BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Joint Application of Pacific Gas and Electric Company (U 39-E), Southern California Edison (U 338-E) and San Diego Gas & Electric Company (U 902-E) Requesting Commission Approval of Proposals for a BCR Calculation Methodology, Audit Methodology, and Cost Recovery Conditions as Specified in Resolution SPD-37.	Application No. 26-02-___

JOINT APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY (U 39-E), SOUTHERN CALIFORNIA EDISON (U 338-E) AND SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E) REQUESTING COMMISSION APPROVAL OF PROPOSALS FOR A BCR CALCULATION METHODOLOGY, AUDIT METHODOLOGY, AND COST RECOVERY CONDITIONS AS SPECIFIED IN RESOLUTION SPD-37

REQUEST FOR EXPEDITED SCHEDULE

JOEL B. CRANE
NICK KARKAZIS
PACIFIC GAS AND ELECTRIC COMPANY
Law Department, 19th Floor
300 Lakeside Drive, Suite 210
Oakland, CA 94612
Telephone: (510) 207-5694
Facsimile: (510) 898-9696
E-Mail: Joel.Crane@pge.com

CLAIRE TORCHIA
PETER SHAKRO
SOUTHERN CALIFORNIA EDISON
2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, CA 91770
Telephone: (626) 302-6945
Email: Claire.Torchia@sce.com

ROSS FULTON
SAN DIEGO GAS & ELECTRIC COMPANY
8330 Century Park Court, CP32D
San Diego, CA 92123-1548
Telephone: 619-372-7529
Email: rfulton@sdge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY,
SOUTHERN CALIFORNIA EDISON and
SAN DIEGO GAS & ELECTRIC COMPANY

Dated: February 9, 2026

TABLE OF CONTENTS

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF AUTHORITIES

Page

CALIFORNIA AUTHORITIES

Statutes and Regulations

California Public Utilities Commission

Decisions

Resolutions

Rules of Practice and Procedure

Miscellaneous

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Joint Application of Pacific Gas and Electric Company (U 39-E), Southern California Edison (U 338-E) and San Diego Gas & Electric Company (U 902-E) Requesting Commission Approval of Proposals for a BCR Calculation Methodology, Audit Methodology, and Cost Recovery Conditions as Specified in Resolution SPD-37.	Application No. 26-02-___

JOINT APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY (U 39-E), SOUTHERN CALIFORNIA EDISON (U 338-E) AND SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E) REQUESTING COMMISSION APPROVAL OF PROPOSALS FOR A BCR CALCULATION METHODOLOGY, AUDIT METHODOLOGY, AND COST RECOVERY CONDITIONS AS SPECIFIED IN RESOLUTION SPD-37

REQUEST FOR EXPEDITED SCHEDULE

Pursuant to Resolution SPD-37 (SPD-37) issued December 10, 2025, Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric Company (SDG&E) (collectively the Investor-Owned Utilities or IOUs) submit this Joint Application Requesting Approval of Proposals for a Benefit Cost Ratio (BCR) Calculation Methodology, Audit Methodology and Cost Recovery Conditions (Phase 1 Application). The processes, methodologies, cost recovery conditions and other considerations addressed in this proceeding apply only to a Senate Bill (SB) 884 10-year undergrounding program and are not applicable to other programs or proceedings.

Following the background information provided in Section I below, the IOUs address the specific issues raised by the California Public Utilities Commission (Commission or CPUC) in SPD-37, namely the proposed method for calculating a BCR, an audit methodology framework, additional cost recovery conditions, and other considerations (Sections II through V). In Section VI, the IOUs provide additional information required by the Commission's Rules of Practice and Procedure for applications.

I. BACKGROUND

The California Legislature passed SB 884 in September 2022, directing the Commission to "establish an expedited utility distribution infrastructure undergrounding program"[1] that would "substantially increase electric reliability by reducing the use of … deenergization events and any other outage programs and substantially reduce the risk of wildfire."[2] SB 884 divided responsibility for implementing the distribution undergrounding program between The Office of Energy Infrastructure Safety (Energy Safety) and the Commission. Energy Safety is responsible for developing technical guidelines a utility should follow to demonstrate that it has selected undergrounding projects that meet SB 884 requirements (Phase 1).[3] The Commission is responsible for developing the guidelines for recovering SB 884 project costs (Phase 2).[4]

In March 2024, the Commission adopted Resolution SPD-15 (SPD-15) that established portfolio-level conditions for SB 884 plan cost recovery in Phase 2 of the SB 884 undergrounding program. SPD-15 appropriately balanced three critical policy considerations: "(1) expediting review of undergrounding plans that have the potential to increase reliability and reduce wildfire risk; 2) providing regulatory certainty around the conditions that must be met and will suffice for any cost recovery associated with undergrounding to potentially reduce financing costs; and 3) ensuring that costs passed on to ratepayers are just and reasonable."[5]

Between October 2024 and June 2025, the Commission solicited input from stakeholders about the CPUC SB 884 Guidelines and held a number of workshops and technical working groups to ensure alignment between the Energy Safety 10-Year Electrical Undergrounding Plan Guidelines (EUP Guidelines) issued in February 2025 for Phase 1 of the SB 884 undergrounding program and the Commission's cost recovery requirements for Phase 2.

---

[1] Pub. Util. Code, § 8388.5(a).

[2] Pub. Util. Code, § 8388.5(d)(2).

[3] Pub. Util. Code, § 8388.5(c).

[4] Pub. Util. Code, § 8388.5(e)(1). Cost recovery also includes a reasonableness review process for certain program costs that are considered in Phase 3.

[5] SPD-15, p. 7.

In August 2025, the Commission issued Draft Resolution SPD-37. The changes and updates in Draft Resolution SPD-37 changed cost recovery from portfolio-level to project-level[6] and implemented a new BCR methodology[7] that contradicted the method established by the Commission in the Risk-Based Decision-Making Framework (RDF).[8] The proposed changes to SPD-37 would have introduced significant cost recovery risk and uncertainty into the EUP process.

On December 4, 2025, the Commission approved Resolution SPD-37 (SPD-37), Revision 3 that: (1) updates and adds Phase 2 Application requirements that aid the Commission in developing a record to determine whether cost recovery is reasonable; (2) explains a process for ensuring costs recovered via the memorandum account adopted in Resolution SPD-15 are capped and not excessive; (3) adopts primary and secondary objectives for an audit of any costs recorded to the one-way balancing account adopted in Resolution SPD-15; and (4) establishes a joint CPUC Phase 1 Application process[9] to resolve issues not addressed in the Resolution. This includes how Cost-Benefit Ratios (CBR)[10] should "be calculated; whether large electrical corporations' proposed audit methodology is adequate; and whether any additional conditions should be placed on what costs are allowed to be recovered through the one-way balancing

---

6 Draft SPD-37, Attachment A, SB 884 Program: CPUC Guidelines (Aug. 15, 2025) p. 12, Conditions for Approval of Plan Costs, Numbers 5-8.

7 Draft SPD-37, Attachment A, SB 884 Program: CPUC Guidelines (Aug. 15, 2025), Appendix 1: Cost Benefit Ratio Calculation Guidelines.

8 D.22-12-027 is the Phase 2 decision in the RDF (Rulemaking (R.) 20-07-013). Recently the Commission issued a Phase 4 decision (D.25-08-032) in the same proceeding. The BCR methodology in the Phase 4 decision is consistent with the BCR methodology in the Phase 2 decision.

9 This CPUC Phase 1 Application process is separate from Energy Safety's EUP Guidelines for Phase 1 of the SB 884 program.

