an account could allow several billion dollars of additional costs to accumulate, which would constitute a ticking time bomb that could destroy the Commission's efforts to regain control over electric rates and promote electrification. Instead, the revised guidelines should specify that utilities must gain the Commission's approval before incurring costs that do not satisfy the Phase 2 conditions.

---

[13] SPD-15, p. 8.

These issues – whether a memorandum account is needed and how a memorandum account can be avoided – are further discussed in Section 4.2.2, and in response to Questions B1 and B2, found in Section 6.2, and in response to Questions D1 and D2, found in Section 6.4.

4. Summary of TURN's Proposed Revisions to the Phase 2 Process and Conditions

This section has two purposes. First, in Section 4.1, TURN offers what it hopes is a coherent blueprint of the key issues that need to be addressed in the Commission's review of a Phase 2 application. Second, Section 4.2 presents TURN's recommendations for cost recovery conditions that should be added to the conditions already specified in SPD-15. Both sections are in response to the April 8, 2025 Workshop discussion and the April 11, 2025 questions.

4.1. The Commission's Review of the Phase 2 Application Should Determine the Conditions that Must Be Met to Satisfy the Just and Reasonable Standard and Other Requirements of SB 884

The CPUC's Guidelines adopted in SPD-15 specify 20 categories of information that must be included in the utility's Phase 2 application, including the information required in Appendix 1.[14] (The Guidelines (item 11) note that Appendix 1 is preliminary and will be updated based on Energy Safety's rules, which have now been issued.) As the Guidelines correctly note, the Phase 2 application may request "conditional approval," not final approval, of the plan's costs.[15]

Thus, a key purpose of the proceeding to review the Phase 2 application is to determine the conditions that plan costs must satisfy before they can be added to rates. SPD-15 correctly explains that the Phase 2 Conditions are those that are necessary and sufficient to determine that the costs are just and reasonable.[16] The "just and reasonable" requirement is fundamental and is imposed both by Section 451 and by SB 884 in Section 8388.5(e)(6). However, it is important to recognize that SB 884 specifies other required elements that should inform the Phase 2 conditions, including showings that:

- The Phase 2 plan will achieve substantial improvements in costs compared to other hardening and risk mitigation measures over the duration of the plan;
- The Phase 2 plan includes cost targets that, at a minimum, will result in feasible and attainable cost reductions as compared to the utility's historical undergrounding costs;
- The Phase 2 plan specifies declining cost targets due to cost efficiencies and economies of scale; and

[14] SPD-15 Guidelines, pp. 7-10.

[15] SPD-15 Guidelines, p. 10; Public Utilities Code Section 8388.5(e)(1).

[16] SPD-15, p. 5.

- The Phase 2 plan demonstrates a strategy for achieving cost reductions over time.[17]

Based on the Phase 2 conditions currently specified in SPD-15, some of the key tasks of the Phase 2 proceeding will be the following:

(1) Determining the total annual cost cap for each year of the plan, per Condition 1.
(2) Determining the average unit cost cap for each year of the plan, per Condition 3.
(3) Determining the average threshold CBR for each year of the plan, per Condition 4.
(4) Determining any further reasonable conditions, per item 5 in the SPD Guidelines.[18]

TURN anticipates that the Scoping Ruling for Phase 2 will include each of these issues, which will then be litigated in the proceeding.

4.2. The Commission Should Add Phase 2 Conditions to Ensure that Plan Costs Are Just and Reasonable and Satisfy SB 884's Additional Requirements

The April 11, 2025 questions indicate that the Commission is considering whether to specify *additional* Phase 2 conditions in a resolution updating SPD-15. In response to those questions, TURN urges the Commission to adopt the following additional conditions.

4.2.1. The Commission Should Require Each Undergrounding Project to Be More Cost-Effective than Alternatives Providing Comparable Ignition Risk Reduction

First and most important, in response to Question B4, the Commission should add a condition that undergrounding projects may not move forward if the undergrounding CBR is lower than the CBR of any feasible alternatives (or combinations of alternatives) providing comparable reduction of ignition risk. As explained in Section 2, this condition is needed to give effect to the provisions of SB 884 that emphasize the need for undergrounding projects to be more cost effective than the alternatives. It also is necessary to satisfy the just and reasonable requirement. Undergrounding costs are not just and reasonable when comparable risk reduction can be achieved by less costly mitigations.

It is now beyond dispute that risk reduction comparable to undergrounding can be achieved by overhead hardening combined with other mitigations. PG&E's 2026-2028 WMP acknowledges two alternatives that, on average, are 97% effective or higher in reducing ignition risk and therefore highly comparable to undergrounding in that regard: (1) Line Removal with Remote

---

[17] Section 8388.5(e)(1)(A)-(D).

[18] These conditions and item 5 are set forth in the SPD-15 Guidelines, p. 11.

Grid (98% effectiveness) and (2) Covered Conductor + EPSS + PSPS (97% effectiveness).[19] While the alternatives for a given project should not necessarily be limited to these options, this information in PG&E's WMP shows that, for virtually all projects, there should be at least one feasible alternative providing comparable ignition risk reduction. In addition, over time, more options are likely to become feasible for at least some circuits (e.g., REFCL), thereby increasing the alternatives, including combinations, that should be considered.

TURN also notes that the CBRs for overhead hardening alternatives that involve temporary outages include the offset to the risk reduction benefits from the outage impact. Thus, an accurately calculated CBR – based on a reasonable methodology for calculating reliability costs (see the response to Question E1, found in Section 6.5) offers a fair cost-effectiveness comparison that takes into account any reliability disadvantages of overhead hardening alternatives that include fast trip settings (EPSS) and PSPS. This means that, when comparing undergrounding with Covered Conductor + EPSS +PSPS, a lower CBR for undergrounding for a given location would show that, even when the outage impacts of EPSS and PSPS are considered, the combination of overhead hardening mitigations is more cost-effective – i.e., provides more net risk reduction benefits per dollar – than undergrounding.

TURN understands that Energy Safety's rules will require that the Screen 2 Undergrounding Projects List (which would become the basis for the CPUC Phase 2 application) include for each project a CBR comparison with at least two alternative mitigations or combinations of mitigations.[20] Thus, this information will be available when the utility submits its Phase 2 application and should be required by the CPUC, as further discussed in response to Question A1.

Because the utility will have already calculated these comparative CBRs for each project, the Commission should specify that this condition *applies to the utility's application* – meaning that only projects that satisfy the condition should be included in the Phase 2 application – and that *the condition should continue to apply throughout the SB 884 process*. That is, if at any point in the development of the project, the undergrounding CBR falls below the CBR of an alternative (or combination of alternatives) offering comparable ignition risk reduction, the utility will know that the undergrounding project will not gain CPUC approval and should not move forward. In this way, the Commission will ensure that undergrounding is only approved where the utility has demonstrated that it is the most cost-effective mitigation to achieve comparable ignition risk

---

[19] PG&E 2026-2028 Base WMP (R0), Table 6.1.3-1, p. 128.

[20] OEIS Guidelines, p. 18.

reduction, consistent with Section 8388.5(e)(1)(A) (the plan provides substantial reductions in risk *and costs* compared to alternatives).

4.2.2. The Commission Should Adopt a Condition Denying Phase 2 Cost Recovery When a Project's Unit Costs and CBR Vary By More than a Prescribed Percentage from the Values in the Phase 2 Application

In response to Question B2, TURN recommends that the Commission adopt a condition that does not allow cost recovery via the one-way balancing account authorized in the Phase 2 decision when recorded values differ by more than a prescribed percentage from the key assumptions on which a project's approval was premised – such as unit cost and CBR. When this condition is triggered, the utility should be required to seek and obtain pre-approval of the changed project before construction begins. The percentage variances that trigger this condition need not be determined now; this should be an issue to be resolved in the Phase 2 application proceeding.

TURN has discussed the benefits of this condition in Section 3 above and will discuss further details in Section 5.3 and in its response to Question B2. Here, we note that TURN recommends a different process than suggested in Question B2 when a utility learns that a project will not satisfy this condition. Rather than allowing the utility to book to a Phase 3 memorandum account the costs of any projects that fail this condition, the utility should be required to gain an advance authorization from the Commission to proceed with the project notwithstanding the variance, in effect an exemption from the condition. In this way, once the utility knows about the variance, it can seek a Commission determination regarding the terms under which the project would be funded. This process serves the interests of both ratepayers and utilities. Utilities can avoid an uncertain Phase 3 proceeding and would be able to recover the costs meeting the Commission's terms via the one-way balancing account. Ratepayers will have an opportunity to raise concerns about projects with significant variances from original assumptions – e.g., those that are materially more costly than forecast in Phase 2 – before the project is constructed and before most project costs are incurred.

4.2.3. The Commission Should Adopt a Condition Establishing a CBR Threshold that Each Project Must Meet

In response to Question B3, TURN recommends that the Commission adopt Option 1 in that question by adding a condition that all undergrounding projects demonstrate that they have a CBR above a prescribed value, to be determined in the Phase 2 proceeding. If, as TURN strongly urges, the comparative CBR condition described in the previous section is added, the main purpose of this condition would be to weed out undergrounding projects in relatively low risk areas that would not be sufficiently cost-effective to justify funding.

Unlike the comparative CBR condition, which can be applied to the application itself, this condition would apply beginning with the review process after the Phase 2 decision (discussed in Section 5 below). Establishing the value for the CBR threshold would be an issue to be resolved in the Phase 2 proceeding. Notwithstanding the CPUC's efforts to standardize CBR calculations in R.20-07-013, there are still likely to be differences in the utilities' methodologies that would cause similar projects to have different CBR scores. For example, as TURN understands will be discussed in Mussey Grade Road Alliance's (MGRA) comments, the utility can use the risk scaling function to unreasonably distort and inflate risk scores, risk reduction calculations, and CBRs. Parties should have an opportunity to understand a utility's methodology and, if necessary, make recommendations to correct flaws, before recommending an appropriate CBR threshold.

5. TURN's Recommended Process After the Phase 2 Decision for Ensuring Compliance with the Specified Conditions

This section describes TURN's recommended process after the Phase 2 decision to ensure that all applicable Phase 2 conditions have been satisfied before costs may be added to rates.[21]

5.1. SB 884 Requires the CPUC to Determine that Recorded Costs of Projects Are Just and Reasonable *Before* Costs May Be Added to Rates

Although SPD-15 is not crystal clear on this point, it seems to contemplate that, after the Phase 2 decision, a utility could automatically book incurred costs to implement the approved plan to a one-way balancing account and then recover them in rates. SPD-15 alludes to a subsequent process that would occur in Phase 3, sometimes referred to as an "audit," to assess whether the booked costs satisfy the Phase 2 conditions. Costs that do not meet the conditions would be subject to refund.[22] According to SPD-15, the details of this "audit" process would be determined in a later decision or order.[23] In sum, as TURN understands SPD-15, it would allow *up-front* recovery in rates of costs to implement a plan *before a determination that the Phase 2 conditions were satisfied*.

As TURN has previously explained, <u>an up-front cost recovery process is contrary to SB 884 and therefore would constitute clear and obvious legal error</u>.[24] As discussed in Section 4.1, the Phase 2 application process allows a utility to seek and obtain only *conditional* approval of Plan costs.[25] Section 8388.5(e)(6) provides that, after issuing a Phase 2 conditional approval

---

[21] TURN uses the word "applicable" because, as explained in Section 4.2.2, TURN is recommending a process by which a utility could gain project exemptions from the Question B2 variance condition that TURN is recommending.

[22] SPD-15, pp. 2-3, 4-5, 16.

[23] SPD-15, pp. 5-6.

[24] TURN Comments on Draft SPD-15, December 28, 2023, pp. 3-5.

[25] Section 8388.5(e)(1).

decision, the Commission "shall authorize recovery of *recorded* costs that are *determined to be just and reasonable*."[26] This provision means that the Commission cannot authorize recovery until the Commission has determined that recorded costs presented for cost recovery satisfy all conditions necessary for a just and reasonable determination. A process that allows up-front recovery of recorded costs before a determination that the Phase 2 conditions have been satisfied would therefore violate Section 8388.5(e)(6). For this reason, the Commission must reject the process described in Question C2 to the extent it allows rate recovery before a Commission determination that the Phase 2 conditions have been met and instead relies on a post-rate recovery review and refund process.

5.2. TURN's Recommended Process In Response to the April 11, 2025 Questions

Given the legal invalidity of the process that SPD-15 describes (as TURN understands it), TURN is pleased that, in Questions C1 through C3, the Commission is now re-visiting the process by which costs would be approved for cost recovery. TURN recommends a version of the process described in Question C1. Under TURN's recommended process, no costs would be booked to the balancing account until the Commission has determined in an annual process that recorded costs for that year have met all applicable Phase 2 conditions, as well as the used and useful requirement.[27]

Previously, TURN recommended an expedited application process for the Commission's required determination that recorded costs satisfy the Phase 2 conditions and are just and reasonable.[28] TURN continues to believe that process would best ensure a complete and high quality record for the CPUC's determination.

Nevertheless, TURN here outlines a process – a variant of what is proposed in Question C1 -- that would yield a faster decision than TURN's previously proposed expedited application process. The Commission should consider it to be the minimum process necessary to supply the Commission with the information it needs to make an informed determination of whether conditions have been satisfied and to comport with basic requirements of due process.

---

[26] Section 8388.5(e)(6) (emphasis added).

[27] As Question C1(c) implies, in addition to satisfying the Phase 2 conditions, costs must satisfy the "used and useful" requirement to qualify for recovery in rates.

[28] TURN Comments on Draft SPD-15, December 28, 2023, pp. 5-7.

TURN recommends a Resolution process that requires utilities to present complete and fully supported requests for cost recovery[29] and allows sufficient opportunity for intervenor discovery, analysis and comments. Specifically, TURN recommends:

- Three-business day turnaround on data requests, as Energy Safety specifies for WMPs;
- At least 75 days for interested parties to submit comments on the request and 20 days thereafter for reply comments;
- Issuance of a Draft Resolution with an opportunity for opening and reply comments.

While this recommended process has some similarities (as well as differences) compared to the Tier 3 advice letter process, this process should be considered to be distinct from the General Order (GO) 96-B process to avoid importing unintended rules and requirements from that General Order.[30]

In response to Question C1, TURN will explain why 75 days should be the minimum period for intervenor comments and why a longer period may prove necessary, depending on how the CPUC decides to deal with updates to risk models and CBR methodology and calculations, topics addressed in the Section D and E questions.

5.3. TURN's Recommended Process for Re-Review of Projects With a Significant Variance from Original Estimates

In Sections 3 and 4.2.2, TURN recommended, in response to Question B2, inclusion of a condition to re-review projects in which the utility has determined that that there will be a significant variance in one or more key project assumptions (e.g., unit cost, total project cost, CBR) compared to the values for the project in the approved Plan. Once the utility learns of such a variance, the utility should be required to either remove the project from the Plan or gain a full or partial exemption from the variance condition by presenting a justification to continue with the project. As discussed in Sections 3 and 4.2.2, this re-review to gain an exemption from the variance condition should take place before the utility proceeds with construction of the project.

---

[29] As TURN stated on page 5 of its December 28, 2023 comments, to facilitate such an expedited process, the Commission must specify (in its Phase 2 decision) the detailed data submission requirements that the utility must meet in its cost recovery request based on the Phase 2 conditions that must be satisfied. In addition, if a utility were to claim confidentiality for any of the information in its request, it should be required to include a model nondisclosure agreement to facilitate the parties' prompt receipt of such data.

[30] Section 5.1 of GO 96-B states that the advice letter process is not appropriate for matters that are expected to be controversial, which is likely to be the case with rate recovery requests for hundreds of millions of dollars of capital expenditures.

TURN recommends that the same process for the annual cost recovery requests described in Section 5.2 be used for any requests for an exemption from the variance condition. Such exemption requests would be separate from the cost recovery requests but proceed on the same schedule: expedited discovery, 75 days for opening comments, 20 days for reply comments, and opening and reply comments on a Draft Resolution. The Commission's options in acting upon the request would include establishing a new set of project metrics that must be met for the project costs to be approved in a future cost recovery request, e.g., new conditions for unit costs, total project costs, and CBR. Such determinations would ensure that projects with significant variations from original estimates in the Phase 2 application satisfy the just and reasonable standard and other SB 884 requirements and provide the utility with clear guidance regarding the costs that will (and will not) be funded.

6. Response to Questions

6.1. Section A: Should the Commission Consider Supplementing the Phase 2 Application Requirements?

SPD-15 included a list of 20 requirements that must be included in any Application submitted to the Commission seeking conditional approval of Plan costs. Would it be appropriate for the Commission to consider adding the following requirements?:

1. *Include the data associated with the list of all projects (SB 884 Project List Data Requirements) as required by Screen 2 of the Energy Safety Guidelines*
    a. *Require the utility to provide us with a forecasted scope of all projects for the ten-year plan, with the expectation that projects far in the future would change.*
    b. *This requirement would make it explicit that the Underground Project List, which is an output from Screen 2 in the Energy Safety Guidelines, must be ready for the Commission to review before an Application can be submitted.*

<u>Response to Question 1</u>

Yes, the information in both subparts should be provided in the Phase 2 application. Utilities should be encouraged to make their best efforts to describe the projects as accurately as possible in the Phase 2 application. To that end, rather than stating a Commission "expectation" that projects far in the future "would" change, TURN recommends rephrasing to "recognize the possibility that projects far in the future may change."

2. *Require the utilities to provide a detailed explanation for any spans that extend beyond the HFTD for any project included in the Underground Project List from Screen 2 of the Energy Safety Guidelines.*
    a. *The Energy Safety Guidelines allow for undergrounding circuit segments with assets inside the HFTD, then each span that crosses the Tier 2 or 3 HFTD boundary and up to two adjacent spans outside of a Tier 2 or 3 HFTD may*

also be included in a project.

b. This requirement would ask the utilities to provide a detailed explanation regarding why they must include any spans that extend beyond the HFTD.

Response to Question 2

Without addressing whether Energy Safety's provisions for the inclusion of non-HFTD spans in the utility's Plan comport with SB 844,[31] TURN agrees that this information should be required in the Phase 2 application.

3. *Require utility to submit a depreciation study with updated information of the type of assets that are impacted by an SB-884 Application*
    a. *Depreciation studies are typically updated when a utility files its GRC.*
    b. *Because undergrounding projects have large capital expenditures, there is a potential that depreciation and salvage costs may be contested in an EUP cost recovery Application.*
    c. *This would require a depreciation study be included in the record, but it should be a depreciation study with updated information since an EUP cost recovery Application will not necessarily be submitted in the same time frame as a GRC.*

Response to Question 3

TURN agrees that the utility should be required to submit an updated depreciation study for the assets at issue in the SB 884 application. Whether that updated study needs to be a disputed issue in the Phase 2 proceeding would depend on the timing of the SB 884 Phase 2 application in relation to the utility's GRC and whether the depreciation issues for the SB 884 assets have been addressed in the GRC. If the relevant issues have recently been resolved in the GRC and the changes to the depreciation study are minor or non-existent, then it would likely be unnecessary to re-visit those issues in the SB 884 Phase 2 proceeding.

4. *Require both nominal and present value lifetime calculations for the capital expenditures for each project included in the Undergrounding Project List from Screen 2 of the Energy Safety Guidelines.*
    a. *PUC 739.15 specifically calls out the need for greater clarity on the lifetime cost and benefit of a capital expenditure project such as those submitted in an EUP cost recovery Application.*

---

[31] Section 8388.5(c)(2) states: "Only undergrounding projects located in tier 2 or 3 high fire-threat districts or rebuild areas may be considered and constructed as part of the program."

b. *This would require both nominal and present value lifetime calculations for the capital expenditure of each undergrounding project.*

Response to Question 4

TURN agrees that the utility should be required to provide nominal and present value calculations for the forecast capital costs for each undergrounding project included in the Phase 2 application. The costs presented in the application should be based on the *full costs* to ratepayers of each project, and those full costs based on lifetime revenue requirement estimates should be used in the CBRs. Direct capital costs paid by utilities do not include such elements as rate of return, taxes and other loaders, and thus very likely understate the total costs to ratepayers over the life of a capital asset.

Moreover, as subpart (a) recognizes, including the full revenue requirement impact of capital investments is consistent with the intent of Public Utilities Code Section 739.15, recently added by AB 2847 (2024), which specifically authorizes the Commission, including *in SB 884 applications*, to require utilities to estimate the revenue requirement impacts for each year that the capital costs will remain in rate base.[32]

TURN expects utilities to contend that calculating revenue requirements on a project basis is unduly burdensome. However, the utility will ultimately need to calculate the revenue requirement impact of each project when it seeks rate recovery. If this exercise can be done later, it can be done when the application is presented. TURN recognizes that some long-term inputs into the revenue requirement calculation will need to be estimated and may be subject to change. However, provided that the utility makes good faith estimates, lifetime revenue requirement impact is much more representative of the total costs that ratepayers will face than the direct costs to the utility, for the reasons stated. The benefit to the decision-making process of having more accurate cost information outweighs any burden to the utility.

To be clear, TURN is not recommending that the annual cost caps required for Condition 1 of SPD-15 be based on annual revenue requirement calculations. Instead, those should be based on the capital expenditures for each year approved by the Commission, as the cap is intended to serve as a cap on expenditures. Moreover, *annual* revenue requirements (as opposed to the lifetime revenue requirement estimates discussed above) are affected by tax issues that cause the first year of revenue requirement for an undergrounding project to be low or even negative and for the succeeding years' revenue

---

[32] Public Utilities Code Section 739.15(b) (applying the statute's information requirements to "an application for conditional approval of the costs of an undergrounding plan pursuant to 8388.5….")

requirements to be higher to make up for the deferred tax liability in the first year.

5. *Require data retention policy for lifetime of EUP for tabular and geodatabase data. This should be required for both the initial application and any of the data updated through the six-month progress reports.*
    a. *Since there are no additional requirements for data retention related to an EUP, this will require the utility to retain all tabular and geodatabase information submitted as part of the EUP and any data included in six-month progress reports.*
    b. *Staff intend to hold data template working groups later in the spring.*

<u>Response to Question 5</u>

TURN supports this requirement.

6. *Require utilities to submit the same Key Decision-Making Metrics (KDMM) data for Commission review as provided for in the submission to Energy Safety.*

<u>Response to Question 6</u>

TURN supports inclusion of the seven KDMMs specified by Energy Safety in the Phase 2 application. Those all provide useful information. Energy Safety also allows the utility to add up to five more KDDMs of the utility's choosing. Without knowing those additional KDMMs, TURN cannot opine as to whether they will provide useful information.

6.2. Section B: What, if Any, Additional Phase 2 Conditions Should the Commission Consider?

1. *Should the Commission consider imposing Conditions on the Memorandum Account (MA)? Ifso, what Conditions should be considered?*
    a. *Option 1: Establish a maximum total cap for the MA, limiting it to no more than 25% ofthe total sum of the ten-year annual caps established for the balancing account.*
    b. *Others?*

<u>Response to Question 1</u>

TURN's primary recommendation is that no memorandum account be allowed, for the reasons explained in Section 3.

If a memorandum account is allowed, it should be capped at no more than 10% of the total ten-year Plan costs approved in the Phase 2 decision. Even a 10% cap could allow for the opportunity for multiple billions of dollars of additional cost recovery, depending on the size of the utility's approved Plan.

As discussed in Section 3, Section 4.2.2, and Section 5.3, a memorandum account would undermine cost control incentives by permitting utilities to seek recovery of cost overruns after the money has been spent and undergrounding plant has become operational. Instead, the Commission should focus on ways to require re-review and pre-approval of revised projects when project plans – and associated costs and CBRs -- change materially over time.

2. *Should the Commission consider assessing the variance between the forecast data submitted according to the SB 884 Project List Data Requirements in the initial cost-recovery Application to the Commission and the updated data submitted according to the SB 884 Project List Data Requirements in a six-month progress report and if so how?*
    a. *Option 1: If the variance between the forecasted CBRs and unit cost of a project presented in an Application compared to the updated CBRs and unit cost of a project presented in a six month Progress Report (after a project passes Energy Safety's Screen 4) exceeds a certain threshold, then all costs for that project must be recorded in the MA.*
    b. *Others?*

Response to Question 2

As discussed in Section 3, Section 4.2.2 and Section 5.3, TURN recommends that the Commission adopt a new condition based on Option 1: no cost recovery would be allowed for projects if there is a significant variance (the amount of the variance to be determined in the Phase 2 proceeding) in one or more key project assumptions (e.g., unit cost, total project cost, CBR) compared to the values for the project in the approved Plan.

The important difference in TURN's recommendation compared to subpart (a) is that TURN is recommending that costs of projects that trigger this condition would not be recorded in a memorandum account. Instead, projects to which this condition applies would either be removed from the Plan or would be the subject of a re-review request using the process described in Sections 4.2.2 and Section 5.3. That process would give all parties an opportunity to address whether the project is still worth funding in the face of changed economic features of the project – such as increased unit or total costs or a reduced CBR.

Unless the utility gained such pre-approval, effectively an exemption from this condition, the utility would know that the Commission will not fund the project. The Commission's Resolution authorizing a changed project would specify any changes to the conditions for cost recovery, such as revised cost caps (unit and total) and a revised CBR threshold. The revised conditions specified by the Commission could differ from those proposed by the utility -- e.g, the project is authorized for up to $20 million (not the utility's requested $22 million) at a unit cost no higher than $2 million/per mile (not the utility's requested $2.2 million/mile).

3. *Should the Commission consider adopting a CBR Threshold, and if so, what should the criteria be?*
    a. *Option 1: Require all projects to have a CBR greater than a specified value.*
    b. *Option 2: If a project's recorded CBR is less than a specified value, the utility must provide a detailed justification for this project.*
    c. *Option 3: After Screen 2, any project ranked below a certain CBR percentile threshold is ineligible for cost recovery via the BA.*
    d. *Others?*

Response to Question 3

See Section 4.2.3, recommending Option 1. Alternatively, Option 3 is another way to weed out projects that do not compare favorably with other projects in terms of cost-effectiveness.

4. *Should the Commission consider requiring a comparative CBR analysis of project alternatives? If so, how should this analysis be conducted?*
    a. *Option 1: If an Undergrounding Project has a CBR above a specified CBR Threshold but the Alternative(s) has a CBR that is a specified amount greater than the Undergrounding Project's CBR, then the undergrounding project should not move forward.*
    b. *Others?*

Response to Question 4

TURN urges the Commission to adopt a condition that requires each undergrounding project to have a higher CBR than the CBR of any feasible alternatives (or combinations of alternatives) providing comparable reduction of ignition risk. In Sections 2 and 4.2.1, TURN has explained the need for this condition and how it should be applied.

5. *Should the Commission consider applying some of Energy Safety's KDMMs to the Commission's consideration of whether to grant cost recovery for projects and if so, how?*
    a. *Option 1: After Screen 3, if the reduction in Ignition Risk and/or Outage Program Risk does not meet the required Project Level Standard set in the approved Plan, the project will not be eligible for cost recovery via the one-way balancing account.*
    b. *Others?*

Response to Question 5

TURN understands this question to ask whether the KDDMs required by Energy Safety should provide the basis for additional Phase 2 conditions. TURN believes this is a good issue for the Phase 2 proceeding, at which time parties will have access to the actual

KDDM data and can better assess its usefulness for framing additional conditions.

6.3. Section C: What methods could the Commission use to Address the Audits and/or Review Procedure?

1. *Should the Commission consider adopting the following review structure to ensure a rigorous review of the costs associated with an EUP?*
    a. *Annual post-implementation review process with intervenor participation.*
    b. *Objectives of the review should include verifying project completion, cost overheads, CBR methodology and an incrementality showing.*
    c. *Once deemed "used and useful" in a progress report, a project's costs may be included in rate base via an Advice Letter that must be disposed via Commission Resolution.*
    d. *Commission Resolution will determine whether recorded costs met the Phase 2 Conditions and other objectives of the review.*
    e. *Approved costs would enter rates via Annual True-up.*

Response to Question 1

As discussed in Section 5.2, TURN recommends a process similar to the process described in this question, with some important differences. TURN responds to the subparts as follows:

Subpart (a): Yes, there should be an annual post-implementation review process with intervenor participation. TURN describes its recommended process in Section 5.2.

Subpart (b): The objectives of the review should include each of the items identified in the question – verification of project completion, inclusion of (no more than) appropriate cost overheads, (TURN would add inclusion of only costs needed to implement the project), use of a reasonable CBR methodology, and an incrementality showing. In addition, a key objective not listed in Subpart (b) should be a determination that all applicable Phase 2 conditions – as determined in the update to SPD-15 and in the CPUC decision on the Phase 2 application -- have been satisfied.

Subpart (c): TURN agrees that "used and useful" is an important showing that the utility must make before the costs may be included in rates. However, this is just one showing that must be made in this post-implementation review process. Commission precedent is clear that a used and useful showing is insufficient to justify inclusion of costs in rate base; the costs must also satisfy the just and reasonable standard.[33] Thus, in addition to used and useful, the utility must show all of the elements discussed in response to Subpart (b), including the important showing that all applicable Phase 2 conditions have been satisfied.

As discussed in Section 5.2, the process TURN recommends would not be an advice letter process under GO 96-B, although it would result in a Commission Resolution.

Subpart (d): TURN agrees that a Commission Resolution should determine whether all applicable requirements for cost recovery have been met.

Subpart (e): Only after the Commission has determined that all applicable requirements for cost recovery have been met, the costs in question would then become eligible to be booked in the one-way balancing account. The disposition of those costs in rates would be addressed in the Annual Electric True-Up advice letter proceedings.

Need for a minimum 75-day period for analysis and comment. Here, as previewed in Section 5.2, TURN explains the need for its recommended 75-day period (as a minimum) for analysis and comment on whether the recorded costs presented by a utility should be authorized for rate recovery. TURN bases this recommendation on its assessment, as best as can be determined at this point, of the nature of the analysis that will be necessary to determine whether the applicable requirements, including the additional conditions recommended by TURN in these comments, have been met.

Some of the requirements are best assessed, in the first instance, by the review of accountants who report to the CPUC, not the utility. Those requirements include assessing whether the claimed costs are adequately supported, are necessary for the project in question, and do not include excessive overheads. In addition, an auditor could offer an assessment regarding compliance with Conditions 1 and 3 in SPD-15, as these conditions require determining that the utility has included appropriate costs and accurately calculated the numbers for these conditions. In addition, an auditor could opine as to whether Condition 2 has been satisfied by seeking documentation of any available external funding amounts.

(In TURN's experience, the Commission should be wary of expecting an auditor to provide a valuable assessment of incrementality. In the SB 884 context, the incrementality issue is

---

[33] *E.g.,* D.23-11-069, p. 775 ("PG&E asserts that it may receive cost recovery for any capital investment in assets that are used and useful regardless of whether the Commission has reviewed the costs for reasonableness. That is not correct.")

likely to be whether the utility's SB 884 plan is incremental to the undergrounding work that has been funded in its GRC or other proceedings. To do this analysis correctly, the reviewer needs to determine whether the undergrounding mileage that was authorized in the GRC was completed, not just whether the GRC authorized funds were fully spent. For example, the utility may have been authorized $300 million for 100 miles of undergrounding, but only performed 50 miles for that $300 million cost. In this case, ratepayers should not be required to pay the utility again to fund the 50 miles of work that was supposed to be completed with the GRC authorization, i.e., those 50 miles are not incremental to what was funded in the GRC. Determining whether the SB 884 undergrounding application is seeking to have ratepayers pay a second time to underground those 50 miles requires legal and policy judgments that are not typically within the expertise of auditors.)

If the Commission were to use an auditor to provide an opinion on these matters, the auditor's opinion should be subject to comment by the parties. Because the auditor's recommendations speak to whether the costs should be recoverable in rates, ratepayer representatives, and other interested parties should be able to address such matters as whether the auditor used appropriate and thorough procedures and reached reasonable conclusions. For the parties to have a meaningful comment opportunity on an auditor's opinions, the auditor's report - which should be fully documented -- should be finished before the utility costs are presented in the utility's annual cost recovery request and should be distributed to the utility and interested parties at the same time.

As discussed in TURN's November 12, 2024 Informal Comments, some of the conditions – particularly those involving CBR calculations – would not be appropriate for an auditor opinion.[34] As the Commission knows, CBRs (and their predecessor, RSEs) are complex calculations based on complex methodologies. When determined in accordance with Commission requirements and otherwise using reasonable inputs and assumptions, they can provide extremely valuable information regarding the cost-effectiveness of proposed projects and competing alternatives. However, because of their complexity, utilities also have the opportunity to skew the calculations in favor of their preferred outcomes. Commission requirements still afford utilities a significant measure of discretion and judgment in how they calculate CBRs.

TURN understands that, through the questions presented in Section E, the Commission is exploring whether it should limit that discretion, and, if so, how. As discussed at the workshop, TURN understands CPUC Staff's notion to be that the Commission could prescribe a methodology that the utility would be required to use in its SB 884 application and in each cost

[34] Informal Comments of TURN, November 12, 2024, pp. 3, 5-6.

recovery request for the full ten years of an SB 884 Plan, thereby minimizing the scope of potential disputes regarding CBR calculations. However, the questions in Section E raise complex and likely controversial issues that may be difficult to fully resolve in the updated Resolution that will emerge from these comments.

In addition, even if the Commission specified a prescriptive *methodology* for calculating CBRs for purposes of SB 884 Plans and required that same methodology to be used in every submission for the full ten-year program (which could be characterized as a methodology "freeze"), there remains the issue of whether it is appropriate to freeze all of the *inputs and assumptions* in applying that methodology. Over the course of ten years, assumptions and inputs regarding ignition risk, mitigation effectiveness, and consequences of an ignition are likely to change. As just a few examples, covered conductor effectiveness could improve, REFCL could prove to be more reliable and effective, wildfire consequences could become more severe based on advances in climate change modeling, or less severe as properties are required to be hardened against wildfires by insurance companies, among other changes. Any or all of these changes could affect CBRs and would need to be reviewed and addressed in utility cost recovery requests.

For this reason, TURN believes that 75 days – with the expedited discovery recommended by TURN -- is the minimum period necessary for intervenors to be able to analyze and meaningfully comment upon any changes to the utility's models and assumptions for calculating CBRs in the annual cost review process.

2. *Should the Commission instead consider adopting the following review structure to audit the costs associated with an EUP?*
    a. *Annual audit by independent auditor with CPUC oversight.*
    b. *Objective of the audit should include verifying project completion, cost overheads, andan incrementality showing.*
    c. *Once deemed "used and useful" in a progress report, a project's costs may be included in rates via annual True-up and become subject to audit.*
    d. *If the audit finds that project costs were incorrectly recorded to the Balancing Account, then the utility must issue a refund to ratepayers*.

Response to Question 2

For the reasons explained in Section 5.1, a process that allows up-front recovery of Plan costs before the CPUC has made a determination that the costs are just and reasonable and satisfy all other applicable requirements is contrary to SB 884 and should be rejected. Moreover, the process described in this question would be both contrary to due process and extremely unwise in that it would allow cost recovery without providing a meaningful opportunity for ratepayer representatives and other intervenors to be heard regarding whether the auditor opinion is accurate and complete and whether the requested costs are legally entitled to be added to rates.

3. *Supporting Questions:*
    a. *How should the timing of the Independent Monitor's (IM) review and the utility's right to correct a deficiency found by the IM within 180 days (PUC 8838.5 (g)(2)) interact with the annual review of the costs of a project?*
    b. *How should projects that fail to meet key criteria be treated vis-a-vis cost recovery? What key criteria should be considered?*
    c. *Should intervenors participate in Options 1 and 2 above? If so, how and where?*
    d. *Should the Commission consider using a different option than 1 or 2 above? If so, explain each step in the proposed process. How and where would intervenor participation be accounted for in the proposed option?*

<u>Response to Question 3</u>

Subpart (a): The Commission can and should consider any unresolved issues found by the Independent Monitor in making its determination whether cost recovery should be allowed, in the process described by TURN in Section 5.2 and in response to Question C2.

Subpart (b): Costs that do not meet all prescribed conditions and other applicable requirements should not be recovered in rates at any time. Utilities will have full knowledge of the conditions and applicable requirements and can plan their work accordingly. As discussed in Sections 4.2.2 and 5.3, projects that trigger the variance condition (and that the utility still wishes to pursue) should be re-reviewed and pre-approved before construction, using the process described in those sections.

Subpart (c): It is critical that intervenors participate in the review of costs before they can be added to rates. Depriving ratepayers of this opportunity would be contrary to the letter and spirit of Section 454, which requires notice to customers and an opportunity to be heard before allowing rate increases. Preventing ratepayers and their representatives from presenting their analysis and views regarding whether all applicable requirements have been satisfied would deprive the Commission of a complete and balanced record for its determination.

Subpart (d): TURN recommends the process described in Sections 5.2 and 5.3 and in response to Question C1.

6.4. Section D: How could the Commission address changes to approved projects?

1. *Should new costs added to approved projects after the Phase 2 Decision be booked to the Memo Account?*
    a. *If the updated rolling average CBR falls below the Phase 2 Condition threshold, should all new costs be deemed non-recoverable?*

Response to Question 1

For the reasons discussed in Section 3, the Guidelines should avoid allowing costs that violate applicable conditions and other requirements to be recovered after they have been incurred. For this reason, TURN has proposed the variance condition discussed in Section 4.2.2 and Section 5.3, which would allow the utility to seek re-review and pre-approval of projects that vary materially from the approved Phase 2 projects. If a utility wishes to seek relief from *other* conditions (e.g, annual cost caps, unit cost caps, average CBR threshold), it can submit a petition for modification (PFM) of the Phase 2 decision (just as ratepayer representatives who believe that the Phase 2 conditions have proven ineffective in achieving just and reasonable rates can submit a PFM). By submitting a PFM, the utility can gain an up-front determination of whether any conditions will be relaxed, before it builds a project and spends the money. Either way, there is no need to book to a memorandum account recorded costs that violate conditions that have been found necessary to ensure just and reasonable rates.

2. *Should certain categories of cost overruns (e.g., inflation-driven, safety-driven) be treated differently from discretionary cost increases?*

In light of SB 884's focus on cost control and promotion of declining costs over time, a utility that is seeking to increase Plan costs above Phase 2 approved levels, either through TURN's proposed process for the variance condition or through a PFM, should be required to demonstrate the increased costs result from conditions wholly outside of the utility's control. Utilities need to know that the Commission will not allow additional recovery for costs that could be avoided through managerial and operational acumen.

6.5. Section E: Should the Commission include an Appendix with guidance for calculating the CBR of an undergrounding project?

1. *What level of granularity[16] should the utility use when applying the Interruption Cost Estimator (ICE) Calculator to generate a Monetized Value of Electric Reliability? Should the analysis be based on:*
   a. *HFTD and PEDS-activated circuits*
   b. *Operational Region and HFTD[17]*
   c. *Others?*

Response to Question 1

For calculating the Monetized Value of Electric Reliability, TURN recommends that the utilities use a disaggregated approach based on both geographic risk tiers and customer classes to accurately reflect the varied impacts of outages across different locations. The minimum required level of granularity should follow Safety and Policy Division's (SPD) four-tier geographic categorization model:

1. HFTD Tier 3 (Extreme)

2. HFTD Tier 2 (Elevated)
3. Non-HFTD with PEDS/EPSS Enabled
4. Non-HFTD with PEDS/EPSS Non-Enabled

This approach is supported by the recent ALJ Ruling in PG&E's RAMP (A.24-05-008), which required PG&E to "provide parallel reliability cost calculations using the disaggregated approach recommended in the SPD Evaluation Report."[35] The SPD analysis showed significant variations in $/CMI values across these four tiers (as well as within the three customer classes in each tier) demonstrated in the table below:[36]

Table 1: Customer Distribution and Reliability Costs by Geographic Tier (SPD)

Geographic Tier	Residential	Small C&I	Medium and Large C&I	2023 $/CMI SPD Report
PG&E - HFTD Tier 3-Extreme	315,786	29,975	5,168	1.47
PG&E - HFTD Tier 2-Elevated	152,264	11,237	1,567	2.05
PG&E - NONHFTD-EPSS	1,143,635	115,614	33,122	2.94
PG&E - NONHFTD-NONEPSS	3,349,740	312,761	124,103	3.43
System Average				**2.47**

However, SPD's four-category typology, although an improvement from the systemwide average, still falls short of addressing the issue of appropriate reliability valuation across the three

---

[35] April 22, 2025 ALJ Ruling, A.24-05-008, p. 10

[36] Table reproduced from SPD's Evaluation Report on PG&E's 2024 RAMP Application (A.24-05-008), Nov. 8, 2014, p.18, found here: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/reports/spd-evaluation-report-2024-pge-ramp-final-with-attachments.pdf

customer classes. For example, rural California, where fire risk is high, has a low concentration of C&I customers who distort outage costs ($/CMI) for residential customers located there.[37] [38]

TURN therefore recommends further disaggregation to a twelve-tier model that combines the four geographic tiers with three customer classes (Residential, Small C&I, and Medium/Large C&I). Table 2 below shows the customer class distribution across these 12 categories.

Table 2: Customer Distribution Percentages by Geographic Tier and Customer Class

Geographic Tier	Residential (%)	Small C&I (%)	Medium and Large C&I (%)
PG&E - HFTD Tier 3-Extreme	90%	9%	1%
PG&E - HFTD Tier 2-Elevated	92%	7%	1%
PG&E - NONHFTD-EPSS	88%	9%	3%
PG&E - NONHFTD-NONEPSS	88%	8%	3%

TURN's twelve-tier approach (i.e., 4 geo tier * 3 customer classes) would yield more accurate reliability valuations for CBR calculations, especially in rural HFTD areas where reliability impacts for residential customers have been over-estimated under both system-wide, and geo-tier only averages, when averaging $/CMI across the three customer classes for each of the four geo-tiers.[39] The ICE calculator already outputs these costs in its main output segregated

[37] This concern is supported by multiple findings in PG&E's RAMP proceeding: SPD's Evaluation Report (Nov. 8, 2024, p.17) noted that "system-wide average...incorporates the high costs of an outage to Commercial and Industrial customers despite large parts of PG&E's territory having few, if any, such customers." The above-referenced ALJ Ruling (April 22, 2025, p.9) affirmed this observation, stating that, "Rural parts of California where certain risks are more likely to occur, such as wildfire, have few Commercial and Industrial customers." MGRA's analysis (Oct. 11, 2024, p.11) also quantified this disparity, demonstrating that "in the HFTD areas, 30 percent of customers live on circuit segments without Commercial and Industrial businesses" with a significantly lower reliability value of only "$0.68/CMI".

[38] https://www.latimes.com/environment/story/2022-12-27/more-than-half-of-rural-california-in-very-high-fire-zone

[39] For example, per PG&E's original calculations in RM-RMCBR-8 Module_1-Estimate_Interruption_Costs_w PGE Input.xlsm, residential cost per CMI ($0.06) is dramatically lower than either Small C&I ($9.99) and Medium/Large C&I ($77.89) costs (2023

by the three customer tiers, and residential customer costs per CMI as well as costs per unserved kWh are found to be consistently lower (in some cases orders of magnitude lower), compared to the two non-residential classes. The customer-segregated reliability values can be further refined using customer type-specific inputs, including backup generation prevalence, MWh consumption patterns by customer type/time, and regional economic data.

This enhanced granularity will ensure more accurate CBR calculations that properly reflect both wildfire risk reduction and reliability benefits for SB 884 undergrounding projects, preventing systemwide averages from overvaluing projects based on reliability benefits.

2. *How should the utility calculations of CBR be presented when using the three discount rate scenarios (Weighted Average Cost of Capital, Social and Hybrid) required by D.24-05-064?*

Response to Question 2

Discount rates can have a significant impact on CBR calculations. In R.20-07-013, TURN has raised particular concerns about CBRs that use different discount rates in the numerator and denominator, which TURN believes can bias and distort the results.[40] TURN is concerned that a utility may choose a discount rate option to further its financial interests, highlight the results of its chosen option in its Phase 2 pleadings, and effectively bury in dense workpapers the CBR calculations using the other required options.