10 SPD-37 established this Phase 1 Application to resolve certain issues including how Cost-Benefit Ratios (CBR) must be calculated (SPD-37, p. 2). During the Risk-Based Decision-Making (RDF) process the Commission referred to "CBR" but in its Phase IV decision (D.25-08-032, p. 128, Conclusion of Law (COL) 39) began referring to "BCR" (Benefit-Cost Ratio) instead of CBR. The Commission did not change CBR to BCR in Resolution SPD-37 but noted that any reference to CBR in SPD-37 is synonymous with BCR. (SPD-37, p. 2, footnote 3). The Joint IOUs refer to BCR in this Application unless directly quoting from SPD-37 where it refers to CBR.

account adopted in Resolution SPD-15."[11] The approved resolution dismissed the proposed project-level cost recovery requirements and reverted back to the portfolio-level conditions for cost recovery. Finally, the approved resolution eliminated the Benefit-Cost Ratio (BCR) methodology proposed in draft Resolution SPD-37 and gave the IOUs an opportunity to propose a joint BCR methodology that generally aligns to the method approved in the RDF.

II. BENEFIT COST RATIO CALCULATION METHODOLOGY

SPD-37 requires the IOUs to detail at least one standardized and consistent method for evaluating the cost-efficiency of undergrounding and alternative mitigations in SB 884-related applications. The Joint IOUs use the BCR to evaluate the economic efficiency of a project. BCR is calculated by dividing the dollar value of total mitigation benefit by the present value of the capital cost. The key components of such a methodology must include at a minimum: total capital cost; risk scaling; total mitigation benefit; BCR year zero; Interruption Cost Estimate (ICE) calculator granularity; and backcasting.[12]

The IOUs support the BCR methodology developed in the Commission's Risk-Based Decision-Making Framework (RDF)[13] and recommend that the RDF methodology be adopted in this proceeding.[14] The RDF BCR calculation methodology is the approach that must be used for calculating BCR in the EUP Guidelines[15] and other related proceedings including General Rate Cases (GRCs) and Risk Assessment and Mitigation Phase (RAMP) proceedings. It would be unreasonable to use two different methods for calculating BCRs in the two phases of the same or related proceedings.

---

[11] SPD-37, p. 2.

[12] SPD-37, Attachment A, SB 884 Program: CPUC Guidelines (Dec. 10, 2025), pp. 5-6.

[13] R.20-07-013.

[14] We note that SPD-37 references the BCR calculation methodology from the RDF Phase II Decision (D.22-12-027) when describing how a BCR must be calculated.

[15] Energy Safety, 10-Year Electrical Undergrounding Plan Guidelines (Feb. 20, 2025) (EUP Guidelines), Appendix A, p. A-1, "CPUC CBR".

A. The Joint IOU Proposal for Calculating BCR in the EUP

The Commission has stated that the RDF framework provides the foundation for a BCR methodology and that the BCR methodology proposed by parties should work within that framework.[16] In line with the Commission's guidance, the BCR methodology proposed by the joint IOUs—and that is discussed in the following sections—closely aligns with the RDF methodology. Table 1 below lists the individual elements of the BCR calculation, provides a brief description of each element and, in certain cases, explains how the IOUs will address it. It also includes a reference to the RDF or indicates if an element is not required by the RDF. In the sections that follow, the IOUs discuss the various BCR elements in greater detail.

The Commission describes the RDF proceeding as a five-year process designed to regulate the way large electrical corporations assess and disclose risks that have safety, reliability, and financial consequences. The goal of the RDF is to increase transparency and accountability of how the utilities prioritize and mitigate safety risks. The RDF provided the Commission's Safety Policy Division (SPD) with a process for evaluating whether the utilities follow the Commission's expectations and requirements for making risk-based decisions.[17] PG&E, SCE and SDG&E were active participants in all phases of the RDF proceeding. During that proceeding, parties, including the three large electrical corporations, conducted detailed analyses and thoroughly evaluated various technical requirements and methodologies that included considerations for consistency and transparency around how electric corporations evaluate and mitigate risk in a cost-efficient manner. Given the significant time and effort parties invested in developing a BCR methodology in the RDF, it is reasonable to follow that same approach for calculating BCRs in the EUP.

---

[16] CPUC Voting Meeting (Dec. 4, 2025), comments from Commissioner John Reynolds starting at 2:57:32, available at: <https://www.adminmonitor.com/ca/cpuc/voting_meeting/20251204/> (accessed Feb. 4, 2026).

[17] CPUC, Information Sheet, The Risk-Based Decision-Making Framework, available at: <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/documents/rdf-factsheet_011024.pdf> (accessed Feb. 4, 2026).

TABLE 1
JOINT IOU BCR METHODOLOGY

Topic	Brief Description	Reference to RDF
Total Capital Cost and Total Operations & Maintenance (O&M) Costs	• Consists of total capital and expense costs for mitigation implementation + net ongoing O&M costs. • O&M costs and O&M savings will be reflected in the denominator of the BCR calculation.	• D.25-08-032, Appendix A, p. A-19, Row 25 (definition of capital cost). • D.24-05-064, Finding of Fact (FOF) 38.
Total Mitigation Benefit	• Mitigation benefit can include all enterprise risks within the enterprise risk register, consistent with the RDF. • All benefits associated with enterprise risks including wildfire and reliability risk reduction. This includes standard reliability and public safety (public contact with electrical equipment).	Benefit – "The reduction in Risk, as measured by the changes in Attribute levels, that would occur when a program or set of activities are implemented." D.25-08-032, Appendix A, p. A-3.
Risk Scaling	• Allow utilities to apply their own risk-aversion frameworks and report results both with and without risk-aversion adjustments, showing scaled and unscaled values. • IOU will make decisions based on scaled values if scaling is applied.	D.25-08-032, Appendix A, p. A-10, Row 7.
Discount Rate	• Provide three discount rates: Weighted Average Cost of Capital (WACC); Societal Discount Rate; Hybrid Discount Rate. • IOUs may select the discount rate it will use for decision-making. IOUs may also select different discount rates.	D.24-05-064 p. 102 " the approach we adopt here is to direct the IOUs to use three discount rate scenarios for mitigations. For each mitigation, the IOUs may express their preference for one of the three discount rate scenarios, but they must present the results of the three discount rate scenarios for their [BCR] calculation…."
ICE Calculator	• RDF requires IOUs to use the current ICE Calculator to determine a standard dollar value of	D.22-12-027, COL 13.

Topic	Brief Description	Reference to RDF
	electric reliability risk unless the IOU proposes and justifies an alternative method. • Given the time required to incorporate ICE values into risk models and decision-making tools, the IOUs will clearly identify the version of the ICE Calculator used in its assessment as well as subsequent reporting. • IOUs will not distinguish between customer type in the HFTD and non-HFTD.	
Backcasting	• Use updated inputs (e.g., new RRUs, new risk models) to recalculate Benefit-Cost Ratios, pre-mitigated risk, post-mitigated risk or other data points as required by the RDF, Commission Ruling or Commission Decision. The goal of a Backcast is to establish a bridge between the prior inputs and the new inputs, which ensure an "apples-to-apples" comparison. • The utility must provide a Backcast of post-mitigated risk, risk reduction and Benefit-Cost Ratios submitted in the previous cycles of RAMPs and GRCs that are impacted by an update to the RRU's level of granularity. • IOUs will perform a backcast only when it introduces substantive updates to its risk models.	• D.25-08-032, Appendix A, p. A-3. • D.25-08-032, Appendix A, p. A-16, Row 15.1. • Energy Safety EUP Guidelines, Section 2.8.5.3.
Net Salvage Values	• Do not recommend incorporating net salvage value as a unique element of the BCR calculation. • Salvage values are addressed via other cost considerations such as depreciation rates or PVRR calculations.	• Not required in RDF. • SPD-37, SB 884 Program: CPUC Guidelines, 12/10/25, BCR Calculation, p. 5.
BCR Year Zero	• BCR Year 0 is the year a utility's EUP becomes effective and should apply to all EUP projects. • Defining BCR Year 0 as a single year—in this case the year a utility's EUP becomes effective—ensures consistency when comparing the BCRs for all projects in a utility's EUP portfolio.	• Not required in RDF. • SPD-37, SB 884 Program: CPUC Guidelines, 12/10/25, BCR Calculation, p. 6.

B. Total Capital Costs

SPD-37 defines Total Capital Cost as the "capital expenditures tied to project implementation" and asks the IOUs to address the "relationship between Total Capital Costs and other [cost] categories such as Operation and Maintenance (O&M) Costs, O&M Savings, and Net Salvage Values…."[18]

The total capital costs that the IOUs will include in the BCR calculation will include the total amounts incurred for constructing an undergrounding project from project initiation through close-out. This can include costs for design, engineering, permitting, civil and electrical construction, and any other type of design, engineering, and construction-related costs incurred. This approach aligns to the RDF, which states that the costs for capital program in the denominator of the BCR "should include incremental expenses made necessary by the capital investment."[19] The IOUs recommend including any expense costs that a utility may incur for project implementation in the total capital costs as well. Because a utility may incur and include expense amounts as part of project implementation, the IOUs recommend renaming this item "Total Implementation Costs."

In alignment with the RDF, O&M costs should be incorporated into the total costs reflected in the denominator of the BCR calculation and "should include incremental expenses made necessary [or avoided] by the capital investment."[20]

The IOUs recommend that O&M costs (the costs associated with operating and maintaining the project) and O&M savings (as the avoided O&M expenditures eliminated by the proposed project as compared to the No-Build Baseline) be accounted for in the *denominator* of the BCR calculation. Incorporating these values into the total cost component and including them in the denominator aligns to the RDF requirements.[21] The IOUs recommend that the Commission affirm that the BCR calculation will be defined as the present value of project or subproject benefits divided by the present value of project or subproject costs where:

---

[18] SPD-37, p. 26.

[19] D.25-08-032, Appendix A, p. A-18, Row 25.

[20] D.25-08-032, Appendix A, p. A-18, Row 25.

[21] D.25-08-032, Appendix A, p. A-18, Row 25.

- Benefits are shown in the numerator of the BCR calculation and are defined by the reduction in Risk, as measured by the changes in Attribute levels, that would occur when a program or set of activities are implemented;[22] and
- Costs are shown in the denominator of the BCR calculation and are defined as the sum of the forecast or actual capital and expense implementation costs and net O&M costs (the difference between O&M costs and O&M savings).

C. Total Mitigation Benefit

In alignment with the RDF, the IOUs recommend that the total mitigation benefits be defined as all benefits associated with any enterprise risk on a large electrical corporation's enterprise risk register.[23] The benefits included in the BCR calculation will reflect the full set of benefits associated with an undergrounding project that are the result of the incurred cost.[24] The benefits included in the BCR may encompass wildfire and reliability risk-reduction benefits, as well as, benefits related to other enterprise risks, such as standard reliability benefits from distribution overhead asset failures and public-safety benefits from public contact with electrical equipment. Incorporating standard reliability and public safety benefits into the BCR calculation also aligns with requirements in SB 884 that requires a large electrical corporation to prioritize "work based on wildfire risk reduction, public safety, cost efficiency, and reliability benefits."[25] Each benefit will be clearly identified to facilitate transparency and to avoid double-counting.

---

[22] D.25-08-032, Appendix A, p. A-3.

[23] Per D.25-08-032, Appendix A, p. A-3, Benefit is defined in RDF as "[t]he reduction in Risk, as measured by the changes in Attribute levels, that would occur when a program or set of activities are implemented." The Commission defines Enterprise Risk Register in D.25-08-032, Appendix A, p. A-4 and further explains that a utility's risk is defined in their respective risk registers (D.25-08-032, Appendix A, p. A-11, Row 8).

[24] D.25-08-032, Appendix A, p. A-19, Row 25.

[25] Pub. Util. Code, § 8388.5(c)(2).

D. Risk Scaling

The IOUs recommend following the approved RDF method for calculating BCR values. Under this method, large electrical corporations may choose to apply a risk-averse scaling function, but they are not required to do so. The RDF also allows each IOU to use a different risk-averse scaling function if they choose to apply one. The Commission stated:

> It is reasonable to afford the IOUs the same flexibility to incorporate Risk Attitude and Risk Tolerance into the Cost-Benefit Approach as they would under the current MAVF structure until further RDF refinements are adopted.[26]

The IOUs acknowledge that the RDF requires large electrical corporations to report unscaled BCR values in the RAMP Data Template (which is similar to the SB 884 Project List Data Requirements) so that SPD and parties can understand the implications of selecting and prioritizing proposed mitigations without the influence of scaled BCRs while also allowing utilities to submit another dataset with scaled risk values if they desire.[27] The IOUs do not object to reporting BCR values both with and without a scaling function in the EUP as long as a large electrical corporation is allowed to make mitigation decisions based on either scaled or unscaled BCRs, consistent with the RDF.

E. ICE Calculator

The RDF requires "IOUs to use the current ICE Calculator to determine a standard dollar [value] of electric reliability risk, unless the IOU proposes and justifies an alternative method…."[28] The IOUs recommend using ICE Calculator version 2.0 to determine a standard dollar value of electric reliability risk until a utility has time to fully review and evaluate the new information in ICE 2.1 and to then incorporate it into its risk models and mitigation decision-making tools. The IOUs recommend coordinating the integration of ICE 2.1—and any new updates to the ICE Calculator during the life of an EUP—with risk model version changes as

---

[26] D.22-12-027, p. 60, COL 14. While additional decisions have been issued in the RDF proceeding (Phase 3, D.24-05-064 and Phase 4, D.25-08-032), both still allow utilities to use a risk-averse scaling function.

[27] D.25-08-032, p. 122.

[28] D.22-12-027, p. 57, FOF 13.

defined in the Energy Safety EUP Guidelines. Energy Safety defines version changes as qualitative updates that substantially change the way that the risk model operates.[29] Under this approach, when a utility implements a model version change, an update could include updating from the ICE Calculator version the utility is currently using to an updated version of the ICE Calculator.

The IOUs propose deriving the discrete values of service by customer type (e.g., residential and non-residential) from the ICE calculator without distinguishing them between HFTD and non-HFTD regions. As PG&E discusses in its June 20, 2025, Response to the April 22, 2025 ALJ Ruling[30], the approach of using a single ICE value for each customer type across IOU's service territory avoids the risks and equity concerns that arise when reliability value for customers of the same type is differentiated by factors such as location or economic status.

As an example, in some communities, the HFTD boundary bisects a single street, placing customers on one side in non-HFTD and customers across the street in HFTD. Despite this regulatory distinction, both sets of customers experience the same Public Safety Power Shutoff (PSPS) and Enhanced Powerline Safety Settings (EPSS) operational impacts. In these circumstances, applying different value-of-service assumptions to otherwise similarly situated customers creates an inequitable basis for comparing alternatives. Adopting the IOUs' recommendation ensures that mitigation decisions reflect the actual, shared customer experience rather than an artificial boundary distinction.

For monetizing the reliability consequence at a specific location (e.g. circuit, feeder, circuit segment) impacted by a reliability risk event, the IOUs then propose to apply these discrete values of service by customer type from the ICE calculator to the respective customer mix at each location to get the 'blended VOS' by location. Each IOU may determine the

---

[29] EUP Guidelines, pp. 39-40, Section 2.5.7.2.