The Commission should be aware that the appropriate discount rate will be an issue in the Phase 2 proceeding that it will need to resolve. In order to make clear the impact of different discount rate options on CBR calculations, the Commission should require the utility to provide in its Phase 2 pleadings (i.e., not just in the workpapers) tables showing alternative CBR calculations using alternative discount rates.

3. *Since the Energy Safety Guidelines allow the utility to consider an Ignition Tail Risk Threshold and High Frequency Outage Program Threshold, if the utility applies a convex risk scaling function to the calculation of CBR, how should the utility also present calculations that do not apply a convex risk scaling function, as required by D.24-05-064?*

---

dollars). This difference between residential and non-residential $/CMI persists in the 4 geo-tiered calculation.

[40] TURN White Paper on Discount Rates, R.20-07-013, October 31, 2023, pp. 8-9, found at: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M520/K763/520763597.PDF

Response to Question 3

Consistent with the April 22, 2025 Ruling in the PG&E RAMP (A.24-05-008), any utility that chooses to use a convex (risk-averse) scaling function – which furthers the utility's financial interest in justifying higher rate base levels[41] -- should also include parallel results using a risk-neutral scaling function. Specifically, the utility should:

- Provide parallel monetized levels of each attribute or attributes without applying its risk-averse Risk Attitude Function; and
- Provide CBRs (and any other cost-benefit analysis) without applying its risk-averse Risk Attitude Function.[42]

TURN understands that MGRA's comments will discuss in detail the problems with risk-averse scaling functions and why CBR results based on such functions are not useful for purposes of estimating risks and CBRs.[43] TURN agrees with MGRA that the Commission should base its decisions and conditions in SB 884 proceedings on risk-neutral scaling functions.

4. *How should the Commission consider the combined CBR benefits of Ignition Risk reduction and Outage Program Risk reduction, given that a proposed mitigation may also reduce outage program risk?*
    a. *Option 1: Calculate the CBR benefit based on the Ignition Risk reduction only.*
    b. *Option 2: Calculate the CBR benefit based on a combination of Ignition Risk reduction and Outage Program Risk reduction?*
        i. *Should the CPUC assume mutual exclusivity between Ignition Risk and Outage Program Risk when aggregating the CBR benefits? If not, how should these risks be combined?*

---

[41] See TURN's January 3, 2025 Comments in R.20-07-013, pp. 8-13, discussing the utilities' financial interest in a risk-averse approach to risk analysis that justifies higher risk mitigation spending, as compared to the interest of many ratepayers whose risk attitude is shaped by the affordability of an essential service they cannot live without. These comments can be found at: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M553/K185/553185395.PDF

[42] ALJ Ruling in A.24-05-008, April 22, 2025, p. 8.

[43] TURN has also previously addressed this issue. *See, e.g.,* TURN's Opening Comments in PG&E's RAMP, A.24-05-008, Dec. 6, 2024, pp. 2-6, found at: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M549/K057/549057536.PDF

Response to Question 4

In general, the benefits of a mitigation should be based on the reduction of risk (pre-mitigation risk minus post-mitigation risk). Risk is calculated as the product of likelihood and consequence of a risk event. In that calculation, all consequences should be considered including the impact of the mitigation on reliability. If a mitigation reduces the need for outage programs, that reliability benefit should be included in the benefit calculation.

The challenge is ensuring that the utility's assumptions and calculations of such reliability benefits are reasonable and are not tainted by the utility's financial interest in enhancing rate base. For example, while overhead hardening can reduce the need for PSPS and EPSS (although likely not as much as undergrounding), a utility that seeks to justify a large undergrounding footprint may understate these reliability benefits of overhead hardening in the comparison of grid hardening alternatives. This concern is one illustration of the detailed CBR-related issues that may arise in cost recovery requests that underscore the need for TURN's minimum 75-day analysis and comment period recommended in response to Question C1 in Section 6.3.

The subpart (i) question regarding "mutual exclusivity" may be raising a significant issue. However, outside the context of specific calculations and illustrations, TURN does not fully understand the issue and is not able to provide a generalized answer at this time.

5. *What is the appropriate point in time for utilities to use as CBR Year Zero in CBR calculations?*
    a. *Option 1: The first year of application cycle.*
    b. *Option 2 : The year the project is expected to become used and useful.*

Response to Question 5

TURN is inclined to support Option 2, that CBR Year Zero in the Phase 2 application be based on the year the utility expects the project to become operational. This means that Year Zero could differ by project. This CBR will be the CBR on which CBR-based conditions will be based. The same Year Zero should be used when the utility seeks cost recovery for the project, in order to yield an apples-to-apples comparison. Indeed, this may be the more important point – that whatever CBR Year Zero is used for a project in the Phase 2 application should be the same CBR Year Zero that is used when requesting cost recovery.[44]

---

[44] TURN is not confident that it has been able to think through all nuances associated with this issue, so offers this response somewhat tentatively.

7. Conclusion

TURN appreciates the opportunity to respond to SPD's questions. Please contact the undersigned or Elise Torres (ETorres@turn.org) with any questions about TURN's responses.

Dated: April 25, 2025

Prepared by:

/s/ *Thomas J. Long*

Thomas Long, Director of Regulatory Strategy
tlong@turn.org

THE UTILITY REFORM NETWORK
360 Grand Avenue, # 150
Oakland, CA 94610
Telephone: (415) 929-8876

Attachment 10

Draft Resolution SPD-37 (issued 8/15/25)

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

SAFETY POLICY DIVISION

Agenda ID # 23691
Resolution SPD-37
September 18, 2025

R E S O L U T I O N

RESOLUTION SPD-36 Update and Revision of Senate Bill 884 Program: CPUC Guidelines, Program for Expediting the Undergrounding of Distribution Equipment of Large Electrical Corporations.

PROPOSED OUTCOME:
Refines the *SB 884 Program: CPUC Guidelines, Program for Expediting the Undergrounding of Distribution Equipment of Large Electrical Corporations,* previously adopted in Resolution SPD-15, issued March 8, 2024. Aligns the Commission's program with the recently adopted SB 884 *10-Year Electrical Undergrounding Plan Guidelines* of the Office of Energy Infrastructure Safety.

SAFETY CONSIDERATIONS:
Reduce utility caused wildfires and increase reliability through the adopted expedited utility distribution infrastructure undergrounding program.

COSTS:
None; no costs are approved by this resolution. Any program costs will be considered and conditionally approved through subsequent SB 884 Applications submitted by participating utilities, an audit process, and a just and reasonable cost review process for certain costs.

1. SUMMARY

This Resolution builds on earlier Resolution SPD-15 implementing Senate Bill (SB) 884 (McGuire; Stats. 2022, Ch. 819), codified at Public Utilities Code (PU Code) Section 8388.5.[1] The Commission approved Resolution SPD-15, issued March 8, 2024, adopting the *Senate Bill (SB) 884 Program: CPUC Guidelines, Program for Expediting the Undergrounding of Distribution Equipment of Large Electrical Corporations* (SPD-15 Guidelines) that addressed the process and requirements for Commission review of any

[1] PU Code Section 8388.5 https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=8388.5.&lawCode=PUC.

regulated large electrical corporation's 10-year distribution infrastructure undergrounding plan (hereafter known as the Electric Undergrounding Plan (EUP) or Plan) application and conditional approval or denial of related costs. The Commission noted in Resolution SPD-15 that additional issues remained to be resolved.

This second Resolution adopts the following outcomes:

1. Updates and adds Phase 2 Application requirements that ensure the Commission has adequate undergrounding project cost information to determine whether cost recovery is reasonable.
2. Adds Phase 2 Conditions that build on newly adopted requirements in the Office of Energy Infrastructure Safety (Energy Safety) guidelines for EUPs (*Energy Safety Guidelines*) to ensure the most cost-efficient undergrounding projects are implemented. Additional scrutiny is provided for EUP projects whose economic metrics (total costs, unit costs, and cost-benefit ratios) upon which the Commission's Phase 2 Decision will be based substantively change as the project is scoped further and constructed.
3. Explains a process for ensuring costs recovered via the memorandum account adopted in Resolution SPD-15 are capped and not excessive.
4. Adopts primary and secondary objectives for an audit of any costs recorded to the one-way balancing account adopted in Resolution SPD-15.
5. Explains how Cost-Benefit Ratios (CBR)[2] must be calculated to ensure projects achieve wildfire risk reduction without undue expense and provide a means for equitable comparison against potential alternative mitigations.

2. BACKGROUND

The SPD-15 Guidelines set forth a three-phased process for implementation of SB 884's requirements. The first phase requires the EUP to be reviewed and approved or denied by Energy Safety prior to review by the Commission (Phase 1). In the second phase (Phase 2), the Commission reviews and may conditionally approve or deny an application for the EUP's costs (Phase 2 Application). Any conditional approval will authorize the creation of a one-way balancing account to potentially recover plan costs

[2] CBR is calculated by dividing the dollar value of Total Mitigation Benefit by the Present Value of the Capital Costs. See D.22-12-027 Phase II Decision Adopting Modifications, Risk-Based Decision-Making Framework, Appendix A, p. A-3.

contingent on the satisfaction of conditions placed on approval. If the Commission conditionally approves cost recovery in the one-way balancing account, the Commission will also authorize the large electrical corporation to establish a memorandum account to potentially recover any EUP costs that fail to meet the conditions set forth by the Commission. Resolution SPD-15 also established that the one-way balancing account requires an audit, and if any costs recorded to the account do not meet conditions imposed in the Commission's decision on the Phase 2 Application (Phase 2 Decision), such costs may be subject to refund to ratepayers. The third phase (Phase 3) consists of EUP implementation, progress reporting, and ongoing monitoring and review. Any EUP costs recorded in the authorized memorandum account must be submitted to the Commission for review of justness and reasonableness in separate applications (Phase 3 Application) prior to recovery in rates.

To implement the first phase, Energy Safety issued its *10-Year Electrical Undergrounding Plan Guidelines* (*Energy Safety Guidelines*) on February 20, 2025. Among other reasons, this Resolution updates and refines the SPD-15 Guidelines in consideration of the *Energy Safety Guidelines*. This Resolution conforms the guidelines to the discussion herein and attaches the new *CPUC Guidelines*[3] as Attachment A hereto.

2.1 SB 884 Background

SB 884, effective January 1, 2023, requires the Commission to establish an expedited utility distribution infrastructure undergrounding program in Tier 2 and Tier 3 High Fire-Threat District (HFTD) areas and in wildfire rebuild areas for the state's large electrical corporations. The statute authorizes, but does not require, utilities with 250,000 or more customer accounts (large electrical corporations) to participate.

To begin the process, each participating large electrical corporation submits a 10-year EUP to Energy Safety for review. Energy Safety must approve or deny the EUP within nine months of filing. If approved by Energy Safety, the large electrical corporation must then submit to the Commission, within 60 days of Energy Safety's approval, a copy of the approved EUP and Phase 2 Application requesting conditional approval of the EUP's costs. The Commission must approve or deny the Phase 2 Application within nine months of submission.

Pursuant to PU Code Section 8388.5(f), if the EUP is approved by Energy Safety and the Commission, the large electrical corporation shall do all the following:

[3] References to the guidelines adopted in Resolution SPD-15 are to "*SPD-15 Guidelines*." The guidelines adopted in this Resolution, which supersede the *SPD-15 Guidelines* are titled "*CPUC Guidelines*."

(1) Every six months, file a progress report with [Energy Safety] and the commission. The large electrical corporation and Energy Safety shall publish these progress reports on their respective internet websites.
(2) Include ongoing work plans and progress in annual wildfire mitigation plan filings.
(3) Hire an independent monitor, selected by [Energy Safety], to review and assess the large electrical corporation's compliance with its plan and submit a report with Energy Safety each December 1 over the course of the plan.

Under PU Code Section 8388.5(j), "[e]ach 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."

Finally, PU Code Section 8388.5(i)(2) provides that "[t]he commission may assess penalties on a large electrical corporation that fails to substantially comply with a commission decision approving its plan."

2.2 SPD-15 Guidelines

The SPD-15 Guidelines establish several key elements of the SB 884 program. These elements include the requirements for Phase 2 Application submittal; minimum conditions for conditional approval (Phase 2 Conditions); accounting structures for tracking and recording costs related to an EUP; the concept of an audit and potential refund to ratepayers for costs recorded in an authorized one-way balancing account; the structure and timing of any applications submitted pursuant to Phase 3 of the program; information to be included in progress reports; and identification of a preliminary dataset that must be included in a Phase 2 Application. Resolution SPD-15 deferred finalizing several of these concepts, including the audit of the one-way balancing account, progress report filings, and the *SB 884 Project List Data Requirements Guidelines*, to a later Commission decision or order, and this Resolution acts on those items and others that have arisen since SPD-15's adoption.

2.3 Audit of Balancing Account

Resolution SPD-15 provided that "[t]he details of th[e] [balancing account] audit, including but not limited to who will perform it, content, frequency, venue, method for true-up and refund mechanism will be determined in a future decision or order."[4] This

[4] SPD-15 at 15.

Resolution, including Attachment A, provides the separate audit process and details required by SPD-15.

2.4 Progress Reports

The Commission adopted Resolution SPD-15 before Energy Safety adopted its own Guidelines. The SPD-15 Guidelines anticipated that the details of six-month progress report filings and the data filing requirements, included as Appendix 1 of the SPD-15 Guidelines, would require future refinement after finalization of the *Energy Safety Guidelines* and consultation amongst the agencies. The *SB 884 Project Lists Data Requirements-Preliminary* were refined and revised following a series of Technical Working Group (TWG) meetings,[5] as authorized by SPD-15,[6] and are included with this Resolution as the *SB 884 Project List Data Requirements Guidelines* in Appendix 2 of the *CPUC Guidelines*.

2.5 EUP Detail Needed for Determination of Cost Recovery

Detailed information on specific undergrounding projects is essential for the Commission and stakeholders to assess and determine the appropriate Phase 2 Conditions, which are used to determine whether cost recovery for EUP projects is appropriate. This Resolution expands on the process and requirements in Resolution SPD-15 for such cost recovery.

After the Commission adopted Resolution SPD-15, on February 20, 2025, Energy Safety adopted Guidelines setting forth the details of the EUP approval process that were not yet developed at the time of SPD-15's adoption. The *Energy Safety Guidelines* detail the requirements and process for execution of Phase 1 of the SB 884 program. Under the *Energy Safety Guidelines*, it is likely the vast majority of undergrounding projects in the approved EUP will only be preliminarily scoped, as explained below, and will be subject to substantive change following approval of the EUP. This scoping and project selection process is implemented through Energy Safety's "Project Acceptance Framework" approach.

Energy Safety's Project Acceptance Framework approach for its review and approval of EUPs is a multi-step process that a large electrical corporation must establish and use to identify and select undergrounding projects for construction through its EUP.[7] The

[5] Presentation materials and recordings of the Technical Working Group meetings are available on the Commission's SB 884 webpage at: https://www.cpuc.ca.gov/about-cpuc/divisions/safety-policy-division/risk-assessment-and-safety-analytics/electric-undergrounding-sb-884.
[6] SPD-15, Ordering Paragraph 3 at 21.
[7] *Energy Safety Guidelines* at 11.

Project Acceptance Framework contains four increasingly specific screening criteria, which allow a large electrical corporation to filter all potential undergrounding projects down to a list of prioritized undergrounding projects at the final fourth screen. A brief overview of Energy Safety's Project Acceptance Framework is provided below.[8]

- **Screen 1 – Circuit Segment Eligibility**: The large electrical corporation must assess all of its circuit segments[9] to determine EUP eligibility based on locational constraints (location in Tier 2 or Tier 3 HFTD areas), and then determine whether each of these circuit segments meet specific project-level thresholds (whether the individual project's risk score shows a required level of risk establishing the need for mitigation). Circuit segments that meet both locational and project-level requirements are considered to "pass" Screen 1 and are included in an "Eligible Circuit Segments List" (the output of Screen 1).
- **Screen 2 – Project Information and Alternative Mitigation Comparison**: The large electrical corporation must confirm whether sufficient information is available on a circuit segment to establish a preliminary scoping. It must conduct cost-benefit analysis comparisons of undergrounding to two separate alternative mitigations to determine which projects from the Eligible Circuit Segments List can be treated as undergrounding projects. Circuit segments that meet the informational requirements and present a comparison of the project to at least two alternative mitigations are considered to "pass" Screen 2 and are include in an "Undergrounding Projects List" (the output of Screen 2).
- **Screen 3 – Project Risk Analysis**: The large electrical corporation must evaluate each individual undergrounding project that is included in the "Undergrounding Projects List" according to the information obtained through the project development process (the "scoping phase").[10] In Screen 3, the large electrical corporation must determine if the undergrounding project meets expected wildfire risk reduction and reliability improvements of the "Plan Mitigation Objective."[11] The large electrical corporation also compares "Key Decision-

[8] For a detailed explanation of the Project Acceptance Framework, see *Energy Safety Guidelines* at 11-24.
[9] In the *Energy Safety Guidelines*, all potential undergrounding projects are assessed at "circuit segment" granularity. "Circuit segment" is defined as "an isolatable circuit segment" (See *Energy Safety Guidelines* at A-1).
[10] The scoping phase typically identifies the size and timeline of the project. It also determines the feasibility of construction and possible timing of execution of an undergrounding project. While Energy Safety in some places refers to this as the "scoping process" or "project scoping phase", this resolution uses the term "scoping phase" throughout.
[11] The Plan Mitigation Objective is the total amount of change in risk (wildfire and reliability) that is necessary to meet the requirement of section 8388.5(d)(2). For discussion of the Plan Mitigation Objective see *Energy Safety Guidelines* at 3-5.

Making Metrics" (KDMMs) in Screen 3 to identify fixed areas where undergrounding work will occur (identified as "Confirmed Project Polygons").[12] Undergrounding projects that meet the informational requirements for the scoping process, demonstrate contribution to the Plan Mitigation Objective, and present a comparison of KDMMs between the undergrounding project and alternative mitigations are considered to "pass" Screen 3 and are included in a "Confirmed Projects List" (the output of Screen 3).

- **Screen 4 – Project Prioritization**: The EUP must set forth a means of prioritization and its definition for each of the factors in PU Code Section 8388.5(c)(2) (wildfire risk reduction, public safety, cost efficiency and reliability benefits) and conduct a comparison of the costs, benefits, and CBR for the design variations that were used in Screen 3.[13] After taking the Confirmed Project List (the output of Screen 3), and applying the means of prioritization established in Screen 4, the large electrical corporation is left with the "Prioritized Projects List" (the output of Screen 4).

The *Energy Safety Guidelines* permit an EUP to be filed by a large electrical corporation once 25 undergrounding projects have passed through Screen 3 of the Project Acceptance Framework.[14] This requirement does not preclude a large electrical corporation from filing an EUP that has more than 25 undergrounding projects that have passed through Screen 3. However, the 10-year duration of EUPs suggests that, at the time a Phase 2 Application is filed with the Commission, only a small fraction of undergrounding projects that may be constructed as part of the EUP will have progressed through at least Screen 3.[15] Further, a large electrical corporation will not be required to obtain Energy Safety approval of undergrounding projects it later intends to construct. Rather, as set forth below, the large electrical corporation will provide detail about new projects in progress reports. This Resolution addresses how the Commission will assess the appropriateness of cost recovery for such projects.

---

[12] Energy Safety defines a Confirmed Project Polygon as "a special boundary generated at the beginning of Screen 3 that encompasses the entire Eligible Circuit Segment on which the Undergrounding Project is defined, except any sections already contained in another Confirmed Project Polygon." *Energy Safety Guidelines* at A-1. KDMMs are up to 12 top-level metrics that the large electrical corporation proposes to use to evaluate the efficacy of an Undergrounding Project. See *Energy Safety Guidelines* at 30-32.

[13] The CBR calculation must follow the guidelines found in D.24-05-064 Appendix A or the most recent decision from the risk-based decision-making framework (RDF) Proceeding (R.20-07-013) or its successor proceeding.

[14] *Energy Safety Guidelines* at 12.

[15] PG&E in response to Energy Safety-DR-EUP-24-06 Question 1 states that the PG&E scoping team estimates it will complete an average of thirty projects per quarter, which would potentially result in approximately 1,200 projects over the ten years of the EUP.

PU Code Section 8388.5(c)(2) requires, in part, that an EUP filing identify "the undergrounding projects that will be constructed as part of the program…." With the exception of the 25 projects that are required to pass through Screen 3, the *Energy Safety Guidelines* find that this requirement is satisfied when the projects in the EUP have passed Screen 2 (are included in the "Undergrounding Projects List").[16] As explained above, Screen 2 is an early step in the scoping process for an undergrounding project.

The time for approval of an EUP is short. PU Code Section 8388.5(d)(2) requires that Energy Safety approve or deny an EUP within nine months of its filing. Furthermore, PU Code Section 8388.5(e)(1) requires that a large electrical corporation must file its Phase 2 Application with the Commission within 60 days of Energy Safety approving its EUP. Because significant changes can be made to the economic metrics (total costs, unit costs, and cost benefit ratios) of an undergrounding project as it is more accurately scoped in Screens 3 and 4, the large majority of forecasted data available to the Commission at the time a Phase 2 Application is filed, and upon which its EUP cost approval conditions in the Phase 2 Decision will be based, will not be sufficiently precise to provide the intended cost containment controls and ratepayer protections anticipated in Resolution SPD-15. Accordingly, this Resolution closes such gaps to ensure the Commission has the information essential to determining the appropriateness of cost recovery.

2.6 Stakeholders Participating in SB 884 Program Development

The large electrical corporations eligible to seek cost recovery in this program are: Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE). All the large electrical corporations have been participating in the development and refinement of the guidelines. PG&E and SDG&E have confirmed their intent to file EUPs.[17]

Other stakeholders that have participated in the Commission's process to implement SB 884 include the Commission's Public Advocates Office (Cal Advocates); The Utility Reform Network (TURN); Mussey Grade Road Alliance (MGRA); California Farm Bureau (CFB); Green Power Institute (GPI); Coalition of California Utility Employees (CUE); AT&T California/California Broadband and Video Association/Crown Castle Fiber, LLC/Sonic Telecom, LLC (collectively, Communication Providers); ExteNet

[16] *Energy Safety Guidelines* at 12.

[17] For SDG&E see response to Data Request No. SPD-SDGE-SB884-006, available at https://www.sdge.com/sites/default/files/regulatory/Data%20Request%20SPD-SDGE-SB884-006_Response.pdf. For PG&E see A.25-05-009, Exhibit (PG&E-4) Chapters 1-9 at 2-13.

Systems, LLC/ExteNet Systems (California) LLC (ExteNet); DISH Wireless LLC; and INCOMPAS.

2.7 Procedural History

A chronological history of events beginning with the Commission's adoption of the SPD-15 Guidelines and continuing to the present is as follows:

- March 8, 2024 – Commission issued Resolution SPD-15, "SB 884 Program: CPUC Guidelines, Program for Expediting the Undergrounding of Distribution Equipment of Large Electrical Corporations."
- October 14, 2024 – Safety Policy Division (SPD) issued "Questions for Stakeholders Regarding the CPUC SB-884 Guidelines" for stakeholder comment.
- November 12, 2024 – Responses to "Questions for Stakeholders Regarding the CPUC SB-884 Guidelines" received from stakeholders.
- February 20, 2025 – Energy Safety issued its "10-year Electrical Undergrounding Plan Guidelines."
- April 8, 2025 – SPD workshop to discuss potential modifications to the SPD-15 Guidelines following publication of the *Energy Safety Guidelines*.
- April 11, 2025 – SPD issued "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines" soliciting comments on topics discussed at the April 8, 2025, workshop.
- April 25, 2025 – Responses to the "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines" received from stakeholders.
- May 20, 2025 – SPD issued "Staff Report on SB-884 Projects List Data Requirements Guideline" providing background, purpose, and details of proposed changes to SB 884 data requirements and providing a set of "Technical Working Group Questions" to prompt discussion for upcoming TWG meetings.
- June 3, 2025 - SPD TWG meeting #1 on potential updates to the *SB 884 Project List Data Requirements Guidelines*.
- June 10, 2025 - SPD TWG meeting #2 on potential updates to the *SB 884 Project List Data Requirements Guidelines*.
- June 24, 2025 - SPD TWG meeting #3 to discuss the Interruption Cost Estimate Calculator (ICE 2.0).
- June 24, 2025 – Responses to "Technical Working Group Questions" received from stakeholders.
- July 24, 2025 – SPD published the Revised *SB 884 Project List Data Requirements Guidelines* and *SB 884 Project List Data Template.*

2.8 Organization of Resolution

This Resolution builds on the SPD-15 Guidelines, focusing on the following five program elements:

1. Additional Phase 2 Application requirements;
2. Additional Phase 2 Conditions;
3. Memorandum account limitations;
4. Balancing account audits; and
5. CBR guidance.

These elements are discussed in further detail in the Discussion section below, along with recommendations and comments from stakeholders.

3. DISCUSSION

This Resolution introduces refinements to the guidelines to: (1) align programmatic information required by the *Energy Safety Guidelines* and *CPUC Guidelines*, (2) clarify the procedure for an audit as anticipated in Resolution SPD-15, (3) add new data reporting requirements pursuant to SPD-15's directive, and (4) provide additional information needed to ensure the Commission can effectively assess cost recovery for EUPs.

Between the adoption of the SPD-15 Guidelines issued March 8, 2024, and the *Energy Safety Guidelines* on February 20, 2025, Commission Staff issued and received responses to "Questions for Stakeholders Regarding the CPUC SB-884 Guidelines" on November 12, 2024, which provided additional information and insight into potential future refinements of the guidelines.[18] Following the adoption of the *Energy Safety Guidelines*, Commission Staff hosted a workshop on April 8, 2025, and issued and received responses to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines" on April 25, 2025. Prior to the commencement of TWG meetings, authorized by SPD-15 to refine data requirements for the Commission's SB 884 program, Commission Staff issued a "Staff Report on SB-884 Projects List Data Requirements Guideline" on May 20, 2025, which included a set of "Technical Working Group Questions." Commission Staff then hosted a series of three TWG meetings in June 2025, and accepted stakeholder responses to the "Technical Working Group Questions" on June 24, 2025. The input received from stakeholders, along with the

[18] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/documents/sb-884-consolidated-responses-to-informal-questions_111224.pdf

adoption of the *Energy Safety Guidelines*, informs the *CPUC Guidelines* presented in this Resolution. In addition to the changes that are described in the following sections, changes have also been made to the *CPUC Guidelines* to reflect that the version of the *CPUC Guidelines* adopted in SPD-37 has undergone a process of aligning the *CPUC Guidelines* with the *Energy Safety Guidelines*.

SB 884 instituted requirements for the Commission to create a novel program that expedites the review and approval of EUPs and conditional approval of their costs. An inherent challenge with this program is balancing the expedited nature of reviewing an unprecedented volume, cost, and duration of electrical distribution infrastructure hardening via undergrounding with growing pressure on ratepayer affordability.

To clarify the cost recovery process and establish a means to achieve the intended outcomes of SB 884, the SPD-15 Guidelines used the "conditional approval" provision in PU Code Section 8388.5(e)(1) to establish Phase 2 Conditions. The Phase 2 Conditions are a central feature of the guidelines. These conditions provide direction to large electrical corporations on the amount of EUP costs that will be authorized to recover in rates via the balancing account, while ensuring ratepayer interests are protected. The conditions provide regulatory clarity and certainty for large electrical corporations while ensuring EUP costs borne by ratepayers are just and reasonable. Under the SPD-15 framework, an audit and refund process is necessary for the one-way balancing account. The large electrical corporation initially asserts that EUP project costs have met the Phase 2 Conditions upon recording in the one-way balancing account. It is only during the audit process that the Commission verifies whether the Phase 2 Conditions were met (Primary Objectives).

Following adoption of the *Energy Safety Guidelines* and consideration of stakeholder input, the Commission provides more detail in this Resolution on the process for large electrical corporations to record EUP costs in the balancing account and seek to recover EUP costs in the memorandum account. The process is intended to further strengthen program oversight, bolster ratepayer protections, increase rate stability, and improve the efficiency of the cost recovery process by clarifying the objectives of the EUP Audit discussed in Section 3.4 of this Resolution.

As established in the SPD-15 Guidelines, Phase 2 Conditions are predicated on information presented by large electrical corporations in Phase 2 Applications. The Phase 2 Conditions establish the parameters that govern cost recovery via the one-way balancing account and must reflect the most accurate and up-to-date EUP project related information. However, much of the project-specific information received at the time a Phase 2 Application is filed is expected to lack refined scoping information. Projects other than those that pass Screen 3 at the time of an EUP submittal to Energy Safety will only include the output of Screen 2 of the *Energy Safety Guidelines*. The Commission adopts the requirements below to ensure the necessary information for Commission review accompanies all projects, including those that have not yet passed Screen 3 at the time of a Phase 2 Application submittal.

This Resolution adopts a change to one existing Phase 2 Application requirement (Existing Application Requirement No. 11), adds seven new Phase 2 Application requirements, and adopts four new Phase 2 Conditions. This Resolution also adopts a cap on the total cumulative costs recoverable via the memorandum account, provides the process and details for the EUP Audit, and adopts guidance for the execution of CBR calculations required for this program.

3.1 Additional Application Requirements

Following the adoption of the *Energy Safety Guidelines*, the Commission received input from stakeholders during the April 8, 2025, workshop and written responses to questions soliciting input on potential additional Phase 2 Application requirements on November 12, 2024, and April 25, 2025. The Commission now determines that additional Phase 2 Application requirements are necessary to: (1) align programmatic information required by the *Energy Safety Guidelines* and *CPUC Guidelines*, (2) clarify the procedure for an audit, (3) add new data reporting requirements pursuant to SPD-15's directive, and (4) provide additional information needed to ensure the Commission can effectively assess cost recovery for EUPs.

The SPD-15 Guidelines established twenty Phase 2 Application requirements.[19] Staff presented potential additional Phase 2 Application requirements during the above noted workshops and review of feedback from stakeholders. Considering the workshop and stakeholder feedback the Commission adopts the following Phase 2 Application requirements:[20]

1. Existing Application Requirement No. 11 is revised as follows: "For each project included in the Application, the large electrical corporation shall provide, at a

[19] Resolution SPD-15, Attachment 1 at 6.

[20] The new Application requirements adopted by this Resolution are not necessarily incorporated sequentially in the *CPUC Guidelines*, as reflected in the redlined version of the *CPUC Guidelines* included as Attachment B to this Resolution.

minimum, all data listed in the *SB 884 Project List Data Requirements Guidelines* in tabular format. This information shall be provided as both a Microsoft Excel file and a searchable pdf file[21] to supplement the Application. The large electrical corporation shall provide the latest version of the data required by the *SB 884 Project List Data Requirements Guidelines* at the time of its Application submission."

2. First New Application Requirement: "The Application shall include the latest data associated with the list of all projects (*SB 884 Project List Data Requirements Guidelines*) as required by Screen 2 of the *Energy Safety Guidelines*. The large electrical corporation shall provide a forecasted scope of all projects in the approved 10-year EUP and included in the Undergrounding Projects List, as an output from Screen 2 of the *Energy Safety Guidelines*."
3. Second New Application Requirement: "The Application shall include a detailed explanation of the necessity for any spans that extend beyond the HFTD boundary for any project included in the Application."
    a. "The Application shall only include undergrounding projects that have been designated as an In-Area circuit segment as required by Screen 1 in the *Energy Safety Guidelines*.[22]"
4. Third New Application Requirement: "The Application shall include:
    a. The same Key Decision-Making Metrics (KDMMs) data for Commission review as was provided in the EUP approved by Energy Safety.
    b. The KDMMs included in any six-month progress report submitted to Energy Safety during the nine-month period that the large electrical corporation's EUP is under review by Energy Safety."
5. Fourth New Application Requirement: "The Application shall include a Results of Operation (RO) Model for that portion of its revenue requirement that relates to the undergrounding cost recovery it seeks, with Energy Division oversight and a non-disclosure agreement in place,[23] that demonstrates how the large electrical corporation calculated the revenue requirement provided.[24]"
6. Fifth New Application Requirement: "The Application shall include a detailed description of the method that establishes how the auditor will validate whether the large electrical corporation has satisfied the primary and secondary objectives

[21] See Rules of Practice and Procedure: California Code of Regulations Title 20, Division 1, Chapter 1. Article 1, Rule 1.3(b) for complete submission requirements of pdf files.
[22] *Energy Safety Guidelines* at 12. The large electrical corporation indicates to Energy Safety whether a circuit segment is designated as "In-Area" in Table C.6 under the "is_in_area" field.
[23] The non-disclosure agreement shall ensure that the large electrical corporation personnel in charge of the RO modeling will not disclose changes to the RO Model requested by the Commission to the personnel working on the Phase 2 Application and related matters.
[24] See also D.00-07-050 at 11-12 and D.20-01-002 at 65-67.

of the audit. For the primary objectives, this method must include an approach for:

a. Verifying that the total annual costs did not exceed the approved cost cap for a given year of the EUP (Existing Condition #1);
b. Verifying that any third-party funding obtained was applied to reduce the established cost cap for the specific year in which the third-party funding was obtained (Existing Condition #2);
c. Determining that the average recorded unit cost for all projects completed in any given two-year period did not exceed the approved average unit cost cap (Existing Condition #3);
d. Determining that the average recorded CBR for all projects completed in any given two-year period equals or exceeds the approved threshold CBR value. (Existing Condition #4);
e. Determining whether the forecasted CBR of an alternative mitigation exceeds a certain threshold value above the forecasted CBR of an undergrounding project (First New Condition);
f. Verifying that a project did not exceed the approved CBR percentage difference threshold (Second New Condition);
g. Verifying that a project did not exceed the approved unit cost percentage difference threshold (Third New Condition); and
h. Verifying that the undergrounding project meets or exceeds the applicable Project-Level Standard, in the large electrical corporation's EUP approved by Energy Safety (Fourth New Condition).

For the secondary objectives, this method must include an approach for:

i. Verifying that a project is used and useful.
j. Verifying the incrementality showing found in Application Requirement No. 2.
k. Validating the methodology used to calculate a CBR for a given project, as found in the *CBR Calculation Guidelines* in Appendix 1 of the *CPUC Guidelines*."

7. Sixth New Application Requirement: "The Application shall only include undergrounding projects that have a forecasted CBR greater than or equal to 1."
8. Seventh New Application Requirement: "The Application shall only include undergrounding projects that have met one or more of the large electrical corporation's three Project-Level Thresholds.[25]"

[25] *Energy Safety Guidelines* at 42. The large electrical corporation indicates to Energy Safety whether a circuit segment falls into one of the mitigation eligibility categories in Table C.8 under the "risk_category" field.

Resolution SPD-15 acknowledged the project data template, attached to SPD-15 as Appendix 1 of the SPD-15 Guidelines, was preliminary. The Commission directed Staff to refine, update, and finalize Appendix 1 following a series of TWG meetings after the publication of the *Energy Safety Guidelines*.[26] Staff has completed this process, and the data requirements in the *SB 884 Project List Data Requirements Guidelines* are no longer preliminary. Thus, Existing Application Requirement No. 11 is updated to include the instruction for the large electrical corporation to provide the most recent data required by the *SB 884 Project List Data Requirements Guidelines* at the time of its Phase 2 Application submission.

The First New Application Requirement reflects the process set forth in the *Energy Safety Guidelines* and makes explicit that a large electrical corporation is required to provide specific information required by Energy Safety when submitting its Phase 2 Application. This includes the addition of the "Undergrounding Projects List" that is an output from Screen 2 of the *Energy Safety Guidelines*, adopted after the issuance of SPD-15.

The *Energy Safety Guidelines* provide that, "[i]f a Circuit Segment has portions both within and outside of a Tier 2 or 3 HFTD, each span crossing the Tier 2 or 3 HFTD boundary and up to two adjacent spans outside of a Tier 2 or 3 HFTD may be considered for undergrounding."[27] To ensure consistency between the *Energy Safety Guidelines* and the *CPUC Guidelines*, the Second New Application Requirement requires a large electrical corporation to explain why undergrounding work outside of Tier 2 or 3 HFTD areas is necessary to meet the purpose of SB 884. The sub-requirement of the Second New Application Requirement states all undergrounding projects in the Application must be designated as an "In-Area" circuit segment located inside the Tier 2 HFTD, Tier 3 HFTD, or a wildfire rebuild area, and align with the in-area requirement associated with Screen 1 of the *Energy Safety Guidelines*.[28]

Regarding the Third New Application Requirement, the *Energy Safety Guidelines* created the concept of KDMMs, defined "to be the collection of top-level metrics that the [l]arge [e]lectrical [c]orporation proposes to use to evaluate the efficacy of an [u]ndergrounding [p]roject."[29] Large electrical corporations must submit KDMM data with an EUP[30] and

[26] SPD-15, Ordering Paragraph 3 at 21.
[27] *Energy Safety Guidelines* at 16.
[28] *Energy Safety Guidelines* at 12.
[29] *Energy Safety Guidelines* at 30.
[30] *Energy Safety Guidelines* at 26.

update the KDMM data in the six-month progress reports, including any reports submitted during the nine months while Energy Safety is reviewing the EUP.[31] Given this process, it is reasonable to require a large electrical corporation to include any updated KDMM data provided in its six-month progress reports submitted while its EUP is under review with its Phase 2 Application.

Staff solicited input from stakeholders on the inclusion of KDMM data in a Phase 2 Application.[32] TURN supported the Commission's inclusion of KDMMs,[33] while PG&E and SDG&E argued that the Commission would already have access to KDMM data through the EUP.[34] However, PG&E agreed to "provide the most recent six-month progress report which will include the most recent KDMM information"[35] when submitting its Phase 2 Application. It is not sufficient to rely on data in the record of another state agency; large electrical corporations must provide all required information to the Commission and serve it on stakeholders.

The Fourth New Application Requirement is added to ensure that Phase 2 Applications present a detailed and accurate forecast of the large electrical corporation's revenue requirement for the 10-year period of the EUP. The SPD-15 Guidelines already require the large electrical corporation to provide a "best estimate, including all underlying assumptions, of the proposed annual revenue requirements."[36] In its November 12, 2024, response to "Questions for Stakeholders Regarding the CPUC SB-884 Guidelines," PG&E stated that an RO Model should be used to generate revenue requirements in a Phase 2 Application.[37] This Resolution specifies how a revenue requirement must be calculated via an RO Model.

SPD-15 recognized that the Commission will assess whether costs recorded in the one-way balancing account meet the Phase 2 Conditions: "This audit mechanism [to

---

[31] *Energy Safety Guidelines* at 25.

[32] "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," Question A.6.

[33] TURN response to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," Question A.6 at 16.

[34] PG&E response to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," Question A.6 at 7; and SDG&E response to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," Question A.6 at 5.

[35] PG&E response to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," Question A.6 at 7.

[36] The need for a forecasted revenue requirement is listed in Application Requirement #3 in the *CPUC Guidelines* at 7.

[37] PG&E Informal Responses to Questions, November 12, 2024, at 3.

evaluate whether Phase 2 Conditions are satisfied], coupled with the fact that any costs not meeting the established conditions are subject to refund if the Commission so orders, adds a critical ratepayer protection to ensure the large electrical corporations are complying with the determinations made in any Phase 2 Decision."[38] To carry out this intent SPD-15 adopted an audit process requirement, but left details to a later Resolution.[39] This Resolution adopts an audit process, discussed in Section 3.4, and establishes a Fifth New Application Requirement requiring the large electrical corporation to include a proposed methodology for validating how it will satisfy the primary and secondary objectives of the audit in its Phase 2 Application. The Fifth New Application Requirement will support the auditor's ability to verify whether the costs of a project satisfy the Phase 2 Conditions.

A large electrical corporation shall propose a methodology for verifying that it satisfied the Phase 2 Conditions and the secondary objectives of the audit in its Phase 2 Application.[40] The appropriate methodology can then be addressed during the Phase 2 Application proceeding and detailed in the Phase 2 Decision. This upfront determination of the appropriate methodology to ensure the satisfaction of Phase 2 Conditions and the secondary objectives of the audit provides dual benefits. First, having this knowledge upfront allows large electrical corporations to understand the expectations of the one-way balancing account audit and reduce the need for future refunds. Second, establishing the methodology will enable the auditor to efficiently review project costs and allow the Commission to determine whether the costs were appropriately recorded.

The Sixth New Application Requirement is added to ensure that undergrounding projects presented in a Phase 2 Application provide a cost-efficient overall benefit to ratepayers. As discussed in SPD-15 and the SPD-15 Guidelines, CBR is calculated by dividing the monetized benefits of a particular mitigation by its costs. A CBR of 1.0 is considered a breakeven point, where the benefits of a particular mitigation are equal to its costs. Conversely, CBRs less than 1.0 indicate that the costs of a particular mitigation exceed its benefits. Allowing undergrounding projects that have forecasted CBRs below 1.0 to be included in a Phase 2 Application would be unreasonable, especially considering that undergrounding is the most capital-intensive grid hardening investment available.

---

[38] SPD-15 at 12.

[39] SPD-15 at 15.

[40] The EUP Audit is detailed later in this Resolution.

Staff solicited input from stakeholders on this topic in the "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines."[41] PG&E, the largest electrical corporation eligible to file an EUP, stated its support for a requirement for undergrounding projects presented in a Phase 2 Application to have a forecasted CBR greater than or equal to 1.0 "because that is indicative of a good investment."[42] By adding this requirement, the Commission does not intend to imply that all projects submitted in a Phase 2 Application with a forecasted CBR greater than or equal to 1.0 are necessarily a good investment.

Energy Safety Guidelines provide that "the EUP must present Project-Level Thresholds that establish the need for risk mitigation."[43] To ensure consistency between the *Energy Safety Guidelines* and the *CPUC Guidelines*, the Seventh New Application Requirement requires that each undergrounding project in the Phase 2 Application meet one or more of the large electrical corporation's three Project-Level Thresholds (i.e., High Risk Threshold, Ignition Tail Risk Threshold, or High Frequency Outage Program Threshold).[44] Screen 1 of the *Energy Safety Guidelines* requires such information for circuit segment eligibility.[45] To ensure alignment with the *Energy Safety Guidelines*, it is reasonable to include the Seventh New Application Requirement.

3.2 Additional Phase 2 Conditions for Approval

Resolution SPD-15 adopted five Phase 2 Conditions as part of its SB 884 review.[46] The *Energy Safety Guidelines* later introduced data requirements and information required for its review and approval of EUP filings. After considering the results of the workshops and stakeholder feedback noted above, and the *Energy Safety Guidelines*, we adopt the following Additional Phase 2 Conditions as explained below:

---

[41] See "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," Question B.3.a, published on April 11, 2025.

[42] PG&E's response to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," filed on April 25, 2025, at 9.

[43] *Energy Safety Guidelines* at 17.

[44] The High Risk Threshold is the Overall Utility Risk level above which a Circuit Segment is considered eligible for examination for expedited undergrounding. The Ignition Tail Risk Threshold is the measure of consequence above which a Circuit Segment is considered to have significant potential for ignition of a catastrophic wildfire, so that it merits special consideration. The High Frequency Outage Program Threshold is the measure of likelihood above which a Circuit Segment is considered to have a significantly high likelihood of frequent or prolonged disruption of service to customers. For details see *Energy Safety Guidelines* at 42.

[45] *Energy Safety Guidelines* at 17.

[46] *CPUC Guidelines* at 10-11.

1. First New Phase 2 Condition: "The forecasted CBR of the undergrounding project must exceed the forecasted CBR of all alternative mitigations considered for that project by a certain threshold value, which is to be determined in the Phase 2 Decision."
2. Second New Phase 2 Condition: "In all cases, when an undergrounding project becomes used and useful, if the value of its recorded CBR, as reported in the applicable six-month progress report, is less than the value of its forecasted CBR at the time of the Phase 2 Application submission, then the percentage difference between the two CBR values must not exceed the specified threshold value determined in the Phase 2 Decision.."
3. Third New Phase 2 Condition: "In all cases, when an undergrounding project becomes used and useful, if the value of its recorded unit cost, as reported in the applicable six-month progress report, is greater than the value of its forecasted unit cost at the time of the Phase 2 Application submission, then the percentage difference between the two unit cost values must not exceed the specified threshold value determined in the Phase 2 Decision."
4. Fourth New Phase 2 Condition: "The undergrounding project must meet or exceed the applicable Project-Level Standard(s), in the large electrical corporation's EUP approved by Energy Safety.[47]"

The *Energy Safety Guidelines* require that the large electrical corporation provide two alternative mitigations for comparison with the undergrounding project as part of Screen 2.[48] After the project scoping phase is complete in Screen 3, the *Energy Safety Guidelines* require the large electrical corporation to compare the costs, benefits, and CBR between the "Undergrounding as Scoped" and the "Screen 3 Alternative Mitigations" in order for the project to pass Screen 4.[49] It is prudent to include the First

[47] *Energy Safety Guidelines* at 17 and 43. The large electrical corporation indicates to Energy Safety whether an undergrounding project has met the Project-Level Standard(s) in Table C.12 of the *Energy Safety Guidelines* under the "fulfills_project_level_standard" field. The "applicable Project-Level Standard(s)" can be verified by how the utility completes the "risk_category" field in Table C.8 of the *Energy Safety Guidelines*. If the undergrounding project does not meet the applicable Project-Level Standard(s), the *Energy Safety Guidelines* still permit a large electrical corporation to record a justification for this project in Table C.12 under the "additional_justification" field, which can be reviewed as part of a Phase 3 Application to determine the just and reasonableness of the costs associated with a project that does not meet this condition.

[48] *Energy Safety Guidelines* at 18.

[49] *Energy Safety Guidelines* at 44-45. "Undergrounding as Scoped" is defined as a design variation that "must include only the portion of the Circuit Segment that is to be undergrounded (e.g. just the Undergrounding Subproject(s) without any of the non-undergrounding Subprojects). This design variation must be used to justify the Portfolio-Level Standards, Plan Mitigation Objective, and Plan Tracking Objective. If the Circuit Segment will not contain multiple mitigations, this design variation will

New Phase 2 Condition, which uses the comparative analysis of mitigation alternatives required by the *Energy Safety Guidelines*, to ensure that the optimal mitigation is selected for reducing risk in the most cost efficient manner. The exact threshold for the First New Phase 2 Condition will depend on the Screen 2 data submitted with the Phase 2 Application and be determined in the Commission's Phase 2 Decision.

In its April 25, 2025 responses to the "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," TURN stated that once a comparative threshold (i.e., the CBR of the undergrounding project compared to the CBR of a mitigation alternative) is established, if at any point in the development of the undergrounding project the CBR falls below that threshold, then "the utility will know that the undergrounding project will not gain CPUC approval."[50] TURN also noted that through a comparative threshold "the Commission will ensure that undergrounding is only approved where the utility has demonstrated that it is the most cost-efficient mitigation to achieve comparable ignition risk reduction, consistent with Section 8388.5(e)(1)(A)."[51] The Commission agrees that the Phase 2 Decision must establish a threshold of comparison between the CBR of mitigation alternatives required by the *Energy Safety Guidelines* and the CBR of undergrounding.

As discussed earlier in this Resolution, the Project Acceptance Framework adopted in the *Energy Safety Guidelines* is a multi-step process that the large electrical corporation must establish and use to identify and select undergrounding projects for construction through its EUP. While all the undergrounding projects presented in the Phase 2 Application will have passed through Screen 2 of Energy Safety's Project Acceptance Framework, projects only progress further through the scoping phase in Screens 3 and 4.

PG&E notes that, "[b]etween Screens 2 and 4, we will revise our cost estimates (which impact CBRs) to account for better information we learn during the scoping phase such as more precise route selection and addressing tree-strike, ingress/egress, and/or feasibility issues."[52] PG&E also states that, "[i]t is not unusual for estimated costs and

be identical to Project as Scoped." "Screen 3 Alternative Mitigations" is defined as a design variation that "must, at a minimum, include aboveground line hardening, covered conductor and some type of protective equipment and device settings for any line not removed, as in Screen 2 Alternative Mitigation 1. The Large Electrical Corporation must also include any other mitigation or combination of mitigations that it has determined would be well-suited for the specific project location."

[50] TURN Informal Responses to Post-Workshop Questions, April 25, 2025 at 8.

[51] TURN Informal Responses to Post-Workshop Questions, April 25, 2025 at 8.

[52] PG&E response to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines" at 9.

CBRs to vary between the initial estimate and the updated estimate as we learn more about project scope, schedule and cost through the project scoping process."[53] However, the *Energy Safety Guidelines* permit a large electrical corporation to file an EUP with only 25 undergrounding projects that have passed Screen 3.[54] Once an EUP is filed, Energy Safety must approve it within nine months.[55] Similarly, once an EUP is approved by Energy Safety, the large electrical corporation must file its Phase 2 Application to the Commission within 60 days.[56] Thus, it is expected that the data and information available in a Phase 2 Application will be imprecise, as the majority of projects will likely not have progressed far enough in the scoping phase to ensure the Commission has the necessary information to assess cost recovery for EUPs. Nevertheless, the Commission must issue its decision on the Phase 2 Application within nine months of its submittal.[57] Because the data and information upon which a Phase 2 Decision is based will be preliminary, the Commission requires large electrical corporations to satisfy the Second and Third New Phase 2 Conditions to recover EUP costs via the one-way balancing account.

TURN supports the adoption of conditions for determining when a project's unit costs or CBRs vary by more than a prescribed percentage from the values upon which the original approval was based, and states "the Commission can ensure that a project whose economic metrics have changed is still worth funding…."[58] TURN also supports the Phase 2 Decision determining the threshold for the Second and Third New Phase 2 Conditions.[59]

The *Energy Safety Guidelines* require each undergrounding project to meet at least one of three project-level standards: High-Risk, High Frequency Outage Program, and Tail Risk Project-Level Standards (Project-Level Standards). Meeting these standards demonstrate the project's contribution to the Plan Mitigation Objective.[60] To ensure consistency between the *Energy Safety Guidelines* and the *CPUC Guidelines*, the Fourth New Phase 2 Condition states the undergrounding project must meet or exceed the

[53] PG&E response to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines" at 9.
[54] *Energy Safety Guidelines* at 12.
[55] PU Code Section 8388.5(d)(2).
[56] PU Code Section 8388.5(e)(1).
[57] PU Code Section 8388.5(e)(5).
[58] TURN response to "Questions for Stakeholders Regarding the CPUC SB-884 Guidelines" at 5.
[59] TURN response to "Questions for Stakeholders Regarding the CPUC SB-884 Guidelines" at 9.
[60] For detailed definitions of each of the three Project-Level Standards see *Energy Safety Guidelines* at 43. The large electrical corporation indicates to Energy Safety whether an undergrounding project fulfills the Project-Level Standard in Table C.12 under the "fulfills_project_level_standard" field.

applicable Project-Level Standard, and align with the circuit segment eligibility requirement associated with Screen 1 of the *Energy Safety Guidelines*.[61] If the project does not meet or exceed the applicable Project-Level Standard, the large electrical corporation must identify and provide justification for such projects to Energy Safety in its six-month progress reports.[62] For projects that do not meet the Fourth New Phase 2 Condition, the costs of those projects shall be recorded in the memorandum account where the justification provided to Energy Safety can be considered.

3.3 Memorandum Account Cap

The Commission established a memorandum account in Resolution SPD-15 in light of the inherent uncertainties associated with forecasting 10 years of undergrounding projects in an EUP. The memorandum account was intended for amounts above the one-way balancing account cost cap, and that review would "determin[e] whether the costs recorded in the memorandum account were prudently incurred, incremental to other funding granted to the large electrical corporation, and just and reasonable."[63] The Commission noted that allowing a memorandum account "reasonably recognizes that there are significant uncertainties in undergrounding electrical distribution equipment that are likely to grow over a 10-year period. Further, this provision creates a pathway for a large electrical corporation to demonstrate that such costs are just and reasonable, and incremental."[64] However, the Commission did not state or intend for the memorandum account to be a limitless repository for costs from projects that do not meet the goals of SB 884 or prudent wildfire mitigation.

The vast majority of undergrounding projects associated with the approved EUP will likely not be completely scoped until a project successfully passes Screen 3 and Screen 4 of the *Energy Safety Guidelines*. Thus, a Phase 2 Application will likely contain projects that lack a refined scope or detail where construction is scheduled later in the 10-year Plan cycle.

The Commission must prevent the memorandum account from becoming a structural incentive to continuing work on imprudent projects. A cost-cap on amounts recovered via the memorandum account will improve both ratepayer and shareholder certainty and avoid potential volatility in the SB 884 program. Utilities record costs in memorandum accounts as they are incurred, and costs are subject to reasonableness

---

[61] *Energy Safety Guidelines* at 17.

[62] The large electrical corporation provides a justification for the inclusion of the Undergrounding Project in Table C.12 under the "additional_justification" field.

[63] SPD-15 at 8.

[64] SPD-15 at 8.

review before recovery in rates. Because of the elapse of time between recording and recovery, utilities may accumulate large balances with uncertain recovery. Allowing uncapped spending could create a significant amount of risk to both ratepayers and shareholders.

To address this issue, Staff proposed a maximum total cost cap for the memorandum account at the April 8, 2025, workshop and solicited written feedback in the "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," published on April 11, 2025.[65] Most stakeholders were supportive of this concept, with some exceptions.[66] PG&E noted that it "would not oppose establishing a reasonable maximum total cap for the Memorandum Account, in general, if there are no restrictions on what costs can and cannot be included."[67] SDG&E stated that it "opposes establishing a maximum total cap for the Memorandum Account at this time."[68]

Ultimately, there was general agreement among stakeholders that it may be valuable to include cost caps on the memorandum account, but setting a specific number for such cap could be premature before total EUP costs and other project details are known after the Phase 2 Application is filed. Accordingly, the Commission finds it is prudent to include a cost cap on the memorandum account but defers establishment of the specific amount of the cap to the Phase 2 Application proceeding. Specifically, in this Resolution we adopt the *CPUC Guidelines* and establish a cost cap for the memorandum account, as follows:

> *The total cumulative costs recovered via the memorandum account throughout the duration of an EUP shall be capped as a percentage of the total sum of the 10 years of cost caps placed on the one-way balancing account. The percentage value of the memorandum account cost cap will be established in the Phase 2 Decision.*

A cap will better ensure the reasonableness of costs and establish certainty for both ratepayers and shareholders by establishing an upper bound on the total potential costs of an EUP. A cap will also provide ratepayers and the Commission with an increased

[65] "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," Question B.1.a.
[66] See Cal Advocates responses to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," at 5; and TURN responses to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," at 3.
[67] PG&E responses to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," at 8.
[68] SDG&E responses to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," at 6.

level of transparency and understanding of overall programmatic impact.

3.4 Audit of the One-Way Balancing Account

Here we explain the process and procedure for auditing the one-way balancing account, going forward referred to as the EUP Audit. The procedure sets forth the primary and secondary objectives of the audit as well as how the results should be considered by the Commission. A similar procedure was presented by Staff to stakeholders during a Commission workshop on April 8, 2025. Staff adjusted the procedure based on feedback received in response to the "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines" from PG&E, TURN, SDG&E, Cal Advocates and MGRA as well as PG&E's response to "Technical Working Group Questions."

In Resolution SPD-15, the Commission noted that due to the importance of the Phase 2 Conditions, it was necessary to include a process to assess whether the costs recorded in the one-way balancing account meet such conditions.[69] The Commission stated:

> [P]eriodic audits of the established balancing account will be performed to ensure that costs booked to the one-way balancing account meet the conditions established by the Phase 2 Decision (e.g., unit cost caps, CBR thresholds, etc.). If the audit demonstrates that costs were incorrectly recorded or failed to meet the Phase 2 Conditions, the Commission may order a refund.[70]

SPD-15 also noted that "[t]he details of this audit, including but not limited to who will perform it, content, frequency, venue, method for true-up and refund mechanism will be determined in a later decision or order."[71] This Resolution adopts the EUP Audit process. Inherent complexities with this program exist, given the volume of data and information expected in the six-month progress reports, and the likelihood of changes to project-related information (CBRs, total costs, and unit costs) between a Phase 2 Application submission date and when the project is deemed used and useful. It is prudent to establish clear primary and secondary objectives for the auditor to review to ensure that costs recovered via the one-way balancing account meet the requirements of the program.

SPD-15 requires forecasted expenditures for the Application as well as for each project in a large electrical corporation's Phase 2 Application.[72] Such information will enable the

[69] SPD-15 at 5.
[70] SPD-15 at 5.
[71] SPD-15 at 5-6.
[72] See SPD-15, Appendix A at 7 and 9 for Application requirements #1 and #11.

Commission to evaluate costs that are as close to final as possible and establish Phase 2 Conditions. SPD-15 requires recorded costs of used and useful EUP projects to meet the Phase 2 Conditions in order to be recoverable via the one-way balancing account.[73]

According to SPD-15, it is in Phase 3 that the large electrical corporation must report on its progress implementing the EUP and begin booking costs to the one-way balancing account.[74] After publication of the *Energy Safety Guidelines* on February 20, 2025, and pursuant to the holding in SPD-15 that the details of the audit would be developed later, SPD proposed audit details at the April 8, 2025, workshop. Key stakeholder input is described below.

PG&E recognized that Screen 2 data is not sufficiently mature to determine reasonably accurate project costs. When commenting on the need to establish a baseline for determining a threshold associated with the Second and Third New Phase 2 Conditions, PG&E stated that "[i]t would be unreasonable to establish baseline values at Screen 2, which is *well before a utility has developed a sound project cost estimate*. In PG&E's case, a sound cost estimate is developed after project estimating."[75] Nevertheless, in accordance with the *Energy Safety Guidelines* and as discussed earlier, the Commission's Phase 2 Decision may issue before a large electrical corporation has developed "sound project cost estimates" for its EUP.[76] As PG&E notes, this data would be incomplete. It is only at Screen 4 when an undergrounding project is fully scoped and estimating is complete that a reasonably accurate cost forecast can be provided.[77]

TURN urged the Commission not to allow large electrical corporations to book costs into the balancing accounts or flow those costs into rates without a Commission review process that incorporates stakeholder input. In its April 25, 2025, response to the "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," TURN recommended a process where "no costs would be booked to the balancing account until the Commission has determined in an annual process that recorded costs for that year have met all applicable Phase 2 [C]onditions, as well as the used and useful

---

[73] SPD-15 at 2.

[74] SPD-15 at 3.

[75] PG&E responses to the "Technical Working Group Questions," June 24, 2025, at 7 (emphasis added).

[76] PU Code Section 8388.5(e)(5) requires the Commission to approve or deny a Phase 2 Application within nine months after it is filed.

[77] In its response to the "Technical Working Group Questions," June 24, 2025, at 6, PG&E indicates that Screen 2 cost estimates can vary from +100% to -50%, whereas at the completion of estimating that range is reduced to +20% to -15%.

requirement."[78]

Per SPD-15, the Commission has already found it is reasonable for the Commission to determine upfront what amounts a large electrical corporation may recover in a balancing account and condition recovery on specific requirements.[79] In SPD-15, the Commission implemented the "conditional approval" provision in SB 884 to place specific requirements on what incurred EUP costs are eligible to be booked to the EUP one-way balancing account.

One of the criteria SPD-15 established as a requirement for cost recovery via the balancing account is that an undergrounding project must be used and useful.[80] Additionally, the SPD-15 Guidelines established that a Phase 2 Application must identify and exclude any undergrounding costs that have been approved by the Commission for cost recovery in another venue and propose the appropriate venue (the EUP or another cost recovery application) for undergrounding costs still in consideration by the Commission for cost recovery.[81] Thus, it is reasonable to include verification of whether a project is used and useful and determination of whether recorded costs are incremental as a part of the one-way balancing account audit. This Resolution includes a used and useful verification and incrementality determination in the secondary objectives of the audit detailed later in this section.

PG&E acknowledges that the Phase 2 Decision will "influence recovery of millions or billions of dollars of undergrounding work performed over a ten-year period."[82] Additional safeguards are necessary for the audit to ensure that ratepayers only bear costs that the auditor finds meet the Phase 2 Conditions and secondary objectives.

TURN also recommended additional audit objectives should include "verification of project completion, inclusion of (no more than) appropriate cost overheads…use of a reasonable CBR methodology, and an incrementality showing."[83] The Commission agrees with TURN that additional audit objectives would further strengthen program

[78] TURN response to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," April 25, 2025, at 11.
[79] SPD-15, Finding No. 4 at 19.
[80] *CPUC Guidelines*, Footnote 5 at 4.
[81] *CPUC Guidelines*, Application Requirement No. 2 at 7.
[82] PG&E responses to the "Technical Working Group Questions," June 24, 2025, at 3.
[83] TURN response to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," April 25, 2025, at 19.

oversight and provide additional ratepayer protections. Except for the recommended audit objective to assess the appropriateness of cost overheads, which the Commission finds to be lacking sufficient detail and explanation, the Commission finds it is reasonable to include TURN's recommended audit objectives and has done so in the secondary audit objectives listed below.

This Resolution adopts an audit process that verifies costs recovered via the balancing account are just and reasonable while reducing the time and effort needed to determine if the large electrical corporations should issue ratepayer refunds.[84] The EUP Audit is designed to verify that the large electrical corporation has met the Phase 2 Conditions and the secondary objectives. The following details the process and procedural objectives of the EUP Audit.

At a minimum, the six-month progress reports filed by a large electrical corporation shall include an update of the *SB 884 Project List Data Requirements Guidelines* in Appendix 2 of the *CPUC Guidelines*, as well as any other reporting requirements in SPD-15, the *Energy Safety Guidelines*, and the Phase 2 Decision. Large electrical corporations shall file and serve the six-month progress reports in the applicable Phase 2 Application docket. Parties may review, file and serve opening comments on the progress report in the Phase 2 Application docket no later than 42 days (or such period specified in the Phase 2 Decision) after the progress report is filed and served by the large electrical corporation. Reply comments on the progress report may be filed and served in the Phase 2 Application docket no later than seven (7) days (or such period specified in the Phase 2 Decision) after the due date for opening comments.

A EUP Audit of the one-way balancing account shall occur annually. The EUP Audit shall begin no later than 60 days (or such period specified in the Phase 2 Decision) after the due date for reply comments on the second six-month progress report in a given 12-month period. Each EUP Audit shall review EUP projects that become used and useful during the 12-month period covered by the audit. Each EUP Audit may also review recorded costs of projects or portions of projects that are not used and useful and may recommend refunds.

The primary objective of an EUP Audit is to determine whether the costs recorded in the large electrical corporation's balancing account have met all nine Phase 2 Conditions.[85] The audit shall also verify whether the recorded costs have met the

[84] See the Fifth New Application Requirement discussed in Section 3.1.
[85] The nine conditions include:

following secondary objectives set forth in this Resolution:

1) Verify that projects are "used and useful;"
2) Determine whether the recorded costs are incremental – and do not duplicate costs allowed through another decision, mechanism or received from a third party; and
3) Validate that the methodology used to calculate a CBR, and the CBR results for a given project, comply with the *CBR Calculation Guidelines*.

A Phase 2 Decision may also add primary and/or secondary objectives for the Audits specific to that EUP.

In its Phase 2 Application, as required by the Fifth New Application Requirement, a large electrical corporation shall propose the methodology for the auditor to determine whether the costs of undergrounding projects recovered via the one-way balancing account meet the primary and secondary objectives. The Phase 2 Decision will include

1. Total annual costs must not exceed a cap based on the approved cost cap for that specific year.
2. Third-party funding obtained, if any, shall be applied to reduce the established cost cap for the specific year in which the third-party funding is obtained, so that ratepayers receive the benefit. The large electrical corporation shall file an advice letter documenting which annual cost caps are reduced based on third-party funding received.
3. The average recorded unit cost for all projects completed in any given two-year period (the current year, and the prior year) must not exceed the approved average unit cost cap for the current year. The unit costs shall be calculated per mile of undergrounding performed, rather than per mile of overhead replaced, to focus on reduction of construction costs.
4. The average recorded CBR for all projects completed in any given two-year period (the current year, and the prior year) must equal or exceed the approved threshold CBR value for the current year.
5. The forecasted CBR of the undergrounding project must exceed the forecasted CBR of all alternative mitigations considered for that project by a certain threshold value, which is to be determined in the Phase 2 Decision.
6. In all cases, when an undergrounding project becomes used and useful, if the value of its recorded CBR, as reported in the applicable six-month progress report, is less than the value of its forecasted CBR at the time of the Phase 2 Application submission, then the percentage difference between the two CBR values must not exceed the specified threshold value determined in the Phase 2 Decision.
7. In all cases, when an undergrounding project becomes used and useful, if the value of its recorded unit cost, as reported in the applicable six-month progress report, is greater than the value of its forecasted unit cost at the time of the Phase 2 Application submission, then the percentage difference between the two unit cost values must not exceed the specified threshold value determined in the Phase 2 Decision.
8. The undergrounding project must meet or exceed the applicable Project-Level Standard(s), as established by Energy Safety in the large electrical corporation's approved EUP.
9. Any further reasonable conditions supported by the record of the proceeding and adopted by the Commission in the Phase 2 Decision.

the Commission's determination on the appropriate methodology to be used by the auditor to determine whether the primary and secondary objectives are met. In addition, any data that should be reviewed by the auditor, beyond what is submitted to the Commission in six-month progress reports, will be determined in the Phase 2 Decision. The auditor may also request information and conduct interviews with large electrical corporation personnel, including custodians of records, to gather information for the audit.

The EUP Audit will result in an audit report that will be filed and served to the Phase 2 Application docket within five (5) days (or such period specified in the Phase 2 Decision) of its completion and approval. The audit report shall be completed within six months (or such period specified in the Phase 2 Decision) after it is initiated.[86] Parties may file and serve opening comments on the audit report in the Phase 2 Application docket no later than 20 days (or such period specified in the Phase 2 Decision) after the audit report is filed and served by the large electrical corporation. Reply comments on the audit report may be filed and served in the Phase 2 Application docket no later than five days (or such period specified in the Phase 2 Decision) after the due date for opening comments. If a Party believes a refund is necessary based on the audit report they may file a petition for modification requesting to reopen the Phase 2 Application proceeding and set forth the amount of the refund and the reasons for it in the petition. The Commission may also determine the appropriateness of reopening the Phase 2 Application proceeding based on its own review as described below.

Following its review of the audit report, six-month progress reports, associated comments, and any petitions received, the Commission may reopen the Phase 2 Application proceeding to consider the need for refunds. If the Commission reopens the Phase 2 Application proceeding, for projects that do not meet the primary objectives and/or one or more of the secondary objectives, the Commission may direct the large electrical corporation to refund related project costs to ratepayers in a subsequent decision. If the Commission directs a large electrical corporation to issue a refund, the large electrical corporation shall not seek to recover such costs through any other means.

The large electrical corporation shall not have input into the direction, focus, or

[86] Staff are authorized to extend the deadline for the audit report should a determination be made that such an extension is necessary to adequately complete the audit.

outcome of the audit that goes beyond the input afforded to other Parties to the Commission's SB 884 proceeding or process. The large electrical corporation shall provide access to all information requested by the auditor and SPD to carry out the audit within five days (or such period specified in the Phase 2 Decision) of each data request. The large electrical corporation shall also make personnel available for interviews on five days' notice (or such period specified in the Phase 2 Decision) if the auditor seeks substantive information and a custodian of records for questions about the location and content of requested information.

The EUP Audit described above is added to satisfy the audit requirement in SPD-15, while taking into consideration information learned following the adoption of the *Energy Safety Guidelines* and stakeholder input.

3.5 Cost-Benefit Ratio (CBR) Calculation Guidance

As referenced in Resolution SPD-15, the CBR calculation is a cost-benefit analysis methodology that has been developed in the Commission's risk-based decision-making framework (RDF) proceeding (Rulemaking (R.) 20-07-013). At its core, a CBR calculation provides a tool to aid the Commission in making decisions between competing options for utility spending in an objective manner by quantifying both mitigation costs and the benefit of avoided harm in a way that allows them to be directly compared.

Because the RDF proceeding is applicable to assessing utility spending across its entire portfolio of all enterprise risks, any directives regarding CBR calculations must inherently be broadly applicable. However, in the context of EUPs, which discretely focus on the specific risks of wildfire and reliability impacts from outage programs, the Commission provides more specific, targeted direction for CBR calculations.

In the "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," issued on April 11, 2025, Staff solicited stakeholder input on whether the Commission should provide additional guidance for CBR calculations made in the context of SB 884.[87] The questions explored a variety of topics related to CBR calculations, including the appropriate granularity for monetizing electric reliability, discount rate scenarios, risk scaling, and the treatment of combined benefits (impacts on both wildfire and reliability) of mitigations. One stakeholder, PG&E, explicitly objected to the Commission providing additional guidance on calculating CBRs for EUPs as it believes doing so "is unnecessary and will add additional delay to issuing any updated

[87] "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," Questions E.1-E.5.

cost recovery guidelines."[88] Given the range of responses received to questions on the specific, technical aspects impacting CBR calculations for an EUP, the Commission provides additional guidance in this Resolution, as provided in the *CBR Calculation Guidelines* included as Appendix 1 to the *CPUC Guidelines* in Attachment A.

The *CBR Calculation Guidelines* establishes a standardized and consistent methodology for evaluating and comparing the cost-efficiency of undergrounding and alternative mitigations in SB 884-related applications. The *CBR Calculation Guidelines* is appended to the *CPUC Guidelines* and is designed to promote comparability, transparency, and traceability in CBR calculations across large electrical corporations, while remaining adaptable to future improvements in data availability and analytical approaches. It complements the *SB 884 Project List Data Requirements Guidelines* by outlining how to calculate the CBR for the purposes of EUPs and provides more information on its key components. These key components include:

- **Total Capital Costs**, defined as capital expenditures tied to project implementation, excluding ineligible categories such as Net Operating and Maintenance (O&M) Costs[89] or Net Salvage values.[90]
- **Risk Scaling,** which is limited to using unscaled (i.e., risk-neutral) risk values in the CBR calculations.
- **Total Mitigation Benefit,** which may include:

    a. Risk Reduction, which is limited to Wildfire Ignition Risk and Outage Program Risk. Large electrical corporations must exclude other enterprise risks such as Public Contact with Energized Electrical Equipment (PCEEE) and Distribution Overhead Asset Failure (DOVHD).

    b. Net O&M Costs, calculated as the difference in O&M Cost Savings and New O&M Costs between the proposed project and the No-Build Baseline.[91]

[88] PG&E responses to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," April 25, 2025, at 16.
[89] Calculated as "O&M Cost Savings" – "New O&M Costs."
[90] Net Salvage value means the salvage value of an electrical infrastructure related asset that has been retired less the cost of removal of that asset.
[91] No-Build Baseline represents a well-defined baseline scenario or what happens if no project or Risk Reporting Unit (RRU) is implemented. The Build Baseline is used to compare the relative costs and benefits of various design or implementation alternatives.

- **CBR Year Zero**, defined as the year a project becomes "used and useful," which serves as the reference year for discounting both Total Benefit and Capital Costs.
- **Interruption Cost Estimate (ICE)**[92] **Calculator Granularity**, the level of granularity (Customer Class separated by HFTD and Non-HFTD regions) that large electrical corporations must use to disaggregate the monetized value of electric reliability.
- **Backcasting**, a method for recalculating CBRs and unit costs using updated Risk Reporting Unit (RRU) structures and risk model inputs to establish a bridge between prior inputs and new inputs, to ensure an "apples-to-apples" comparison.
- **CBR Percentage Difference**, quantifies the percentage difference between the original forecasted CBR as reported in the Phase 2 Application (or the backcasted CBR of the original forecast, recalculated using revised inputs and current RRU structures) and the CBR reported in subsequent six-month progress reports.

Through responses to the "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines" submitted on April 25, 2025, SPD received feedback from stakeholders on each of the six *CBR Calculation Guidelines* topics listed above.

When commenting on the First New Phase 2 Condition, regarding the need for a threshold CBR for the comparison between undergrounding and alternative mitigations, PG&E informed SPD that its current approach envisions a CBR calculation that may produce a negative CBR value because PG&E argues it should be allowed to deduct O&M savings from the denominator (i.e., costs) of the ratio.[93] A more reasonable approach, in the context of this capital-intensive program, is to only present capital expenditures in the denominator and allow O&M savings to be presented as a benefit in the numerator of the CBR calculation to ensure an apples-to-apples comparison between undergrounding an alternative mitigation programs. Such an approach is consistent with requirements for accurate program evaluation according to the U.S. Department of Transportation.[94] Requiring capital expenditures in the denominator and

[92] https://icecalculator.com/, see also D.22-12-027 OP 2b.

[93] PG&E responses to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," April 25, 2025, at 11.

[94] See generally U.S. Department of Transportation, Benefit Cost Analysis Guidelines for Discretionary Grant Programs, published in May 2025, https://www.transportation.gov/sites/dot.gov/files/2025-05/Benefit%20Cost%20Analysis%20Guidance%202025%20Update%20II%20%28Final%29.pdf.

allowing O&M savings to be reflected as a benefit in the numerator is a reasonable approach to calculating a CBR in the context of the Commission's SB 884 Program. This approach is reflected in the definitions for Capital Cost and Total Mitigation Benefit found in the *CBR Calculation Guidelines*.

When commenting on the CBR threshold, MGRA noted that allowing the large electrical corporations to introduce a scaling function to make decisions as part of the SB 884 program would effectively allow them to skew the CBR.[95] The Commission agrees that it is imperative that CBRs represent an objective assessment of cost-efficiency, and only a neutral scaling function should be used for this kind of evaluation. Moreover, requiring the large electrical corporations to present unscaled (i.e., risk-neutral) risk values in the CBR calculations will ensure closer alignment with the *Energy Safety Guidelines.*[96]

PU Code section 8388.5(d)(2) states, "[t]he office may only approve the plan if the large electrical corporation has shown that the plan will substantially increase electrical reliability by reducing the use of public safety power shutoffs, enhanced powerline safety settings, deenergization events, and any other outage programs, and substantially reduce the risk of wildfire." Accordingly, the *Energy Safety Guidelines* define "Overall Utility Risk" as the combined measure of Ignition Risk and Outage Program Risk that measures the total risk of wildfires and Outage Program Events related to wildfire risks.[97] Therefore, in this Resolution and the *CBR Calculation Guidelines*, the Commission clarifies that only Wildfire Ignition Risk and Outage Program Risk may be included in the CBR's Risk Reduction component for calculating Total Mitigation Benefit.

All stakeholders unanimously agreed on the definition of CBR Year Zero as presented in the *CBR Calculation Guidelines* and that definition is adopted here.[98]

The granularity of the ICE Calculator ensures that the monetized value of electric reliability appropriately captures the reliability consequence and risk reduction that will be considered in a large electrical corporation's Phase 2 Application. The "Post-

---

[95] MGRA responses to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," April 25, 2025, at 5.
[96] *Energy Safety Guidelines* at 31.
[97] *Energy Safety Guidelines* at Appendix A, A-4.
[98] See, for instance, PG&E responses to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," April 25, 2025, at 19 and TURN responses to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," April 25, 2025, at 29.

Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines" solicited stakeholder feedback on this granularity issue. Specifically, SPD sought feedback on whether large electrical corporations should establish the granularity of the ICE Calculator according to their Operational Divisions broken down by HFTD.[99] Such an ICE Calculator granularity approach would align with a Staff Proposal in the RDF Proceeding regarding requirements for use of ICE Calculator 1.0.[100]

PG&E stated that it intends to use a monetized value of electric reliability generated by the ICE Calculator 1.0 using values from across its entire service territory and rejected the need to generate monetized values of electric reliability at the operational division-level.[101] TURN recommended the need for a clear disaggregation of the large electrical corporation's territory by HFTD Tiers and recommended further disaggregation across customer classes (Residential Customers, Small Commercial & Industrial Customers, and Medium and Large Commercial & Industrial Customers) for estimating monetized values of electric reliability using ICE Calculator 1.0.[102] In the June 24, 2025, Technical Working Group meeting on the ICE Calculator 2.0,[103] PG&E demonstrated how it generates territory-wide values across its customer classes, which in ICE Calculator 2.0 only includes Residential and Non-Residential.[104]

PG&E's demonstrated approach aligns with TURN's recommendation of ICE Calculator granularity across customer classes except it did not disaggregate the customer classes further by HFTD Tiers. In order to align with the requirements of SB 884,[105] the *CBR*

---

[99] "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," Question E.1, published Aprill 11, 2025.

[100] For details see R.20-07-013, ALJ Ruling Entering Phase 4 Technical Working Group Materials and Related Staff Proposal into the Record and Setting Comment Schedule, Attachment 2: Proposed Data Template Guideline for RAMP and GRC Applications, February 7 at 5 and 18-19. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M556/K602/556602764.PDF.

[101] PG&E responses to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," April 25, 2025, at 17.

[102] TURN responses to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," April 25, 2025, at 24-27.

[103] The ICE Calculator 2.0 was released on April 28, 2025. For details regarding the differences between the ICE Calculator 1.0 and ICE Calculator 2.0 see https://ice-calc-docs.s3.us-west-2.amazonaws.com/documents/ICE+2.0+vs+1.0+Comparison+May2025.pdf.

[104] PG&E's June 24, 2025, presentation detailed how it complied with an April 22, 2025, ALJ Ruling in the PG&E RAMP Proceeding (A.24-05-008) directing PG&E by June 20, 2025, "to serve additional information and comply with other requirements" related to its 2027 General Rate Case (GRC) application (A.25-05-009). This included the requirement to "[p]rovide electric reliability cost calculations using the disaggregated approach recommended in the SPD evaluation report."

[105] PU Code Section 8388.5(c)(2) limits EUP projects to Tier 2 or 3 HFTD areas or wildfire rebuild areas.

Calculation Guidelines simplifies the ICE Calculator 2.0 granularity, from what was asked in the "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," by requiring the large electrical corporation to disaggregate across HFTD and Non-HFTD regions and across the two customer classes, Residential and Non-Residential.[106]

After weighing the recommendations from all stakeholders, the Commission finds the approach to ICE Calculator Granularity in the *CBR Calculation Guidelines* to be reasonable and aligned with direction provided in the RDF Proceeding to require large electrical corporations to use the most current version of the ICE Calculator.[107]

After the adoption of Resolution SPD-15, the *Energy Safety Guidelines* introduced the concept of the "subproject."[108] During the scoping phase (after Screen 2), the *Energy Safety Guidelines* allow the large electrical corporation to divide an "Eligible Circuit Segment" into one or more subprojects for operational reasons or to reflect that a portion of the circuit segment will be treated with a wildfire mitigation other than undergrounding.[109] The Commission's *SB 884 Project List Data Requirements Guidelines* refer to the subproject designation as an RRU in order to align with approaches established in the RDF Proceeding.[110]

The *Energy Safety Guidelines* allow the large electrical corporation to establish subprojects after Screen 2, which could happen after the Commission's Phase 2 Decision is adopted. This change created a need to incorporate the concept of "backcasting" into the *CBR Calculation Guidelines*.[111] When a large electrical corporation elects to use the subproject designation, the concept of a backcast is essential in the SB 884 context to enable a consistent comparison between the forecasted RRU values reported in the

[106] Although this would generate four values, because all the projects in a large electrical corporation's Phase 2 Application must be within the HFTD, only two values (HFTD Residential and HFTD Non-Residential) may be applied to the natural units of the reliability consequence attribute to estimate wildfire risk or outage program risk on a circuit segment and CBRs for an undergrounding project.
[107] D.22-12-027, Ordering Paragraph 2(b).
[108] Energy Safety defines subproject as "a delimited portion of work on a Confirmed Project." *Energy Safety Guidelines* at A-6.
[109] *Energy Safety Guidelines* at 14.
[110] For more information on the RRU, see R.20-07-013, Phase 4 Workshop 1, SPD Staff Proposal on Definition of Scoped Work and the Risk Reporting Unit, November 8, 2024. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M545/K343/545343783.PDF
[111] Although used in slightly different ways, the concept of a backcast further aligns with what the *Energy Safety Guidelines* refer to as a "backtest," used to validate new wildfire risk models. See *Energy Safety Guidelines* at 52.

progress reports and the backcasted RRU values that would have been calculated had the RRU structure been applied in the Phase 2 Application using the data submitted at that time.

In its June 24, 2025, responses to "Technical Working Group Questions," PG&E stated, "[i]f required, PG&E could calculate a subproject level CBR for the undergrounding portions of the subproject…."[112] Although it is able to produce such a calculation, PG&E argued that the backcasting requirement should be omitted "because PG&E uses project-level (circuit segment level) CBRs and costs to make mitigation decisions…."[113] However, PG&E's data request responses clearly demonstrate that it uses a decision-tree for determining the scope of undergrounding subprojects for hybrid projects (projects that use multiple mitigation methods) which PG&E stated will be used to inform an EUP.[114]

After reviewing all these considerations, the Commission finds that the *CBR Calculation Guidelines* requirement for backcasting is reasonable and allows for greater alignment with the *Energy Safety Guidelines*.

As discussed in Section 3.2 above, TURN supported the need for a percentage difference threshold in unit costs and CBR values between the time of the Phase 2 Application submission and when the project becomes used and useful as set forth in the Second and Third New Phase 2 Condition.[115] The *CBR Calculation Guidelines* clarifies how a large electrical corporation must calculate that percentage difference. The Commission agrees that this clarification is reasonable and will support the verification of the Second and Third New Phase 2 Conditions, as required by the EUP Audit discussed in Section 3.4 above.

SPD-15 authorized SPD to reconcile the data template in Appendix 1 of the SPD-15 Guidelines within one month of a final TWG meeting. The *SB 884 Project List Data Requirements Guidelines* and *SB 884 Project List Data Template* were issued by SPD on July 24, 2025. This resolution authorizes SPD to make future updates and changes to the *SB 884 Project List Data Requirements Guidelines* and *SB 884 Project List Data Template* after hosting at least one TWG meeting about said updates and changes without the need for

---

[112] PG&E responses to "Technical Working Group Questions," June 24, 2025, at 16.
[113] PG&E responses to "Technical Working Group Questions," June 24, 2025, at 15.
[114] PG&E response to Data Request SPD-PGE-SB884-018, May 16, 2025, Question 3a, available at https://www.pge.com/assets/pge/docs/outages-and-safety/safety/eup-spd-data-request-018.zip.
[115] TURN responses to Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," April 25, 2025, at 9.

a Commission Decision or Staff Resolution. The large electrical corporations must complete the *SB 884 Project List Data Template*[116] according to the requirements found in the *SB 884 Project List Data Requirements Guidelines* and submit the completed *SB 884 Project List Data Template* with their Phase 2 Application and six-month progress reports.

COMMENTS

PU Code section 311(g)(1) provides that this Resolution must be served on all parties and subject to at least 30 days public review. However, given that this Resolution is issued outside of a formal proceeding, interested stakeholders need not have party status in a Commission proceeding to submit comments. Opening comments are due within 20 days from the mailing date of this Resolution, on September 4, 2025, and in accordance with any instructions accompanying the notice. Reply comments are due five (5) days after Opening comments on September 9, 2025. Section 311(g)(2) provides that this 30-day review period and 20-day comment period may be reduced or waived upon the stipulation of all parties in the proceeding.

The 30-day review and 20-day comment period for the draft of this resolution was neither waived nor reduced. Accordingly, this Draft Resolution was mailed to the SB 884 Notification List and service lists of A.25-05-009, A.23-05-010, A.22-05-016, and R.18-10-007 and will be placed on the Commission's agenda no earlier than 30 days from today.

FINDINGS

1. On October 14, 2024, the Commission's Safety Policy Division (SPD) staff issued a list of "Questions for Stakeholders Regarding the CPUC SB-884 Guidelines" for stakeholder comment.
2. On November 12, 2024, responses to "Questions for Stakeholders Regarding the CPUC SB-884 Guidelines" was received from stakeholders.
3. On February 20, 2025, Energy Safety issued its own SB 884 *10-Year Electrical Undergrounding Plan Guidelines* (*Energy Safety Guidelines*).
4. On April 8, 2025, SPD held a workshop to discuss potential modifications to the SPD-15 Guidelines following publication of the *Energy Safety Guidelines*.

---

[116] The *SB 884 Project List Data Template* is available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/documents/sb-884-project-list-data-template-clean-version_2.xlsx.

5. On April 25, 2025, responses to the "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines" were received from stakeholders.
6. On June 3, 2025, and June 10, 2025, SPD held technical working group (TWG) meetings on potential updates to the *SB 884 Project List Data Requirements Guidelines*.
7. On June 24, 2025, SPD held a TWG meeting to discuss the Interruption Cost Estimator Calculator (ICE 2.0) element of the SB 884 program.
8. The *Energy Safety Guidelines* do not require all projects submitted in an Electrical Undergrounding Plan (EUP) to pass through Screens 3 and 4 before being approved by Energy Safety.
9. The vast majority of undergrounding projects approved by Energy Safety through its Project Acceptance Framework may only be preliminarily scoped.
10. It is not until a project successfully passes Screen 3 and Screen 4 of the *Energy Safety Guidelines* that a project will be completely scoped.
11. A large electrical corporation will not be required to obtain Energy Safety approval of undergrounding projects it intends to construct after Energy Safety approves its EUP.
12. A large electrical corporation will provide new details about undergrounding projects in its six-month progress reports.
13. Because significant changes can be made to the economic metrics of an undergrounding project as it is more accurately scoped in Screens 3 and 4, the large majority of forecasted data available to the Commission at the time the Phase 2 Application is considered, and upon which its EUP cost approval conditions will be based, will not be sufficiently precise to provide the necessary cost containment controls.
14. In consideration of the *Energy Safety Guidelines*, the questions and responses from stakeholders, and feedback from the SPD workshop and TWG meetings, described above, it is reasonable to update and refine the guidelines adopted in Resolution SPD-15 issued March 8, 2024.
15. Updates and additions to the Phase 2 Application requirements are necessary to align programmatic information required by the *Energy Safety Guidelines* and *CPUC Guidelines* and to ensure the Commission has adequate undergrounding project cost information to determine whether cost recovery is reasonable.
16. Allowing undergrounding projects that have forecasted Cost-Benefit Ratios (CBR) below 1.0 to be included in a Phase 2 Application would be unreasonable, especially considering that undergrounding is the most capital-intensive grid hardening investment available.
17. After considering the results of the workshops and stakeholder feedback, and the *Energy Safety Guidelines*, additional Phase 2 Conditions in this resolution are

necessary to ensure the most cost-efficient undergrounding projects are implemented.

18. Staff proposed a maximum total cost cap for the memorandum account at the April 8, 2025, workshop and solicited written feedback in the "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," published on April 11, 2025.
19. Stakeholders generally agreed at the April 8, 2025, workshop that it may be valuable to include cost caps on the memorandum account, but setting a specific number for such cap could be premature before total EUP costs and other project details are known after the Phase 2 Application is filed.
20. It is prudent to establish an upper bound on the total potential costs of an EUP by capping the total costs recovered from the memorandum account at a percentage of the total sum of the 10 years of cost caps placed on the one-way balancing account.
21. The percentage value of the memorandum account cost cap should be established in the Phase 2 Decision.
22. An EUP Audit of the one-way balancing account should occur annually.
23. The primary objective of the EUP Audit is to determine if the costs recorded into the one-way balancing account met the Phase 2 Conditions.
24. The secondary objectives of the EUP Audit include verifying that an undergrounding project is used and useful, verifying the incrementality showing found in Application Requirement No. 2, and validating the methodology used to calculate a CBR for a given project.
25. Additional primary and/or secondary objectives for an EUP Audit may be included in the Phase 2 Decision.
26. The EUP Audit should begin no later than 60 days (or such period specified in the Phase 2 Decision) after the due date for reply comments on the second six-month progress report in a given calendar year.
27. The large electrical corporation should not have input into the direction, focus, or outcome of the EUP Audit that goes beyond the input afforded to other Parties to the Commission's SB 884 proceeding or process.
28. The large electrical corporation should provide access to all information requested by the auditor and SPD to carry out the audit within five days (or such period specified in the Phase 2 Decision) of each data request.
29. The large electrical corporation should make personnel available for interviews on five days' notice (or such period specified in the Phase 2 Decision) if the auditor seeks substantive information, and a custodian of records for questions about the location and content of requested information.
30. In the "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884

Guidelines," issued on April 11, 2025, Staff solicited stakeholder input on whether the Commission should provide additional guidance for CBR calculations made in the context of SB 884.