[30] PG&E Response to the April 22, 2025 ALJ Ruling that Directed the Submission of Additional Information Regarding the 2027 General Rate Case (June 20, 2025), pp. 3-5, Sec. II. B. "Approach to Disaggregation for ICE 2.0".

appropriate level of granularity for individual locations to apply unique 'blended' VOS depending on the nature of the reliability risk event and IOU's grid characteristics. An illustrative example of calculation is shown in Table 2 below.

TABLE 2
EXAMPLE OF VALUE OF SERVICE BY CUSTOMER TYPE CALCULATION

	Duration	$/CMI		Number of Customers			$/CMI	$		
	Hour	Res.	Non-Res.	Res.	Non-Res.	Total	Total	Res.	Non-Res.	Total
Location	[A]	[B]	[C]	[D]	[E]	[F]=[D]+[E]	[G]=([B][C]+[D][E])/[F]	[H]=60[A][B][D]	[I]=60[A][C][E]	[J]=[H+[I]
Circuit A	5	$0.09	$24	100	10	110	$2.26	$2,700	$72,000	$74,700
Circuit B	5	$0.09	$24	30	80	110	$17.48	$810	$576,000	$576,810
Circuit C	5	$0.09	$24	55	55	110	$12.05	$1,485	$396,000	$397,485

F. Discount Rate

The RDF requires utilities to calculate BCR values using three different discount rates: Weighted Average Cost of Capital (WACC) Discount Rate Scenario; Societal Discount Rate Scenario; and Hybrid Discount Rate Scenario.[31] While utilities are required to calculate BCR values using three discount rates, the IOUs recommend that a utility be allowed to make its risk-based decisions based on the discount rate it chooses, as is allowed by the RDF.[32] The IOUs understand that each utility can select whichever rate it chooses but must use that same rate formulation for the duration of the EUP. For example, if a utility chooses to use the Societal Discount Rate Scenario with its EUP submittal, it must use the Societal Discount Rate for the life of its EUP though it may vary the specific Societal Discount Rate used if inputs into the formulation of the Societal Discount Rate change.

G. Backcasting

The RDF, Resolution SPD-37, and the Energy Safety EUP Guidelines all require some type of backcasting (referred to as "backtesting" in the Energy Safety EUP Guidelines). The definitions and requirements for backcasting among the three documents are slightly different.

- The RDF requires using updated inputs (e.g. new RRUs, new risk models) to recalculate BCRs, "pre-mitigated risk, post-mitigated risk, or other data" required by the RDF in order "to establish a bridge between prior inputs and the new inputs, [to] ensure an "apples-to-apples" comparison."[33]
- Resolution SPD-37 defines backcasting as "a method for recalculating [BCRs] 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…."[34]

[31] D.25-08-032, Appendix A, p. A-19, Row 25.

[32] D.24-05-064, p. 102.

[33] D.25-08-032, Appendix A, p. A-3.

[34] SPD-37, p. 27.

- The Energy Safety EUP Guidelines definition of backtesting states, "If the Large Electrical Corporation changes its Risk Modeling Methodology in a way that triggers a versioning update, it must backtest the new models using historical data back to the start of the EUP. These backtests must include a Project-Level analysis of each Confirmed Project that passed through Screen 3 (Project Risk Analysis) in that time."[35]

The IOUs support aligning on a single definition of backcasting (or backtesting) to ensure consistency in the data provided to the Commission (and in RAMP and other filings) and to Energy Safety in the EUP. The IOUs recommend adopting the definition from the Energy Safety EUP Guidelines. Because a utility will select projects at the circuit segment level (per the EUP Guidelines)[36] it is reasonable to conduct backcasting/backtesting at the same level of detail. Conducting backcasting at a subproject or RRU level as contemplated by the RDF and Resolution SPD-37 would introduce misalignment between project selection at the circuit segment level and recalculations required when a utility introduces a new risk model if it were to be conducted at the RRU or subproject level.

H. Salvage Values

The RDF does not require utilities to include net salvage values as a stand-alone component in a BCR calculation and, therefore, the IOUs do not recommend adding them to the SPD-37 BCR requirements.

Salvage values are addressed by the utilities in different ways. For example, PG&E relies on "group accounting," which studies all its distribution assets to develop depreciation rates as opposed to individual assets in separate filings.

> In group accounting, all units having like mortality characteristics or all units of an account are considered together. Accruals for the group are based on composite or weighted average values of salvage and service life expectancy. The resulting values are applied to the surviving plant balances each year or each

[35] EUP Guidelines, p. 52, Section 2.8.5.3.

[36] EUP Guidelines, pp. 11, Section 2.4.

> accounting period. A deficiency due to early retirement of a particular unit is made up through other accruals on a unit which outlives the average. … Because of greater simplicity in maintaining records, the group basis is more feasible for most "classes of utility property" where large numbers of units are involved. It is the more generally used among electric gas, telephone, and water utilities.[37].

I. BCR Year Zero

SPD-37 defines BCR Year Zero "as the year a project becomes 'used and useful.'" BCR Year Zero "serves as the reference year for discounting both costs and benefits."[38] The IOUs recommend that BCR Year Zero instead be defined as the year that a utility's EUP becomes effective,[39] and this definition should apply to all EUP projects. Defining BCR Year Zero as a single year—in this case the year a utility's EUP becomes effective—ensures consistency when comparing the BCRs for all the projects in a utility's EUP portfolio. Requiring utilities to have a different BCR Year Zero for every project and subproject based on operative year would make comparison, prioritization, and aggregation of BCRs inconsistent. Establishing the effective date of an EUP as BCR Year Zero is reasonable and consistent with how utilities forecast costs in their GRC where all costs are based on a test year forecast that does not change and all cost analyses are anchored to the test year values.

Further, the year a project is expected to become "used and useful" may change over the course of the EUP period as project details like permitting requirements are better understood. Changing the BCR Year Zero on a project may create confusion and misaligned data from one report to another. The IOU's recommendation of a consistent BCR Year Zero for the entire EUP period will allow for an "apples to apples" comparison between projects.

---

[37] CPUC, Water Division, Standard Practice U-4, Determination of Straight-Line Remaining Life Depreciation Accruals, p. 8.

[38] SPD-37, Attachment A, SB 884 Program: CPUC Guidelines (Dec.10, 2025)p. 6.

[39] The EUP effective date will be the year a utility begins recording project costs to an EUP balancing account. For example, if a utility's Phase I and Phase 2 applications are approved by October 31, 2027, and the utility begins recording costs to its EUP balancing account on January 1, 2028, the effective date of their EUP is 2028.

III. AUDIT METHODOLOGY

SPD-37 requires the large electrical corporations to submit a proposed audit methodology for Commission consideration that will support the auditor's ability to verify whether the costs of a project satisfy the Phase 2 Conditions primary and secondary objectives adopted by the Commission. The Phase 1 Application must "include a description of the proposed methodology that establishes how the auditor will validate whether the large electrical corporation has satisfied the primary and secondary objectives of the audit[:]"

> (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 BCR for all projects completed in any given two-year period equals or exceeds the approved threshold BCR value. (Condition #4)".[40]

Additionally, the proposed audit "method must include an approach for [v]erifying that a project is used and useful [and v]erifying the incrementality showing in Application Requirement No. 2."[41]

As a general note, SPD-37 states that the EUP Audit will result in an audit report.[42] Recognizing that the report will not be a true financial audit, the IOUs recommend clarifying that the report will be a report addressing the CPUC primary and secondary cost recovery conditions for an SB 884 program.

In the following sections, the utilities discuss the proposed general objectives for the EUP audit and then provide an audit framework that can be applied by an auditor to address each of

---

[40] SPD-37, Attachment A, SB 884 Program: CPUC Guidelines (Dec. 10, 2025), pp. 6-7.