31. Guidance on how to calculate CBRs is necessary to ensure projects achieve wildfire risk reduction without undue expense and provide a means for equitable comparison against potential alternative mitigations.
32. The *CBR Calculation Guidelines* requirement for backcasting is reasonable and allows for greater alignment with the *Energy Safety Guidelines*.
33. The *CBR Calculation Guidelines* establishes a standardized and consistent methodology for evaluating and comparing the cost-efficiency of undergrounding and alternative mitigations in SB 884-related applications.
34. The *CPUC Guidelines* contained in Attachment A herein are reasonable and necessary for the continued development of the Commission's SB 884 program.
35. The *SB 884 Project Lists Data Requirements-Preliminary* were refined, revised, and finalized following a series of TWG meetings, as authorized by SPD-15, and are included for information only with this Resolution as the *SB 884 Project List Data Requirements Guidelines* in Appendix 2 of the *CPUC Guidelines*.
36. The *SB 884 Project List Data Requirements Guidelines* and *SB 884 Project List Data Template* were issued by SPD on July 24, 2025.
37. Future updates and changes to the *SB 884 Project List Data Requirements Guidelines* and *SB 884 Project List Data Template* may be necessary.
38. It is reasonable to authorize SPD to make future updates and changes to the *SB 884 Project List Data Requirements Guidelines* and *SB 884 Project List Data Template* after hosting at least one TWG meeting to present and discuss the changes.

THEREFORE, IT IS ORDERED THAT:

1. Resolution SPD-37 is approved and adopted.
2. The large electrical corporations shall demonstrate that the Phase 2 Conditions, including the Additional New Phase 2 Conditions, have been met in their six-month progress reports.
3. Costs recovered in the memorandum account shall be capped as a percentage of the total sum of the 10 years of cost caps placed on the one-way balancing account and according to the requirements established in the large electrical corporation's Phase 2 Decision.
4. An Electrical Undergrounding Plan Audit shall be conducted annually for undergrounding project costs recovered by the large electrical corporation through the one-way balancing account.
5. The primary objective of an Electrical Undergrounding Plan Audit is to verify

whether the costs of the large electrical corporation's undergrounding projects recovered through the one-way balancing account meet the Phase 2 Conditions.

6. The secondary objectives of an Electrical Undergrounding Plan Audit are to verify that an undergrounding project is used and useful, verify the incrementality showing found in Application Requirement No. 2, and validate the methodology used to calculate a Cost-Benefit Ratio for a given project.
7. The *Senate Bill 884 Program: California Public Utilities Commission Guidelines* applicable to all large electrical corporations have been updated and appear as Attachment A hereto. They supersede the guidelines adopted in Resolution SPD-15.
8. Large electrical corporations shall comply with the *Senate Bill 884 Program: California Public Utilities Commission Guidelines* attached hereto as Attachment A.
9. The large electrical corporations shall use the *Cost-Benefit Ratio Calculation Guidelines* when calculating the Cost-Benefit Ratio for Senate Bill 884 projects.
10. The large electrical corporations must complete the *SB 884 Project List Data Template*[117] according to the requirements found in the *SB 884 Project List Data Requirements Guidelines* and submit the completed *SB 884 Project List Data Template* with their Phase 2 Application and six-month progress reports.
11. Parties may review, file and serve opening comments on the progress report in the Phase 2 Application docket no later than 42 days (or such period specified in the Phase 2 Decision) after the progress report is filed and served by the large electrical corporation. Reply comments on the progress report may be filed and served in the Phase 2 Application docket no later than seven (7) days (or such period specified in the Phase 2 Decision) after the due date for opening comments.
12. We authorize Safety Policy Division to make future updates and changes to the *SB 884 Project List Data Requirements Guidelines* and *SB 884 Project List Data Template* after hosting at least one technical working group meeting to present and discuss the changes.

[117] The *SB 884 Project List Data Template* is available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/documents/sb-884-project-list-data-template-clean-version_2.xlsx.

This Resolution is effective today.

The foregoing resolution was duly introduced, passed and adopted at a conference of the Public Utilities Commission of the State of California held on September 18, 2025; the following Commissioners voting favorably thereon:

Commissioner Signature blocks to be added upon adoption of the resolution

Dated September 18, 2025, at San Francisco, California

ATTACHMENT A

SB 884 Program: CPUC Guidelines With Appendices

California Public
Utilities Commission

SB 884 Program: CPUC Guidelines

SAFETY POLICY DIVISION

August 15, 2025

Table of Contents

Purpose:

These *Guidelines,* and the adopting Commission Resolution, satisfy the Commission's statutory obligation, pursuant to Public Utilities Code Section 8388.5(a), to establish an expedited utility distribution infrastructure undergrounding program consistent with Senate Bill (SB 884.)[1] These *Guidelines* address the process and requirements for the Commission's review of any large electrical corporation's 10-year distribution infrastructure undergrounding plan (as defined below) and related costs.

[1] McGuire; Stats. 2022, Ch. 819

Background:

SB 884, effective January 1, 2023, authorizes electrical corporations with 250,000 or more customer accounts within the state (i.e. large electrical corporations) to participate in an expedited utility distribution infrastructure undergrounding program.

To participate in the program, the large electrical corporation must submit a 10-year distribution infrastructure undergrounding plan (hereafter, "Plan" or "EUP"), including, among other requirements, the undergrounding projects to be constructed as part of the Plan, to the Office of Energy Infrastructure Safety (Energy Safety). Energy Safety is required to review and approve or deny the Plan within nine months of submission. Energy Safety may require the large electrical corporation to modify the Plan before approving it. Energy Safety may only approve the Plan upon finding it will achieve, at least, both of the following:[2]

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

The large electrical corporation must submit to the Commission, within 60 days of Energy Safety's approval, a copy of the Plan and an application requesting review and conditional approval of the Plan's costs (hereafter, "Application"). However, prior to formally filing the Application with the Commission, the large electrical corporation shall provide a copy of the Application it intends to file to the Commission's Safety Policy Division (SPD) for a completeness review to identify any obvious omissions or errors in the intended Application. SPD will conclude its completeness review within 10 business days of receipt and issue a report noting any deficiencies that should be corrected before the Application is officially submitted and filed with the Commission.

On or before nine months after the Application's official filing date, the Commission shall review and conditionally approve or deny the Application. The Commission may, however, require the large electrical corporation to (i) modify or (ii) modify and resubmit the Application prior to conditional approval. As further explained below, if the Commission or staff determines that minor corrections or clarifications are needed for the filed Application, the large electrical corporation may be required to modify the Application and provide corrections or clarifications within five (5) business days after being noticed. If the Commission or staff determines the filed Application 1) omits material information required pursuant to the Commission Resolution adopting these *Guidelines*, 2) omits material information deemed necessary to process the Application within nine months, or 3) omits information otherwise required by SB 884, the Commission or staff may then require the large electrical corporation to modify and resubmit the Application, and such resubmission will restart the nine-month timeline for Commission review.

If the Plan is approved by Energy Safety and the Application requesting review and conditional approval of the Plan's costs is approved by the Commission, the large electrical corporation must file progress reports with the Commission and Energy Safety every six months, include ongoing work plans and progress in its annual wildfire mitigation plan submissions, hire an independent monitor (selected by Energy Safety) to

[2] Energy Safety has issued guidelines detailing the requirements for submission and review of undergrounding Plans. See https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=58006&shareable=true

review and assess its compliance with the Plan, apply for all available federal, state, and other non-ratepayer moneys throughout the duration of the approved Plan, and use those non-ratepayer moneys to reduce the Plan's costs to its ratepayers.

The independent monitor must annually produce and submit a report to Energy Safety no later than December 1 of each year over the course of the Plan.[3] The independent monitor's report will identify any failure, delays, or shortcomings in the large electrical corporation's compliance with the Plan and provide recommendations for improvements. After consideration of the independent monitor's report and whether the large electrical corporation has corrected the deficiencies identified therein, Energy Safety may recommend penalties to the Commission. The Commission may assess penalties on a large electrical corporation that fails to substantially comply with the Commission decision approving its Plan pursuant to Public Utilities Code, Section 8388.5(i)(2).

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

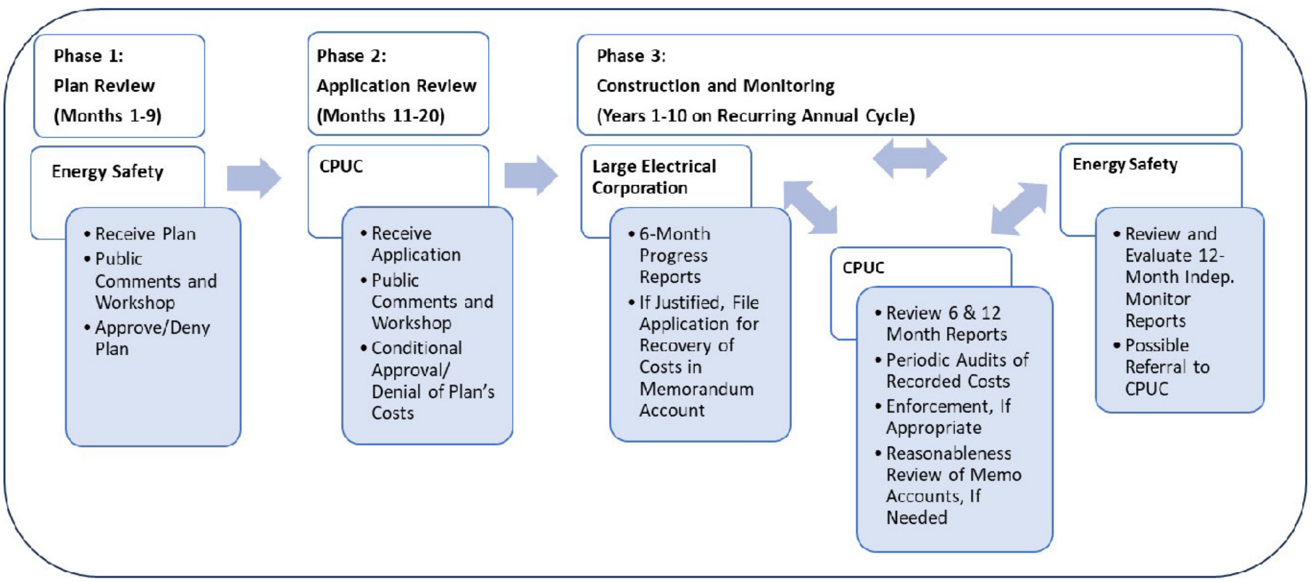

Figure 1: SB 884 Plan, Application, Reporting, and Cost Recovery Timeline

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

SB 884 Program Process and Requirements:

The SB 884 Program will be executed in up to three phases:

1) Phase 1: Energy Safety Plan review and approval/denial
2) Phase 2: Application submitted to Commission for review and conditional approval.
3) Phase 3: Construction and periodic audits of costs recorded in the one-way balancing account, as well as just and reasonableness reviews of recorded costs in the memorandum account described below.

If Energy Safety approves the large electrical corporation's Plan, Phase 2 will commence with the large electrical corporation's submission of an Application for Commission consideration and conclude with the Commission's disposition of such Application (i.e., conditional approval or denial) via a Phase 2 Decision. The Commission will review the costs submitted in any Application. Only if costs[4] meet certain conditions (Phase 2 Conditions), will the Commission authorize their recovery via a one-way balancing account, which shall remain subject to audit. If an audit demonstrates any costs recorded to the one-way balancing account did not meet the Phase 2 Conditions, subject to Commission review and determination, such costs may be subject to refund. The Phase 2 Conditions for recovering costs via the one-way balancing account will include those listed in the "Conditions for Approval of Plan Costs" section herein, as well as any other conditions the Commission deems appropriate in the relevant Application's proceeding. If the Commission approves cost recovery in the one-way balancing account, the Commission will also authorize the large electrical corporation to record, in a memorandum account, any Plan costs that fail to meet the Phase 2 Conditions.

If the Commission conditionally approves the large electrical corporation's Application, Phase 3 will commence upon the Commission's issuance of the Phase 2 Decision. During Phase 3, the large electrical corporation will execute its undergrounding Plan in accordance with the Resolution adopting these *Guidelines*, the Commission's Phase 2 Decision, and any other Commission decision on an Application submitted pursuant to the SB 884 program. The large electrical corporation shall also report on its progress and begin booking costs to the one-way balancing account established in Phase 2, subject to periodic audits and refunds if the Commission so orders. In Phase 3, given the inherent uncertainties with planning across a 10-year period and certain costs being unforeseeable during Phase 2, the large electrical corporation may also request rate recovery (via a separate Phase 3 Application) for implementation costs that do not meet the Phase 2 Conditions, and were recorded in the designated memorandum account up to a cap determined in the Phase 2 Decision. During Phase 3, the Commission will review any Phase 3 Applications for recovery of costs recorded in the memorandum account to determine whether such costs were just and reasonable, and incremental to any other costs approved by the Commission. When making these determinations the conditions set forth in the Resolution adopting these *Guidelines*, the Commission's Phase 2 Decision, and any other Commission decision on an Application submitted pursuant to SB 884 should be considered in light of the fact that such costs must be found to be just and reasonable before being authorized for recovery. Phase 3 will conclude with the Commission's disposition of the last cost recovery application associated with the memorandum account, or the final independent monitor report, whichever is last.

Given the importance of the Phase 2 Conditions and the requirement that any costs recorded in the one-way balancing account must meet the Phase 2 Conditions, these *Guidelines* include a process to assess

[4] Costs can only be recovered once the undergrounding project is considered used and useful.

whether the recorded costs meet such conditions. Accordingly, periodic audits of the established balancing account will be performed to ensure the costs booked to the balancing account meet the conditions established by the Phase 2 Decision (e.g., unit cost caps, CBR thresholds, etc.). If the audit demonstrates that costs were incorrectly recorded or failed to meet the Phase 2 Conditions, the Commission may order a refund. If the Commission directs a large electrical corporation to issue a refund, the large electrical corporation shall not seek to recover such costs through any other means.

Due to the SB 884 Program's expedited schedule, unless otherwise directed by the Commission, large electrical corporations shall respond to discovery requests within five (5) business days in either Phase of the SB 884 Program.

Application Conditional Approval, Denial, or Modification & Resubmittal:

On or before nine months after the Application's filing date, the Commission shall review and conditionally approve or deny the Application. Before conditionally approving or denying the Application, the Commission or staff may require the large electrical corporation to (i) modify or (ii) modify and resubmit the Application.[5] If the Commission or staff determines that minor corrections or clarifications are needed for the Application, then the Commission or staff may require the large electrical corporation to modify the Application and such minor corrections or clarifications shall be provided within five (5) business days of notice. If the Commission or staff determines that the Application 1) omits material information required pursuant to the Commission Resolution adopting these *Guidelines*, 2) omits material information deemed necessary to process the Application within nine months, or 3) omits information otherwise required by SB 884, then the Commission or staff may require the large electrical corporation to modify and resubmit the Application, and such resubmission will restart the nine-month timeline for the Commission's review.

Pre-Submission Application Completeness Review:

Before submission of the Application, the large electrical corporation shall provide a copy of the intended Application to Commission's Safety Policy Division (SPD)[6] for a completeness review. The pre-submission process is a precursor to and separate from the Commission's Application review process. The intent of the completeness review will be to identify any obvious omissions or errors and avoid unnecessary delays resulting from post-submittal modification of the Application for such omissions or errors, given the expedited schedule for review. SPD will conclude its completeness review within 10 business days of receipt and issue a report noting any deficiencies that should be corrected in the submitted Application. Accordingly, it is the large electrical corporation's responsibility to provide SPD with a copy of the intended Application with sufficient time to conduct the completeness review (i.e., 10 business days) while ensuring that the 60-day deadline for Application submission, following Energy Safety's approval of the Plan, is met pursuant to Public Utilities Code, Section 8388.5(e)(1). SPD's report is solely for completeness review; it is

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

[6] Pre-submission of the Application for completeness review shall be submitted to SB884@cpuc.ca.gov.

not a substantive review or disposition of the Application and does not limit the Commission's or staff's ability to require the large electrical corporation to otherwise modify or resubmit the Application.

Phase 2 – Application Submission and Review:

These *Guidelines* recognize that Plans approved by Energy Safety will have been found to show that implementation of the Plan will substantially increase reliability and substantially reduce wildfire risk, as required in Public Utilities Code, Section 8388.5(d)(2). The Commission will then review such Plans and either conditionally approve or deny the costs, as presented in the subsequent Application.

Application Submission Requirements:

Applications submitted to the Commission seeking conditional approval of Plan costs shall meet all the following requirements.

Submission Deadline:

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

Application Type:

Applications shall be submitted according to the Commission's Rules of Practice and Procedure and any other requirements set forth in the Commission Resolution adopting these *Guidelines.*[7] Each section of the Application shall indicate the person who sponsors the section and would serve as a witness if evidentiary hearings are required.

Application Submission:

The Application shall be filed and served with the Commission's Docket Office, with a copy to the Commission's Chief Administrative Law Judge, the service list for the large electrical corporation's most recent general rate case (GRC), the SB 884 notification list linked here,[8] as updated, SB884@cpuc.ca.gov, and any other service lists, as determined by the large electrical corporation, that will cause the Application to broadly reach interested parties. A copy of the application should also be sent to each communications company that has equipment on poles where undergrounding is planned.

Application Requirements:

For the purposes of these *Guidelines*, all program and project costs reported in the Application shall include the standard project costs including, but not limited to, program management, project execution, design, estimating, mapping, construction, internal labor, contracted labor, parts, tools, materials, overhead, and

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

[8] The SB 884 notification list is periodically updated and uploaded to CPUC SB 884 webpage: https://www.cpuc.ca.gov/about-cpuc/divisions/safety-policy-division/risk-assessment-and-safety-analytics/electric-undergrounding-sb-884.

permitting. In addition, all ratepayer impacts shall be shown by all ratepayer classifications (e.g., residential, agricultural, commercial, etc.) to the extent such information is available.

All cost and Cost-Benefit Ratio (CBR) data, required as described below, shall be supported by workpapers and Excel worksheets included with the Application submission.

The following are required contents of all Applications:

1) The Application shall present both capital and operating expense cost forecasts for each year of the 10-year Application period, consistent with the cost targets presented in the Plan approved by Energy Safety.
2) The Application shall clearly identify all undergrounding targets (*e.g.*, miles to underground together with their conversion rate[9]) and cost forecasts[10] in the Plan that overlap with undergrounding targets and any and all related targets and cost forecasts either approved or under consideration in the large electrical corporation's most recent GRC or any other cost recovery venues. Furthermore:
    a) Where undergrounding targets and cost forecasts in the Application overlap with undergrounding targets and cost forecasts <u>approved</u> in the most recent GRC or other cost recovery venue, such undergrounding targets and costs shall be clearly identified and associated costs will be excluded from consideration for recovery in the Application.
    b) Where undergrounding targets and cost forecasts in the Application overlap with undergrounding targets and cost forecasts <u>still under consideration</u> in a GRC or other cost recovery venue, the Application shall specify which overlapping targets and costs are under consideration and identify the proceeding or advice letter in which the Commission is considering them. The Application shall propose in which venue the Commission should consider the overlapping costs. Both costs and the corresponding mileage must be paired and presented for consideration in a single venue.
    c) The Application shall include a detailed description of the controls the large electrical corporation will implement to ensure that undergrounding costs related to execution of the Plan are incremental to any other costs approved by the Commission.
3) The Application shall include the large electrical corporation's best estimate, including all underlying assumptions, of the proposed annual revenue requirements and proposed ratepayer impacts for each year that the large electrical corporation proposes will be necessary for rate recovery of the Application's forecasted annual costs.
4) The Application shall include a Results of Operation (RO) Model for that portion of its revenue requirement that relates to the undergrounding cost recovery it seeks, with Energy Division

[9] As used in this context, "conversion rate" means the ratio of underground mileage required to replace the equivalent overhead lines. Given prior evaluation of undergrounding requests in other Commission proceedings, it is known that a mile of undergrounding corresponds to replacement of less than one mile of overhead assets.

[10] For clarity, the term cost forecasts is used in place of the term cost targets that are discussed in PUC 8838.5 (3)(1).

oversight and a non-disclosure agreement in place,[11] that demonstrates how the large electrical corporation calculated the revenue requirement provided.[12]

5) The Application shall identify, for each year of the 10-year Application period, any forecast wildfire mitigation costs that will be reduced, deferred, or avoided because of implementing the proposed undergrounding Plan (e.g., vegetation management), collectively "savings," and how spending on such programs or areas of work will be affected, including any cost reductions, deferrals, or avoidances that are expected to continue beyond the 10-year Application period and the time period for which such cost reductions, deferrals, or avoidances are expected to continue beyond the 10-year period.[13]
    a) The Application shall distinguish between forecast costs already approved by the Commission for recovery and forecast costs that have not yet been the subject of a request for recovery.
    b) For forecast costs already approved by the Commission for recovery, the Application shall identify any accounts used to track such costs; the amounts in each such account; and the Commission decision(s) authorizing recovery.
    c) The application shall explain the proposed disposition of all identified savings and explain the methodology by which the Commission can ensure that all identified savings are passed on to ratepayers.
6) The Application shall include cost forecasts for each year of the 10-year Application period that, at a minimum, result in feasible and attainable cost reductions as compared to the large electrical corporation's historical undergrounding costs.
    a) Cost forecasts shall be provided for each projected year in the 10-year Plan.
    b) Annual historical undergrounding unit costs shall be provided for the previous 10 years, with separate categories for Rule 20 projects, other undergrounding projects, and wildfire mitigation projects, as available.
    c) Comparisons between the Plan's unit cost targets and historical undergrounding unit costs shall be provided using the average historical wildfire mitigation undergrounding costs for the previous three years (before the Plan's first year). The comparison shall include a statement of how the targeted cost reductions are feasible and attainable compared to historical costs.
7) The Application shall include an explanation of how the cost forecasts are expected to decline over time due to cost efficiencies and economies of scale.
8) The Application shall include a description of a strategy for achieving cost reductions over time per Public Utilities Code, Section 8388.5(e), which may include factors other than cost efficiencies or

---

[11] The non-disclosure agreement shall ensure that the large electrical corporation personnel in charge of the RO modeling will not disclose changes to the RO Model requested by the Commission to the personnel working on the Phase 2 Application and related matters.

[12] See also D.00-07-050 at 11-12 and D.20-01-002 at 65-67.

[13] For examples of cost benefits that may be appropriate to include, refer to the Lawrence Berkeley National Laboratory white paper. Peter H. Larsen, "A method to estimate the costs and benefits of undergrounding electricity transmission and distribution lines" in Energy Economics Vol. 60, 2016 pp. 47-61. Please note that this methodology is referenced for illustrative purposes only. Different methodologies and/or cost categories may be appropriate to include.

economies of scale such as, but not limited to, identifying, developing, and deploying new technologies.

9) The Application shall present the forecasted average Cost-Benefit Ratio (CBR) across all projects expected to be completed in each of the 10 years of the Application period, broken out by year and for the total Application period. Cost and Benefits must be calculated as defined in Commission Decision (D.)22-12-027[14] or its successor. The calculated annual and total benefits must relate to the mitigation of overhead line miles, not miles of undergrounding.[15] The costs and benefits of any projects that will include secondary lines and service drops must also be included.
10) The Application shall include the forecasted CBRs across all projects, by year and for the total Application period, for each alternative wildfire mitigation hardening method considered, in place of undergrounding, including forecasted CBRs for combinations of non-undergrounding hardening mitigation measures. The calculated annual and total benefits must relate to the mitigation of overhead line miles, including any secondary lines and service drops, not miles of undergrounding.
    a) The large electrical corporation shall use reasonable and comparable assumptions in its calculations of forecasted CBRs for both undergrounding and each alternative wildfire mitigation method considered, including combinations thereof.
11) The Application shall include a description of any substantial improvements in safety risk and reduction in costs compared to other hardening and risk mitigation measures over the duration of the Plan.
    a) Substantial improvements in safety risks shall be substantiated using the above required benefits calculations by comparing undergrounding benefits to alternative hardening and risk mitigation measures, including combinations of alternative measures.
    b) Reduction in costs shall be substantiated using the same cost calculations as required above by comparing undergrounding costs to alternative hardening and risk mitigation measures, including combinations of alternative measures.
12) For each project included in the Application, the large electrical corporation shall provide, at a minimum, all data listed in the *SB 884 Project List Data Requirements Guidelines* in tabular format. This information shall be provided as both a Microsoft Excel file and searchable pdf file[16] to supplement the Application. The large electrical corporation shall provide the latest version of the data required by the *SB 884 Project List Data Requirements Guidelines* at the time of its Application submission.
13) The Application shall include the latest data associated with the list of all projects (*SB 884 Project List Data Requirements Guidelines*) as required by Screen 2 of the *Energy Safety Guidelines.* The large electrical corporation shall provide a forecasted scope of all projects in the approved 10-year EUP and included in the Undergrounding Projects List, as an output from Screen 2 of the *Energy Safety Guidelines.*

---

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

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

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

14) The Application shall only include undergrounding projects that have a forecasted CBR greater than or equal to 1.
15) The Application shall only include undergrounding projects that have met one or more of the large electrical corporation's three Project-Level Thresholds.[17]
16) The Application shall include a detailed explanation of the necessity for any spans that extend beyond the HFTD boundary for any project included in the Application.
    a) The Application shall only include undergrounding projects that have been designated as an In-Area circuit segment as required by Screen 1 in the *Energy Safety Guidelines*.[18]
17) The Application shall include:
    a) The same Key Decision-Making Metrics (KDMMs) data for Commission review as was provided in the EUP approved by Energy Safety.
    b) The KDMMs included in any six-month progress report submitted to Energy Safety during the nine-month period that the large electrical corporation's EUP is under review by Energy Safety.
18) For each project included in the Plan and Application, the large electrical corporation shall provide GIS data for all project boundaries in a Geodatabase or other suitable format.
    a) The GIS data shall include the entire circuit within which projects are planned and indicate the locations of which segments will be undergrounded.
    b) The GIS data shall identify the locations of circuit segments that will continue to support overhead transmission lines (if any) after distribution lines are undergrounded.
    c) The GIS data shall indicate the locations of poles which have lease agreements with communications companies, and which are jointly owned.
19) The Application shall include a list of all non-ratepayer moneys (i.e., third-party funding) the large electrical corporation has applied for and/or received to minimize the Plan's costs on ratepayers. At a minimum, for each potential source of third-party funding, the list shall include:
    a) The source of third-party funding;
    b) The date when third-party funds were requested;
    c) The amount of funding requested;
    d) The status of the request, including funding already received;
    e) Next steps, including timelines for processing of the funding request; and
    f) The amount of funding granted/authorized (if any).
20) The Application shall include a description of how any net tax benefits associated with the third-party funding will be disposed of to the benefit of ratepayers.
21) The Application shall include a statement affirming costs, tax benefits, and tax liabilities associated with federal funding sources used to fund projects included in the Plan are being tracked consistent with Resolution E-5254.[19]
22) The Application shall include an attestation that the large electrical corporation will continue to search and apply for third-party funding to reduce the cost of the Plan to ratepayers throughout the duration of the Plan.

---

[17] *Energy Safety Guidelines* at 42. The large electrical corporation indicates to Energy Safety whether a circuit segment falls into one of the mitigation eligibility categories in Table C.8 under the "risk_category" field.

[18] *Energy Safety Guidelines* at 12. The large electrical corporation indicates to Energy Safety whether a circuit segment is designated as "In-Area" in Table C.6 under the "is_in_area" field.

[19] Resolution E-5254 adopted procedural mechanisms for review and approval of electric and gas investor-owned utility cost recovery requests related to various federal funding and grant programs. Resolution E-5254 is available on the Commission's website at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M506/K016/506016078.PDF.

23) The Application shall include a description of how the large electrical corporation plans to coordinate with communication companies to maximize benefits to California, including but not limited to:
    a) The ownership and use of existing utility poles where undergrounding projects are planned;
    b) How the large electrical corporation will address the affected shared poles, including who will own and maintain the poles if the responsible communication provider opts not to concurrently underground their infrastructure;
    c) The full array of currently offered or discussed proposals for how to add conduit for such communication companies in the large electrical corporation's trenches, including, wherever possible, the proposed unit costs associated with such offerings or proposals.
24) The Application shall include a plan of how and when the large electrical corporation will remove poles from its rate base whose ownership is transferred to a communications company.
25) The Application shall include workforce development cost forecasts for each year of the Plan.
26) The Application shall include a detailed description of the method that establishes how the auditor will validate whether the large electrical corporation has satisfied the primary and secondary objectives of the audit. For the primary objectives, this method must include an approach for:
    a) Verifying that the total annual costs did not exceed the approved cost cap for a given year of the EUP (Condition #1);
    b) Verifying that any third-party funding obtained was applied to reduce the established cost cap for the specific year in which the third-party funding was obtained (Condition #2);
    c) Determining that the average recorded unit cost for all projects completed in any given two-year period did not exceed the approved average unit cost cap (Condition #3);
    d) Determining that the average recorded CBR for all projects completed in any given two-year period equals or exceeds the approved threshold CBR value. (Condition #4);
    e) Determining whether the forecasted CBR of an alternative mitigation exceeds a certain threshold value above the forecasted CBR of an undergrounding project (Condition #5);
    f) Verifying that a project did not exceed the approved CBR percentage difference threshold (Condition #6);
    g) Verifying that a project did not exceed the approved unit cost percentage difference threshold (Condition #7); and
    h) Verifying that the undergrounding project meets or exceeds the applicable Project-Level Standard in the large electrical corporation's EUP approved by Energy Safety (Condition #8).

    For the secondary objectives, this method must include an approach for:
    i) Verifying that a project is used and useful.
    j) Verifying the incrementality showing found in Application Requirement No. 2.
    k) Validating the methodology used to calculate a CBR for a given project, as found in the *CBR Calculation Guidelines* in Appendix 1 of these *Guidelines*.
27) The Application shall include a copy of the Plan approved by Energy Safety.

Public Workshop & Comments:

The Commission will facilitate a public workshop for presentation of the Application and take public comment for at least 30 days in accordance with Public Utilities Code Section 8388.5(e)(4). Formal comments from the workshop will be solicited by a ruling in the proceeding, and a workshop report provided by the parties who participated in the workshop may be ordered.

Conditions for Approval of Plan Costs:

Public Utilities Code, Section 8388.5(e)(1) specifies that an Application may request "conditional approval of the plan's costs…" To protect ratepayers from unexpected and inefficient cost overruns, the Commission establishes the following conditions for any costs booked to the one-way balancing account established in Phase 2:

1) Total annual costs must not exceed a cap based on the approved cost cap for that specific year.[20]
2) Third-party funding obtained, if any, shall be applied to reduce the established cost cap for the specific year in which the third-party funding is obtained, so that ratepayers receive the benefit. The large electrical corporation shall file an advice letter documenting which annual cost caps are reduced based on third-party funding received.
3) The average recorded unit cost for all projects completed in any given two-year period (the current year, and the prior year) must not exceed the approved average unit cost cap for the current year. The unit costs shall be calculated per mile of undergrounding performed, rather than per mile of overhead replaced, to focus on reduction of construction costs.
4) The average recorded CBR[21] for all projects completed in any given two-year period (the current year, and the prior year) must equal or exceed the approved threshold CBR value[22] for the current year.
5) The forecasted CBR of the undergrounding project must exceed the forecasted CBR of all alternative mitigations considered for that project by a certain threshold value, which is to be determined in the Phase 2 Decision.
6) In all cases, when an undergrounding project becomes used and useful, if the value of its recorded CBR, as reported in the applicable six-month progress report, is less than the value of its forecasted CBR at the time of the Phase 2 Application submission, then the percentage difference between the two CBR values must not exceed the specified threshold value determined in the Phase 2 Decision.
7) In all cases, when an undergrounding project becomes used and useful, if the value of its recorded unit cost, as reported in the applicable six-month progress report, is greater than the value of its forecasted unit cost at the time of the Phase 2 Application submission, then the percentage difference between the two unit cost values must not exceed the specified threshold value determined in the Phase 2 Decision.
8) The undergrounding project must meet or exceed the applicable Project-Level Standard(s) in the large electrical corporation's EUP approved by Energy Safety.[23]
9) Any further reasonable conditions supported by the record of the proceeding and adopted by the Commission in the Phase 2 Decision.

---

[20] Any costs exceeding the cap shall be recorded in a memorandum account and are subject to review and approval as described in the Phase 3 section of these *Guidelines*.

[21] The "recorded CBR" is the CBR calculated using recorded cost values, as opposed to cost forecasts.

[22] The "threshold CBR value" will establish the minimum CBR that must be achieved for cost recovery.

[23] *Energy Safety Guidelines* at 17 and 43. The large electrical corporation indicates to Energy Safety whether an undergrounding project has met the Project-Level Standard(s) in Table C.12 of the *Energy Safety Guidelines* under the "fulfills_project_level_standard" field. The "applicable Project-Level Standard(s)" can be verified by how the utility completes the "risk_category" field in Table C.8 of the *Energy Safety Guidelines*. If the undergrounding project does not meet the applicable Project-Level Standard(s), the *Energy Safety Guidelines* still permit a large electrical corporation to record a justification for this project in Table C.12 under the "additional_justification" field, which can be reviewed as part of a Phase 3 Application to determine the just and reasonableness of the costs associated with a project that does not meet this condition.

Memorandum Account Cap:

The total cumulative costs recovered via the memorandum account throughout the duration of an EUP shall be capped as a percentage of the total sum of the 10 years of cost caps placed on the one-way balancing account. The percentage value of the memorandum account cost cap will be established in the Phase 2 Decision.

Phase 3 – Review of Memorandum Account Recorded Costs for Rate Recovery:

Phase 3 of the program will be initiated if the Commission conditionally approves a Phase 2 Application submitted by a large electrical corporation. During Phase 3, the large electrical corporation will execute its undergrounding Plan in accordance with the Resolution adopting these *Guidelines*, the Commission's Phase 2 Decision, and any other Commission decision on an Application submitted pursuant to the SB 884 program, the large electrical corporation shall also report on its progress, and begin booking costs to the one-way balancing account established in Phase 2, which shall remain subject to periodic audits, and refund if the Commission so orders. In Phase 3, the large electrical corporation may also request rate recovery (via a separate Phase 3 Application) for any implementation costs that do not meet the Phase 2 Conditions and were recorded in the designated memorandum account. The large electrical corporation may only seek recovery for costs recorded in the memorandum account by filing a Phase 3 Application. The total cumulative costs recovered via the memorandum account throughout the duration of an EUP shall not exceed the cap established for such accounts in the Phase 2 Decision. The purpose of any Phase 3 Application will be to determine whether the costs recorded in the memorandum account meet the conditions set forth in the "Conditions for Approval of Recorded Costs in Memorandum Account" section below. When making these determinations the conditions set forth in the Resolution adopting these *Guidelines*, the Commission's Phase 2 Decision, and any other Commission decision on an Application submitted pursuant to SB 884 should be considered in light of the fact that such costs must be just and reasonable. No more than one Phase 3 Application may be filed each year.

The elements of recorded costs must be consistent with the elements included in the costs presented in the Application, including but not limited to, program management, project execution, design, estimating, mapping, construction, internal labor, contracted labor, parts, tools, materials, overhead, and permitting.

The Phase 3 Application must include, at a minimum, all six-month progress reports and annual compliance reports submitted pursuant to this program, relevant information from wildfire mitigation plan filings and compliance reports, and the following program data presented in Table 1 for the requested recovery period.[24] The project data that supports the program recorded cost values requested for recovery shall be provided in tabular format in a sortable Excel spreadsheet. Additional data requirements for a Phase 3 Application may be included in the Phase 2 Decision.

---

[24] Recovery period means the period under consideration in the most recent Phase 3 Application filing.

Table 1: Conditionally Approved Target and Actual Recorded Cost Data

Conditionally Approved Targets for the Recovery Period	Actual Recorded Costs in the Recovery Period
Program Cost	Program Cost
Program CBR	Program CBR
Program Unit Cost	Program Unit Cost
	Project Data for the Recorded Projects

Conditions for Approval of Recorded Costs in Memorandum Account:

To further protect ratepayers from unexpected and inefficient cost overruns:

1) The Commission will closely scrutinize any Phase 3 Application to determine whether the costs recorded were prudently incurred, incremental to other funding granted to the large electrical corporation, and just and reasonable.
2) When making these determinations the conditions set forth in the Resolution adopting these *Guidelines*, the Commission's Phase 2 Decision, and any other Commission decision on an Application submitted pursuant to SB 884 should be considered in light of the fact that such costs must be just and reasonable.
3) No costs recorded to the memorandum account established in the Commission's Phase 2 Decision shall be authorized for recovery unless and until the large electrical corporation has shown that it has applied all third-party funding previously received to reduce its relevant balancing account cost cap.
4) No costs recorded to the memorandum account established in the Commission's Phase 2 Decision shall be authorized for recovery unless such costs are consistent with the approved Plan.

Progress Reports:

Public Utilities Code Section 8388.5(f)(1) requires large electrical corporations with approved Plans and conditionally approved Applications to file progress reports every six months with both Energy Safety and the Commission. Accordingly, without affecting the required progress report elements specified by Energy Safety, these *Guidelines* require that the six-month progress reports shall include, but should not be limited to, the following:

1) Total recorded costs to date;
2) Third-party funds received, with an explanation of how third-party funding was used to reduce the burden on ratepayers;
3) Average recorded CBR for completed projects in any given two-year period;
4) Average recorded unit cost per mile of undergrounding for completed projects in any given two-year period;
5) Miles of overhead replaced by undergrounding by circuit segment;
6) Miles of undergrounding completed by circuit segment;
7) GIS data showing location and status of each project (in Geodatabases or other suitable format);
8) An updated list of all third-party funding the large electrical corporation has applied for, as specified in Application Requirements 19-21; and

9) Total and average avoided costs and workpapers showing calculation of avoided costs.
10) An updated dataset that follows the requirements of the *SB 884 Project List Data Requirements Guidelines*.

At a minimum, the six-month progress reports filed by a large electrical corporation shall include an update of the *SB 884 Project List Data Requirements Guidelines* in Appendix 2, as well as any other reporting requirements in the *Energy Safety Guidelines*, the Phase 2 Decision(s), and the Phase 2 Application Requirements listed above. Large electrical corporations shall file and serve the six-month progress reports in the applicable Phase 2 Application docket. Parties may review, file, and serve opening comments on the progress report in the Phase 2 Application docket no later than 42 days (or such period specified in the Phase 2 Decision) after the progress report is filed and served by the large electrical corporation. Reply comments on the progress report may be filed and served in the Phase 2 Application docket no later than seven (7) days (or such period specified in the Phase 2 Decision) after the due date for opening comments.

Audit of the One-Way Balancing Account:

An audit of the one-way balancing account shall occur annually (hereafter, EUP Audit). The EUP Audit shall begin no later than 60 days (or such period specified in the Phase 2 Decision) after the due date for reply comments on the second six-month progress report in a given 12-month period. Each EUP Audit shall review EUP projects that become used and useful during the 12-month period covered by the audit. Each EUP Audit may also review recorded costs of projects or portions of projects that are not used and useful and may recommend refunds.

The primary objective of an EUP Audit is to determine whether the costs recorded in the large electrical corporation's balancing account have met all nine[25] Phase 2 Conditions. The audit shall also verify whether the recorded costs have met the following secondary objectives set forth in SPD-37:

1) Verify that projects are "used and useful;"
2) Determine whether the recorded costs are incremental – and do not duplicate costs allowed through another decision, mechanism or received from a third party; and
3) Validate that the methodology used to calculate a CBR, and the CBR results for a given project comply with the *CBR Calculation Guidelines* (See Appendix 1).

A Phase 2 Decision may also add primary and/or secondary objectives for the Audits specific to that EUP.

In its Phase 2 Application, as required by Application Requirement #26, a large electrical corporation shall propose the methodology for the auditor to determine whether the costs of undergrounding projects recovered via the one-way balancing account meet the primary and secondary objectives. The Phase 2 Decision will include the Commission's determination on the appropriate methodology to be used by the auditor to determine whether the primary and secondary objectives are met. In addition, any data that should be reviewed by the auditor, beyond what is submitted to the Commission in six-month progress reports, will be determined in the Phase 2 Decision. The auditor may also request information and conduct interviews with large electrical corporation personnel, including custodians of records, to gather information for the audit.

---

[25] The EUP Audit scope will also include any Phase 2 Conditions adopted in the Phase 2 Decision beyond the nine listed herein.

The EUP Audit will result in an audit report that will be filed and served to the Phase 2 Application docket within five (5) days (or such period specified in the Phase 2 Decision) of its completion and approval. The audit report shall be completed within six months (or such period specified in the Phase 2 Decision) after it is initiated.[26] Parties may file and serve opening comments on the audit report in the Phase 2 Application docket no later than 20 days (or such period specified in the Phase 2 Decision) after the audit report is filed and served by the large electrical corporation. Reply comments on the audit report may be filed and served in the Phase 2 Application docket no later than five days (or such period specified in the Phase 2 Decision) after the due date for opening comments. If a Party believes a refund is necessary based on the audit report, they may file a petition for modification requesting to reopen the Phase 2 Application proceeding and set forth the amount of the refund and the reasons for it in the petition. The Commission may also determine the appropriateness of reopening the Phase 2 Application proceeding based on its own review as described below.

Following its review of the audit report, six-month progress reports, associated comments, and any petitions received, the Commission may reopen the Phase 2 Application proceeding to consider the need for refunds. If the Commission reopens the Phase 2 Application proceeding, for projects that do not meet the primary objectives and/or one or more of the secondary objectives, the Commission may direct the large electrical corporation to refund related project costs to ratepayers in a subsequent decision. If the Commission directs a large electrical corporation to issue a refund, the large electrical corporation shall not seek to recover such costs through any other means.

The large electrical corporation shall not have input into the direction, focus, or outcome of the EUP Audit that goes beyond the input afforded to other Parties to the Commission's SB 884 proceeding or process. The large electrical corporation shall provide access to all information requested by the auditor and SPD to carry out the audit within five days (or such period specified in the Phase 2 Decision) of each data request. The large electrical corporation shall also make personnel available for interviews on five days' notice (or such period specified in the Phase 2 Decision) if the auditor seeks substantive information and a custodian of records for questions about the location and content of requested information.

Wildfire Mitigation Plan Integration:

Public Utilities Code Section 8388.5(f)(2) requires large electrical corporations to include ongoing work plans and progress relating to their undergrounding plans in annual wildfire mitigation plan filings. Staff understand that further guidance on incorporating this information into annual wildfire mitigation plan filings will be provided by Energy Safety.

Compliance Reports:

Public Utilities Code Section 8388.5(f)(3) requires a large electrical corporation with an approved Plan and conditionally approved Application to hire an independent monitor selected by Energy Safety. The independent monitor must assess whether the large electrical corporation's progress on undergrounding work is consistent with the objectives identified in its approved Plan.[27] For each year the Plan is in effect,

[26] Staff are authorized to extend the deadline for the audit report should a determination be made that such an extension is necessary to adequately complete the audit.

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

the independent monitor must annually produce a compliance report detailing its assessment by December 1.[28] The independent monitor's compliance report must also specify any failure, delays, or shortcomings of the large electrical corporation and provide recommendations for improvements to accomplish the objectives set forth in the approved Plan.[29] The large electrical corporation shall have 180 days to correct and eliminate any deficiency specified in the independent monitor's report.[30] Energy Safety shall consider the independent monitor's compliance report and whether the large electrical corporation cured the deficiencies identified therein when making its determination on whether to recommend penalties to the Commission.[31]

Penalties:

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

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

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

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

[31] Public Utilities Code, Section 8388.5(i)(1).

Appendix 1: Cost Benefit Ratio Calculation Guidelines

Cost Benefit Ratio (CBR) Calculation Guidelines

SAFETY POLICY DIVISION

August 15, 2025

Contents

Executive summary

The *Cost Benefit Ratio (CBR) Calculation Guidelines* establishes a standardized and consistent methodology for evaluating and comparing the cost-efficiency of undergrounding and alternative mitigations in Senate Bill (SB) 884 applications. This appendix to the *CPUC Guidelines* is designed to promote comparability, transparency, and traceability in CBR calculations while remaining adaptable to future improvements in data availability and analytical approaches. It complements the *SB 884 Project List Data Requirements Guidelines*[1] by outlining how to calculate the CBR and providing more information on its key components. These key components include:

- **Total Capital Costs**, defined as capital expenditures tied to Project implementation, excluding ineligible categories such as Net Operating and Maintenance (O&M) Costs[2] or Net Salvage values.[3]
- **Risk Scaling,** which is limited to using unscaled (i.e., risk-neutral) risk values in the CBR calculations.
- **Total Mitigation Benefit,** that may include:

  a. Risk Reduction, which is limited to Wildfire Ignition Risk[4] and Outage Program Risk.[5] Large electrical corporations must exclude other enterprise risks such as Public Contact with Energized Electrical Equipment (PCEEE) and Distribution Overhead Asset Failure (DOVHD).

  b. Net O&M Costs, calculated as the difference in O&M Cost Savings and New O&M Costs between the proposed Project and the No-Build Baseline.[6]
- **CBR Year Zero**, defined as the year a Project becomes "Used and Useful," which serves as the reference year for discounting both Total Mitigation Benefit and Capital Costs.
- **Interruption Cost Estimate (ICE)[7] Calculator Granularity**, the level of granularity (Customer Class separated by High Fire-Threat District (HFTD) and Non-HFTD regions) that large electrical corporations must use to disaggregate the monetized value of electric reliability.

---

[1] The *SB 884 Project List Data Requirements Guidelines* were published on July 24, 2025, and are available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/documents/sb-884-project-list-data-requirements-guidelines.pdf.

[2] Calculated as "O&M Cost Savings" – "New O&M Costs."

[3] Net Salvage value means the salvage value of an electrical infrastructure related asset that has been retired less the cost of removal of that asset.

[4] *Energy Safety Guidelines* at Appendix A, A-3.

[5] *Energy Safety Guidelines* at Appendix A, A-4.

[6] No-Build Baseline represents a well-defined baseline scenario or what happens if no Project or RRU is implemented. The Build Baseline is used to compare the relative costs and benefits of various design or implementation alternatives. For example, The No-Build Baseline might be an overhead line that is not hardened, while the Build Baseline might be a proposed undergrounding mitigation. This concept is particularly useful when assessing incremental benefits and costs between competing build options, ensuring that decisions are grounded in a consistent and traceable analytical framework. No-Build Baseline corresponds to the "Baseline", as defined in the *Energy Safety Guidelines* at A-1.

[7] https://icecalculator.com/, see also D.22-12-027 OP 2b.

- **Backcasting**, a method for recalculating CBRs and unit costs using updated Risk Reporting Unit (RRU) structures and risk model inputs to establish a bridge between prior inputs and new inputs to ensure an "apples-to-apples" comparison.
- **CBR Percentage Difference**, quantifies the percentage difference between the original forecasted CBR as reported in the Phase 2 Application (or the backcasted CBR of the original forecast, recalculated using revised inputs and current RRU structures) and the CBR reported in subsequent six-month progress reports.

Notes on Terminology:

- "Risk" in this document corresponds to "Overall Utility Risk" (unless otherwise noted) as defined in the *10-Year Electrical Undergrounding Plan Guidelines* (*Energy Safety Guidelines*) published by Office of Energy Infrastructure Safety (Energy Safety) on February 20, 2025.[8]
- The terms "RRU" and "Project" are used in this document to refer to the units on which the CBR is calculated[9]

1. Introduction to CBR Calculation

The CBR is a fundamental metric for evaluating the cost-efficiency of undergrounding Projects and alternative mitigations proposed under SB 884. It measures the trade-off between the anticipated benefits of Wildfire Ignition and Outage Program Risk Reduction and the associated implementation Costs of mitigation efforts. In addition to assessing individual Projects, the CBR enables a fair and consistent comparison between undergrounding and other Wildfire mitigation strategies, supporting informed decision-making across a range of options. This document outlines the primary components necessary for calculating the CBR, including CBR Year Zero, ICE calculator granularity, Risk Reduction, and Capital Costs.

These guidelines: offer general direction and establish a consistent framework for CBR calculations; are not intended to address every technical detail or potential analytical scenarios; and, complements and are intended for use in tandem with the *SB 884 Project List Data Requirements Guidelines* that define the structure, format, and terminology for SB 884 data submissions by providing the methodology for calculating the CBR and its key components. While these documents aim to provide guidance for consistent and repeatable CBR calculations, SPD Staff anticipate that updates will be made over time as data collection improves and additional requirements emerge. The Commission authorized SPD to make future updates and changes to the *SB 884 Project List Data Requirements Guidelines* after hosting at least one technical working group (TWG) meeting about said updates and changes without the need for a Commission Decision or Staff Resolution.[10]

---

[8] *Energy Safety Guidelines* at A-4.

[9] For definitions of RRU and Project, please see *SB 884 Project List Data Requirements Guidelines*, page 4 and *Energy Safety Guideline* A-5.

[10] SPD-37 at 37.

2. Key Components of the CBR Calculation

2.1 CBR Year Zero

CBR calculations shall use the year in which the Project is expected to become "Used and Useful" as the designated CBR Year Zero. CBR Year Zero is the reference year to which Capital Costs and Risk Reduction and Other Benefits of CBR calculations are discounted, ensuring that the CBR for any Project is calculated at a consistent point in time. CBR Year Zero is also the point that Risk Reduction and Other Benefits begin to be realized.

To calculate CBR, Capital Costs for a Project shall be discounted (i.e., inflated) to CBR Year Zero. By contrast, Risk Reduction and Other Benefits of the Project are assumed to begin accruing starting in CBR Year Zero of the project and shall be discounted back to CBR Year Zero. Figure 1 illustrates CBR Year Zero and discounting of Capital Costs and Risk Reduction. The black "X" represents CBR Year Zero. The orange bars indicate the years in which Project Costs are incurred (pre-CBR Year Zero), and the orange arrows represent how those Costs are discounted to the CBR Year Zero. The green bars show the years that Risk Reduction and Other Benefits are realized (post-CBR Year Zero), while the green arrows demonstrate how those benefits are discounted.

CBR Year Zero is Project or RRU specific, so the CBR Year Zero for one Project may differ from another. Though the CBR for each Project may be anchored to a different point in time, the numerator (Present Value of Risk Reduction) of the Project's CBR and the denominator (Present Value of Costs) of the Project's CBR are discounted to that same year, as noted above (CBR Year Zero of the Project). This ensures that, despite differing timelines for different Projects, the CBR remains a consistent and comparable metric across Projects. In general, this method enables fair comparison between Projects initiated or completed in different years, or Projects with varying asset lifespans.

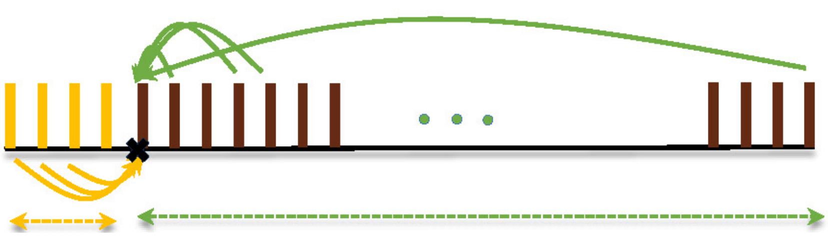

Figure 1: the timing of CBR Year Zero, incurred Project Costs, Risk Reduction, and Other Benefits

2.2 ICE Calculator 2.0 Granularity

Historically, large electrical corporations have applied a single value for dollars per customer-minute interrupted ($/CMI) to represent electric reliability valuation. However, this uniform approach fails to reflect the heterogeneous distribution of customers and risk across service areas. A single value overlooks important differences in how outages affect residential versus non-residential customers and does not account for higher-risk regions such as HFTD areas to which the SB 884 program is limited. Large electrical corporations shall adopt a disaggregated approach to better capture the varying impacts of Projects or RRU across different customer classes and geographic risk tiers. Increased granularity, through segmentation by customer class and geographic tier, not only improves the precision of CBR calculations, but also ensures a more accurate and equitable evaluation of Project value.

For SB 884 Applications, the large electrical corporations shall calculate and use ICE Calculator granularity at the level of Customer Class (i.e., Residential vs Non-Residential) separated by HFTD and Non-HFTD regions. Large electrical corporations shall use the corresponding $/CMI values for each Customer Class in the CBR calculation of an undergrounding Project and alternative mitigations to ensure consistent and representative valuation of electric reliability.

2.3 Risk Scaling

To ensure consistency and comparability with the *Energy Safety Guidelines*, large electrical corporations shall calculate and present the CBR and all related components of the risk using unscaled (i.e., risk-neutral) risk values in the CBR calculations.[11]

2.4 Total Mitigation Benefit

Risk Reduction

Risk Reduction refers to the nominal, monetized value of risk that is reduced by implementing the proposed mitigation. For CBR calculations, only two risk events may be included in the CBR's Risk Reduction component: Wildfire Ignition Risk; and, Outage Program Risk, where Outage Programs exclude maintenance outages and other outages not related to reducing wildfire.

Large electrical corporations shall clearly document the methodology used to calculate and combine Wildfire Ignition Risk Reduction and Outage Program Risk Reduction in the workpapers required for CBR calculations.[12] This includes, but is not limited to, detailing whether these risks are mutually exclusive or explaining how any potential overlap is addressed to avoid double-counting.

Other Benefits (Net O&M Costs)

Large electrical corporations may include Net O&M Costs as part of the Total Mitigation Benefit in the CBR's numerator, where Net O&M Costs is defined as:

$$\text{Net O\&M Costs} = \text{O\&M Cost Savings} - \text{New O\&M Costs} \qquad (\text{Eq. } 1)$$

Where "O&M Cost Savings" are the difference between the O&M costs of the No-Build Baseline and the Build Baseline, and "New O&M Costs" represent the O&M costs that are unique to the Build Baseline. This approach[13] allows the large electrical corporation to account for other contributing benefits of the Project or RRU beyond Risk Reduction, such as avoided or reduced maintenance needs relative to the status quo or No-Build Baseline while ensuring that the O&M costs relative to the Build Baseline are excluded as a

[11] *Energy Safety Guidelines* at 31.

[12] *CPUC Guidelines* at 7.

[13] See generally Department of Transportation, *Benefit Cost Analysis Guidelines for Discretionary Grant Programs*, published in May 2025, https://www.transportation.gov/sites/dot.gov/files/2025-05/Benefit%20Cost%20Analysis%20Guidance%202025%20Update%20II%20%28Final%29.pdf.

benefit. The guidelines here clarify that such Other Benefits may only be accounted for in the numerator of a CBR calculation.

The CBR calculation shall be based only on the incremental difference between the proposed Project or alternative mitigation and the No-Build Baseline, both in terms of benefits and net costs (Net O&M Costs). This comparative framework will assist in preventing double-counting and ensure analytical consistency. Net O&M Costs should be calculated for both the No-Build Baseline and the Build Baseline, while the difference between them may then be factored into the CBR of the Project as Other Benefits.

Present Value of Risk Reduction and Other Benefits

Total Mitigation Benefit represents the Present Value of the Risk Reduction over the Project's lifespan - and potentially the Present Value of Net O&M Costs compared to No-Build Baseline. If the Risk Reduction in year "t" is "RR_t," then the discounted Risk Reduction in CBR Year Zero is calculated as:

$$RR_u = RR_t \times \frac{1}{(1+r)^{t-u}} \quad (Eq.\ 2)$$

Where "t" is greater and equal to CBR Year Zero, "u" is CBR Year Zero, and "r" is the discount rate (e.g., WACC[14]) used to discount future Risk Reduction to the CBR Year Zero of the Project. The Present Value of Net O&M Costs can be calculated similarly.

To calculate the Total Mitigation Benefit, accrued annually over the life of the asset, the Present Value of Risk Reduction and potentially Net O&M Costs shall be added:

$$Total\ Mitigation\ Benefit = \sum_{t=u}^{n=Asset\ life} \frac{RR_t}{(1+r)^{t-u}} + Present\ Value\ of\ Net\ O\&M\ Costs \quad (Eq.\ 3)$$

Where RR_t is the Risk Reduction in year "t," "t" is a year in which Risk Reduction occurs starting from the CBR Year Zero of the Project, "u," "r" is the discount rate, "n" is the final year of the asset's useful life, "u" is the CBR Year Zero.

Total Mitigation Benefit is used in CBR calculations as the numerator.

Constraints

Included Risks

For the purposes of CBR calculations, only Wildfire Ignition Risk and Outage Program Risk may be included in the Risk Reduction component as defined in the *Energy Safety Guidelines.*[15] These two risk types may be combined in the CBR calculation only if the large electrical corporation can demonstrate mutual exclusivity or if any potential overlap is explicitly identified and appropriately addressed to avoid double-counting.

Net Operations and Maintenance may be included in the Project CBR's Total Mitigation Benefit.

---

[14] Weighted average cost of capital.

[15] *Energy Safety Guidelines* at A-4.

Excluded Risks

Other enterprise risk categories, such as Public Contact with Intact Energized Electrical Equipment or Distribution Overhead Asset Failure, shall not be included in the CBR calculation.

2.5 Capital Costs

When incorporating Project costs for a Project that will be built over several years, it is important to account for the time value of money. While Capital Costs refer to the summation of total nominal Capital Costs of Projects for the years the Project is being built, Present Value of Capital Costs is the summation of all discounted Capital Costs for each year to the CBR Year Zero. Present Value of Capital Costs is used in CBR calculation as the denominator.

If the nominal Capital Costs for a Project incurred in year "*t*," is $Cost_t$ and "*u*" is the Project's CBR Year Zero, then:

$$Cost_u = Cost_t . (1 + d)^{u-t} \quad \textit{(Eq. 4)}$$

Where $Cost_u$ is the Capital Costs for the Project in year t, discounted to the CBR Year Zero of the Project, "*d*," is the discount rate, "*u*" is the CBR Year Zero, and "*t*," is the year the cost incurred.

Present Value of all the Capital Costs for the Project can be calculated as:

$$PVCOST = \sum_{t=t0}^{u} Cost_t . (1 + d)^{u-t} \quad \textit{(Eq. 5)}$$

Where $Cost_t$ represents the Capital Costs in year "*t*" (the year the costs were incurred,) "*d*" is the discount rate, "*u*" is the CBR Year Zero, and t_0 is the year Project costs begin accruing.

The Present Value of Capital Costs incurred in year "*t*" can be discounted to the year Project costs begin accruing at "t_0" using the following equation:

$$Cost_t = Cost_{t_0} . (1 + i\,nf)^{t-t_0} \quad \textit{(Eq. 6)}$$

Where "*inf*" is the inflation rate.

In a WACC Discount Rate scenario[16]both the numerator (i.e., Total Mitigation Benefits) and the denominator (i.e., Capital Costs) of the CBR are discounted using the same discount rate. Specifically, the discount rates "*d*" and "*r*" used in Eq. 3 (for the numerator) and Eq. 5 (for the denominator) are equal. In contrast, under the Hybrid scenario different rates are applied, as discussed in the *SB 884 Project List Data Requirements Guidelines*[17]

---

[16] Phase 3 of Risk-Based Decision-Making Framework (RDF) (D.24-05-064) at 102-103.

[17] *SB 884 Project List Data Requirements Guidelines*, Table 1 (page 18), and Table 5 (page 28)

Constraints

Included Costs

For the purposes of CBR calculations, large electrical corporations may only include Capital Costs in the denominator of a CBR calculation. Capital Costs are capital expenditures (Labor, Materials, Permits, and Others), attributable to the implementation of an SB 884 undergrounding and its alternative mitigations Projects, as outlined in the *SB 884 Project List Data Requirements Guidelines*.

Excluded Costs

Net O&M Costs (e.g., Cost Savings and added Costs) and Net Salvage values shall not be incorporated into the Capital Costs and Present Value of Capital Costs used in CBR calculations.

3. Backcast

Backcasting uses updated inputs (e.g., new RRUs, new risk models, and changes to the specific portion of the circuit segment selected for mitigation) to recalculate CBRs, pre-mitigated risk, post-mitigated risk or other data points submitted in Phase 2 Applications. The goal of a Backcast is to establish a bridge between prior inputs and new inputs to ensure an "apples-to-apples" comparison. With the adoption of the *Energy Safety Guidelines*, Energy Safety introduced the concept of the "Subproject."[18] As Projects are being further scoped, the *Energy Safety Guidelines* allow the large electrical corporation to establish Subprojects by dividing Projects into one or more units for operational reasons or to reflect that a portion of a circuit segment will be treated with a wildfire mitigation other than undergrounding.[19] These types of changes can occur after the Commission's Phase 2 Decision is adopted. Thus, the need to incorporate the concept of backcasting is essential to enable consistent comparison of a forecasted versus realized Project with full transparency and consistency. This comparison is particularly important when a large electrical corporation elects to use the Subproject Designation to provide an ability to track changes in Project structure occur over time, such as the transition from Project-level to RRU-level (or Subproject-level) tracking.

Large electrical corporations that elect to use the Subproject Designation to define RRUs after the Phase 2 Application must rely on Backcasting to enable consistent evaluation across reporting periods. Specifically, if an OEIS_Project_ID field value does not have a corresponding value in the RRU_ID field at the time of the Phase 2 Application submission, then the large electrical corporation must later backcast and report CBR-relevant metrics found in the *SB 884 Project List Data Requirements Guidelines,* including the following fields:

- Backcasted_Total_Mitigation_Benefit,
- Backcasted_Present_Value_Costs, and
- Backcasted_Cost_Benefit_Ratio

These fields may be left blank at the time of Phase 2 Application filing and completed later in subsequent six-month progress reports once the RRU structure is finalized.

---

[18] Energy Safety defines Subproject as "a delimited portion of work on a Confirmed Project." *Energy Safety Guidelines* at A-6.

[19] *Energy Safety Guidelines* at 14.

4. Calculation Methodology

4.1 CBR Calculation

The CBR is calculated using the CBR Year Zero of the Project as the reference point. It is defined as the ratio of the Present Value of Risk Reduction and Other Benefits to the Present Value of Capital Costs, with all values discounted to CBR Year Zero to ensure temporal consistency.

$$CBR = \frac{Present\ Value\ of\ Risk\ Reduction\ and\ Other\ Benefits}{Present\ Value\ of\ Capital\ Costs} \quad (Eq.\ 7)$$

4.2 CBR Percentage Difference

CBR Percentage Difference refers to the percentage difference between the originally forecasted CBR as reported in the Phase 2 Application (or the backcasted CBR of the original forecast, recalculated using revised inputs and current RRU structures) and the CBR reported in subsequent six-month progress reports. This percentage difference is particularly important for assessing the cost efficiency of Projects or RRUs during implementation, as more information becomes available over time.

CBR_Percentage_Difference is calculated according to the following two scenarios:

a) Assuming the Subproject designation is used by the large electrical corporation and Subproject data was not available in the Phase 2 Application:

(Eq. 8)

$$CBR\_Percentage\_differnce = \frac{Backcasted\_Cost\_Benefit\_Ratio\ - Updated\ Cost\_Benefit\_Ratio\ in\ progress\ report}{Backcasted\_Cost\_Benefit\_Ratio}$$

b) Assuming the large electrical corporation elects not to use the Subproject designation or the detailed Subproject data is available in the Phase 2 Application:

(Eq. 9)

$$CBR\_Percentage\_difference = \frac{Cost\_Benefit\_Ratio\ in\ Phase\ 2\ - Updated\ Cost\_Benefit\_Ratio\ in\ progress\ report}{Cost\_Benefit\_Ratio\ in\ Phase\ 2\ Application}$$

4.3 Unit Cost Percentage Difference

The Unit Cost Percentage Difference refers to the percentage difference between forecasted Unit Costs submitted in the Phase 2 Application and updated Unit Costs in the subsequent progress reports. The Unit Cost of a Project or RRU serves as a valuable metric for assessing costs of the project or the RRU and is calculated as such:

(Eq. 10)

$$\text{Unit\_Cost\_Percentage\_Difference} = \frac{\text{Forecasted Unit Cost in Phase 2 Application} - \text{Updated Unit Cost in progress report}}{\text{Forecasted Unit Cost in Phase 2 Application}}$$

“Unit Costs” refers to the field labeled as “Average_Unit_Cost_per_Mile” field in the *SB 884 Project List Data Requirements Guidelines*, Table 1.

5. Conclusion

This appendix is intended to guide large electrical corporations in calculating CBRs consistently across SB-884 applications. It reflects input from the Technical Working Group and aligns with CPUC and *Energy Safety Guidelines* to ensure transparent and effective risk management.

6. Glossary

Table 1: Glossary of Terms Used in Cost-Benefit Ratio Calculation Guildelines

Term	*Definition*
u	The CBR Year Zero of a Project or when the Project is "Used and Useful".
RR_t	Annual Risk Reduction in year "*t*," where "*t*" is equal or greater than CBR Year Zero "*u*."
RR_u	Present Value of Risk Reduction in CBR Year Zero of the Project. It might include Ignition_Risk_Mitigation_Benefit and Outage_Program_Risk_Mitigation_Benefit.
r	The discount rate (e.g., WACC) used to discount future Risk Reduction to CBR Year Zero.
n	Asset life, i.e., the total number of years benefits are expected to accrue.
t_0	The base year when cost accumulation begins.
$Cost_t$	Capital Costs incurred in year "*t*."
$Cost_u$	The Capital Cost in year "*t*," discounted to CBR Year Zero "*u*"
No-Build Baseline	Represents a well-defined baseline scenario or the outcome if no Project or RRU is implemented.
Build Baseline	Build Baseline is used to compare the relative costs and benefits of various design or implementation alternatives. For example, The No-Build Baseline might be an overhead line that is not hardened, while the Build Baseline might be a proposed undergrounding mitigation.
Salvage value	Net Salvage value means the salvage value of an electrical infrastructure related asset that has been retired less the cost of removal of that asset.

Table 2: Glossary of Equations Used in Cost-Benefi Ratio Calculation Guildeline

Equation Number	*Description*
(Eq. 1)	Net O&M Costs
(Eq. 2)	Present Value of Risk Reduction in CBR Year Zero of the Project
(Eq. 3)	Total Mitigation Benefit
(Eq. 4)	Discounted Capital Costs to CBR Year Zero for a Project
(Eq. 5)	Present value of all Capital Costs for a Project, discounted to the CBR Year Zero.
(Eq. 6)	The Present Value of Capital Costs discounted to the year the Project costs begin accruing
(Eq. 7)	Cost-Benefit Ratio
(Eq. 8)	CBR Percentage Difference assuming the large electrical corporation elects to use the Subproject, and Subproject data was not available in the Phase 2 Application
(Eq. 9)	CBR Percentage Difference assuming the large electrical corporation elects not to use the Subproject designation or the detailed Subproject data is available in the Phase 2 Application
(Eq. 10)	Unit Cost Percentage Difference

Appendix 2: SB 884 Project List Data Requirements Guidelines*

* The *SB 884 Project List Data Requirements Guidelines* were published by Safety Policy Division on July 24, 2025. Additional information, including the data template that large electrical corporations must use to file its Application and six-month progress reports can be found here: https://www.cpuc.ca.gov/about-cpuc/divisions/safety-policy-division/risk-assessment-and-safety-analytics/electric-undergrounding-sb-884. The *SB 884 Project List Data Requirements Guidelines* presented here supersede Appendix 1 of Resolution SPD-15.

California Public
Utilities Commission

SB 884 Project List Data Requirements Guidelines

SAFETY POLICY DIVISION

July 24, 2025

Table of Contents

Background and Purpose:

Pursuant to Senate Bill (SB) 884 (McGuire; Stats. 2022, Ch. 819), the California Public Utilities Commission's (CPUC or Commission) data requirements for a large electrical corporation's Electrical Undergrounding Plan (EUP) intended to mitigate wildfire risk in the High Fire Threat District (HFTD), will be complex and require coordination with the Office of Energy Infrastructure Safety's (Energy Safety) Guidelines and data templates. Attached to Resolution SPD-15,[1] the Commission issued the *SB 884 Project List Data Requirements-Preliminary* to begin the discussion on how a utility should submit tabular and geospatial data in support of a Phase 2 Application related to its EUP.[2] Ordering Paragraph 3 of SPD-15 stated that:

> Following Energy Safety's publication of its SB 884 Guidelines, SPD is authorized to convene a Technical Working Group (TWG) to review and align the preliminary CPUC SB 884 Project List Data Requirements and Geographic Information System (GIS) data requirements with Energy Safety Guidelines, adding any data elements necessary for Commission conditional approval purposes.

Additionally, Ordering Paragraph 4 of SPD-15 stated that:

> SPD is authorized to develop and issue the SB 884 Project List Data Template within 30 days of the final TWG meeting.

As discussed below, the final TWG meeting was held on June 24, 2025. Thus, by issuing the *SB 884 Project List Data Requirements Guidelines* (henceforth referred to as the *CPUC SB 884 Data Guidelines*) to the SB 884 Notification List on July 24, 2025, SPD has completed the requirements of Ordering Paragraph 4 in SPD-15.

On February 20, 2025, Energy Safety published Guidelines that a large electrical corporation must follow to submit an EUP to that agency.[3] Energy Safety's Guidelines include extensive discussion of data requirements that require the Commission to review and determine the best way to align its own data requirements for a large electrical corporation's Phase 2 Application for the EUP. Following the TWGs discussed below, the *CPUC SB 884 Data Guidelines* represents an alignment between the data needs of the Commission to evaluate conditional approval of costs and the requirements found in the Energy Safety Guidelines as was required by Ordering Paragraph 3 in SPD-15.

On January 30, 2025, Safety Policy Division (SPD) presented a Risk Assessment and Mitigation Phase (RAMP) data template Guidelines and data template as part of a TWG in Phase 4 of the Risk-Based Decision-Making Framework (RDF) Proceeding (R.20-07-013).[4] On February 11, 2025, an Administrative

---

[1] Resolution SPD-15 is available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/documents/final-resolution-spd15-adopting-the-commissions-guidelines-for-the-senate-bill-sb-884-program.pdf.

[2] SPD-15, Attachment 1, Appendix 1 at 15-18.

[3] Office of Energy Infrastructure Safety, 10-Year Electrical Undergrounding Plan Guidelines, February 20, 2025, https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=58006&shareable=true.

[4] The RAMP is a process a utility complies with before initiating a GRC that requires energy-utility safety-risk threat assessments along with associated proposed mitigation plans and estimated costs and spending requests. The RDF proceeding examines how

Law Judge Ruling filed SPD's RAMP data template Guidelines and data template to the RDF Proceeding[5] SPD recognizes that it will be crucial that a data template for a Phase 2 Application also align with the data template needed in a RAMP and General Rate Case (GRC) Application. The structure of the *CPUC SB 884 Data Guidelines* is influenced by the discussion of Staff's data template Guidelines presented in the RDF Proceeding.

Commission Staff issued a "Staff Report on SB-884 Projects List Data Requirements Guideline" (or Staff Report) on May 20, 2025, which included a set of "Technical Working Group Questions". Commission Staff then hosted a series of three TWG meetings in June 2025. During the SPD TWG meeting #1, held on June 3, 2025, SPD Staff presented the Staff Report and addressed questions from stakeholders regarding potential updates to the SB 884 Project List Data Requirements. In a May 15, 2025, e-mail to the SB 884 Notification List, SPD offered the opportunity for any stakeholder to present their feedback and recommendations on the Staff Report. No stakeholders accepted this opportunity. However, Staff did receive a list of questions from Pacific Gas and Electric Company (PG&E), which it requested to be discussed during the SPD TWG meeting #2 on June 10, 2025. Additionally, the SPD TWG meeting #3 on June 24, 2025, included presentations from Lawerence Berkeley National Labs and PG&E on the Interruption Cost Estimate Calculator (ICE 2.0). Stakeholders held additional discussion related to the way ICE 2.0 was addressed within the Staff Report. Finally, Staff accepted stakeholder responses to the "Technical Working Group Questions" on June 24, 2025. The input received from stakeholders, along with the adoption of the Energy Safety Guidelines, informs the *CPUC SB 884 Data Guidelines* presented in this document.

The purpose of the *CPUC SB 884 Data Guidelines* is to provide clarity on the field name, field description, and field value constraints in the SB 884 Project List Data Template. Additionally, the *CPUC SB 884 Data Guidelines* is a revision of *SB 884 Project List Data Requirements-Preliminary* that was attached to SPD-15.

For each project included in the Plan and Application, the large electrical corporation shall provide, at a minimum, all data listed in the *CPUC SB 884 Data Guidelines* in tabular format. This information shall be provided as both a Microsoft Excel file and a searchable pdf file to supplement the Application. The large electrical corporation shall provide the latest version of the data required by the *CPUC SB 884 Data Guidelines* at the time of its Application submission. Additionally, at a minimum, the six-month progress reports filed by a large electrical corporation shall include an update of the data required in the *CPUC SB 884 Data Guidelines.*[6] The data values provided in each update of the data required in the *CPUC SB 884 Data Guidelines* should correspond to the date listed in each of the Reporting_Date fields found at the end of Tables 1-6.

---

to calculate risk mitigation levels for various safety measures in order to ensure utilities focus on the most cost-efficient risk reduction strategies in their safety work, including wildfire-related safety.

[5] Administrative Law Judge's Ruling Entering Phase 4 Technical Working Group Materials and Related Staff Proposal into the Record and Setting Comment Schedule, February 11, 2025, https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=556602565.

[6] Energy Safety Guidelines at 25-26.

Note on Terminology:

1. The term "Risk" in this document corresponds to "Overall Utility Risk" (unless otherwise noted) as defined in the Energy Safety Guidelines.[7]

[7] The 10-Year Electrical Undergrounding Plan Guidelines published by Office of Energy Infrastructure Safety on February 20, 2025, page A-4.

Template and Tables Structure

Table 1: Data Set

This table collects the key elements and characteristics of a Risk Reporting Unit (RRU), including unique identifiers, mitigation plans, and associated risks.[8] Table 1 defines how risk-related data elements are structured and categorized for consistent reporting across various progress reports and geographic locations.

As stated in the introduction, it is necessary to align the SB 884 Project List Data Template with the RAMP Data Template discussed in the RDF Proceeding.[9] Here we present a definition of asset, RRU, and system to clarify that these concepts must be shared across RAMP and SB-884 Applications.

- Asset: A retirement unit as defined by Federal Energy Regulatory Commission (FERC) Uniform System of Accounts (USOA) that exhibits risk.[10]
- Risk Reporting Unit (RRU): A CPUC jurisdictional effort within Electric Operations or Gas Operations that simultaneously removes or mitigates the risk associated with a group of contiguous assets or systems that exhibit high levels of risk. The RRU must include common elements that must include, but are not limited to Consequence Attributes, Risk level, line-item costs, benefit-cost ratios (CBRs), work units and time. The RRU can be aggregated along several dimensions based on unique identifiers that include, but are not limited to, hierarchy,[11] scenario,[12] version,[13] risk event, tranche, and mitigation type.
- System: A regularly interacting or interdependent group of items forming a unified whole that exhibits risk and cannot be classified as a retirement unit.

Unless otherwise specified, such as certain fields in Table 4, all data requirements related to assets, RRUs, and systems apply to but are not limited to, primary, secondary and service lines.

Additionally, to conform with the requirements of the CPUC's SB 884 Guidelines found in SPD-15 or any successor Commission order or decision, the RRU must be:

1. Traceable through all stages of a lifecycle, including but not limited to the project's scoping, designing, permitting, construction/implementation, post-construction, retirement/decommissioning.
2. Auditable in terms of timing, location, work units, costs, and Risk Reduction.
3. Forecastable to at least the 10th year of the EUP.

[8] For more information on the RRU, see R.20-07-013, Phase 4 Workshop 1, SPD Staff Proposal on Definition of Scoped Work and the Risk Reporting Unit, November 8, 2024.

[9] Any updates in the RDF Proceeding may result in an update in the SB-884 Data Template Guidelines.

[10] For the FERC USOA, see 18 CFR Part 101 https://www.ecfr.gov/current/title-18/chapter-I/subchapter-C/part-101

[11] Hierarchy refers to a utility's organizational hierarchy, such as an Electric Distribution Division or a Gas Distribution Division. as well as other ways of categorizing high risk assets and systems (i.e. HFTDs, circuits, regions, etc.).

[12] Scenario refers to forecasts, results, and projections.

[13] Version refers to a risk model version.

4. Able to aggregate up to the EUP.[14]

Utilities shall use these definitions and requirements to present RRU level data in their EUP. The level of granularity required is discussed below.

Tables 1 through 4 are anchored around the RRU_ID field, which references uniquely identifiable RRUs with unique identification numbers (i.e., IDs). A utility's RRU_ID naming schema must be simple and transparently understandable. A utility's RRU_ID naming schema must include the GRC Activity Code of the Undergrounding Project, which must also be listed in Table 1. A utility's RRU_ID naming schema must not result in the reuse of an RRU_ID.

Table 1 shall be submitted with the Phase 2 Application and all subsequent progress reports. In cases where RRU_IDs have not yet been created for certain projects, for the reasons outlined below, the table must be submitted using the corresponding OEIS_Project_ID.[15] Once more detailed and updated information becomes available, reporting in six-month progress reports shall transition to the RRU_IDs. The utility must continue reporting OEIS_Project_IDs to enable traceability and continuity across reports.

The fields OEIS_Project_ID and OEIS_Subproject_ID directly align to the Energy Safety Guidelines and enable coordination with the data templates submitted with the EUP to Energy Safety.[16] All requirements found in the Energy Safety Guidelines for OEIS_Project_ID and OEIS_Subproject_ID also apply to this data template.

If the utility submits a Phase 2 Application that does not use Subprojects, then the Commission requires that the granularity of the RRU be identical to that of the Project as defined in the Energy Safety Guidelines (see Figure 1). If the utility submits a Phase 2 Application that uses Subprojects the Commission requires that the granularity of the RRU be identical to that of the Subproject once detailed Subproject data is available, which means that each RRU_ID can only be tied to a single OEIS_Subproject_ID (Figure 2). Once an RRU_ID is created for a Subproject, all data must be reported using the unique RRU_IDs, OEIS_Project_IDs and OEIS_Subproject_IDs.

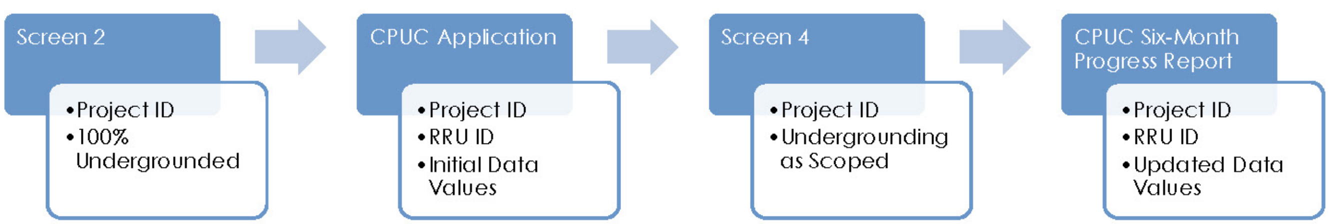

Figure 1: Process for creating an RRU_ID and Data Submissions for Phase 2 Application without Subprojects

[14] These three requirements have been adapted from the Staff Scoped Work Proposal to conform to the requirements of the SB-884 program.

[15] OEIS_Project_ID corresponds to project_ID, as defined in the 10-Year Electrical Undergrounding Plan Guidelines published by Office of Energy Infrastructure Safety on February 20, 2025 (at C-24).

[16] OEIS_Subproject_ID corresponds to subproject_ID, as defined in the 10-Year Electrical Undergrounding Plan Guidelines published by Office of Energy Infrastructure Safety on February 20, 2025 (at C-36).

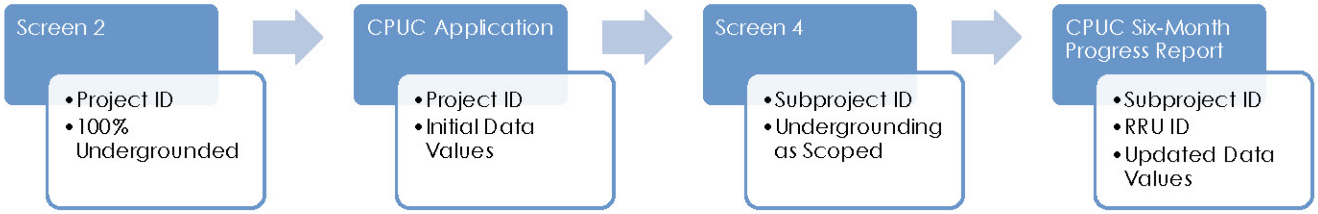

Figure 2: Process for creating an RRU_ID and Data Submissions for Phase 2 Application with Subprojects

If the utility elects to use Subprojects in its Phase 2 Application, then when the utility submits its Phase 2 Application to the Commission, it is possible that detailed Subproject level forecasts may not be available. In the case where the utility submits a Phase 2 Application that uses Subprojects and the Subproject level forecasts are not available, for the initial dataset submitted with the utility's Phase 2 Application, the utility may present forecasts at the Project Level, which should correspond with the Screen 2 data presented by the utility in Table C.11 of the Energy Safety Guidelines.[17] The forecasts presented at the Project Level in the initial dataset submitted with the Application will correspond to the "100% Undergrounded" concept defined in the Energy Safety Guidelines.[18] The RRU_ID field may be left blank at this point. Once detailed Subproject data is available, an RRU_ID must be created for each Subproject, and all data must be reported using the unique RRU_IDs, OEIS_Project_IDs and OEIS_Subproject_IDs.

When the utility submits its Phase 2 Application or six-month progress reports to the Commission, it is required that for any Project (i.e., OEIS_Project_ID) that passes Screen 4 of the Energy Safety Guidelines, the utility shall provide data values in the Commission's data template that should correspond with the Screen 4 data presented by the utility in Table C.13 of the Energy Safety Guidelines.[19] If the utility submits a Phase 2 Application that uses Subprojects, then the detailed RRU level data values submitted to the Commission should correspond with the Subproject data presented by the utility in Table C.14 of the Energy Safety Guidelines.[20]

If the Project has passed Screen 4 of the Energy Safety Guidelines, then the information presented at the Project or Subproject Level in the dataset submitted with either the Phase 2 Application or the six-month progress reports will correspond to the "Undergrounding as Scoped" concept defined in the Energy Safety Guidelines.[21]

For utilities that submit Projects in their Phase 2 Application and do not plan to break them into Subprojects later, the utility may continue reporting data at the Project level throughout both the Phase 2 Application and subsequent six-month progress reports. In these cases, the utility must still align its data with the appropriate Energy Safety Guidelines tables initially using Table C.11 for Screen 2 forecasts and then updating with Table C.13 data for Projects that pass Screen 4. RRU_IDs shall be created for the

---

[17] Office of Energy Infrastructure Safety, 10-year Electrical Undergrounding Plan Guidelines, February 20, 2025, at C-25 – C-26.

[18] Office of Energy Infrastructure Safety, 10-year Electrical Undergrounding Plan Guidelines, February 20, 2025, at 44.

[19] Office of Energy Infrastructure Safety, 10-year Electrical Undergrounding Plan Guidelines, February 20, 2025, at C-30 – C-32.

[20] Office of Energy Infrastructure Safety, 10-year Electrical Undergrounding Plan Guidelines, February 20, 2025, at C-33 – C-35.

[21] Office of Energy Infrastructure Safety, 10-year Electrical Undergrounding Plan Guidelines, February 20, 2025, at 44.

Project, and all reporting remains at the Project level. All data must be reported using the unique RRU_ID and OEIS_Project_IDs from the Phase 2 Application. (Figure 2)

Table 1 also collects Backcasted_Cost_Benefit_Ratio, Backcasted_Total_Mitigation_Benefit and Backcasted_Present_Value_Costs. In order to align with the concept of a Backcast as discussed in the RDF Proceeding, the following definition applies:

- Backcast: use updated inputs (e.g., new RRUs, new risk models) to recalculate Cost-Benefit Ratios, pre-mitigated risk, post-mitigated risk or other data elements. The goal of a Backcast is to establish a bridge between prior inputs and new inputs, to ensure an "apples-to-apples" comparison.

When a utility elects to use the Subproject designation, the concept of a Backcast is essential in the SB-884 context to enable a consistent comparison between the forecasted RRU values reported in the progress reports and the backcasted RRU values that would have been calculated, had the RRU structure been applied in the Phase 2 Application using the data submitted at that time. For a utility that elects to use the Subproject designation the Backcasted_Total_Mitigation_Benefit, Backcasted_Present_Value_Costs and Backcasted_Cost_Benefit_Ratio fields may be left blank in the Phase 2 Application for OEIS_Project_IDs that have yet to establish an RRU_ID. For a utility that elects to align an RRU_ID with the OEIS_Project_ID (i.e. does not use the Subproject designation) there is no need to complete the Backcasted_Total_Mitigation_Benefit Backcasted_Present_Value_Costs, and Backcasted_Cost_Benefit_Ratio fields.

Table 1 also collects Unit_Cost_Percentage_Difference, calculated as:

$$\text{Unit\_Cost\_Percentage\_Difference} = \frac{\text{Forecasted Unit Cost in Phase 2 Application} - \text{Updated Unit Cost in progress report}}{\text{Initial Forecasted Unit Cost in Phase 2 Application}}$$

Where "Unit Costs" refers to the Average_Unit_Cost_per_Mile in Table 1

and also

CBR_Percentage_Difference calculated according to the following two scenarios:

a- Assuming the large electric corporation elects to use the Subproject designation and detailed Subproject data is not available, then this is calculated as the percentage difference between the Backcasted_Cost_Benefit_Ratio and updated Cost_Benefit_Ratio in the subsequent progress reports

$$\text{CBR\_Percentage\_Difference} = \frac{\text{Backcasted\_Cost\_Benefit\_Ratio} - \text{Updated Cost\_Benefit\_Ratio in the progress report}}{\text{Backcasted\_Cost\_Benefit\_Ratio}}$$

b- Assuming the large electric corporation elects not to use the Subproject designation or the detailed Subproject data is available in the Phase 2 Application, this is calculated as the percentage difference forecasted Cost_Benefit_Ratio submitted in the Phase 2 Application and the updated Cost_Benefit_Ratio presented in the subsequent progress reports

$$\text{CBR\_Percentage\_Difference} = \frac{\text{Cost\_Benefit\_Ratio in Phase 2 Application} - \text{Updated Cost\_Benefit\_Ratio in the progress report}}{\text{Cost\_Benefit\_Ratio in Phase 2 Application}}$$

These two fields provide insight into the extent to which the CBR and Unit Cost have deviated from their original forecasted values, allowing for a clearer assessment of project performance and cost-effectiveness over time.

In Table 1, for each RRU (or project)[22] there will be one row for the utility's Undergrounding mitigation and one separate row for each alternative.[23]

All the Post-Mitigation fields must be completed by the utility using Screen 2 data or more updated data if available in the utility's Phase 2 Application. If the utility has data for scoped projects that have passed Screen 3 at the time of submitting its Phase 2 Application, then it must use that data. These fields will be updated by the utility in six-month progress reports as Screen 3 data becomes available.