[41] SPD-37, Attachment A, SB 884 Program: CPUC Guidelines (Dec. 10, 2025), p. 7.

[42] SPD-37, p. 22.

the Commission's primary and secondary audit objectives. While the IOUs provide a stand-alone framework for each audit objective, the IOUs assume that the auditor will prepare a single audit report each time they conduct an audit of the balancing account.

A. Developing an Audit Methodology

The main objective of the audit should be to assess whether the costs recorded to the one-way balancing account meet the conditions established by the Phase 2 Decision. For the audit to achieve its objective, the auditors should be provided with the Phase 2 Decision, establish compliance criteria based on that decision, and then perform a statistically appropriate level of sampling to confirm that the costs are properly recorded to the one-way balancing account.

The IOUs recommend that the auditor be required to meet professional auditor standards, specifically, the American Institute of Certified Public Accountants (AICPA) Consulting Standards. The AICPA Standards are appropriate for the following reasons:

(1) Flexibility: The AICPA Consulting Standards provide auditors with greater flexibility in addressing areas of concern. The standards allow for professional judgment in determining the appropriate procedures and methodologies to assess recovery of costs through a one-way balancing account. This flexibility permits a customizable evaluation and approach based on the unique circumstances of the program and account.

(2) Applicability to Commercial Entities: Compared to another standard, GAGAS (Generally Accepted Government Auditing Standards), which primarily focuses on government entities, the AICPA Consulting Standards are specifically designed for commercial entities. Using standards tailored to the nature of the program can help ensure the evaluation is conducted in a manner that aligns with industry practices and the specific needs of the organization, program, and conditions.

(3) Comprehensive Guidance: The AICPA Consulting Standards provide comprehensive guidance for performing consulting engagements. They encompass a range of considerations, including independence, objectivity, competency, and due professional

care. By adhering to these standards, the Commission and stakeholders can ensure that an evaluation will be conducted in accordance with recognized professional practices.

B. Audit Framework for Evaluating the Annual Cost Cap

The IOUs recommend applying the audit framework shown in Table 3 below to verify that the total annual costs for qualifying projects and/or subprojects did not exceed the approved cost cap for a given year of the EUP. Qualifying projects and/or subprojects are defined as the projects and/or subprojects that were deemed used and useful in a calendar year. The costs recorded to the balancing account will include all costs incurred for each of the qualifying projects from project scoping through project closeout.

TABLE 3
JOINT IOU AUDIT FRAMEWORK
VERIFYING THAT THE TOTAL ANNUAL COSTS DID NOT EXCEED THE APPROVED COST CAP FOR A GIVEN YEAR OF THE EUP (CONDITION #1)

Step	Description	Additional Information
1. Define Audit Year	Auditor defines the "Audit Year"	• For example: EUP Year 1 (2029), EUP Year 2 (2030), etc.
2. Confirm Annual Cost Cap and Year	Auditor confirms the annual cost cap for a given year that is included in the Phase 2 Decision.	• Assumes that the Phase 2 Decision will include annual cost caps for each year of a utility's EUP. • All project costs (e.g. scoping, design, engineering, construction, close-out costs) incurred for a project that is deemed used and useful. Recognizes that project costs are likely to be incurred over multiple years. • Project costs will count against the annual cost cap only when the project is deemed used and useful.
3. Validate Projects to be Considered for the Given Year	Auditor validates the Qualifying Projects identified by the Large Electrical Corporation.	• Large Electrical Corporation identifies projects and/or subprojects that are included in the particular audit year. These are referred to as "Qualifying Projects."(A) • Qualifying Projects: Defined as projects and/or subprojects that

Step	Description	Additional Information
		are used and useful in a given year. • Includes all project/subproject costs from initial scoping through project close-out.
4. Review and Validate Accuracy of Costs Recorded to Balancing Account (BA) for the Given Year for the Qualifying Projects	Auditor determines if the costs recorded to the BA are within the approved cost cap based on a method developed by the Auditor to assure an independent and valid audit.	• Large Electrical Corporation provides cost information at the request of the Auditor. May include accounting system reports, invoices, and/or other supporting information. • At the request of the Auditor, Large Electrical Corporation meets with the Auditor to review and discuss costs recorded to the BA and/or supporting information.
5. Prepare Audit Report	Auditor prepares draft report outlining finding related to the BA annual cost cap audit.	• Auditor determines if the costs recorded to the BA for a given year are less than equal to the annual cost cap. • Large Electrical Corporation and parties comment on the draft audit report per the processes and timelines established in SPD-37 or otherwise modified in the Phase 2 Decision.
Note: (A) Over the life of the EUP a utility will complete some number of undergrounding miles in a given year for a project or subproject but will not complete the entire project or subproject until the following year. For example, if a project or subproject consists of 5 undergrounding miles, a utility may complete 2 miles in Year 1 and 3 miles in Year 2. The entire 5-mile project or subproject would be considered qualified in Year 2. However, there may be circumstances in the EUP process (e.g. meeting the Energy Safety Plan Tracking Objectives) where it is reasonable to account for the 2 miles completed and energized in Year 1 even though the 5-mile project or subproject will not be considered a Qualifying Project until Year 2.		

C. Audit Framework for Reviewing Third-Party Funding

The IOUs recommend applying the audit framework shown in Table 4 below to verify 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. Utilities will attempt to obtain third-party funding to reduce the costs to customers for undergrounding projects and/or subprojects. The audit will then determine if the third-party funding that was received was deducted from the costs recorded to the balancing account resulting in lower costs to utility customers.

The IOUs note that there are several issues related to recording third-party costs to a balancing account and determining if they off-set rate payer funding—including if a utility will record third-party costs to the balancing account or if the third-party funding will be recorded some other way. Given that these are complex issues the IOUs recommend addressing them during the Phase 2 Cost Recovery Application process.

TABLE 4
JOINT IOU AUDIT FRAMEWORK
VERIFYING THAT ANY THIRD-PARTY FUNDING OBTAINED WAS APPLIED TO REDUCE THE ESTABLISHED ANNUAL COST CAP (CONDITION #2)

Step	Description	Additional Information
1. Identify Third-Party Funding Obtained During the Audit Year	Large Electrical Corporation determines if third-party funding was received during the audit year.	• Large Electrical Corporation provides a list of all third-party funding received during the audit year to the Auditor. • If no third-party funding was received during the audit year, the Large Electrical Corporation will provide an affirmative statement in writing to the Auditor stating that no third-party funding was received.
2. Evaluate Third-Party Funding Conditions	Auditor validates if third-party funding received can be applied to reduce the annual EUP cost cap for a given year.	• Auditor conducts a detailed review of the conditions associated with the third-party funding received to determine if any of the funding can be used to reduce undergrounding costs.
3. Determine if Third-Party Funding Obtained was Applied to Reduce the Established Cost Cap	Auditor reviews the books and records to determine whether any eligible third-party funding was actually used to reduce the established cost cap. Review is based on a method developed by the Auditor to assure an independent and valid audit.	• Large Electrical Corporation will outline its process for applying third-party funding to the EUP program to reduce the established cost cap. • Large Electrical Corporation provides supporting information at the request of the Auditor. • At the request of the Auditor, Large Electrical Corporation meets with the Auditor to review and discuss the application of third-party funding to the cost cap.

Step	Description	Additional Information
4. Prepare Audit Report	Auditor prepares draft report outlining findings related to the third-party funding audit.	• Auditor determines if any third-party funding received was used to reduce the annual EUP cost cap for a given year. • Large Electrical Corporation and parties comment on the draft audit report per the processes and timelines established in SPD-37 or otherwise modified in the Phase 2 Decision.