For each RRU (or project), there should be one row representing the utility's undergrounding mitigation and one row for each alternative mitigation. Since each of these mitigation programs must be evaluated using three separate discount rates scenarios, this results in a total of nine rows per RRU (or project).

Table 2: Capital Cost Breakdown

This table breaks down the Capital Costs associated with mitigation efforts, including labor, materials, and permits, for projects under the Risk Reporting Unit. It provides detailed cost allocation to track expenditure efficiently. Data may be submitted at the project level in the Phase 2 Application and at RRU level when RRUs are created as described above.

Table 3: Risk Model Change Tracker

This table tracks changes and updates to the risk modeling and how that affects the risk associated with the assets and systems mitigated by the RRUs. Changes that include New Data Inputs to the Risk Model can include, but are not limited to, the addition of climate change variables or wildfire suppression related information. This allows us to compare current and previous risk models, risk scores and Costs across each of the six-month progress reports. It ensures transparency and accountability in how risks related to the electric grid are managed and reported.

Utilities regularly update their risk models. At times, the outputs (calculated risks) of new risk model versions might be substantially different from the previous version(s). In some cases, utilities have changed the length and names of each circuit segment from one risk model to another. To address the lack of clarity of the impact caused by changing risk models between the six-month progress reports, SPD created a template (Table 3) to track changes in each RRU (or Project) and how those changes would impact the calculation of risk from one risk model to the next. Table 3 collects data regarding changes in calculated risk, length, and name of each RRU (or Project), which utilities plan to include in its undergrounding projects. This enables analysis and comparison of data created across different risk models and supports comparison of such data across the six-month progress reports and even maybe among various proceedings where such data may be presented. Data

[22] Data may be submitted at the project level in the initial Application and at RRU level in subsequent progress reports when RRUs are created as described at page 4-5. This requirement follows for any other location in these Guidelines that state "RRU (or Project)".

[23] Please see the Proposed and Alternative Mitigations field described below and in the Excel data template attached to this Guideline.

may be submitted at the project level in the Phase 2 Application and at RRU level when RRUs are created as described above. This table complements some of the information presented in Table C.7 of the Energy Safety Expedited Undergrounding Plan Guidelines.[24]

Table 4: HFTD and Associated Asset

This table documents low-risk associated assets mitigated alongside primary electric grid infrastructure due to operational constraints or interconnected systems.[25] It includes associated Costs, miles, and Total Mitigation Benefit for comprehensive project management of risk on electric grid infrastructure.

Table 4 attempts to collect and clarify information regarding how the additional electric grid infrastructure associated assets can affect the Total Mitigation Benefit, Capital Costs, and CBR of the proposed RRU (or Project).-Data may be submitted at the project level in the Phase 2 Application and at RRU level when RRUs are created as described above

Table 5: Financial Inputs

This table provides financial parameters and metrics required to calculate and evaluate risk mitigations, including discount rates, the value of statistical life (VSL), and Present Value revenue requirements (PVRR). These inputs ensure that economic factors are systematically integrated into risk evaluations.

Table 6: Interruption Cost Estimate (ICE) Calculator Inputs

Since SB-884 requires undergrounding projects to be completed within the HFTD, the ICE Calculator inputs must be relevant only to the HFTD. The utility must also disaggregate their inputs according to HFTD and non-HFTD regions. This table provides inputs that can be integrated into the ICE Calculator 2.0 to estimate the cost per customer-minute interruption, by categorizing outages by time of day, season, and customer type. The ICE Calculator integrates key reliability metrics such as SAIDI and SAIFI to estimate the impact of service interruptions. This table requires the utility to calculate the Electric_Reliability_Valuation_Residential and Electric_Reliability_Valuation_Non_Residential fields as a $/CMI value which is further used to calculate the monetized value of electric reliability consequence within the HFTD.[26]

---

[24] Office of Energy Infrastructure Safety, 10-year Electrical Undergrounding Plan Guidelines, February 20, 2025, at C-12 – C-14.

[25] In Table 4, "low-risk" is defined as electric grid infrastructure assets whose risk level is below the "High-Risk Threshold" defined by Office of Energy Infrastructure Safety, 10-year Electrical Undergrounding Plan Guidelines, February 20, 2025, page 42.

[26] The calculation of Pre-mitigated and Post-mitigated Ignition and Outage Program Risk must include Pre-mitigated and Post-mitigated monetized values of electric reliability consequence, which must be calculated as a product of the $/CMI values from the Electric_Reliability_Valuation_Residential and Electric_Reliability_Valuation_Non_Residential fields in Table 6 and the following corresponding eight fields:

1. Ignition_Pre_Mitigated_Residential_Reliability_Consequences
2. Ignition_Pre_Mitigated_Non_Residential_Reliability_Consequences
3. Ignition_Post_Mitigated_Residential_Reliability_Consequences
4. Ignition_Post_Mitigated_Non_Residential_Reliability_Consequences

Table Relationships

The data template Guidelines uses three primary key fields, RRU_ID, OEIS_Project_ID, and Undergrounding_Alternative_Mitigations, to connect Tables 1, 2, and 4 and ensure data consistency.
Every row in Tables 2 and 4 must correspond to a matching row in Table 1 using these fields. This structure supports accurate cost allocation, risk modeling, and asset tracking.
Table 3 uses RRU_ID and OEIS_Project_ID as its primary keys, which can be linked to Tables 1, 2, and 4 when tracking changes to risk models or asset definitions.

5. Outage_Program_Pre_Mitigated_Residential_Reliability_Consequences
6. Outage_Program_Pre_Mitigated_Non_Residential_Reliability_Consequences
7. Outage_Program_Post_Mitigated_Residential_Reliability_Consequences
8. Outage_Program_Post_Mitigated_Non_Residential_Reliability_Consequences

Tables and Data Requirements

Table 1: Data Set

Field Name	Field Description	Field Value Constraints
RRU_ID	A unique value identifying the Risk Reporting Unit (RRU).[27]	VARCHAR (255)
OEIS_Subproject_ID	A unique value identifying the Subproject. This is the same value as found in the Energy Safety Guidelines. The utility must retain the same Subproject ID over time. New Subprojects must receive new Subproject IDs which have not been used for any previously submitted Subproject.	VARCHAR (255)
OEIS_Project_ID	A unique value identifying the Undergrounding Project. This is the same value as found in the Energy Safety Guidelines. OEIS_PROJECT_IDs must remain consistent over time and not be altered during updates.	VARCHAR (255)
Circuit_Segment_ID	A unique value identifying the Circuit Segment ID on which this Undergrounding Project was defined. This is the same value as found in the Energy Safety Guidelines. If the Circuit Segment changes, the Circuit_Segment_ID remains identified with the original Circuit Segment, at the point the OEIS_PROJECT_ID is created	VARCHAR (255)
QDR_Circuit_Segment_ID	If the Circuit Segment was included in the most recent Quarterly Data Report submission as part of the WMP process, list the name used in that report. This must be the same value as found in the Energy Safety Guidelines in Table C.6.	VARCHAR (255)
GRC_Activity_Code	This is the Activity Code for the Proposed Mitigation relevant to this RRU. Field values are expected to utilize the following notational systems: PG&E: Maintenance Activity Type (MAT) SCE: Work Breakdown Structure (WBS) Sempra: Capital Programs are defined at the budget code; Expense programs are defined at the workpaper.[28]	VARCHAR (255)

[27] For more information see R.20-07-013, Phase 4 Workshop 1, SPD Staff Proposal on Definition of Scoped Work and the Risk Reporting Unit, November 8 2024 at 20. See also the discussion in R.20-07-013, Phase 4 Workshop 3, SPD Staff Proposal on Risk Mitigation Accountability Reports December 30 2024at 22.

[28] D.24-05-064, Appendix A, Row 28.

Field Name	Field Description	Field Value Constraints
Filings	List of all filing(s), including advice letters, where the RRU (or Project) is reported and a budget is requested including but not limited to a GRC application and Wildfire Mitigation and Catastrophic Events (WMCE) application.	TEXT
Customer_Count_Residential	Number of Residential customers served by the RRU (or Project)	INT
Customer_Count_Non_Residential	Number of Non-Residential customers served by the RRU (or Project)	INT
State_Legislative_District	State Legislative District of the service territory in which the RRU (or Project) is located.	VARCHAR (255)
Tranche_Level	The Tranche that includes the Assets or Systems that the Project[29] mitigates. Each Project can only mitigate the risk exhibited by Assets or Systems found in one Tranche. Tranches are the quintiles of Likelihood of Risk Event (LoRE) and Consequence of Risk Event (CoRE) for Wildfire Ignition Risk. The structure of the Tranche level to record in this field is represented as LoRE quintile and CoRE quintile that make up each tranche. Thus, the Tranche Level should be presented in the following shorthand: CoRE 1×LoRE 2 or CoRE 2×LoRE 1 If the utility has presented an alternative approach to tranches via a whitepaper in a previous RAMP Proceeding, it must create a clear and concise shorthand for the structure of the tranches.[30]	VARCHAR (255)

[29] Projects or RRUs reported in the Phase 2 Application. For any Projects reported in the Phase 2 Application, the corresponding RRUs are presumed to fall within the same Projects' Tranches.

[30] For more detail on the Tranche Level field, see D.24-05-064 at 26-33 and D.24-05-064, Appendix A, Row 14. Even if the utility records a Tranche Level in this field that accords with the tranche structure in its alternative approach to tranches, SPD reserves its right to challenge any alternative approach to tranches (See D.24-05-064 at 31).

Field Name	Field Description	Field Value Constraints
Asset_System_List	List of the unique Assets and/or the unique Systems that exhibit risk, which is mitigated by the RRU(or Project).[31] This should include, but not limited to, the following examples: Isolatable Circuit Segments or Circuit Segments, Poles and Spans. This field should also include the List of Associated Assets, if any, found in Table 4.	TEXT
Total_Circuit_Miles	Total number of pre-mitigated circuit miles included in the RRU (or Project).	REAL
Total_Circuit_Miles_UG	Total number of post-mitigated undergrounded circuit miles included in the RRU (or Project). This field only applies if Undergrounding_Alternative_Mitigations is listed as undergrounding mitigation.	REAL
Risk_Ranking	Ranking of the total pre-mitigated risk that is exhibited by the assets or systems that the RRU (or Project) mitigates (E.g., where the risk level of the assets or systems mitigated by the RRU (or Project) lies in comparison with risk level of the assets or systems mitigated by other RRUs (or Projects) across the entire Proposed Mitigation Program).	VARCHAR (255)
Scoping_Date	The year, month and day the utility intends to begin or did begin the scoping process of this mitigation for the RRU (or Project).	Date (YYYY-MM-DD)[32]
Start_Date	The year, month and day the utility intends to begin or did begin the construction or implementation of the RRU (or Project).	Date (YYYY-MM-DD)[33]
Undergrounding_Alternative_Mitigations	This field must include the Undergrounding Mitigation and the Alternative Mitigations that the utility has considered for this RRU (or Project). All the following risk and cost analyses are carried out based on the value inputted within this field.[34] This field enables comparison of risk and cost analyses of alternative mitigations and the proposed undergrounding program for the same RRU (or Project).	VARCHAR (255)

[31] Asset is a retirement unit that exhibits risk, as defined by Federal Energy Regulatory Commission (FERC) Uniform System of Accounts (USOA). A System is defined as a regularly interacting or interdependent group of items forming a unified whole that exhibits risk and cannot be classified as a retirement unit. See R.20-07-013, Phase 4 Workshop 1, SPD Staff Proposal on Definition of Scoped Work and the Risk Reporting Unit, November 8 2024 at 20.

[32] If the year, month and day is available, the utility must record this information in this field using the YYYY-MM-DD format.

[33] If the day is not yet confirmed, the utility must use 01 for the day (i.e. 2025-02-01).

[34] For more information on alternative mitigation analysis, see D.18-12-014 at 34.

Field Name	Field Description	Field Value Constraints
Undergrounding_Mitigation_Justification1	Primary reason for choosing the Undergrounding mitigation that the utility proposed for the RRU (or Project). This field can include, but is not limited to, responses such as project-level thresholds required in the Energy Safety EUP Guidelines: the High-Risk Threshold; the Ignition Tail Risk Threshold, the High Frequency Outage Program Threshold, operational limitations, cost efficiency, and continuity.	VARCHAR (255)
Undergrounding_Mitigation_Justification2	Other reasons for choosing the Undergrounding mitigation that the utility proposed for the RRU (or Project). This field can include, but is not limited to, responses such as project-level thresholds required in the Energy Safety EUP Guidelines: the High-Risk Threshold, the Ignition Tail Risk Threshold; the High Frequency **Outage** Program Threshold, operational limitations, cost efficiency, and continuity. If a utility does not have a secondary reason for choosing the Undergrounding mitigation the utility should leave this field blank.	VARCHAR (255)
Status	Preset domain values to identify the current status of the RRU (or Project) are:[35] • Scoping: Identifying the size and timeline of the RRU (or Project) Scoping is the first step to providing visibility to the construction feasibility and possible execution timing. Designing: Delineation of a plan for implementing the RRU (or Project) including determining the RRU's (or Project) integration within existing infrastructure or operations and need for materials, training, or permitting. The costs for completing the RRU (or Project), including for permitting, labor and materials, are forecasted at this stage. • Permitting: The process of obtaining the rights and permits from relevant stakeholders to implement the RRU (or Project). This stage of the lifecycle also includes negotiating of contracts to implement the RRU (or Project) as well as final estimation of the costs associated with implementing the RRU (or Project).	VARCHAR (255)

[35] Information about the Status field can also be found in R.20-07-013, Phase 4 Workshop 1, SPD Staff Proposal on Definition of Scoped Work and the Risk Reporting Unit, November 8 2024 at 10-11.

Field Name	Field Description	Field Value Constraints
	• Construction/Implementation: During this stage a capital investment is built out or an operational activity is put into action. Capital investments are complete when they are used and useful. Operational activities could be an ongoing means of maintaining a level of risk.[36] • Post-Construction: For capital investments, there can be final paperwork and updates to asset registries after the scoped work is used and useful.[37]	
Used_and_Useful_Date	The year, month and day the utility intends to make or did make this RRU (or Project) used and useful. Used and useful means to be fully complete and providing service to customers.	Date (YYYY-MM-DD)[38]
CBR_Year_Zero	The year the risk and costs for the Undergrounding_Alternative_Mitigations program for the RRU (or Project) are discounted to.	INT
Useful_Life	The value of the useful life of the Undergrounding_Alternative_Mitigations program, represented as the number of years.	REAL
Ignition_Pre_Mitigated_Likelihood	The likelihood of Ignition before Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project).	REAL
Ignition_Pre_Mitigated_Safety_Consequences	The unscaled expected value of Safety Consequences of Ignition (e.g., injuries or fatalities) before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Ignition_Pre_Mitigated_Residential_Reliability_Consequences	The unscaled expected value of Residential Reliability Consequences of Ignition (e.g., Customer minutes interrupted) before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL

[36] The "Construction/Implementation" status value corresponds to the "Ready for Construction" and "Construction in Progress" values in table C-14 of the *Energy Safety Guidelines*.

[37] The "Post-Construction" status value corresponds to the "Construction Completed" and "Overhead De-energized" values in table C-14 of the *Energy Safety Guidelines*.

[38] If the day is not yet confirmed, the utility must use 01 for the day (i.e. 2025-02-01).

Field Name	Field Description	Field Value Constraints
Ignition_Pre_Mitigated_Non_Residential_Reliability_Consequences	The unscaled expected value of Non-Residential Reliability Consequences of Ignition (e.g., Customer minutes interrupted) before Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Ignition_Pre_Mitigated_Financial_Consequences	The unscaled expected value of Financial Consequences of Ignition before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Ignition_Post_Mitigated_Likelihood	The likelihood of Ignition occurring after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project).	REAL
Ignition_Post_Mitigated_Safety_Consequences	The unscaled expected value of Safety Consequences of Ignition (e.g., injuries or fatalities) after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Ignition_Post_Mitigated_Residential_Reliability_Consequences	The unscaled expected value of Residential Reliability Consequences of Ignition (e.g., Customer minutes interrupted) after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Ignition_Post_Mitigated_Non_Residential_Reliability_Consequences	The unscaled expected value of Non-Residential Reliability Consequences of Ignition (e.g., Customer minutes interrupted) after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Ignition_Post_Mitigated_Financial_Consequences	The unscaled expected value of Financial Consequences of Ignition after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Outage_Program_Pre_Mitigated_Likelihood	The likelihood of Outage Program occurring before Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project).	REAL

Field Name	Field Description	Field Value Constraints
Outage_Program_Pre_Mitigated_Safety_Consequences	The unscaled expected value of Safety Consequences of Outage Program (e.g., injuries or fatalities) before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Outage_Program_Pre_Mitigated_Residential_Reliability_Consequences	The unscaled expected value of Residential Reliability Consequences of Outage Program (e.g., Customer minutes interrupted) before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Outage_Program_Pre_Mitigated_Non_Residential_Reliability_Consequences	The unscaled expected value of Non-Residential Reliability Consequences of Outage Program (e.g., Customer minutes interrupted) before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Outage_Program_Pre_Mitigated_Financial_Consequences	The unscaled expected value of Financial Consequences of Outage Program before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Outage_Program_Post_Mitigated_Likelihood	The likelihood of Outage Program occurring after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project).	REAL
Outage_Program_Post_Mitigated_Safety_Consequences	The unscaled expected value of Safety Consequences of Outage Program (e.g., injuries or fatalities) after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Outage_Program_Post_Mitigated_Residential_Reliability_Consequences	The unscaled expected value of Residential Reliability Consequences of Outage Program (e.g., Customer minutes interrupted) after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project) (Natural Units)	REAL
Outage_Program_Post_Mitigated_Non_Resdiential_Reliability_Consequences	The unscaled expected value of Non-Residential Reliability Consequences of Outage Program (e.g., Customer minutes interrupted) after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project) (Natural Units)	REAL

Field Name	Field Description	Field Value Constraints
Outage_Program_Post_Mitigated_Financial_Consequences	The unscaled expected value of Financial Consequences of Outage Program after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Pre_Mitigated_Ignition_Risk	Unscaled value of Ignition Risk before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Dollar Value)	REAL
Post_Mitigated_Ignition_Risk	Unscaled value of Ignition Risk after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Dollar Value)	REAL
Pre_Mitigated_Outage_Program_Risk	Unscaled value of Outage Risk before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Dollar Value)	REAL
Post_Mitigated_Outage_Program_Risk	Unscaled value of Outage Risk after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Dollar Value)	REAL
Pre_Mitigated_Overall_Utility_Risk	Unscaled value of Overall Utility Risk before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Dollar Value)	REAL
Post_Mitigated_Overall_Utility_Risk	Unscaled value of Overall Utility Risk after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Dollar Value)	REAL
Discount_Rate_Scenario	The discount rate (See Table 5) used to calculate the Total_Mitigation_Benefit, Present_Value_Capital_Costs, and Cost_Benefit_Ratio, among others. Input in this field shall include one row for each of the following three discount rate scenarios: • WACC Discount Rate Scenario • Societal Discount Rate Scenario • Hybrid Discount Rate Scenario	VARCHAR (255)
Ignition_Risk_Mitigation_Benefit	Present Value of the Wildfire Ignition Risk Reduction from the Undergrounding_Alternative_Mitigations program for the RRU (or Project). (Dollar Value)	REAL
Outage_Program_Risk_Mitigation_Benefit	Present Value of the Outage Program Risk Reduction from the Undergrounding_Alternative_Mitigations program for the RRU (or Project). (Dollar Value)	REAL

Field Name	Field Description	Field Value Constraints
Net_OM_Costs_PV	Present Value of Operations and Maintenance (O&M) Cost Savings minus Present value of O&M New Costs from the Undergrounding_Alternative_Mitigations program for the RRU (or Project). Utilities may include Present Value of Net O&M Costs[39] as part of the Total_Mitigation_Benefit in the CBR's numerator for the RRU (or Project). (Dollar Value)	
Total_Mitigation_Benefit	Present Value of the Risk Reduction and potentially the Present Value of Net O&M Costs from the Undergrounding_Alternative_Mitigations program for the RRU (or Project). (Dollar Value)	REAL
Average_Unit_Cost_per_Mile	The average Unit Cost of the Undergrounding_Alternative_Mitigations program for the RRU (or Project) per mile.	REAL
Total_CapEx	Total nominal value of the Capital expenditures of the Undergrounding_Alternative_Mitigations program for the RRU (or Project).	REAL
Present_Value_Capital_Costs	Present Value of the Capital Costs (Total_CapEx) of the Undergrounding_Alternative_Mitigations program for the RRU (or Project).	REAL
Cost_Benefit_Ratio	Cost-Benefit Ratio of the Undergrounding and Alternative Mitigations for the RRU (or Project).	REAL
Backcasted_Total_Mitigation_Benefit	Recalculated Total_Mitigation_Benefit from the Undergrounding and Alternative Mitigations measure submitted in the Phase 2 Application based on the new inputs including but not limited to the RRU and/or new risk models and/or changes to the portion of the circuit scoped for mitigation (Dollar Value)	REAL
Backcasted_Present_Value_Capital_Costs	Recalculated Present_Value_Capital_Costs of the Proposed and Alternative Mitigations submitted in the Phase 2 Application based on the new inputs including but not limited to the RRU and/or new risk models and/or changes to the portion of the circuit scoped for mitigation (Dollar Value)	REAL

[39] The CBR calculation shall only be based on the incremental difference between the proposed project and the No-Build Baseline, both in terms of benefits and net costs (Net O&M Costs). No-Build Baseline represents a well-defined baseline scenario or what happens if no project or RRU is implemented.

Field Name	Field Description	Field Value Constraints
Backcasted_Cost_Benefit_Ratio	Recalculated Cost_Benefit_Ratio of the Undergrounding and Alternative Mitigations submitted in the Phase 2 Application based on the new inputs including but not limited to the RRU and/or new risk models and/or changes to the portion of the circuit scoped for mitigation (Dollar Value)	REAL
Unit_Cost_Percentage_Difference	The percentage difference between forecasted Average_Unit_Cost_per_Mile submitted in the Phase 2 Application and updated Unit Costs in the subsequent six-month progress reports.	REAL
CBR_Percentage_Difference	If the utility elects to use the Subproject designation, then this is calculated as the percentage difference between the Backcasted_Cost_Benefit_Ratio and the Cost_Benefit_Ratio presented in the subsequent six-month progress reports. If the utility elects not to use the Subproject designation or the detailed Subproject data is available in the Phase 2 Application this is calculated as the percentage difference between forecasted Cost_Benefit_Ratio submitted in the Phase 2 Application and the updated Cost_Benefit_Ratio presented in the subsequent six-month progress reports.	REAL
Risk_Model	Name and Version of Risk Model used to calculate Cost_Benefit_Ratio of the Undergrounding and Alternative Mitigations for the RRU (or Project).	VARCHAR (255)
Reporting_Date	The date, the risk and costs for the Undergrounding and Alternative Mitigations for the RRU (or Project) are reported.	Date (YYYY-MM-DD)
Calculated_Date	The date, the risk and costs for the Undergrounding and Alternative Mitigations for the RRU (or Project) are calculated.	Date (YYYY-MM-DD)

Table 2: Cost Breakdown

Field Name	Field Description	Field Value Constraints
RRU_ID	A unique value identifying the RRU.	VARCHAR (255)
OEIS_Subproject_ID	A unique value identifying the Subproject. This is the same value as found in the Energy Safety Guidelines. The utility must retain the same Subproject ID over time. New Subprojects must receive new Subproject IDs which have not been used for any previously submitted Subproject.	VARCHAR (255)
OEIS_Project_ID	A unique value identifying the Undergrounding Project. This is the same value as found in the Energy Safety Guidelines. PROJECT_IDs must remain consistent over time and not be altered during updates.	VARCHAR (255)
Undergrounding_Alternative Mitigations	This field must include the Undergrounding Mitigation and the Alternative Mitigations that the utility has considered for this RRU (or Project). All the following cost analyses are carried on based on the value inputted within this field. This field enables comparing risk analyses of several alternative mitigations' options for the same RRU (or Project). This value must be identical with the Undergrounding_Alternative_Mitigations field in Table 1.	VARCHAR (255)
CapEx_Labor	Including all the required Engineering, Design, and Construction.	REAL
CapEx_Materials	All the required material s.	REAL
CapEx_Permits_Environmental	Permitting fees from local and state agencies that cover, for instance, but not limited to, environmental impact assessments.	REAL
CapEx_Other_Costs	Other Capital Expenditure that are not categorized in the rows above.	REAL
Total_CapEx	Total nominal value of the Capital expenditures of the Undergrounding_Alternative_Mitigations for the RRU. This value must be equal to Total_CapEx fields in Table 1.	REAL
Initial_Application_Total_Costs	Total nominal value of the Total_CapEx of the Undergrounding_Alternative_Mitigations for the RRU (or Project) that was presented in the Phase 2 Application to the Commission. This field should remain blank when the utility submits its Phase 2 Application.	REAL

Field Name	Field Description	Field Value Constraints
Reporting_Date	The date, the risk and costs for the Undergrounding and Alternative Mitigations for the RRU (or Project) are reported.	Date (YYYY-MM-DD)
Calculated_Date	The date the risk and costs for the Undergrounding and Alternative Mitigations for the RRU (or Project) are calculated.	Date (YYYY-MM-DD)

Table 3: Risk Model Change Tracker

Field Name	Field Description	Field Value Constraints
RRU_ID	A unique value identifying the RRU.	VARCHAR (255)
OEIS_Subproject_ID	A unique value identifying the Subproject. This is the same value as found in the Energy Safety Guidelines. The utility must retain the same Subproject ID over time. New Subprojects must receive new Subproject IDs which have not been used for any previously submitted Subproject.	VARCHAR (255)
OEIS_Project_ID	A unique value identifying the Undergrounding Project. This is the same value as found in the Energy Safety Guidelines. PROJECT_IDs must remain consistent over time and not be altered during updates.	VARCHAR (255)
Current_Asset_System_List	List of current unique Assets and/or the unique Systems that exhibit risk, which is mitigated by the RRU (or Project). The list in this field must be the same as the list in the Asset_System_List field in Table 1. This should include, but not limited to, the following examples: This should include, but not limited to, the following examples: Isolatable Circuit Segments or Circuit Segments, Poles and Spans	TEXT
Current_Risk_Model	Name and Version of the updated Risk Model used to calculate the risk score for the assets mitigated by the RRU (or Project). (E.g., V2)	VARCHAR (255)
Current_Total_Miles	Total circuit miles under Current Risk Model for the RRU (or Project). This must be the same as the Total_Circuit_Miles in Table 1.	VARCHAR (255)

Field Name	Field Description	Field Value Constraints
Current_Non_HFTD_Miles	Total miles (if any) that extend beyond the High Fire-Threat District (HFTD) under Current Risk Model for the RRU (or Project).	VARCHAR (255)
Current_Pre_Mitigated_Overall_Utility Risk_Score	The pre-mitigated risk score for the assets mitigated by the RRU (or Project) calculated under the Current Risk Model. (Dollar Value). This must be the same as the Pre_Mitigated_Overall_Utility_Risk field presented in Table 1.	VARCHAR (255)
Current_Risk_Percentage	The Pre_Mitigated_Overall_Utility_Risk risk score for the assets mitigated by the RRU (or Project) divided by the total risk score calculated using the Current Risk Model.	VARCHAR (255)
Change_Type	Identification of how the circuit segment or partial circuit segment mitigated by the RRU has been defined and redefined since the last update: • New Data Inputs to Risk Model • New Construction of the circuit segment or partial circuit segment • Renaming of the circuit segment or partial circuit segment • Splitting of the circuit segment or partial circuit segment • Merging of the circuit segment or partial circuit segment • Other	VARCHAR (255)
Change_Date	Date the Change_Type was implemented on the RRU (or Project).	Date (YYYY-MM-DD)

Field Name	Field Description	Field Value Constraints
Previous_Asset_System_List	For each RRU (or Project), if the value in the Change_Type field in this Table is one of the following: • New Construction of the circuit segment or partial circuit segment • Renaming of the circuit segment or partial circuit segment • Splitting of the circuit segment or partial circuit segment Merging of the circuit segment or partial circuit segment Then list the unique Assets and/or the unique Systems mitigated by the RRU(or Project), prior to the Change_Date. This should include, but not limited to, the following examples: Isolatable Circuit Segments or Circuit Segments, Poles and Spans	TEXT
Previous_Risk_Model	Name and Version of the previous Risk Model used to calculate the risk score for the assets mitigated by the RRU (or Project).	VARCHAR (255)
Previous_Total_Miles	Total circuit miles under the Previous Risk Model for the RRU (or Project).	VARCHAR (255)
Previous_Non_HFTD_Miles	Total miles (if any) that extend beyond the High Fire-Threat District (HFTD) under Previous Risk Model for the RRU (or Project).	VARCHAR (255)
Previous_Pre_Mitigated_Risk_Score	The pre-mitigated risk score for the assets mitigated by the RRU (or Project) calculated under the Previous Risk Model. (Dollar Value)	VARCHAR (255)
Previous_Risk_Percentage	The pre-mitigated risk score for the assets mitigated by the RRU (or Project) divided by the total risk score calculated using the Previous Risk Model.	VARCHAR (255)

Field Name	Field Description	Field Value Constraints
Initial_Application_Total_Miles	Total number of circuit miles included in the RRU (or Project) from the Phase 2 Application to the Commission. Even if the total circuit miles do not change in a six-month progress report, this value must still be entered.	REAL
Initial_Application_Non_HFTD_Miles	Total miles (if any) that extend beyond the High Fire-Threat District (HFTD) for the RRU (or Project) from the Phase 2 Application to the Commission. Even if the total circuit miles do not change in a six-month progress report, this value must still be entered.	REAL
Reporting_Date	The date the risk and costs associated with the Current Risk Model are reported.	Date (YYYY-MM-DD)
Calculated_Date	The date the risk and costs associated with the Current Risk Model are calculated.	Date (YYYY-MM-DD)

Table 4: HFTD and Associated Asset

Field Name	Field Description	Field Value Constraints
RRU_ID	A unique value identifying the RRU.	VARCHAR (255)
OEIS_Subproject_ID	A unique value identifying the Subproject. This is the same value as found in the Energy Safety Guidelines. The utility must retain the same Subproject ID over time. New Subprojects must receive new Subproject IDs which have not been used for any previously submitted Subproject.	VARCHAR (255)
OEIS_Project_ID	A unique value identifying the Undergrounding Project. This is the same value as found in the Energy Safety Guidelines. PROJECT_IDs must remain consistent over time and not be altered during updates.	VARCHAR (255)
Undergrounding_Alternative_Mitigations	This field must include the Undergrounding Mitigation and the Alternative Mitigations that the utility has considered for this RRU (or Project). All the following cost and risk analyses are carried on based on the value inputted within this field. This field enables comparing risk analyses of several alternative mitigations' options for the same RRU (or Project). This value must be identical with the Undergrounding_Alternative_Mitigations field in Table 1.	VARCHAR (255)
Associated_Assets	List of all connected low-risk Associated Assets that the utility plans to mitigate because of operational constraints or reasons other than the reducing risk (e.g., Service lines and Secondary lines).	TEXT
HFTD_Tier2_Miles	If applicable, the total number of miles included in the RRU (or Project) located in HFTD Tier 2.	REAL
HFTD_Tier3_Miles	If applicable, the total number of miles included in the RRU (or Project) located in HFTD Tier 3.	REAL
Wildfire_Rebuild_Miles	If applicable, the total number of miles included in the RRU (or Project) located in the Wildfire Rebuild Area.	REAL
Associated_Asset_Miles	Total associated asset miles included in the RRU (or Project) that the utility plans to mitigate.	REAL

Field Name	Field Description	Field Value Constraints
Discount_Rate_Scenario	The discount rate (See Table 5) used to calculate the Associated_Assets_Total_Mitigation_Benefit, and Associated_Assets_Present_Value_Capital_Costs, among others. Input in this field should be one of the following: • WACC Discount Rate Scenario • Societal Discount Rate Scenario • Hybrid Discount Rate Scenario	VARCHAR (255)
Associated_Assets_Present_Value_Capital_Costs	The Present Value of Capital Costs of the Undergrounding and Alternative Mitigations for all of the Associated Assets that the utility plans to mitigate.	REAL
Associated_Assets_Total_Mitigation_Benefit	The Present Value of the Risk Reduction and possible Present Value of Net O&M Costs of the Undergrounding_Alternative_Mitigations for all of the Associated Assets that the utility plans to mitigate.	REAL
Reporting_Date	The date the risk and Costs for the Undergrounding_Alternative_Mitigations for the RRU (or Project) are reported.	Date (YYYY-MM-DD)
Calculated_Date	The date the risk and costs for the Undergrounding_Alternative_Mitigations for the RRU (or Project) are calculated.	Date (YYYY-MM-DD)

Table 5: Financial Inputs

Field Name	Field Description	Field Value Constraints
WACC_Discount_Rate	The Weighted Average Cost of Capital (WACC) Discount Rate Scenario the utility must use to calculate Present Value Benefits and Costs component of the CBR for an RRU (or Project).[40]	REAL
Societal_Discount_Rate	The Societal Discount Rate Scenario the utility must use to calculate the Present Value of Benefit and Costs component of the CBR for an RRU (or Project).[41]	REAL
VSL	Dollar value of statistical life used to monetize the Safety Consequence.[42]	REAL
Financial	Dollar value used to monetize the Financial Consequence, and it equals to $1.	REAL
PVRR	If applicable, PVRR or Present Value Revenue Requirement is the financial metric the utility used in its rate case and long-term planning to evaluate the cost implications of investments or programs over the life of the asset. Providing the PVRR is optional.	REAL
ICE_Calculator_Version	The ICE Calculator version that utility uses to estimate dollar value per customer minute interrupted	REAL
Reporting_Date	The date the Financial Inputs are reported	Date (YYYY-MM-DD)
Calculated_Date	The date the financial Inputs are calculated	Date (YYYY-MM-DD)

[40] D.24-05-064 at 103.

[41] D.24-05-064 at 102-103.

[42] D.22-12-027, OP 2a.

Table 6: Interruption Cost Estimate Calculator Inputs[43]

Field Name	Field Description	Field Value Constraints
HFTD_Region	Interruption Cost Estimate calculator inputs broken down by HFTD and Non-HFTD. Acceptable values are: • HFTD • Non-HFTD	VARCHAR (255)
Affected_Customers_Residential	Total number of residential customers affected by risk events by HFTD_Region	REAL
Affected_Customers_Non_Residential	Total number of non-residential customers affected by risk events by HFTD_Region	REAL
Average_Annual_Usage_Residential	Average annual electricity usage in kilowatt-hours for residential customers by HFTD_Region	REAL
Average_Annual_Usage_Non_Residential	Average annual electricity usage in kilowatt-hours for non-residential customers by HFTD_Region	REAL
Residential_BUG	Percentage of residential customers with backup generation by HFTD_Region	REAL
Residential_work_from_Home	Percentage of residential customer working from home by HFTD_Region	REAL
Non_Residential_Manufacturing	Percentage of non-residential customers engaged in manufacturing by HFTD_Region	REAL
Non_Residential_Health_Social	Percentage of non-residential customers engaged in health care and Social Assistance by HFTD_Region	REAL
Outage_Summer	Percentage of outages occurring in the Summer, from June through September by HFTD_Region	REAL
Outage_Weekend	Percentage of outages occurring at the weekend by HFTD_Region	REAL

[43] D.22-12-027, OP 2b.

Field Name	Field Description	Field Value Constraints
Non-Residential_Advanced_Warning	Percentage of customers with advanced warning of an outage by HFTD_Region	REAL
SAIDI	System Average Interruption Duration Index by HFTD_Region. It is calculated by dividing the total minutes of customer interruptions by the total number of customers served.	REAL
SAIFI	System Average Interruption Frequency Index by HFTD_Region. It is calculated by dividing the total number of customer interruptions by the total number of customers served.	REAL
Electric_Reliability_Valuation_Residential	The Residential dollar value per customer minute interrupted as estimated by the Interruption Cost Estimate Calculator for each **HFTD_Region.**	REAL
Electric_Reliability_Valuation_Non_Residential	The Non-Residential dollar value per customer minute interrupted as estimated by the Interruption Cost Estimate Calculator by **HFTD_Region.**	REAL
Reporting_Date	The date the ICE Calculator Inputs are reported	Date (YYYY-MM-DD)
Calculated_Date	The date the ICE Calculator Inputs are calculated	Date (YYYY-MM-DD)

Appendix 3: Statutory Requirements Cross-Reference

Code Section	Statutory Language	*Guidelines* Section (Page Number)
8388.5(a)	The commission shall establish an expedited utility distribution infrastructure undergrounding program consistent with this section.	Purpose (p. 1), and Background (p.2)
8388.5(e)(1)	Upon the office approving a plan pursuant to paragraph (2) of subdivision (d), the large electrical corporation shall, within 60 days, submit to the commission a copy of the plan and an application requesting review and conditional approval of the plan's costs and including all of the following:	Background (p.2), and Phase 2 - Application Submission and Review (p. 6)
8388.5(e)(1)(A)	Any substantial improvements in safety risk and reduction in costs compared to other hardening and risk mitigation measures over the duration of the plan.	Application Requirements (p. 9)
8388.5(e)(1)(B)	The cost targets, at a minimum, that result in feasible and attainable cost reductions as compared to the large electrical corporation's historical undergrounding costs.	Application Requirements (p. 8)
8388.5(e)(1)(C)	How the cost targets are expected to decline over time due to cost efficiencies and economies of scale.	Application Requirements (p. 8)
8388.5(e)(1)(D)	A strategy for achieving cost reductions over time.	Application Requirements (p. 8)

Code Section	Statutory Language	*Guidelines* Section (Page Number)
8388.5(e)(3)	In reviewing an application submitted to the commission pursuant to paragraph (1), the commission shall consider not revisiting cost or mileage completion targets approved, or pending approval, in the electrical corporation's general rate case or a commission-approved balancing account ratemaking mechanism for system hardening.	Application Requirements (p. 7)
8388.5(e)(4)	Upon the commission receiving an application pursuant to paragraph (1), the commission shall facilitate a public workshop for presentation of the plan and take public comment for at least 30 days.	Public Workshop & Comments (p. 12)
8388.5(e)(5)	On or before nine months, the commission shall review and approve or deny the application. Before approving the application, the commission may require the large electrical corporation to modify or modify and resubmit the application.	Background (p.2), and Application Conditional Approval, Denial, or Modification & Resubmittal (p. 5)
8388.5(e)(6)	The commission shall consider continuing an existing commission-approved balancing account ratemaking mechanism for system hardening for the duration of a plan, as determined by the commission, and shall authorize recovery of recorded costs that are determined to be just and reasonable.	SB 884 Program Process and Requirements (p. 4-5), Conditions for Approval of Plan Costs (p. 12), Phase 3 (p. 13, 14), and Audit of the One-Way Balancing Account (p. 15-16)

Code Section	Statutory Language	*Guidelines* Section (Page Number)
8388.5(i)(2)	The commission may assess penalties on a large electrical corporation that fails to substantially comply with a commission decision approving its plan.	Background (p. 2), and Penalties (p. 17)
8388.5(j)	Each large electrical corporation participating in the program shall apply for available federal, state, and other no ratepayer moneys throughout the duration of its approved undergrounding plan, and any moneys received as a result of those applications shall be used to reduce the program's costs on the large electrical corporation's ratepayers.	Background (p. 2), Application Requirements (p. 10), Conditions for Approval of Plan Costs (p. 12), Conditions for Approval of Recorded Costs in Memorandum Account (p. 14), and Progress Report (p. 15)

ATTACHMENT B

SB 884 Program: CPUC Guidelines With Appendices (Redline)

California Public Utilities Commission

SB 884 Program: CPUC Guidelines~~[1]~~

SAFETY POLICY DIVISION

~~March 2024~~August 15, 2025

~~[1] This document was formerly called "Staff Proposal for SB 884 Program." Its title has been updated to reflect that it now contains requirements binding on large electrical corporations along with those in Resolution SPD-15. All references in this document to "*Guidelines*" are intended to refer to this document as renamed "*SB 884 Program: CPUC Guidelines*".~~

Table of Contents

Purpose:

These *Guidelines*, and the adopting Commission Resolution ~~adopting these *Guidelines* will~~, satisfy the Commission's statutory obligation, pursuant to Public Utilities Code Section 8388.5(a), to establish an expedited utility distribution infrastructure undergrounding program consistent with Senate Bill (SB 884~~.~~.)[1] These *Guidelines* address the process and requirements for the Commission's review of any large electrical corporation's 10-year distribution infrastructure undergrounding plan (as defined below) and ~~its~~ related costs.

[1] McGuire; Stats. 2022, Ch. 819

Background:

SB 884, ~~which went into effect~~effective January 1, 2023, authorizes ~~only those~~ electrical corporations with 250,000 or more customer accounts within the state (i.e~~.,~~., large electrical corporations) to participate in an expedited utility distribution infrastructure undergrounding program.

To participate in the program, the large electrical corporation must submit a 10-year distribution infrastructure undergrounding plan (hereafter, "Plan" or "EUP"), including, among other requirements, the undergrounding projects ~~that it will construct~~to be constructed as part of the Plan, to the Office of Energy Infrastructure Safety (Energy Safety). Energy Safety is required to review and approve or deny the Plan within nine months of submission. ~~Before approving the Plan,~~ Energy Safety may require the large electrical corporation to modify the Plan~~.~~ before approving it. Energy Safety may only approve the Plan ~~if it finds that the electrical corporation's Plan~~upon finding it will achieve, at least, both of the following:[2]

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

~~If Energy Safety approves the large electrical corporation's Plan,~~ The large electrical corporation must submit to the Commission, within 60 days of Energy Safety's approval, a copy of the Plan and an application requesting review and conditional approval of the Plan's costs (hereafter, "Application"). However, prior to formally filing the Application with the Commission, the large electrical corporation shall provide a copy of the Application it intends to file to the Commission's Safety Policy Division (SPD) for a completeness review~~. The intent of the completeness review will only be~~ to identify any obvious omissions or errors in the intended Application. SPD will conclude its completeness review within 10 business days of receipt and issue a report noting any deficiencies that should be corrected before the Application is officially submitted and filed with the Commission.

On or before nine months after the Application's official filing date, the Commission shall review and conditionally approve or deny the Application. The Commission may, however, require the large electrical corporation to (i) modify or (ii) modify and resubmit the Application prior to conditional approval. As further explained ~~further~~ below, if the Commission or staff determines that minor corrections or clarifications are needed for the filed Application, ~~then the Commission or staff may require~~ the large electrical corporation may be required to modify the Application and ~~such minor~~provide corrections or clarifications ~~shall be provided~~ within five (5) business days~~. Whereas,~~ after being noticed. If the Commission or staff determines ~~that~~ the filed Application 1) omits material information required pursuant to the Commission Resolution adopting these *Guidelines*, 2) omits material information deemed necessary to process the Application within nine months, or 3) omits information otherwise required by SB 884, ~~then~~ the Commission or staff may then require the large electrical corporation to modify and resubmit the Application, and such resubmission will restart the nine-month ~~clock~~timeline for ~~the Commission's~~Commission review.

---

[2] Energy Safety ~~plans to separately issue~~has issued guidelines detailing the requirements for submission and review of undergrounding Plans. See https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=58006&shareable=true

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

The independent monitor must annually produce and submit a report to Energy Safety no later than December 1 of each year over the course of the Plan.[3] The independent monitor's report will identify any failure, delays, or shortcomings in the large electrical corporation's compliance with the Plan and provide recommendations for improvements. After consideration of the independent monitor's report and whether the large electrical corporation has corrected the deficiencies identified therein, Energy Safety may recommend penalties to the Commission. The Commission may assess penalties on a large electrical corporation that fails to substantially comply with the Commission decision approving its Plan pursuant to Public Utilities Code, Section 8388.5(i)(2).