D. Audit Framework for Determining the Average Recorded Unit Cost

The IOUs recommend applying the audit framework shown in Table 5 below to determine if the average recorded unit cost for all projects and/or subprojects deemed used and useful in any given two-year period did not exceed the approved average unit cost cap. The auditor will review information for projects and/or subprojects deemed used and useful during a given two-year period —recorded costs and undergrounding miles installed—to determine if the average unit cost for those projects and/or subprojects was equal to or less than the average unit cost established in the Phase 2 decision for that two-year period. The IOUs recommend reporting unit costs as the present value of a specific base year. The base year should be defined as the year a utility's EUP becomes effective which would be consistent with BCR Year Zero.

TABLE 5
JOINT IOU AUDIT FRAMEWORK
DETERMINING THAT THE AVERAGE RECORDED UNIT COST FOR ALL PROJECTS COMPLETED IN A TWO-YEAR PERIOD DID NOT EXCEED THE APPROVED AVERAGE UNIT COST CAP (CONDITION #3)

Step	**Description**	**Additional Information**
1. Define Unit Cost Two-Year Audit Period	Auditor defines the "Audit Year".	• For example: EUP Unit Cost Audit Period 1 Covering EUP Years 1 and 2 (2029 and 2030).
2. Confirm Two-Year Average Recorded Unit Cost Cap	Auditor confirms the average unit cost cap for a given two-year year period that is included in the Phase 2 Decision.	• Assumes that the Phase 2 Decision will include average unit cost caps for each two-year period for the estimated duration of a utility's EUP. • These values will be determined during the Phase 2 process.
3. Identify Projects to be Considered for the Given Two-Year Unit Cost Audit Period	Auditor validates the Qualifying Projects identified by the Large Electrical Corporation.	• Large Electrical Corporation identifies projects and/or subprojects that are included in the given two-year audit period. These projects are referred to as "Qualifying Projects." • Qualifying Projects: Defined as projects and/or subprojects that are used and useful in a given two-year period based on the IOU's definition of used and useful. • Unit costs are defined as the cost per mile of undergrounding installed. • The unit cost is calculated as the total cost (as described below) divided by the undergrounding miles installed. • Includes all project/subproject costs from initial scoping through project/subproject close-out.
4. Review and Validate Accuracy of Information Included in the Unit Cost Calculation by Qualifying Project	Auditor reviews the costs and underground mileage recorded for Qualifying Projects and the two-year average cost calculation based on a method developed by the Auditor to ensure an independent and valid audit.	• Large Electrical Corporation to provide information at the request of the Auditor. May include: — Cost Information - Accounting system reports, invoices, cost savings estimates, and/or other supporting information. — Undergrounding installed - construction as-built drawings and/or other supporting information.

Step	Description	Additional Information
		• At the request of the Auditor, Large Electrical Corporation meets with the Auditor to review and discuss costs recorded to the BA, underground miles installed, and/or supporting information.
5. Prepare Audit Report	Auditor prepares draft report for the given two-year period average unit cost cap audit.	• Auditor determines if the average unit cost for Qualifying Projects is less than the approved average unit cost cap for the given two-year period. • Large Electrical Corporation and parties comment on the draft audit report per the processes and timelines established in SPD-37 or otherwise modified in the Phase 2 Decision.

E. Audit Framework for Evaluating the Average Recorded BCR

The IOUs recommend applying the audit framework shown in Table 6 below for determining that the average recorded BCR for all projects and/or subprojects deemed used and useful in any given two-year period equals or exceeds the approved threshold BCR value. The auditor will review the cost and modeled or estimated benefits information used to calculate the BCR for projects and/or subprojects deemed used and useful during a given two-year period to determine if the average recorded BCR for those projects and/or subprojects was equal to or greater than the BCR threshold established in the Phase 2 decision for that two-year period.

The Auditor should only audit costs (denominator) in the BCR calculation and not the risk reduction benefits (numerator). It is not possible for the utility to provide the actual risk reduction achieved (e.g. the actual amount of wildfire risk removed from the system) from implementing a particular undergrounding project or subproject. Rather, the utility can provide the estimated effectiveness of the mitigation at that location. Additionally, it is not possible for the utility to validate the actual amount of O&M savings achieved by implementing a particular undergrounding project or subproject. For example, the utility assumes that relocating an overhead line underground will require fewer inspections and maintenance activities on that overhead line. While the utility cannot confirm the actual number or cost of avoided inspections and maintenance activities that did not occur, it can instead provide an estimated value of those avoided activities and costs.

TABLE 6
JOINT IOU AUDIT FRAMEWORK
DETERMINING THAT THE AVERAGE RECORDED BCR FOR ALL PROJECTS COMPLETED IN ANY GIVEN TWO-YEAR PERIOD EQUALS OR EXCEEDS THE APPROVED THRESHOLD BCR VALUE (CONDITION #4)

Step	Description	Additional Information
1. Define BCR Two-Year Audit Period	Auditor defines the "Audit Year".	• For example: EUP Unit Cost Audit Period 1 Covering EUP Years 1 and 2 (2029 and 2030).
2. Confirm Two-Year Average Recorded BCR Threshold	Auditor validates that an average BCR for a given two-year period that is included in the Phase 2 Decision.	• Assumes that the Phase 2 Decision will include an average BCR threshold value for each two-year period for the estimated duration of a utility's EUP. • These values will be determined during the Phase 2 process.
3. Identify Projects to be Considered for the Given Two-Year BCR Audit Period	Auditor validates the Qualifying Projects identified by the Large Electrical Corporation.	• Large Electrical Corporation identifies projects and/or subprojects that are included in the given two-year audit period. These projects are referred to as "Qualifying Projects." • Qualifying Projects: Defined as projects and/or subprojects that are used and useful in a given two-year period based on the IOU's definition of used and useful. • The BCR for projects (circuit-segments) is calculated based on the BCR calculation methodology described in Section II above. • Includes all project/subproject costs and benefits from initial scoping through project close-out.
4. Review and Validate Accuracy of Information Included in the BCR Calculation by Qualifying Project	Auditor reviews the BCRs recorded for Qualifying Projects based on a method developed by the Auditor to assure an independent and valid audit.	• Large Electrical Corporation to provide information at the request of the Auditor. May include: — Cost Information - Accounting system reports, invoices, cost savings estimates, and/or other supporting information. — Benefits Information – Mitigation effectiveness values, reliability benefits estimates, and/or other supporting information. — Undergrounding installed - construction as-built drawings and/or other supporting information.

Step	Description	Additional Information
		• At the request of the Auditor, Large Electrical Corporation meets with the Auditor to review and discuss costs recorded to the BA, underground miles installed, and/or supporting information.
5. Prepare Audit Report	Auditor prepares draft report for the given two-year period average BCR audit.	• Auditor determines if the average BCR for Qualifying Projects equaled or exceeded the approved average BCR threshold value for the given two-year period. • Large Electrical Corporation and parties comment on the draft audit report per the processes and timelines established in SPD-37 or otherwise modified in the Phase 2 Decision.

F. Audit Framework for Assessing Projects Deemed Used And Useful

The IOUs recommend applying the audit framework shown in Table 7 below for verifying that a project and/or subprojects is used and useful. Each IOU determines if a project and/or subprojects is used and useful based on its own criteria. The auditor will apply the individual IOU's criteria to those projects and/or subprojects the IOU has determined are used and useful to validate that each project and/or subproject meets the established used and useful criteria.

TABLE 7
JOINT IOU AUDIT FRAMEWORK
VERIFYING THAT A PROJECT IS USED AND USEFUL

Step	Description	Additional Information
1. Determine Audit Period	Auditor determines the Used and Useful audit period.	• For example: EUP Used and Useful Audit Period 1 Covering EUP Year 1 (2029).
2. Determine Basis for Used and Useful Showing	Auditor obtains basis for determining an underground asset is considered used and useful.	• For example: PG&E considers a project used and useful when it passes the Fire Risk Safety Audit. Passing the Fire Risk Safety Audit consists of all mileage passing based on a successful QC audit from the applicable QC system of record.
3. Identify Projects to be Considered for the Used and Useful Audit	Auditor validates the Qualifying Projects identified by the Large Electrical Corporation.	• Large Electrical Corporation identifies projects that are included in the used and useful audit period. These projects are referred to as "Qualifying Projects."

Step	Description	Additional Information
		• Qualifying Projects: Defined as projects that are used and useful in a given two-year period based on the IOU's definition of used and useful.
4. Review and Validate Qualifying Undergrounding Projects	Auditor determines if the Qualifying Projects meet the Large Electrical Corporation's requirements for being deemed used and useful.	• Large Electrical Corporation to provide information at the request of the Auditor. May include: — Lists of planned and completed projects, construction documentation, and/or other supporting information. • At the request of the Auditor, Large Electrical Corporation meets with the Auditor to review and discuss information supporting used and useful determination.
5. Prepare Audit Report	Auditor prepares draft report for verifying projects are used and useful.	• Auditor verifies Qualifying Projects are used and useful. • Large Electrical Corporation and parties comment on the draft audit report per the processes and timelines established in SPD-37 or otherwise modified in the Phase 2 Decision

G. Audit Framework for Demonstrating Incrementality

The IOUs recommend applying the audit framework shown in Table 8 below to verify the incrementality showing in application requirement number 2. Application requirement number 2 requires a utility to "clearly identify all undergrounding targets [(miles)] and cost forecasts in [an EUP] that overlap with undergrounding targets … and cost forecasts either approved or under consideration in [a] GRC or other cost recovery venue[ ]."[43] The audit will confirm that the costs for undergrounding projects and/or subprojects for which recovery is sought in the EUP are not also included in a utility's General Rate Case (GRC) or other proceeding.

---

[43] SPD-37, Attachment A, SB 884 Program: CPUC Guidelines (Dec. 10, 2025), p. 10, Item 2 (citations omitted).

TABLE 8
JOINT IOU AUDIT FRAMEWORK
VERIFYING THE INCREMENTALITY SHOWING FOUND IN
APPLICATION REQUIREMENT NO. 2

Step	Description	Additional Information
1. Determine Audit Period	Auditor determines the Used and Useful audit period.	• For example: EUP Incrementality Audit Period 1 Covering EUP Year 1 (2029).
2. Determine Basis for Incrementality Showing	Auditor evaluates the underground miles and costs approved in the Large Electrical Corporation's last approved GRC.	• Obtain the Large Electrical Corporation's last approved GRC filing. • Review testimony, workpapers, and decision to determine the miles and costs for undergrounding approved by the Commission.
3. Identify Projects to be Considered for the Incrementality Audit	Auditor validates the Qualifying Projects identified by the Large Electrical Corporation.	• Large Electrical Corporation identifies projects that are included in the used and useful audit period. These projects are referred to as "Qualifying Projects." • Qualifying Projects: Defined as projects that are used and useful in a given two-year period based on the IOU's definition of used and useful.
4. Review and Validate Undergrounding Projects Included in GRC Rate Base Compared to EUP Projects	Auditor reviews the projects, costs, and underground mileage recorded for Qualifying Projects compared to undergrounding projects, costs, and mileage included in GRC ratebase.	• Compare the miles and costs approved in the last GRC for undergrounding to the miles and costs of undergrounding completed in a given EUP year, looking for potential indications of overlapping costs or double cost recovery. • Large Electrical Corporation to provide information at the request of the Auditor. May include: — Lists of planned and completed projects, accounting system reports, and/or other supporting information. • At the request of the Auditor, Large Electrical Corporation meets with the Auditor to review and discuss costs and miles approved in the GRC, costs recorded to the BA, underground miles installed in the EUP, and/or other information.

Step	Description	Additional Information
5. Verify Incrementality	Auditor prepares draft report for verifying the incrementality showing.	• Large Electrical Corporation and parties comment on the draft audit report per the processes and timelines established in SPD-37 or otherwise modified in the Phase 2 Decision

IV. ADDITIONAL COST RECOVERY CONDITIONS

SPD-37 requires that the Phase 1 Application includes "a proposal for any additional portfolio or project-level conditions necessary to ensure that costs [recorded] to balancing accounts are just and reasonable. At a minimum, large electrical corporations [must consider: (1)] conditions that address how an undergrounding project compares to alternative mitigations; [(2)] conditions that address how the actual BCR of a project compares to its forecasted BCR; and [(3)] conditions that address how the actual unit cost of an undergrounding project compares to its forecasted cost."[44] The IOUs strongly support the portfolio-level conditions for cost recovery and do not recommend adding any new portfolio-level conditions or any project-level conditions for cost recovery. The portfolio-level cost recovery conditions recognize the real-world challenges inherent in managing a complex system hardening program and allow utilities to prudently manage a portfolio of work within established metrics. Managing program costs at the portfolio level is consistent with the well-established process for approving funding and managing programs at the portfolio-level in a utility's GRC.

In the following sections, the IOUs consider each of the three required areas for additional cost recovery conditions and explain how the information already required in either the Commission SB 884 Guidelines and/or the Energy Safety EUP Guidelines provides sufficient information to ensure that the costs recorded to the balancing account are just and reasonable.

[44] SPD-37, Attachment A, SB 884 Program: CPUC Guidelines (Dec. 10, 2025), p. 7.

A. Conditions That Address How An Undergrounding Project Compares to Alternative Mitigations

The Energy Safety EUP Guidelines and the SB 884 Project List Data Requirements require large electrical corporations to report how an undergrounding project compares to alternative mitigations. The IOUs do not recommend any additional project-level conditions associated with comparing undergrounding projects to alternative mitigations because the large electrical corporation is providing significant information on this topic to both Energy Safety and the CPUC through the existing data requirements. Requiring additional comparisons would deviate from Energy Safety's requirements and create inconsistency between filings.

Per the Energy Safety EUP Guidelines, large electrical corporations will report the name of the comparison(s) considered for each circuit segment at Screen 2 (Table C.11), at Screen 3 (Table C.12), at Screen 4 (Table C.13), and in the Project Index Table (Table C.15). In Table C.15, the large electrical corporation will provide compilations of metrics for the performance of the alternatives considered in Screens 2, 3, and 4 including work description, total cost, total risk reduction, and cost/benefit ratio. They will also provide compilations of the project as scoped and the primary alternative considered, including baseline cumulative risk, project as scoped cumulative risk, and alternative project cumulative risk. Additionally, the large electrical corporation will provide a narrative detailing how and why the alternative mitigation was chosen (Table C.12).[45]

In the SB 884 Project List Data Requirements (Table 1), the large electrical corporation will provide the undergrounding mitigation and alternative mitigation considered for each Risk Reporting Unit (RRU)— an RRU is akin to a subproject—and will then provide all required risk and cost analyses (Tables 1 and 2) for each of the values input into that field. The cost information that the large electrical corporation will provide at the RRU level includes costs for labor, materials, permits, and other costs. The large electrical corporation will also provide the

[45] EUP Guidelines, Appendix C, pp. C-11 to C-42, Data Organization and Structure.

cost at the time the Phase 2 application is submitted, allowing for comparisons between forecast and recorded costs.[46]

B. Conditions That Address How The Actual Unit Cost Of An Undergrounding Project Compares To Its Forecasted Cost

The IOUs support the portfolio-level cost recovery conditions for costs recorded to the balancing account with the opportunity to record certain project costs to the memorandum account for further review. These cost recovery conditions address project execution realities where some projects cost less than forecast and others cost more, while still requiring a large electrical corporation to prudently manage its overall project portfolio. The IOUs do not recommend any additional portfolio-level conditions beyond those already included in the Energy Safety EUP Guidelines and the Commission's SB 884 Program Guidelines, which address how the actual unit cost of an undergrounding project compares to its forecasted cost. The IOUs do not recommend any project-level cost recovery conditions.