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

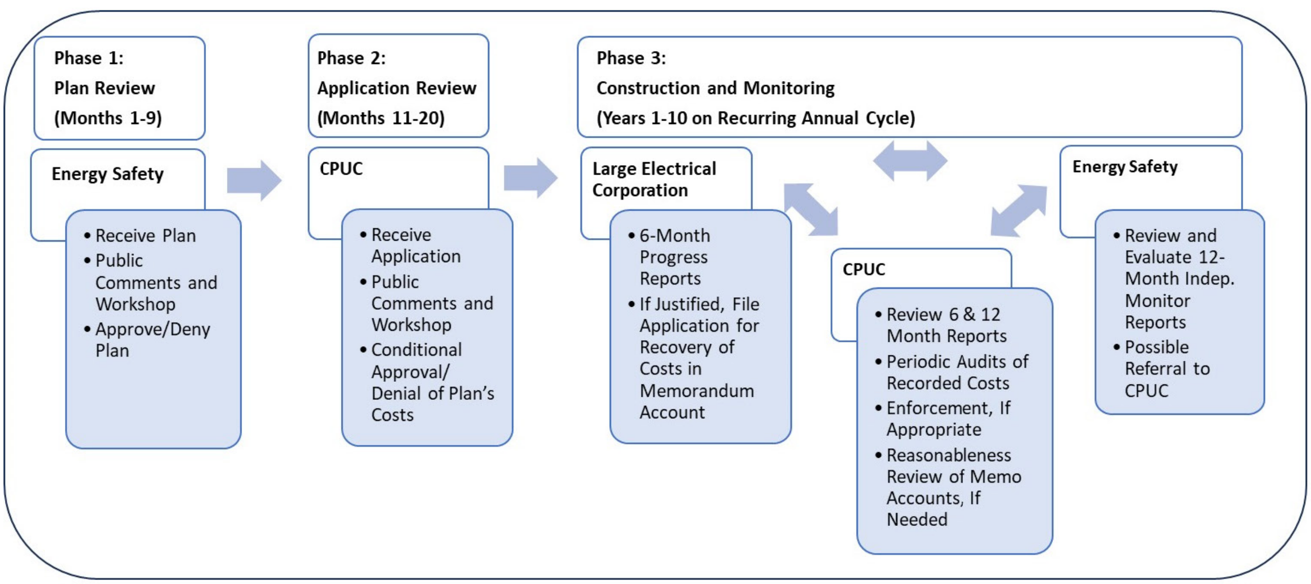

Figure 1: SB 884 Plan, Application, Reporting, and Cost Recovery Timeline

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

SB 884 Program Process and Requirements:

The SB 884 Program will be executed in up to three phases:

1) Phase 1: Energy Safety Plan review and approval/denial
2) Phase 2: Application ~~submission and~~submitted to Commission for review ~~for~~and conditional approval.
3) Phase 3: Construction and periodic audits of costs recorded in the one-way balancing account, as well as just and reasonableness reviews of recorded costs in the memorandum account described below.

If Energy Safety approves the large electrical corporation's Plan, Phase 2 will commence with the large electrical corporation's submission of an Application for Commission consideration and conclude with the Commission's disposition of such Application (i.e., conditional approval or denial) via a Phase 2 Decision. The Commission will review the costs submitted in any Application. Only if costs[4] meet certain conditions (Phase 2 Conditions), will the Commission authorize their recovery via a one-way balancing account, which shall remain subject to audit. If an audit demonstrates any costs recorded to the one-way balancing account did not meet the Phase 2 Conditions, subject to Commission review and determination, such costs may be subject to refund. The Phase 2 Conditions for recovering costs via the one-way balancing account will include those listed in the "Conditions for Approval of Plan Costs" section herein, as well as any other conditions the Commission deems appropriate in the relevant Application's proceeding. If the Commission approves cost recovery in the one-way balancing account, the Commission will also authorize the large electrical corporation to record, in a memorandum account, any Plan costs that fail to meet the Phase 2 Conditions.

If the Commission conditionally approves the large electrical corporation's Application, Phase 3 will commence upon the Commission's issuance of the Phase 2 Decision. During Phase 3, the large electrical corporation will execute its undergrounding Plan in accordance with the Resolution adopting these *Guidelines*, the Commission's Phase 2 Decision, and any other Commission decision on an Application submitted pursuant to the SB 884 program~~,~~. The large electrical corporation shall also report on its progress~~,~~ and begin booking costs to the one-way balancing account established in Phase 2, ~~which shall remain~~ subject to periodic audits~~,~~ and ~~refund~~refunds if the Commission so orders. In Phase 3, given the inherent uncertainties with planning across a 10-year period and ~~the fact that~~ certain costs ~~may have been~~being unforeseeable during Phase 2, the large electrical corporation may also request rate recovery (via a separate Phase 3 Application) for ~~any~~ implementation costs that do not meet the Phase 2 Conditions, and were recorded in the designated memorandum account~~.~~ up to a cap determined in the Phase 2 Decision. During Phase 3, the Commission will review any Phase 3 Applications for recovery of costs recorded in the memorandum account to determine whether such costs were just and reasonable, and incremental to any other costs approved by the Commission. When making these determinations the conditions set forth in the Resolution adopting these *Guidelines*, the Commission's Phase 2 Decision, and any other Commission decision on an Application submitted pursuant to SB 884 should be considered in light of the fact that such costs must be found to be just and reasonable before ~~they are~~being authorized for recovery. Phase 3 will conclude with the Commission's disposition of the last cost recovery application associated with the memorandum account, or the final independent monitor report, whichever ~~comes~~is last.

[4] Costs can only be recovered once the undergrounding project is considered used and useful.

Given the importance of the Phase 2 Conditions and the requirement that any costs recorded in the one-way balancing account must meet the Phase 2 Conditions, these *Guidelines* include a process to assess whether the recorded costs meet such conditions. Accordingly, periodic audits of the established balancing account will be performed to ensure the costs booked to the balancing account meet the conditions established by the Phase 2 Decision (e.g., unit cost caps, CBR thresholds, etc.). If the audit demonstrates that costs were incorrectly recorded or failed to meet the Phase 2 Conditions, the Commission may order a refund. ~~The details of this audit, including but not limited to who will perform it, content, frequency, venue, method for true-up and refund mechanism will be determined in a later order or decision~~If the Commission directs a large electrical corporation to issue a refund, the large electrical corporation shall not seek to recover such costs through any other means.

Due to the SB 884 Program's expedited schedule, unless otherwise directed by the Commission, large electrical corporations shall respond to discovery requests within five (5) business days in either Phase of the SB 884 Program.

Application Conditional Approval, Denial, or Modification & Resubmittal:

On or before nine months after the Application's filing date, the Commission shall review and conditionally approve or deny the Application. Before conditionally approving or denying the Application, the Commission or staff may require the large electrical corporation to (i) modify or (ii) modify and resubmit the Application.[5] If the Commission or staff determines that minor corrections or clarifications are needed for the Application, then the Commission or staff may require the large electrical corporation to modify the Application and such minor corrections or clarifications shall be provided within five (5) business days of notice. If the Commission or staff determines that the Application 1) omits material information required pursuant to the Commission Resolution adopting these *Guidelines*, 2) omits material information deemed necessary to process the Application within nine months, or 3) omits information otherwise required by SB 884, then the Commission or staff may require the large electrical corporation to modify and resubmit the Application, and such resubmission will restart the nine-month ~~clock~~timeline for the Commission's review.

Pre-Submission Application Completeness Review:

Before submission of the Application, the large electrical corporation shall provide a copy of the intended Application to Commission's Safety Policy Division (SPD)[6] for a completeness review. The pre-submission process is a precursor to and separate from the Commission's Application review process. The intent of the completeness review will ~~only~~ be to identify any obvious omissions or errors and avoid unnecessary delays resulting from post-submittal modification of the Application for such omissions or errors, given the expedited schedule for review. SPD will conclude its completeness review within 10 business days of receipt and issue a report noting any deficiencies that should be corrected in the submitted Application. Accordingly, it is the large electrical corporation's responsibility to provide SPD with a copy of the intended Application with sufficient time to conduct the completeness review (i.e., 10 business days) while ensuring

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

[6] Pre-submission of the Application for completeness review shall be submitted to SB884@cpuc.ca.gov.

that the 60-day deadline for Application submission, following Energy Safety's approval of the Plan, is met pursuant to Public Utilities Code, Section 8388.5(e)(1). SPD's report is solely for completeness review; it is not a substantive review or disposition of the Application and ~~it in no way limits~~does not limit the Commission's or staff's ability to require the large electrical corporation to otherwise modify or ~~modify and~~ resubmit the Application.

Phase 2 – Application Submission and Review:

These *Guidelines* recognize that Plans approved by Energy Safety will have been found to show that implementation of the Plan will substantially increase reliability and substantially reduce wildfire risk, as required in Public Utilities Code, Section 8388.5(d)(2). The Commission will then review such Plans and either conditionally approve or deny the costs, as presented in the subsequent Application.

Application Submission Requirements:

Applications submitted to the Commission seeking conditional approval of Plan costs shall meet all the following requirements.

Submission Deadline:

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

Application Type:

Applications shall be submitted according to the Commission's Rules of Practice and Procedure and any other requirements set forth in the Commission Resolution adopting these *Guidelines*.[7] Each section of the Application shall indicate the person who sponsors the section and would serve as a witness if evidentiary hearings are required.

Application Submission:

The Application shall be filed and served with the Commission's Docket Office, with a copy to the Commission's Chief Administrative Law Judge, the service list for the large electrical corporation's most recent general rate case (GRC), the SB 884 notification list linked here,[8] as updated, SB884@cpuc.ca.gov, and any other service lists, as determined by the large electrical corporation, that will cause the Application to broadly reach interested parties. A copy of the application should also be sent to each communications company that has equipment on poles where undergrounding is planned.

Application Requirements:

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

[8] The SB 884 notification list is periodically updated and uploaded to CPUC SB 884 webpage: https://www.cpuc.ca.gov/about-cpuc/divisions/safety-policy-division/risk-assessment-and-safety-analytics/electric-undergrounding-sb-884.

For the purposes of these *Guidelines*, all program and project costs reported in the Application shall include the standard project costs including, but not limited to, program management, project execution, design, estimating, mapping, construction, internal labor, contracted labor, parts, tools, materials, overhead, and permitting. In addition, all ratepayer impacts shall be ~~broken out~~shown by all ratepayer classifications (e.g., residential, agricultural, commercial, etc.) to the extent such information is available.

All cost and Cost-Benefit Ratio (CBR) data, required as described below, shall be supported by workpapers and Excel worksheets included with the Application submission.

The following ~~is a list of~~are required contents ~~in~~of all Applications:

1) The Application shall present both capital and operating expense cost forecasts for each year of the 10-year Application period, consistent with the cost targets presented in the Plan approved by Energy Safety.
2) The Application shall clearly identify all undergrounding targets (*e.g.*, miles to underground together with their conversion rate[9]) and cost forecasts[10] in the Plan that overlap with undergrounding targets and any and all related targets and cost forecasts either approved or under consideration in the large electrical corporation's most recent GRC or any other cost recovery venues. Furthermore:
    a) Where undergrounding targets and cost forecasts in the Application overlap with undergrounding targets and cost forecasts approved in the most recent GRC or other cost recovery venue, such undergrounding targets and costs shall be clearly identified and associated costs will be excluded from consideration for recovery in the Application.
    b) Where undergrounding targets and cost forecasts in the Application overlap with undergrounding targets and cost forecasts still under consideration in a GRC or other cost recovery venue, the Application shall specify which overlapping targets and costs are under consideration and identify the proceeding or advice letter in which the Commission is considering them. The Application shall propose in which venue the Commission should consider the overlapping costs. Both costs and the corresponding mileage must be paired and presented for consideration in a single venue.
    c) The Application shall include a detailed description of the controls the large electrical corporation will implement to ensure that undergrounding costs related to execution of the Plan are incremental to any other costs approved by the Commission.
3) The Application shall include the large electrical corporation's best estimate, including all underlying assumptions, of the proposed annual revenue requirements and proposed ratepayer impacts for each year that the large electrical corporation proposes will be necessary for rate recovery of the Application's forecasted annual costs.
4) The Application shall include a Results of Operation (RO) Model for that portion of its revenue requirement that relates to the undergrounding cost recovery it seeks, with Energy Division

[9] As used in this context, "conversion rate" means the ratio of underground mileage required to replace the equivalent overhead lines. Given prior evaluation of undergrounding requests in other Commission proceedings, it is known that a mile of undergrounding corresponds to replacement of less than one mile of overhead assets.

[10] For clarity, the term cost forecasts is used in place of the term cost targets that are discussed in PUC 8838.5 (3)(1).

oversight and a non-disclosure agreement in place,[11] that demonstrates how the large electrical corporation calculated the revenue requirement provided.[12]

~~4)~~5) The Application shall identify, for each year of the 10-year Application period, any forecast wildfire mitigation costs that will be reduced, deferred, or avoided because of implementing the proposed undergrounding Plan (e.g., vegetation management), collectively "savings," and how spending on such programs or areas of work will be affected, including any cost reductions, deferrals, or avoidances that are expected to continue beyond the 10-year Application period and the time period for which such cost reductions, deferrals, or avoidances are expected to continue beyond the 10-year period.[13]

   a) The Application shall distinguish between forecast costs already approved by the Commission for recovery and forecast costs that have not yet been the subject of a request for recovery.
   b) For forecast costs already approved by the Commission for recovery, the Application shall identify any accounts used to track such costs; the amounts in each such account; and the Commission decision(s) authorizing recovery.
   c) The application shall explain the proposed disposition of all identified savings and explain the methodology by which the Commission can ensure that all identified savings are passed on to ratepayers.

~~5)~~6) The Application shall include cost forecasts for each year of the 10-year Application period that, at a minimum, result in feasible and attainable cost reductions as compared to the large electrical corporation's historical undergrounding costs.

   a) Cost forecasts shall be provided for each projected year in the 10-year Plan.
   b) Annual historical undergrounding unit costs shall be provided for the previous 10 years, with separate categories for Rule 20 projects, other undergrounding projects, and wildfire mitigation projects, as available.
   c) Comparisons between the Plan's unit cost targets and historical undergrounding unit costs shall be provided using the average historical wildfire mitigation undergrounding costs for the previous three years (before the Plan's first year). The comparison shall include a statement of how the targeted cost reductions are feasible and attainable compared to historical costs.

~~6)~~7) The Application shall include an explanation of how the cost forecasts are expected to decline over time due to cost efficiencies and economies of scale.

~~7)~~8) The Application shall include a description of a strategy for achieving cost reductions over time per Public Utilities Code, Section 8388.5(e), which may include factors other than cost efficiencies or

[11] The non-disclosure agreement shall ensure that the large electrical corporation personnel in charge of the RO modeling will not disclose changes to the RO Model requested by the Commission to the personnel working on the Phase 2 Application and related matters.

[12] See also D.00-07-050 at 11-12 and D.20-01-002 at 65-67.

[13] For examples of cost benefits that may be appropriate to include, refer to the Lawrence Berkeley National Laboratory white paper. Peter H. Larsen, "A method to estimate the costs and benefits of undergrounding electricity transmission and distribution lines" in Energy Economics Vol. 60, 2016 pp. 47-61. Please note that this methodology is referenced for illustrative purposes only. Different methodologies and/or cost categories may be appropriate to include.

economies of scale such as, but not limited to, identifying, developing, and deploying new technologies.

~~8)~~9)The Application shall present the forecasted average Cost-Benefit Ratio (CBR) across all projects expected to be completed in each of the 10 years of the Application period, broken out by year and for the total Application period. Cost and Benefits must be calculated as defined in Commission Decision (D.)22-12-027[14] or its successor. The calculated annual and total benefits must relate to the mitigation of overhead line miles, not miles of undergrounding.[15] ~~If~~The costs and benefits of any projects that will include secondary lines and service drops ~~, those costs and benefits~~ must also be included.

~~9)~~10)The Application shall include the forecasted CBRs across all projects,~~ broken out~~ by year and for the total Application period, for each alternative wildfire mitigation hardening method considered, in place of undergrounding, including forecasted CBRs for combinations of non-undergrounding hardening mitigation measures. The calculated annual and total benefits must relate to the mitigation of overhead line miles, including any secondary lines and service drops, not miles of undergrounding.

a) The large electrical corporation shall use reasonable and comparable assumptions in its calculations of forecasted CBRs for both undergrounding and each alternative wildfire mitigation method considered, including combinations thereof.

~~10)~~11)The Application shall include a description of any substantial improvements in safety risk and reduction in costs compared to other hardening and risk mitigation measures over the duration of the Plan.

a) Substantial improvements in safety risks shall be substantiated using the above required benefits calculations by comparing undergrounding benefits to alternative hardening and risk mitigation measures, including combinations of alternative measures.

b) Reduction in costs shall be substantiated using the same cost calculations as required above by comparing undergrounding costs to alternative hardening and risk mitigation measures, including combinations of alternative measures.

~~11)~~12)For each project included in the ~~Plan and~~ Application, the large electrical corporation shall provide, at a minimum, all data listed in ~~Appendix 1~~the *SB 884 Project List Data Requirements Guidelines* in tabular format.~~[16]~~ This information shall be provided as both a Microsoft Excel file and searchable pdf file[17] to supplement the Application. ~~The data listed in Appendix 1 is preliminary, and will be refined in consultation with Energy Safety, as it develops Plan requirements, to support uniformity where possible.~~The large electrical corporation shall provide the latest version of the data required by the *SB 884 Project List Data Requirements Guidelines* at the time of its Application submission.

---

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

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

~~[16] The data requirements in Appendix 1 will be aligned with data submission requirements for the Plan, as developed by Energy Safety.~~

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

13) The Application shall include the latest data associated with the list of all projects (*SB 884 Project List Data Requirements Guidelines*) as required by Screen 2 of the *Energy Safety Guidelines*. The large electrical corporation shall provide a forecasted scope of all projects in the approved 10-year EUP and included in the Undergrounding Projects List, as an output from Screen 2 of the *Energy Safety Guidelines*.
14) The Application shall only include undergrounding projects that have a forecasted CBR greater than or equal to 1.
15) The Application shall only include undergrounding projects that have met one or more of the large electrical corporation's three Project-Level Thresholds.[18]
16) The Application shall include a detailed explanation of the necessity for any spans that extend beyond the HFTD boundary for any project included in the Application.
    a) The Application shall only include undergrounding projects that have been designated as an In-Area circuit segment as required by Screen 1 in the *Energy Safety Guidelines*.[19]
17) The Application shall include:
    a) The same Key Decision-Making Metrics (KDMMs) data for Commission review as was provided in the EUP approved by Energy Safety.
    b) The KDMMs included in any six-month progress report submitted to Energy Safety during the nine-month period that the large electrical corporation's EUP is under review by Energy Safety.

~~12)~~18) For each project included in the Plan and Application, the large electrical corporation shall provide GIS data for all project boundaries in a Geodatabase or other suitable format. ~~[20]~~
    a) The GIS data shall include the entire circuit within which projects are planned and indicate the locations of which segments will be undergrounded.
    b) The GIS data shall identify the locations of circuit segments that will continue to support overhead transmission lines (if any) after distribution lines are undergrounded.
    c) The GIS data shall indicate the locations of poles which have lease agreements with communications companies, and which are jointly owned.

~~13)~~19) The Application shall include a list of all non-ratepayer moneys (i.e., third-party funding) the large electrical corporation has applied for and/or received to minimize the Plan's costs on ratepayers. At a minimum, for each potential source of third-party funding, the list shall include:
    a) The source of third-party funding;
    b) The date when third-party funds were requested;
    c) The amount of funding requested;
    d) The status of the request, including funding already received;
    e) Next steps, including timelines for processing of the funding request; and
    f) The amount of funding granted/authorized (if any).

~~14)~~20) The Application shall include a description of how any net tax benefits associated with the third-party funding will be disposed of to the benefit of ratepayers.

---

[18] *Energy Safety Guidelines* at 42. The large electrical corporation indicates to Energy Safety whether a circuit segment falls into one of the mitigation eligibility categories in Table C.8 under the "risk_category" field.

[19] *Energy Safety Guidelines* at 12. The large electrical corporation indicates to Energy Safety whether a circuit segment is designated as "In-Area" in Table C.6 under the "is_in_area" field.

~~[20] Further details on GIS data submission requirements are expected to be issued by Energy Safety in the establishment of Plan guidelines. The GIS data submission requirements for Application submission are considered preliminary and will align with such GIS data requirements established by Energy Safety.~~

~~15)~~21) The Application shall include a statement affirming costs, tax benefits, and tax liabilities associated with federal funding sources used to fund projects included in the Plan are being tracked consistent with Resolution E-5254.[21]

~~16)~~22) The Application shall include an attestation that the large electrical corporation will continue to search and apply for third-party funding to reduce the cost of the Plan to ratepayers throughout the duration of the Plan.

~~17)~~23) The Application shall include a description of how the large electrical corporation plans to coordinate with communication companies to maximize benefits to California, including but not limited to:

a) The ownership and use of existing utility poles where undergrounding projects are planned;
b) How the large electrical corporation will address the affected shared poles, including who will own and maintain the poles if the responsible communication provider opts not to concurrently underground their infrastructure;
c) The full array of currently offered or discussed proposals for how to add conduit for such communication companies in the large electrical corporation's trenches, including, wherever possible, the proposed unit costs associated with such offerings or proposals.

~~18)~~24) The Application shall include a plan of how and when the large electrical corporation will remove poles from its rate base whose ownership is transferred to a communications company.

~~19)~~25) The Application shall include workforce development cost forecasts for each year of the Plan.

26) The Application shall include a detailed description of the method that establishes how the auditor will validate whether the large electrical corporation has satisfied the primary and secondary objectives of the audit. For the primary objectives, this method must include an approach for:

a) Verifying that the total annual costs did not exceed the approved cost cap for a given year of the EUP (Condition #1);
b) Verifying that any third-party funding obtained was applied to reduce the established cost cap for the specific year in which the third-party funding was obtained (Condition #2);
c) Determining that the average recorded unit cost for all projects completed in any given two-year period did not exceed the approved average unit cost cap (Condition #3);
d) Determining that the average recorded CBR for all projects completed in any given two-year period equals or exceeds the approved threshold CBR value. (Condition #4);
e) Determining whether the forecasted CBR of an alternative mitigation exceeds a certain threshold value above the forecasted CBR of an undergrounding project (Condition #5);
f) Verifying that a project did not exceed the approved CBR percentage difference threshold (Condition #6);
g) Verifying that a project did not exceed the approved unit cost percentage difference threshold (Condition #7); and
h) Verifying that the undergrounding project meets or exceeds the applicable Project-Level Standard in the large electrical corporation's EUP approved by Energy Safety (Condition #8).

For the secondary objectives, this method must include an approach for:

i) Verifying that a project is used and useful.
j) Verifying the incrementality showing found in Application Requirement No. 2.

[21] Resolution E-5254 adopted procedural mechanisms for review and approval of electric and gas investor-owned utility cost recovery requests related to various federal funding and grant programs. Resolution E-5254 is available on the Commission's website at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M506/K016/506016078.PDF.

k) Validating the methodology used to calculate a CBR for a given project, as found in the *CBR Calculation Guidelines* in Appendix 1 of these *Guidelines*.

~~20)~~27)The Application shall include a copy of the Plan approved by Energy Safety.

Public Workshop & Comments:

The Commission will facilitate a public workshop for presentation of the Application and take public comment for at least 30 days in accordance with Public Utilities Code Section 8388.5(e)(4). Formal comments from the workshop will be solicited by a ruling in the proceeding, and a workshop report provided by the parties who participated in the workshop may be ordered.

Conditions for Approval of Plan Costs:

Public Utilities Code, Section 8388.5(e)(1) specifies that an Application may request "conditional approval of the plan's costs…" To protect ratepayers from unexpected and inefficient cost overruns, the Commission establishes the following conditions for any costs booked to the one-way balancing account established in Phase 2:

1) Total annual costs must not exceed a cap based on the approved cost cap for that specific year.[22]
2) Third-party funding obtained, if any, shall be applied to reduce the established cost cap for the specific year in which the third-party funding is obtained, so that ratepayers receive the benefit. The large electrical corporation shall file an advice letter documenting which annual cost caps are reduced based on third-party funding received.
3) The average recorded unit cost for all projects completed in any given two-year period (the current year, and the prior year) must not exceed the approved average unit cost cap for the current year. The unit costs shall be calculated per mile of undergrounding performed, rather than per mile of overhead replaced, to focus on reduction of construction costs.
4) The average recorded CBR[23] for all projects completed in any given two-year period (the current year, and the prior year) must equal or exceed the approved threshold CBR value[24] for the current year.
5) The forecasted CBR of the undergrounding project must exceed the forecasted CBR of all alternative mitigations considered for that project by a certain threshold value, which is to be determined in the Phase 2 Decision.
6) In all cases, when an undergrounding project becomes used and useful, if the value of its recorded CBR, as reported in the applicable six-month progress report, is less than the value of its forecasted CBR at the time of the Phase 2 Application submission, then the percentage difference between the two CBR values must not exceed the specified threshold value determined in the Phase 2 Decision.
7) In all cases, when an undergrounding project becomes used and useful, if the value of its recorded unit cost, as reported in the applicable six-month progress report, is greater than the value of its forecasted unit cost at the time of the Phase 2 Application submission, then the percentage difference between the two unit cost values must not exceed the specified threshold value determined in the Phase 2 Decision.

[22] Any costs exceeding the cap shall be recorded in a memorandum account and are subject to review and approval as described in the Phase 3 section of these *Guidelines*.

[23] The "recorded CBR" is the CBR calculated using recorded cost values, as opposed to cost forecasts.

[24] The "threshold CBR value" will establish the minimum CBR that must be achieved for cost recovery.

8) The undergrounding project must meet or exceed the applicable Project-Level Standard(s) in the large electrical corporation's approved EUP approved by Energy Safety.[25]

~~5)~~9) Any further reasonable conditions supported by the record of the proceeding and adopted by the Commission in the Phase 2 Decision.

Memorandum Account Cap:

The total cumulative costs recovered via the memorandum account throughout the duration of an EUP shall be capped as a percentage of the total sum of the 10 years of cost caps placed on the one-way balancing account. The percentage value of the memorandum account cost cap will be established in the Phase 2 Decision.

Phase 3 – Review of Memorandum Account Recorded Costs for Rate Recovery:

Phase 3 of the program will be initiated if the Commission conditionally approves a Phase 2 Application submitted by a large electrical corporation. During Phase 3, the large electrical corporation will execute its undergrounding Plan in accordance with the Resolution adopting these *Guidelines*, the Commission's Phase 2 Decision, and any other Commission decision on an Application submitted pursuant to the SB 884 program, the large electrical corporation shall also report on its progress, and begin booking costs to the one-way balancing account established in Phase 2, which shall remain subject to periodic audits, and refund if the Commission so orders. In Phase 3, the large electrical corporation may also request rate recovery (via a separate Phase 3 Application) for any implementation costs that do not meet the Phase 2 Conditions~~,~~ and were recorded in the designated memorandum account. The large electrical corporation may only seek recovery for costs recorded in the memorandum account by filing a Phase 3 Application. The total cumulative costs recovered via the memorandum account throughout the duration of an EUP shall not exceed the cap established for such accounts in the Phase 2 Decision. The purpose of any Phase 3 Application will be to determine whether the costs recorded in the memorandum account meet the conditions set forth in the "Conditions for Approval of Recorded Costs in Memorandum Account" section below. When making these determinations the conditions set forth in the Resolution adopting these *Guidelines*, the Commission's Phase 2 Decision, and any other Commission decision on an Application submitted pursuant to SB 884 should be considered in light of the fact that such costs must be just and reasonable. No more than one Phase 3 Application may be filed each year.

[25] *Energy Safety Guidelines* at 17 and 43. The large electrical corporation indicates to Energy Safety whether an undergrounding project has met the Project-Level Standard(s) in Table C.12 of the *Energy Safety Guidelines* under the "fulfills_project_level_standard" field. The "applicable Project-Level Standard(s)" can be verified by how the utility completes the "risk_category" field in Table C.8 of the *Energy Safety Guidelines*. If the undergrounding project does not meet the applicable Project-Level Standard(s), the *Energy Safety Guidelines* still permit a large electrical corporation to record a justification for this project in Table C.12 under the "additional_justification" field, which can be reviewed as part of a Phase 3 Application to determine the just and reasonableness of the costs associated with a project that does not meet this condition.

The elements of recorded costs must be consistent with the elements included in the costs presented in the Application, including but not limited to, program management, project execution, design, estimating, mapping, construction, internal labor, contracted labor, parts, tools, materials, overhead, and permitting.

The Phase 3 Application must include, at a minimum, all ~~biannual~~six-month progress reports and annual compliance reports submitted pursuant to this program, relevant information from wildfire mitigation plan filings and compliance reports, and the following program data presented in Table 1 for the requested recovery period.[26] The project data that supports the program recorded cost values requested for recovery shall be provided in tabular format in a sortable Excel spreadsheet. Additional data requirements for a Phase 3 Application may be included in the Phase 2 Decision.

Table 1: Conditionally Approved Target and Actual Recorded Cost Data

Conditionally Approved Targets for the Recovery Period	Actual Recorded Costs in the Recovery Period
Program Cost	Program Cost
Program CBR	Program CBR
Program Unit Cost	Program Unit Cost
	Project Data for the Recorded Projects

Conditions for Approval of Recorded Costs in Memorandum Account:

To further protect ratepayers from unexpected and inefficient cost overruns:

1) The Commission will closely scrutinize any Phase 3 Application to determine whether the costs recorded were prudently incurred, incremental to other funding granted to the large electrical corporation, and just and reasonable.
2) When making these determinations the conditions set forth in the Resolution adopting these *Guidelines*, the Commission's Phase 2 Decision, and any other Commission decision on an Application submitted pursuant to SB 884 should be considered in light of the fact that such costs must be just and reasonable.
3) No costs recorded to the memorandum account established in the Commission's Phase 2 Decision shall be ~~approved~~authorized for recovery unless and until the large electrical corporation has shown that ~~is~~it has applied all third-party funding previously received to reduce its relevant balancing account cost cap.
4) No costs recorded to the memorandum account established in the Commission's Phase 2 Decision shall be ~~approved~~authorized for recovery unless such costs are consistent with the approved Plan.

Progress Reports:

Public Utilities Code Section 8388.5(f)(1) requires large electrical corporations with approved Plans and conditionally approved Applications to file progress reports every six months with both Energy Safety and the Commission. ~~Because the progress reports are filed with multiple agencies and at the same time, these~~

[26] Recovery period means the period under consideration in the most recent Phase 3 Application filing.

~~*Guidelines* anticipate that Energy Safety and Commission staff will collaborate to develop a singular set of requirements for these reports. Aligning the requirements for these progress reports may eliminate any unnecessary duplication of effort and optimize efficiency of available resources. However, it is possible that each agency will require distinct information in the progress report. Staff understand that Energy Safety plans to detail its requirements in a forthcoming set of guidelines.~~ Accordingly, without affecting the required progress report elements specified by Energy Safety, these *Guidelines* require that the ~~6~~six-month progress reports shall include, but should not be limited to, the following:~~[27]~~

1) Total recorded costs to date;
2) Third-party funds received, with an explanation of how third-party funding was used to reduce the burden on ratepayers;
3) Average recorded CBR for completed projects in any given two-year period;
4) Average recorded unit cost per mile of undergrounding for completed projects in any given two-year period;
5) Miles of overhead replaced by undergrounding by circuit ~~protection zone or isolatable circuit~~ segment;
6) Miles of undergrounding completed by circuit ~~protection zone or isolatable circuit~~ segment;
7) GIS data showing location and status of each project (in Geodatabases or other suitable format); ~~[28]~~
8) An updated list of all third-party funding the large electrical corporation has applied for, as specified in Application Requirements ~~13-15~~19-21; and
9) Total and average avoided costs and workpapers showing calculation of avoided costs.
10) An updated dataset that follows the requirements of the *SB 884 Project List Data Requirements Guidelines.*

At a minimum, the six-month progress reports filed by a large electrical corporation shall include an update of the *SB 884 Project List Data Requirements Guidelines* in Appendix 2, as well as any other reporting requirements in the *Energy Safety Guidelines*, the Phase 2 Decision(s), and the Phase 2 Application Requirements listed above. Large electrical corporations shall file and serve the six-month progress reports in the applicable Phase 2 Application docket. Parties may review, file, and serve opening comments on the progress report in the Phase 2 Application docket no later than 42 days (or such period specified in the Phase 2 Decision) after the progress report is filed and served by the large electrical corporation. Reply comments on the progress report may be filed and served in the Phase 2 Application docket no later than seven (7) days (or such period specified in the Phase 2 Decision) after the due date for opening comments.

Audit of the One-Way Balancing Account:

An audit of the one-way balancing account shall occur annually (hereafter, EUP Audit). The EUP Audit shall begin no later than 60 days (or such period specified in the Phase 2 Decision) after the due date for reply comments on the second six-month progress report in a given 12-month period. Each EUP Audit shall review EUP projects that become used and useful during the 12-month period covered by the audit.

~~[27] Staff reserve the right to amend the below listed progress report requirements following consultation and coordination with Energy Safety.~~

~~[28] Data requirements to be aligned with those specified in Energy Safety guidelines.~~

Each EUP Audit may also review recorded costs of projects or portions of projects that are not used and useful and may recommend refunds.

The primary objective of an EUP Audit is to determine whether the costs recorded in the large electrical corporation's balancing account have met all nine[29] Phase 2 Conditions. The audit shall also verify whether the recorded costs have met the following secondary objectives set forth in SPD-37:

1) Verify that projects are "used and useful;"
2) Determine whether the recorded costs are incremental – and do not duplicate costs allowed through another decision, mechanism or received from a third party; and
3) Validate that the methodology used to calculate a CBR, and the CBR results for a given project comply with the *CBR Calculation Guidelines* (See Appendix 1).

A Phase 2 Decision may also add primary and/or secondary objectives for the Audits specific to that EUP.

In its Phase 2 Application, as required by Application Requirement #26, a large electrical corporation shall propose the methodology for the auditor to determine whether the costs of undergrounding projects recovered via the one-way balancing account meet the primary and secondary objectives. The Phase 2 Decision will include the Commission's determination on the appropriate methodology to be used by the auditor to determine whether the primary and secondary objectives are met. In addition, any data that should be reviewed by the auditor, beyond what is submitted to the Commission in six-month progress reports, will be determined in the Phase 2 Decision. The auditor may also request information and conduct interviews with large electrical corporation personnel, including custodians of records, to gather information for the audit.

The EUP Audit will result in an audit report that will be filed and served to the Phase 2 Application docket within five (5) days (or such period specified in the Phase 2 Decision) of its completion and approval. The audit report shall be completed within six months (or such period specified in the Phase 2 Decision) after it is initiated.[30] Parties may file and serve opening comments on the audit report in the Phase 2 Application docket no later than 20 days (or such period specified in the Phase 2 Decision) after the audit report is filed and served by the large electrical corporation. Reply comments on the audit report may be filed and served in the Phase 2 Application docket no later than five days (or such period specified in the Phase 2 Decision) after the due date for opening comments. If a Party believes a refund is necessary based on the audit report, they may file a petition for modification requesting to reopen the Phase 2 Application proceeding and set forth the amount of the refund and the reasons for it in the petition. The Commission may also determine the appropriateness of reopening the Phase 2 Application proceeding based on its own review as described below.

Following its review of the audit report, six-month progress reports, associated comments, and any petitions received, the Commission may reopen the Phase 2 Application proceeding to consider the need for refunds. If the Commission reopens the Phase 2 Application proceeding, for projects that do not meet the primary objectives and/or one or more of the secondary objectives, the Commission may direct the large electrical corporation to refund related project costs to ratepayers in a subsequent decision. If the Commission directs

[29] The EUP Audit scope will also include any Phase 2 Conditions adopted in the Phase 2 Decision beyond the nine listed herein.

[30] Staff are authorized to extend the deadline for the audit report should a determination be made that such an extension is necessary to adequately complete the audit.

a large electrical corporation to issue a refund, the large electrical corporation shall not seek to recover such costs through any other means.

The large electrical corporation shall not have input into the direction, focus, or outcome of the EUP Audit that goes beyond the input afforded to other Parties to the Commission's SB 884 proceeding or process. The large electrical corporation shall provide access to all information requested by the auditor and SPD to carry out the audit within five days (or such period specified in the Phase 2 Decision) of each data request. The large electrical corporation shall also make personnel available for interviews on five days' notice (or such period specified in the Phase 2 Decision) if the auditor seeks substantive information and a custodian of records for questions about the location and content of requested information.

Wildfire Mitigation Plan Integration:

Public Utilities Code Section 8388.5(f)(2) requires large electrical corporations to include ongoing work plans and progress relating to their undergrounding plans in annual wildfire mitigation plan filings. Staff ~~understands~~understand that further guidance on incorporating this information into annual wildfire mitigation plan filings will be provided by Energy Safety.

Compliance Reports:

Public Utilities Code Section 8388.5(f)(3) requires a large electrical corporation with an approved Plan and conditionally approved Application to hire an independent monitor selected by Energy Safety. The independent monitor must assess whether the large electrical corporation's progress on undergrounding work is consistent with the objectives identified in its approved Plan.[31] For each year the Plan is in effect, the independent monitor must annually produce a compliance report detailing its assessment by December 1.[32] The independent monitor's compliance report must also specify any failure, delays, or shortcomings of the large electrical corporation and provide recommendations for improvements to accomplish the objectives set forth in the approved Plan.[33] The large electrical corporation shall have 180 days to correct and eliminate any deficiency specified in the independent monitor's report.[34] Energy Safety shall consider the independent monitor's compliance report and whether the large electrical corporation cured the deficiencies identified therein when making its determination on whether to recommend penalties to the Commission.[35]

~~Changes to the Plan:~~

~~The procedures for considering a large electrical corporation's request to change elements of its Plan will be determined by the Commission in coordination with Energy Safety in a subsequent process.~~

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

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

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

[34] Public Utilities Code, Section 8388.5(g)(2).

[35] Public Utilities Code, Section 8388.5(i)(1).

Penalties:

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

Attachment 11

TURN's Opening Comments on Draft SPD-37 (9/4/25)

COMMENTS OF THE UTILITY REFORM NETWORK (TURN) ON DRAFT RESOLUTION SPD-37 IMPLEMENTING SB 884

September 4, 2025

Elise Torres, Energy Team Assistant Managing Attorney
etorres@turn.org

A Mireille Fall, Staff Attorney
afall@turn.org

Thomas Long, Outside Counsel
tomjlong@sbcglobal.net

THE UTILITY REFORM NETWORK
360 Grand Avenue, #150
Oakland, California 94610
(415) 929-8876

SUMMARY OF RECOMMENDED CHANGES

<u>Costs that May Not Be Recovered</u>

- Clarify that costs that do not satisfy the Phase 2 Conditions and secondary objectives may not be recovered via the one-way balancing account and *shall* be refunded if previously recovered in rates.

- Draft SPD-37 should be revised to make it clear the memorandum account (if adopted) is not a second chance to recover costs that are found not to meet Phase 2 Conditions or secondary objectives.

-

<u>Audit and Refund Process</u>

- Costs found by the audit report to have not satisfied the Phase 2 Conditions or secondary objectives will be refunded to ratepayers through a Commission Resolution based on the audit report.

- TURN continues to urge the up-front process for review and approval of costs booked to the one-way balancing account described in its April 25, 2025 Comments, pages 10-12. The following recommendations are alternatives in the event this up-front review process is not adopted.

- The opening/reply comment period for comments on the audit report should be changed from 20/5 days to 42/7 days.

- The Draft Resolution's refund process should be modified to allow a more timely and streamlined process to issue refunds, when warranted, via an Audit Refund Resolution, using the following procedure:

    - Based on its review of the audit reports and the comments thereon, the Commission Staff should issue a Draft Audit Refund Resolution ordering any refunds determined to be warranted based on that review. Parties should have 20/5 days for opening and reply comments. After consideration of the comments, which could lead to revisions to the Draft Resolution, the Commission would vote and adopt a final Audit Refund Resolution, which would order any refunds found to be warranted and specify the mechanism for making those refunds to customers.

  - The petition for modification (PFM) option would continue to be available to a party that believes the Audit Refund Resolution did not order sufficient refunds, such as, for example, because of an omission in the auditor's review. In addition, as a matter of fairness, the utility would have the opportunity to submit a PFM if it believes the Audit Refund Resolution ordered excessive refunds. Any such petition would be required to satisfy the Commission's rules and requirements regarding such submissions, including any additional requirements that may be specified in the Phase 2 Decision.

  - The Commission should retain its discretion to reopen the Phase 2 decision on its own motion if it believes other issues not addressed in the Audit Refund Resolution warrant additional refunds.

- The Commission should specify a three-business-day response period for data requests to utilities regarding: (1) the six-month progress reports; and (2) issues raised by the audit report.

<u>Memorandum Account Cap</u>

- If the memorandum account is adopted, it should be limited to costs that exceed the annual cost cap amounts (Phase 2 Condition One). TURN recommends imposing a cap on the memo account of 10% of the total sum of the 10 years of cost caps placed on the one-way balancing account.

<u>Additional Phase 2 Approval Conditions and Application Requirements</u>

- The First New Phase 2 Condition should be revised to require comparison of all reasonable alternative mitigations.

- The CBR Calculation Guidelines should be modified to require utilities to provide an alternative CBR based on the estimated present value of the lifetime revenue requirements associated with capital spending for a given project.

TABLE OF CONTENTS

TABLE OF AUTHORITIES

Statutes

Comments of The Utility Reform Network (TURN)
On Draft Resolution SPD-37 Implementing SB 884

The Utility Reform Network (TURN) submits these comments on Draft Resolution SPD-37 (Draft SPD-37) pursuant to the August 15, 2025, cover letter accompanying Draft SPD-37.

1. Introduction and Summary

TURN appreciates the CPUC's efforts to implement Senate Bill (SB) 884 in a way that is faithful to the complex structure and provisions of that legislation. Draft SPD-37 includes several improvements in the form of ratepayer protections as compared to SPD-15. In particular, the additional audit objectives and Phase 2 Application Requirements and Conditions adopted in Draft SPD-37 strengthen Commission oversight. TURN also appreciates the efforts to develop uniform requirements for calculating Cost Benefit Ratios and generally supports the *CBR Calculation Guidelines* in Appendix 1. However, there are several aspects of Draft SPD-37 that warrant reconsider as they inhibit the Commission's mission to ensure just and reasonable rates and thus violate P.U. Code Section 451. These comments recommend several changes to Draft Resolution SPD-37 to correct legal and factual errors and to set the Electric Undergrounding Plan (EUP) process up for success from a ratepayer perspective and to prevent structural incentives for the utilities to pursue or continue imprudent projects.

Appendix A to these comments includes a mark-up of the Findings of Fact and Appendix B includes a mark-up of Attachment A to Draft SPD-37, the SB 884 Program Guidelines, to show TURN's recommended changes.

2. Draft Resolution SPD-37 Should Be Revised to Clarify that Costs that Do Not Satisfy One or More of the Phase 2 Conditions or the EUP Audit Secondary Objectives Will Not Be Recoverable

Draft SPD-37 affords utilities two opportunities to add costs of undergrounding projects to rates if a utility's Phase 2 application for conditional approval of plan costs is approved: (1) via a one-way balancing account to recover costs up to annual capped amounts; and (2) via a Phase 3 cost recovery application to recover costs that are recorded to a memorandum account. Draft SPD-37 states that the amount of EUP costs that will be authorized to recover in rates via the balancing account will be contingent on the utilities meeting nine minimum conditions for conditional approval, which the Draft SPD-37 refers to as "Phase 2 Conditions".[1] The DR also adopts three "secondary objectives" that will be verified during the EUP Audit of costs recorded to the one-way balancing account and notes that a Phase 2 Decision may add additional objectives.[2]

Even though the Phase 2 Conditions are presented as ratepayer protections that *must* be satisfied for costs to be recovered in rates, Draft SPD-37 contains language that is at odds with this principle. First, with respect to costs in the one-way balancing account, Draft SPD-37 says only that costs that violate the Phase 2 Conditions or secondary objectives "may" -- not "shall" -- be refunded to ratepayers.[3] Second, Draft SPD-37 would allow costs that run afoul of the Phase 2 Conditions or secondary objectives to be booked to the memorandum account and potentially recovered in Phase 3.[4] As discussed below, the result is an internally contradictory Draft Resolution that must be modified to make clear that the Phase 2 Conditions and secondary objectives will be consistently enforced in order to satisfy the just and reasonable requirement of P.U. Code Section 451.

2.1. Draft SPD-37 Should Be Modified to Make Clear that One-Way Balancing Account Costs that Fail to Satisfy the Phase 2 Conditions or Secondary Objectives 'Shall' Be Refunded Via the Audit Process

The structure and intent of SPD-15 and Draft SPD-37 appear to be that costs that fail to satisfy the Phase 2 Conditions or secondary objectives[5] are not recoverable in rates. For example, Draft SPD-37 includes the following passage:

> The Phase 2 Conditions are a central feature of the guidelines. These conditions provide direction to large electrical corporations on the amount of EUP costs that will be authorized to recover in rates via the balancing account, while ensuring ratepayer interests are protected. The conditions provide regulatory clarity and certainty for large electrical

---

[1] Draft Resolution (DR) SPD-37, pp. 2-3, stating that recovery of costs in the one-way balancing account will be "contingent on the satisfaction of conditions placed on approval." Consistent with SPD-15, Draft SPD-37 states that the Phase 2 decision may add additional Phase 2 Conditions. *Id.,* Attachment A (CPUC Guidelines), p. 13, item 9.

[2] DRSPD-37, pp. 27-28.

[3] DR SPD-37, p. 29, and Attachment A (CPUC Guidelines), p. 4.

[4] DR SPD-37, p. 13 and Attachment A (CPUC Guidelines), p. 4.

[5] Particularly, with respect to the secondary objectives, the "used and useful" and incrementality requirements. DR SPD-37, p. 28.

> corporations while ensuring EUP costs borne by ratepayers are just and reasonable. Under the SPD-15 framework, an audit and refund process is necessary for the one-way balancing account. The large electrical corporation initially asserts that EUP project costs have met the Phase 2 Conditions upon recording in the one-way balancing account. It is only during the audit process that the Commission verifies whether the Phase 2 Conditions were met (Primary Objectives).[6]

This passage correctly states that adherence to the Phase 2 Conditions is essential to "ensure" ratepayer interests are protected and the just and reasonable requirement is satisfied. The CPUC Guidelines similarly state that the Commission will authorize recovery of costs via the one-way balancing account "[o]nly if" costs meet the Phase 2 Conditions.[7] Furthermore, in discussing the secondary objectives, the Commission states, "(a)dditional safeguards are necessary for the audit to ensure that ratepayers only bear costs that the auditor finds meet the Phase 2 Conditions and secondary objectives."[8]

Given Draft SPD-37's seeming conviction regarding the need to limit rate recovery to costs that satisfy the Phase 2 Conditions and secondary objectives, it is puzzling that the Guidelines waffle on this point: "If an audit demonstrates any costs recorded to the one-way balancing account did not meet the Phase 2 Conditions, subject to Commission review and determination, such costs *may* be subject to refund."[9] The Draft Resolution does not explain the use of the word "may" in this context or suggest situations in which one-way balancing account costs that fail to satisfy the Phase 2 Conditions or secondary objectives would nevertheless be recoverable. Instead, as noted, the structure and intent of Draft SPD-37 seems clear that such costs are not recoverable and shall be refunded in previously recovered in rates.

Accordingly, to ensure that the final Resolution is consistent with the purpose and intent of the Phase 2 Conditions and secondary objectives – and Section 451's just and reasonable requirement -- Draft SPD-37 should be revised to clarify that one-way balancing account costs that are found to not satisfy the Phase 2 Conditions and secondary objectives "shall" be refunded to

---

[6] DR SPD-37, p. 11.

[7] DR SPD-32, Attachment A (CPUC Guidelines), p. 4.

[8] DR SPD-37, p. 26.

[9] DR SPD-37, Attachment A (CPUC Guidelines), p. 4 (emphasis added).

ratepayers. In Appendix B, TURN recommends changes to the CPUC Guidelines to effectuate this clarification.

2.2. Draft SPD-37 Should Be Modified to Not Allow Utilities to Use the Memorandum Account to Gain Recovery of Costs that Fail to Satisfy the Phase 2 Conditions or Secondary Objectives

As currently written, Draft SPD-37 would allow utilities to use the memorandum account as a vehicle to seek recovery of costs that do not meet the Phase 2 Conditions.[10] Draft SPD-37 never explains why the Phase 2 Conditions, which are described as a "central feature" of the CPUC Guidelines and an essential ratepayer protection to ensure compliance with Section 451's just and reasonable requirement, should be allowed to be circumvented in Phase 3. Nor does Draft SPD-37 offer any standards that would justify recovery of such costs.

Instead, as discussed in the previous section, the structure and apparent intent of Draft SPD-37 is for costs that fail to satisfy the Phase 2 Conditions to *never* be recoverable. Further supporting this point is the provision in Draft SPD-37 that, if the Commission directs a utility to refund costs because of failure to satisfy the Phase 2 Conditions, the utility "shall not seek to recover such costs through any other means."[11]

The Commission should revise Draft SPD-37 to make it clear that the memorandum account is not a second chance to recover costs that are found not to meet Phase 2 Conditions or secondary objectives. Otherwise, there is little incentive for the utility to book only compliant costs to the one-way balancing account. Draft SPD-37 itself recognizes this risk, noting the Commission "must prevent the memorandum account from becoming a structural incentive to continuing work on imprudent projects."[12] The best and only real way to prevent the memorandum account from becoming an incentive to the utilities to continue to pursue undergrounding projects that are imprudent and non-compliant with the Phase 2 Conditions and secondary objectives is to revise

---

[10] DR SPD-37, p. 13 and Attachment A (CPUC Guidelines), p. 4.

[11] DR SPD-37, p. 29 and Attachment A (CPUC Guidelines), p.18.

[12] DR SPD-37, p. 22.

Draft SPD-37 to expressly prohibit the utility from recording any costs to the account for projects that do not satisfy the Phase 2 Conditions and secondary objectives.

In Appendix B, TURN recommends changes to the CPUC Guidelines to reflect this recommendation

3. The Draft Resolution's Audit and Refund Process Should Be Revised to Require Refunds Based on the Audit Findings, Without Requiring Ratepayers to Wait for the Disposition of a Petition for Modification Process

The Draft Resolution would adopt a process that allows the utility to defer refunds of costs found by the auditor to violate Phase 2 Conditions or secondary objectives until the resolution of a petition for modification (PFM) process of uncertain duration and procedural complexity.[13] Even if an auditor clearly documents costs that should be refunded, the Draft Resolution does not require that such findings be promptly implemented in a refund order. As discussed below, the process should be modified to require more timely refunds of such costs via an Audit Refund Resolution.

3.1. An Audit Refund Resolution Would Allow for More Timely and Streamlined Refunds of Costs that Fail to Meet Phase 2 Conditions or Secondary Objectives

Under the Draft Resolution, a utility could impose unduly high rates on its customers for years before being required to refund costs improperly recovered via the one-way balancing account. Although SPD-15 and Draft SPD-37 have yet to explain how a utility will recover costs booked to the one-way balancing account,[14] it appears that the utility would be allowed to initially make its own determination of whether costs are eligible for rate recovery, a process that TURN continues to oppose as blatantly contrary to SB 884.[15] Draft SPD-37 states, "(T)he large electrical

---

[13] Draft Resolution, p. 29, providing that a party seeking refunds based on the audit report must either file a PFM of the Phase 2 decision or wait for the Commission to reopen the Phase 2 proceeding on its own motion.

[14] Draft SPD-37 (p. 4, fn. 4) makes clear that "costs can only be recovered once the undergrounding project is considered used and useful." This means, that unlike a decision in a GRC, rates and revenue requirement will not be changed based on the Phase 2 decision, but instead must await a project becoming used and useful. However, Draft SPD-37 does not explain the process that utilities will be required to use to move costs of used and useful projects into rates.

[15] As TURN explained in its April 25, 2025 comments (pp. 10-11), P.U. Code Section 8388.5(e)(1) directs the commission to authorize recovery of "recorded" costs, *i.e.,* costs recorded to the one-way balancing account, only if *the Commission* has "determined" that they are just and

corporation initially asserts that EUP project costs have met the Phase 2 Conditions upon recording in the one-way balancing account. It is only during the audit process that the Commission verifies whether the Phase 2 Conditions were met (Primary Objectives)."[16] Accordingly, the Audit will play a crucial role in evaluating whether the Phase 2 Conditions or secondary objectives have been satisfied.

Yet, under Draft SPD-37, the utility would keep those funds even after an independent auditor found that costs failed to satisfy one or more Phase 2 Conditions or secondary objectives, violating the statutory requirement in P.U. Code Section 451 that rates be just and reasonable. A ratepayer representative organization would be required to take the additional step of submitting a PFM of the Phase 2 decision to gain refunds of costs identified by the auditor as improperly added to rates. Under Commission procedure, there is no timetable for resolution of a PFM, which can often take 12 months or longer. Because it is unknown what procedures would be followed in a reopened proceeding, the utility could seek and obtain significant additional procedural hurdles to postpone refunds. At a minimum, intervenors would need to devote some of their limited resources to opposing such hurdles.

Thus, the structure of the Draft Resolution is to enable utilities to retain funds that they *self-determined* to be appropriate for inclusion in rates and to force ratepayer representatives to use a PFM process of an uncertain duration and procedural complexity to attempt to gain refunds, even after an auditor found that the utility should never have included the costs in rates.[17] Such a one-sided, protracted process is unfair to ratepayers, particularly those who paid the excessive rates and are no longer customers when refunds are finally issued. In addition, Draft SPD-37 could encourage the utility to take up-front recovery of costs that have no chance of satisfying the relevant conditions and requirements. Although presumably any costs ultimately refunded would include

---

reasonable. The Commission cannot make such a determination without independently assessing whether the costs satisfy the Phase 2 conditions and other requirements. Accordingly, TURN continues to recommend adoption of the process for determining satisfaction with the Phase 2 Conditions and other requirements described at pages 11-12 of TURN's April 25, 2025 comments.

[16] Draft SPD-37, p. 11.

[17] The Draft Resolution (p. 29) states that the Commission may also reopen the Phase 2 proceeding based on its own review, but no timelines are provided for such a process.

interest (the refund interest requirements have yet to be addressed in SPD-15 or Draft SPD-37), if the interest rate were lower than the utility's weighted average cost of capital, the utility could exploit its captive customers to gain significant cash flow benefits from improperly booking costs to the one-way balancing account.

The Commission should not adopt such an unfair and protracted process for customers to be able to gain refunds of costs they never should have paid. Nor should the Commission provide an incentive for a utility to include excessive costs in its one-way balancing account. If the Commission continues to reject TURN's recommendation to undertake an expedited process to assess satisfaction with the Phase 2 Conditions and other requirements before allowing rate recovery, the Draft Resolution should at least be modified to require a more timely and streamlined refund process.

TURN's recommendation is thus that Draft SPD-37's audit and refund process be modified to implement via a Commission Resolution any audit-based refunds the Commission finds to be warranted. Based on the auditor report and opening and reply comments from the parties on that report, the Commission should issue an Audit Refund Resolution to order refunds of any costs found to have violated a Phase 2 Condition or secondary objective. The Audit Refund Resolution should include an explanation of any determination not to order refunds of costs recommended for refund in the audit report. While the PFM process would still be available, the need to resort to such a process will likely be reduced or eliminated under TURN's recommendation.

The following are the details of the changes TURN recommends to Draft SPD-37's audit and refund process, which are reflected in TURN's proposed revisions to the CPUC Guidelines, found in Appendix B to these comments.

- To allow sufficient time for parties to review and provide meaningful comments on the audit report, the comment period on the audit report should be changed from 20/5 days to 42/7 days for opening/reply comments.[18] In addition, as discussed below, to ensure comments are based on accurate information, parties should be allowed a three-business-day turnaround on data requests to utilities regarding issues raised by the auditor report.

---

[18] TURN's recommended comment intervals conform to Draft SPD-37's intervals for comments on the six-month progress reports. Attachment A to Draft SPD-37, p. 14.

- Based on its review of the audit reports and the comments thereon, the Commission Staff should issue a Draft Audit Refund Resolution ordering any refunds determined to be warranted based on that review. Parties should have 20/5 days for opening and reply comments. After consideration of the comments, which could lead to revisions to the Draft Resolution, the Commission would vote and adopt a final Audit Refund Resolution, which would order any refunds found to be warranted and specify the mechanism for making those refunds to customers.

- The PFM option would continue to be available to a party that believes the Audit Refund Resolution did not order sufficient refunds, such as, for example, because of an omission in the auditor's review. In addition, as a matter of fairness, the utility would have the opportunity to submit a PFM if it believes the Audit Refund Resolution ordered excessive refunds. Any such petition would be required to satisfy the Commission's rules and requirements regarding such submissions, including any additional requirements that may be specified in the Phase 2 Decision.

- The Commission would retain its discretion to reopen the Phase 2 decision on its own motion if it believes other issues not addressed in the Audit Refund Resolution warrant additional refunds.

TURN notes that Draft SPD-37 states that its audit process would "reduc[e] the time and effort needed to determine if the [utility] should issue ratepayer refunds."[19] TURN fully supports this goal but believes that TURN's recommended approach would further reduce the time and effort needed to implement refunds of excessive rates. TURN's approach provides a more certain and streamlined path to refunds, while still allowing parties to make informed comments on the refund issues raised by the audit report.

3.2. Three-Business-Day Discovery Turnaround Is Warranted for Data Requests to Utilities Regarding the Six-Month Progress Reports and for Issues Raised by the Audit Reports

The Draft Resolution includes a requirement for utilities to respond to discovery requests within five business days.[20] While TURN supports this rule as a general matter, TURN

---

[19] Draft Resolution SPD-37, p. 27.

[20] Attachment A to Draft Resolution SPD-37 (CPUC Guidelines), p. 5.

recommends a shorter three-business-day response period in two instances: (1) for data requests to the utility related to the six-month progress reports; and (2) for data requests to the utility regarding issues raised by the audit reports. In Appendix B to these comments, TURN has recommended corresponding revisions to the CPUC guidelines.

In these instances, parties will have a limited time to provide comments, 42 days for opening comments in the case of the six-month progress reports and under TURN's recommended process for comments on the audit reports.[21] With such a short comment period, a reduced response time is needed to enable parties to conduct the necessary two to three rounds of discovery (which includes follow-up on prior responses) and then to analyze those responses for incorporation, as appropriate, in comments. The result will be a better record for the Commission's determinations regarding whether refunds are warranted, and in what amounts. A three-day response period is now common practice for parties seeking discovery regarding Wildfire Mitigation Plans submitted to OEIS, where parties have a similarly short period for submitting comments.

Accordingly, TURN recommends that Draft SPD-37 be modified to specify a three-business-day response period for data requests to utilities in these two limited instances.

4. The Memorandum Account Cost Cap Should be 10% of the Total Sum of the 10 Years of Annual Cost Caps

The Commission's discussion of the memorandum account cap determines "it is prudent to include a cost cap on the memorandum account but defers establishment of the specific amount of the cap to the Phase 2 Application proceeding."[22] TURN strongly agrees that, if the memorandum account is adopted, it is prudent to have a firm cost cap on the amount that can be recorded to the memorandum account and urges the Commission to set the upper bounds of the cap now. If the memorandum account in DR SPD-37 is retained, then it should be limited to costs that exceed the annual cost cap amounts (Phase 2 Condition One) and, as discussed in Section 2.2 above, exclude costs that fail to satisfy the Phase 2 Conditions or secondary objectives. TURN recommends

---

[21] As discussed in the previous section, TURN recommends that Draft SPD-37's intervals for opening/reply comments on the audit report be changed from 20/5 days to 42/7 days, the same intervals as apply to the six-month progress report comments.

[22] DR SPD-37, p. 23.

imposing a cap on the memo account of 10% of the total sum of the 10 years of annual cost caps placed on the one-way balancing account.[23]

5. TURN's Recommended Modifications to the Additional Application Requirements and Phase 2 Conditions for Approval

Draft SPD-37 adopts additional application requirements to "(1) align programmatic information required by the Energy Safety Guidelines and CPUC Guidelines, (2) clarify the procedure for an audit, (3) add new data reporting requirements pursuant to SPD-15's directive, and (4) provide additional information needed to ensure the Commission can effectively assess cost recovery for EUPs."[24] TURN commends the work that has gone into these additional application requirements and supports them. Draft SPD-37 also adopts additional Phase 2 Conditions, including a condition requiring the forecasted CBR of a proposed undergrounding project to exceed the CBR of alternatives to that project.[25] TURN supports these additional conditions and applauds the Commission's recognition that undergrounding projects must be more cost-effective than feasible alternatives. The following suggested revisions are intended to strengthen the requirements, not to criticize them.

The first new Phase 2 Condition is a vital safeguard. It requires that "[t]he forecasted CBR of the undergrounding project . . . exceed the forecasted CBR of all alternative mitigations considered for that project by a certain threshold value, which is to be determined in the Phase 2 Decision."[26] As currently phrased, however, it introduces ambiguity into the process and may permit a utility to exclude reasonable alternatives simply by not "considering" them. The language should instead require that "the forecasted CBR of the undergrounding project must exceed the

---

[23] TURN maintains its position that no memorandum account should be allowed because a memorandum account violates the cost control requirements of SB 884. TURN April 25, 2025 Comments, pp 2-5. This section provides an alternative recommendation if the memorandum account is adopted.

[24] DR SPD-37, p. 12.

[25] DR SPD-37, p. 19.

[26] DR SPD-37, p.19.

forecasted CBR of all *reasonable* alternative mitigations *available* for that project. . . ." In Appendix B, TURN recommends revisions to the CPUC Guidelines to reflect this change.

TURN also appreciates the Staff's efforts to develop uniform requirements for calculating CBRs and generally supports the CBR Calculation Guidelines. However, as TURN understands Section 2.5 of those CBR Guidelines, with respect to calculating capital costs for the denominator of the CBR, the utility need only provide the present value of the *direct capital costs*, not the present value of the *lifetime revenue requirements associated with capital spending*. As a result, the costs would exclude key elements such as rate of return, taxes, and other loaders and could significantly understate the total costs that ratepayers would be required to pay. Utilities should therefore be required to provide an alternative CBR calculation based on the estimated present value of the lifetime revenue requirements associated with a project's capital spending. The Commission has clear authority under Pub. Util. Code § 739.15 to require such estimates, and good-faith projections — even if based on assumptions — would provide a far more accurate representation of total costs than direct capital costs alone. Because utilities will eventually calculate the revenue requirement impacts when they seek recovery, it is feasible to include those estimates at the application stage. Transparency on full lifetime revenue requirements will significantly improve the Commission's ability to assess whether projects are just and reasonable.

In sum, TURN appreciates the Commission's efforts to strengthen oversight of undergrounding project applications through new Phase 2 Application Requirements and Phase 2 Conditions. By tightening the comparison standard for alternatives and closing the memorandum account loophole, the Commission can ensure that undergrounding investments are evaluated transparently and approved only when demonstrably cost-effective and just and reasonable.

The following are the details of the changes TURN recommends to Draft SPD 37's Additional Application Requirements and Phase 2 Approval Conditions:

- The First New Phase 2 Condition should be revised to require comparison of all reasonable and available alternative mitigations.
- The CBR Calculation Guidelines should be modified to require utilities to provide an alternative CBR based on the estimated present value of the lifetime revenue requirements associated with capital spending for a given project.

6. Conclusion

For the reasons set forth above, Draft SPD-37 should be revised as described in these comments and in Appendices A and B.

Dated: September 4, 2025

Respectfully submitted,

By: __________/s/_____________
Elise Torres

Elise Torres, Energy Team Assistant Managing Attorney
etorres@turn.org

THE UTILITY REFORM NETWORK

APPENDIX A

TURN Redline of Recommended Changes to Findings of Fact

(Additions are in *italics* and deletions are shown by ~~strikeout~~)

11. A large electrical corporation will not be required to obtain Energy Safety approval of undergrounding projects it intends to construct *during the EUP period* after Energy Safety approves its EUP.

19. Stakeholders generally agreed at the April 8, 2025, workshop that it may be valuable to include cost caps on the memorandum account, *but some parties argued* setting a specific number for such cap could be premature before total EUP costs and other project details are known after the Phase 2 Application is filed.

20. It is prudent to establish an upper bound on the total potential costs of an EUP by capping the total costs recovered from the memorandum account at ~~a~~ *10* percent~~age~~ of the total sum of the 10 years of cost caps placed on the one-way balancing account.

~~21. The percentage value of the memorandum account cost cap should be established in the Phase 2 Decision~~.

25. Additional primary and/or secondary objectives for an EUP Audit may be included in the Phase 2 Decision. *Costs recorded to the balancing account that do not satisfy the Phase 2 conditions and/or secondary objectives of the EUP Audit shall be refunded to ratepayers.*

Insert the following Finding after Finding 29:

29A. It is reasonable for the Commission to order refunds of previously recovered costs, when warranted, in an Audit Refund Resolution, based on the audit report and comments on that report.

APPENDIX B

TURN Redline of Recommended Changes to Attachment A of Draft SPD-37

SB 884 Program: CPUC Guidelines

Summary of TURN's Recommended Revisions to Draft Resolution SPD-37 Attachment A

SB 884 Program: CPUC Guidelines

Description of TURN's Revisions	Location of Proposed Revisions[1]
Clarify that the audit will assess whether costs satisfy the Phase 2 conditions *and the secondary objectives listed on page 16.*	- Pages 4-5
Make clear that costs that do not meet any of the Phase 2 Conditions or secondary objectives that were booked to the one-way balancing account and added to rates *shall* be refunded.	- Pages 4-5
Increase the time for opening and reply comments on the audit report from 20/5 days to 42/7 days.	- Page 17, first paragraph
Costs found by the audit report to have not met any of the Phase 2 Conditions or secondary objectives will be ordered refunded to ratepayers in an Audit Refund Resolution based on the audit report and the comments thereon. The proposed revisions address the Audit Refund Resolution process.	- Page 4, second paragraph - Page 17, first paragraph
Parties who disagree with the Audit Refund Resolution may seek, via a Petition for Modification (PFM) of the Phase 2 decision, either: (1) a decision ordering additional refunds or (2) a decision finding that the refunds ordered in the Audit Refund Resolution were excessive and ordering an offsetting addition to rates.	- Page 4, first paragraph - Page 17, first paragraph
Make clear that the memorandum account is limited to costs that exceed the annual cost caps determined in Phase 2 Condition Number 1, as adjusted by external costs in accordance with Phase 2 Condition Number 2.	- Page 4, second paragraph - Page 4, third paragraph - Page 14, first paragraph under heading "Phase 3 – Review of . . ."

[1] TURN converted the *SB 884 Program: CPUC Guidelines* portion of the Draft Resolution to Word in order to track TURN's proposed changes in redline. This resulted in some pagination changes. The page numbers referenced here refer to the version of the SB 884 Program: CPUC Guidelines attached to TURN's comments and may not align with the page numbers in the version included with the Draft Resolution.

Make clear that the Commission may, based on its own review, reopen the Phase 2 proceeding to order refunds in addition to those ordered in the Audit Refund Resolution.	- Page 17
Make clear that the memorandum account may not be used to recover costs that do not satisfy all of the Phase 2 Conditions (other than Condition 1, as adjusted by Condition 2) and all of the secondary objectives.	- Page 4, second paragraph - Page 4, third paragraph - Page 14, first paragraph under heading "Phase 3 – Review of . . ." - Page 15, first paragraph under first heading
Utilities shall respond to discovery requests related to their six-month progress reports within three (3) business days.	- Page 5, first full paragraph - Page 16, first full paragraph
Utilities shall respond to discovery requests related to issues raised by the audit report within three (3) business days.	- Page 5, first full paragraph - Page 17, first full paragraph
Make clear that Condition 4 requires the utility to compare the CBR of the undergrounding projects to the CBR of all reasonable alternative mitigations that are available to the utility.	- Page 13, Item 5 under Conditions for Approval of Costs

Attachment 12

TURN's Reply Comments on Draft SPD-37 (9/9/25)

REPLY COMMENTS OF THE UTILITY REFORM NETWORK (TURN) ON DRAFT RESOLUTION SPD-37 IMPLEMENTING SB 884

September 9, 2025

Elise Torres, Energy Team Assistant Managing Attorney
etorres@turn.org

A Mireille Fall, Staff Attorney
afall@turn.org

Thomas Long, Outside Counsel
tomjlong@sbcglobal.net

THE UTILITY REFORM NETWORK
360 Grand Avenue, #150
Oakland, California 94610
(415) 929-8876

SUMMARY OF RECOMMENDED CHANGES

In response to other parties' opening comments, TURN revises its Summary of Recommended Changes as follows (additions are shown in *italics*):

Costs that May Not Be Recovered

- Clarify that costs that do not satisfy the Phase 2 Conditions and secondary objectives may not be recovered via the one-way balancing account and *shall* be refunded if previously recovered in rates.

- Draft SPD-37 should be revised to make clear that the memorandum account (if adopted) is not a second chance to recover costs that are found not to meet Phase 2 Conditions or secondary objectives, *other than costs in excess of the cost caps determined under Condition One, as modified by the Third-Party Funding addressed in Condition Two*.

- *If the Commission nevertheless determines that the utility should have an opportunity to seek recovery, via the memorandum account, of costs that failed to meet certain Conditions for Approval of Plan Costs (referred to as Phase 2 Conditions), SPD-37 should clearly specify those particular conditions and that the utility must overcome a presumption against recovery in its Phase 3 application. Further, the Commission should specify certain core Conditions for Approval of Plan Costs, which at a minimum should include Conditions Three, Four, and Five (based on the numbering in the Attachment A CPUC Guidelines),[1] for which costs that fail to satisfy those conditions are not eligible for recovery via the memorandum account.*

Additional Phase 2 Approval Conditions and Application Requirements

- The First New Phase 2 Condition *(Condition 5)* should be revised to require comparison of all reasonable alternative mitigations *that are available for that project.*[2] *TURN would not oppose removing the words "by a certain threshold value", provided that this clarification is made.*

TURN clarifies its Memorandum Account Cap recommendation, as follows:

Memorandum Account Cap

- If the memorandum account is adopted, it should be limited to costs that exceed the annual cost cap amounts (Phase 2 Condition One, *as reduced by the Third-Party Funding addressed in Condition Two*). TURN recommends imposing a cap on the memo account of 10% of the total sum of the 10 years of cost caps placed on the one-way balancing account.

Otherwise, TURN's Summary of Recommended Changes is unchanged from TURN's opening comments.

---

[1] See Draft SPD-37, Attachment A, *SB 884 Program: CPUC Guidelines With Appendices*, p. 12.

[2] The word "available" for that project was included in TURN's opening comments but inadvertently excluded from TURN's Summary of Recommendations.

TABLE OF CONTENTS

TABLE OF AUTHORITIES

Statutes

CPUC Decisions

Reply Comments of The Utility Reform Network (TURN)
On Draft Resolution SPD-37 Implementing SB 884

The Utility Reform Network (TURN) submits these reply comments on Draft Resolution SPD-37 (Draft SPD-37) pursuant to the August 15, 2025, cover letter accompanying Draft SPD-37. These comments focus on responding to the opening comments of Pacific Gas and Electric Company (PG&E) and San Diego Gas and Electric Company (SDG&E). Space limitations preclude responding to all points raised in the utilities' opening comments. Accordingly, TURN's silence should not be viewed as agreement with the point in question.

1. The Commission Should Reject the Utilities' Proposed Changes to the Cost Benefit Ratio Calculation Guidelines

PG&E and SDG&E raise various objections to the Cost Benefit Ratio (CBR) Guidelines. First, they object to the requirement to use unscaled consequence values to calculate CBRs, claiming that the use of unscaled values is inconsistent with D.22-12-027.[3] However, they do not mention that a successor decision to D.22-12-027 requires utilities to provide unscaled values in their Data Templates for RAMP and GRC applications.[4] Moreover, the utilities fail to appreciate that allowing each utility to calculate CBRs using its own preferred and subjective scaling function defeats the goal of the guidelines to create uniform guidelines that facilitate a more streamlined audit and review process for balancing account costs. An auditor is not in a position to adjudicate the reasonableness of a utility's chosen scaling function.

Second, PG&E objects to the requirement to calculate reliability consequences on a more granular basis — breaking down the calculations by customer class (residential/non-residential) and location (HFTD/non-HFTD) — instead of allowing the single average value that PG&E prefers.[5] PG&E's objection — that all customers pay the same rate — completely misses the point that there are significant variations in consequence dollar values based on location of the risk event and affected customer type, such that SPD's more granular calculations yields far more accurate results than PG&E's average-based approach.

Third, PG&E and SDG&E argue that the utility should be able to choose to include secondary cost savings resulting from a mitigation in the CBR denominator, rather than in the numerator as Draft SPD-17 requires.[6] The CPUC should reject these arguments. It is entirely consistent with the current RDF framework to recognize all benefits from a mitigation, including any secondary cost savings that are reasonably forecast. Such cost savings are not appropriate to

---

[3] PG&E Op. Cmts., pp. 7-8; SDG&E Op. Cmts., pp. 3-4.
[4] D.25-08-032, pp. 121-122.
[5] PG&E Op. Cmts., p. 8.
[6] PG&E Op. Cmts., pp. 8-9; SDG&E Op. Cmts., pp. 2-3.

reflect in the costs of the mitigation in the CBR denominator, which as Draft SPD-37 states, could confusingly lead to negative CBRs.[7]

Finally, the Commission should reject PG&E's alternative proposal, in the event PG&E's requested changes are not made, to "pause" adoption of CBR Calculation Guidelines in favor of a further process including written proposals, workshops and comments.[8] The issues addressed in the CBR Guidelines were among the subjects of the April 8, 2025, workshop (including pre- and post-workshop questions) and were addressed in stakeholders April 25, 2025 comments. A re-do is not warranted just because PG&E does not like the results.

2. The Commission Should Reject Utility Proposals to Gut Condition Five Requiring a Showing that Undergrounding Is More Cost-Effective Than Alternatives

PG&E and SDG&E seek the removal of Condition 5 (First New Condition),[9] which would require the utility to show that the undergrounding project has a higher CBR than the alternatives.[10] The Commission should firmly reject this request. Draft SPD-37 correctly finds that this condition is necessary to "ensure that the optimal mitigation is selected for reducing risk in the most cost efficient manner."[11] This condition is consistent with SB 884's focus on a project-by-project examination of undergrounding's cost-effectiveness compared to the alternatives.[12] Notably, even SDG&E agrees that it is appropriate to require the undergrounding project's CBR to be greater than its alternatives.[13]

The Commission should also reject PG&E's alternative proposal, which would render the CBR comparison meaningless and replace it with PG&E's self-designated "net benefit" measure.[14] Measuring cost-effectiveness by the ratio of risk reduction benefits divided by cost has been the Commission's approved measure since adopting the D.18-12-014 settlement, *to which PG&E was a signatory*.[15] Despite PG&E's subsequent efforts, no Commission decision has endorsed net

---

[7] Draft SPD-37, pp. 32-33.
[8] PG&E Op. Cmts., pp. 9-10.
[9] Draft SPD-37 lists the New Phase 2 Conditions on page 19 and provides a full list of the Phase 2 Conditions ("Conditions for Approval of Plan Costs") in Attachment A, *SB 884 Program: CPUC Guidelines With Appendices*, p. 12.
[10] PG&E Op. Cmts., p. 11; SDG&E Op. Cmts., p. 6.
[11] Draft SPD-37, p. 20.
[12] TURN April 25, 2025 Comments, pp. 1-2, citing Public Utilities Code Sections 8388.5(c)(4) and 8388.5(e)(1)(A).
[13] SDG&E Op. Cmts., p. 6 (recommendation re Condition 5).
[14] PG&E Op. Cmts, pp. 10-11. Under PG&E's proposal, the CBR of an undergrounding project need only be within 50% of the CBR of the alternative, in which case, the net benefits measure would become the controlling comparison.
[15] In D.18-12-014, the ratio was called Risk Spend Efficiency (RSE). In D.22-12-027, RSE was replaced with the monetized version, CBR.

benefits as a replacement for the ratio of benefits divided by cost. PG&E claims that the net benefit measure takes into account long-term lifetime benefits,[16] but fails to acknowledge that the numerator of the CBR does the same.

TURN does not object to the utilities' proposal to remove the phrase "by a certain threshold value" from Condition 5, provided that the Commission adopts TURN's recommended clarifications to ensure that the CBRs of the most reasonable alternatives available to the utility are considered.[17]

3. The Variance Conditions (Six and Seven) Serve an Important Purpose and Should Be Retained

PG&E and SDG&E seek the removal of new conditions that require the CBR and unit cost of approved projects not to exceed a variance percentage that will be determined in the Phase 2 decision.[18] The Commission should reject these recommendations. As Draft SPD-37 recognizes, the CPUC is required, within a nine-month period, to decide which if any undergrounding projects should be approved based on the estimates provided by the utility in its application.[19] It is reasonable and consistent with SB 884's cost control objectives to condition balancing account recovery on limiting the variance in a project's unit costs and CBR to a prescribed percentage.

PG&E exaggerates the "recovery risk" associated with these two conditions by assuming that *all* of the costs of a project that fails to satisfy these conditions would not be recoverable via the balancing account.[20] Instead, as TURN understands these conditions, only the *incremental costs that exceed the variance percentages* would be non-recoverable. Interpreted this way, the utility is only at risk of the costs that exceed the variances found reasonable by the CPUC in Phase 2.

TURN's primary position, stated in its opening comments, is that the memorandum account should not be an opportunity to gain relief from conditions such as these. However, if the Commission determines that the utility should have an opportunity to justify project costs that exceed the variance thresholds in Phase 3, TURN would not oppose such an outcome, provided that the utility is required in Phase 3 to overcome a presumption against recovery of costs that exceed the prescribed variance amounts and the Commission imposes a tight cap on memorandum account costs. TURN continues to oppose allowing recovery via the memorandum account of the

---

[16] PG&E Op. Cmts., p. 11.
[17] TURN Op. Cmts., pp. 10-11. Note that this concession moots the concern PG&E expresses in the example in Table 1 on p. 14, as there would be no threshold by which the undergrounding CBR would need to exceed the CBR of reasonable and available alternatives.
[18] PG&E Op. Cmts., pp. 12-13; SDG&E Op. Cmts., p. 6.
[19] Draft SPD-37, p. 21.
[20] PG&E Op. Cmts., pp. 14-15.

costs of any projects that fail to satisfy what TURN views as the core conditions, Conditions Three, Four, and Five.[21]

4. **The Commission Should Reject PG&E's Efforts to Bar Intervenors from Commenting on Audit Results, Which Will Be Key Inputs into Whether Utility Rates Are Found Just and Reasonable**

PG&E seeks to exclude intervenors from the review of the audit results, claiming that this is contrary to standard audit practice.[22] The CPUC should reject this request. PG&E fails to acknowledge that, in this case, the purpose of the audit will include assessing whether the costs recovered via the balancing account meet the requirements necessary to satisfy Section 451's just and reasonable standard. Contrary to PG&E's unsupported contention, TURN submits that it is standard practice in CPUC ratesetting matters to allow intervenors to review and comment upon audit findings, whether the auditor is overseen by the utility or the CPUC.[23] Under well-established Commission practice and consistent with Section 454, intervenors are always given an opportunity to participate in proceedings, both informal and formal, to determine whether the just and reasonable standard has been met.

5. **The Commission should also find no merit in PG&E's criticisms of the requirement for the utility to include in its Phase 2 application a proposed audit methodology for determining whether costs meet the Phase 2 conditions and secondary objections.[24] Because all parties will have an opportunity to respond to the utility proposal, this requirement ensures that the Commission will have a full and transparent record to determine the audit methodology. PG&E's proposal is another effort to exclude public input from the audit process, which the CPUC should soundly reject. The Commission Should Reject PG&E's New and Speculative Arguments Seeking Special Treatment for Rebuilding Costs**

PG&E seeks special rules for rebuild costs,[25] a position that PG&E does not appear to have addressed in its April 25, 2025, comments. PG&E bases this request on the counterintuitive assertion that undergrounding in rebuild areas often costs more than in other locations. PG&E's sole citation for the claim of higher costs is its own recent testimony in the pending 2027 test year

---

[21] Conditions numbers are based on the numbering of conditions in the Attachment A, *SB 884 Program: CPUC Guidelines With Appendices*, p. 12.
[22] PG&E Op. Cmts., p. 18.
[23] As just one of many numerous examples, in A.23-06-008, a pending PG&E cost recovery request, intervenors were given the opportunity to address in their testimony and briefs the results of audits performed by an auditor retained by PG&E and another auditor retained by the CPUC.
[24] PG&E Op. Cmts., pp. 17-18.
[25] PG&E Op. Cmts., p. 19.

GRC, testimony that has not yet been tested in the record of that case. At this point, it is entirely speculative whether additional rebuild projects will be warranted, and, if so, whether the unit costs of those projects will necessarily exceed the unit costs of the other projects in PG&E's plan. If PG&E's concerns come to fruition, PG&E is free to submit a petition for modification of the Phase 2 decision seeking relief based on changed circumstances.

6. The Commission Should Give No Weight to PG&E's Unsupported and Speculative Claims About the Impact of Draft SPD-37 on PG&E's Undergrounding Plans

PG&E's comments include statistical claims not previously presented at the April 8, 2025, workshop or in PG&E's comments about the supposed impact on PG&E's undergrounding plans if Draft SPD-37 is adopted.[26] The Commission should not give these claims any weight. PG&E fails to provide any explanation of how it determined the impacts it cites, preventing the Commission and parties from assessing the accuracy of those claims. For example, as noted in Section 3, PG&E seems to assume that *the entirety of a project* with costs that exceed the variance conditions (Conditions 6 and 7) would be completely ineligible for the program, whereas TURN's understanding is that only the costs in excess of the prescribed variance percentages would be ineligible. Because PG&E did not show its work, there is no way to assess the extent to which PG&E's results are based on unreasonable assumptions and calculations.

Moreover, just because PG&E had hoped to include certain projects in its SB 884 request in order to meet its financial goals and please investors, does not mean that those projects were reasonable and deserving of ratepayer funding. The real question is whether the Draft SPD-37 requirements are reasonable and ensure that only just and reasonable costs are added to rates. PG&E's unsupported statistics do nothing to advance that inquiry and should be disregarded. Instead, the Commission should base its final decision on the merits of the parties' proposed changes to Draft SPD-37. Based on that metric, as discussed in the preceding sections, TURN believes that PG&E's recommended modifications are contrary to the intent and goals of SB 884, and the just and reasonable requirement, and should therefore be rejected.

Dated: September 9, 2025

Respectfully submitted,

By: __________/s/_____________
Thomas Long

Thomas Long, Outside Counsel
tomjlong@sbcglobal.net
THE UTILITY REFORM NETWORK

---

[26] PG&E Op. Cmts., p. 1, asserting, e.g., that 95% of its EUP-eligible miles would become ineligible for undergrounding under Draft SPD-37.

Attachment 13

Documentation of hourly rate billed by Outside Counsel Thomas Long in 2025 and 2026

TURN
THE UTILITY REFORM NETWORK
Lower bills. Livable planet.

360 Grand Avenue, #150
Oakland, CA 94610

(415) 929-8876
TURN.org

January 26, 2026

Thomas Long
843 San Carlos Avenue
Albany, CA 94706

Re: Agreement for Legal and Consulting Services

Dear Mr. Long:

This letter is to confirm the terms of the agreement for legal and consulting services between The Utility Reform Network ("TURN') and Thomas Long ("Consultant"), for work that Consultant performs at TURN's request in CPUC proceedings or other related matters.

Scope and Nature of Work

Working in conjunction with and under the direction of TURN's attorneys, Consultant will provide legal and consulting services on issues related to TURN's participation in designated CPUC proceedings or related matters, with the exact scope of services to be determined by mutual agreement between TURN and Consultant on a case-by-case basis. The services to be provided by Consultant include identification and analysis of issues, preparation of pleadings, preparation of data requests and analysis of data request responses, working with other TURN consultants, preparation and sponsorship of expert witness testimony, and cross examination of other parties' witnesses, the exact nature of services to be determined by mutual agreement between TURN and Consultant on a case-by-case basis.

Compensation and Billing

Consultant agrees to provide these services in 2026 at his 2025 hourly rate of $885 adjusted by the CPUC's adopted escalation rate for 2026 when available. Based on currently available information, that escalation rate is estimated to be 3.3%, resulting in an **interim hourly rate of $915**, **until the CPUC's adopted escalation rate is available**. At that point, the parties will update the hourly rate as necessary to reflect the CPUC's adopted escalation rate, via an email exchange, which will serve as an addendum to this agreement. If necessary, Consultant will submit a revised invoice for work billed under the interim rate to reflect any changes based on the CPUC's adopted escalation rate.

In addition, Consultant will bill at cost for reasonable costs of travel outside of the Bay Area.

Upon receipt of a monthly invoice from Consultant, TURN will pay $300 per hour for services performed in that month, within 30 days. The remaining portion of the invoiced amount will be deferred pending the receipt of TURN's intervenor compensation from the Commission. When and if intervenor compensation is received, TURN will promptly remit payment to Consultant.

Consultant and TURN understand that the Commission may not fully reimburse TURN for work performed by Consultant or may not approve the requested hourly rate. In that event, TURN will reimburse Consultant for all of the deferred invoiced amounts **except for** the deferred portion of the amount disallowed by the Commission. The parties will confer in good faith to determine the correct deferred payment amount in the event of any ambiguity.

In addition, Consultant may from time to time perform work for TURN that is not expected to be eligible for recovery under the intervenor compensation program. Consultant shall be paid $350 per hour for such work, on a monthly basis with no deferral.

<u>Time Sheets</u>

Consultant will submit on a monthly basis, along with any invoice, detailed daily timesheets for work on behalf of TURN and a detailed accounting of any expenses in a format suitable for our compensation requests. Timesheets shall include the sufficient detail to identify the nature of the work and the nature of the issues addressed.

We are pleased to have you consulting for TURN on an ongoing basis. The signatures on this letter signify agreement to the terms set forth in this letter. The effective date of this agreement is January 5, 2026.

Very truly yours,

Hayley Goodson
Managing Attorney

Agreement to the terms described above:

/s/ *Thomas Long*

Thomas Long, Consultant

Thomas Long
tomjlong@sbcglobal.net

INVOICE

DATE: 10/22/25

TO:
Richard Perez/Hayley Goodson
TURN

FOR:
Legal Services in **September 2025 re SB 884 Implementation**

DESCRIPTION	HOURS	RATE	AMOUNT
Legal Services (see accompanying timesheet)	12.25	$885	$10.841.25
Minus: Deferred amount per 6/10/25 agreement	12.25	$585	$(7,166.25)
Amount due now	12.25	$300	$3,675.00
		NOW DUE	**$3,675.00**

THANK YOU!

Thomas Long
tomjlong@sbcglobal.net

INVOICE

DATE: 1/28/26

TO:

Richard Perez/Hayley Goodson
TURN

FOR:

Legal Services in **January 2026 re SB 884 Implementation – Comp Request Prep**

DESCRIPTION	HOURS	RATE	AMOUNT
Legal Services (see accompanying timesheet)	21.0	$457.50 (for comp request prep, 1/2 of $915 hourly rate)	$9,607.50
Minus: Deferred amount per 1/26/26 agreement	21.0	$157.50	$(3,307.50)
Amount due now	21.0	$300.00	$6,300.00
		NOW DUE	**$6,300.00**

THANK YOU!