In most cases, the estimated forecast cost of an undergrounding project varies from the actual cost of the project. The initial forecast cost is developed at the time the project is scoped. Scoping, or project planning, involves estimating the location and route of the underground asset based on desktop mapping reviews. The project cost estimate is refined as the large electrical corporation more fully develops the project, which includes more accurately determining the undergrounding route to address obstacles in the planned route that are varied through field visits by grid design engineers, project estimators, and public safety specialists. The scope of the actual construction and materials needed are not fully confirmed until the underground project estimating is complete.

Because the estimated cost of an undergrounding project is likely to vary from the actual cost—sometimes significantly—the portfolio-level conditions for cost recovery adopted in

---

[46] SPD-37, Attachment A, SB 884 Program: CPUC Guidelines (Dec. 10, 2025), Appendix 1, SB 884 Project List Data Requirements, pp. A1-11 to A1-22, Tables 1 and 2.

Resolution SPD-37[47] represent a reasonable approach for addressing the complexities inherent in constructing a portfolio of long-term, complex projects. Portfolio-level cost recovery via the balancing account recognizes that the actual costs for projects will vary and strikes a balance between recovering costs for projects where the actual cost is greater than the forecast cost with projects where the actual cost is less than the forecast. If actual costs for a project significantly exceed the forecast, SPD-37 establishes a memorandum account where project costs can be recorded for further review[48]. The combination of the portfolio-level cost recovery via the balancing account and the ability to record some costs to the memorandum account is a fair and reasonable approach for cost recovery and requires that the large electrical corporation carefully manage its undergrounding portfolio to ensure that it meets the average unit cost cap. Implementing project-level cost recovery requirements is unnecessary and would punish a large electrical corporation for projects where the difference between forecast and recorded costs exceed an arbitrary variance when it is known that the initial project estimate is provided before a sound project forecast can be fully developed.

C. Conditions That Address Actual And Forecasted BCRs Of A Project

The IOUs support the portfolio-level BCR conditions that do not penalize a utility if an individual project does not meet the BCR threshold as long as the utility prudently manages its overall portfolio to achieve the BCR standard. The forecast and actual BCRs will be based on the forecast and actual project costs and benefits. As discussed above (Section II (B)), the actual costs of an undergrounding project vary from the estimated forecast cost because of the timing and information needed to fully develop a sound project cost estimate. Because the forecast and actual costs will vary, the forecast and actual BCR of an undergrounding project will also vary. The variance is appropriately addressed by the portfolio-level cost recovery processes and controls

[47] SPD-37, Attachment 1, SB 884 Program: CPUC Guidelines (Dec. 10, 2025), p. 14, Conditions for Approval of Plan Costs No. 3.

[48] SPD-37, Attachment 1, SB 884 Program: CPUC Guidelines Dec. 10, 2025), pp. 15-19, Phase 3 – Review of Memorandum Account Recorded Costs for Rate Recovery.

established in SPD-15. For the reasons discussed in Section II (B) above, the IOUs do not recommend any additional portfolio-level conditions that address how the actual BCR of an undergrounding project compares to its forecast BCR nor any project-level cost recovery conditions related to forecast and actual BCRs.

D. Other Issues Impacting Cost Recovery

1. Individual Projects And/Or Subprojects Should Not Be Measured Against Compliance Requirements

The audit frameworks outlined in Section III above describe the methods the auditor will follow to ensure that the costs recorded to the balancing account are just and reasonable and meet the portfolio-level conditions for recovery established in the Phase 2 decision. To conduct the reviews, the auditor will necessarily review project-level information to determine if the portfolio-level conditions are met since the portfolio is made up of individual projects. While it is reasonable and necessary for the auditor to review the costs and BCRs for individual projects and/or subprojects as part of the balancing account audit, none of the *individual* projects and/or subprojects should be measured against compliance requirements as long as the portfolio of which they are a part meets the portfolio-level requirements. Only the utility should decide if an individual project should be excluded from the portfolio that makes up the balancing account and instead included in the memorandum account.

2. Addressing Subprojects That Do Not Meet Portfolio-Level Cost Recovery Conditions

The Auditor will evaluate targets at the portfolio level to determine if the cost recovery requirements have been met. If the IOU meets the portfolio targets, all the actual costs for qualifying subprojects deemed used and useful in the audit year are recorded to the balancing account, and no further review is required.

If the portfolio-level cost recovery targets are not met, the utility will examine individual subprojects to identify individual subprojects that do not meet the portfolio-level targets. Projects (circuit segments) should be reviewed, using the actual plus forecast BCR, against the project's

BCR target that is based on the overhead alternative BCR identified at the time of scoping. Projects that are not forecasted to meet BCR targets, shall have their off-track subprojects—that have become used and useful in the subject year—moved to the memorandum account for reasonableness review.

3. Incorporating a Variance Threshold into the Portfolio-Level Conditions for Cost Recovery

The utilities will determine forecast cost recovery values (annual cost caps, BCR values and unit cost targets) well before most circuit segments will be selected for the EUP. Given the complexity of completing tens or hundreds of individual undergrounding projects over a 10-year period, it will be difficult to accurately forecast the cost recovery values. Therefore, the utilities recommend incorporating a small variance threshold that would be applied to the annual cost caps, BCR values and unit cost targets before utilities are required to move individual projects to the memorandum account.

The joint IOUs recommend that the SPD-37 conditions for cost recovery be revised to include a 2 percent cost recovery variance threshold. For example, if a utility's annual cost cap for EUP Year 1 is $100, the utility could record up to $102 to the balancing account before any project would have to be recorded to the memorandum account for further review. It is reasonable to include a small variance threshold given the challenges with accurately forecasting costs for many individual projects over a multi-year period. The joint IOUs recommend that the Commission make the following three changes shown in red to the SB 884 Program: CPUC Guidelines, Conditions for Approval of Plan Costs.

> Condition 1: Total annual costs must not exceed 102% of a cap based on the approved cost cap for that specific year.

> Condition 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 102% of 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.

Condition 4: The average recorded BCR for all projects completed in any given two-year period (the current year, and the prior year) must exceed or be within 2% of ~~equal or exceed~~ the approved threshold BCR value for the current year.

V. OTHER CONSIDERATIONS

The IOUs recommend allowing a large electrical corporation to consider other factors along with BCR values when selecting mitigation alternatives.[49] While large electrical corporations use sophisticated risk models to analyze system risk and select the most appropriate mitigation solution for a specific location, there are still limitations to these models. It is appropriate, therefore, to supplement these modeling results by considering other factors to ensure that the large electrical corporation is selecting the most effective mitigation considering other environmental factors and state policy objectives. Because each IOU's risk models and service territory are different, each IOU necessarily considers other factors specific to their operations. It is therefore reasonable to allow each IOU to identify and consider those other criteria that may factor into mitigation selection and prioritization.

A. Addressing Risk Model Limitations by Incorporating a BCR Estimate Uncertainty Factor in Project Selection

While the IOUs risk models are industry-leading and have matured considerably in recent years, they do not perfectly represent all real-world conditions. Uncertainties exist in risk modeling due to unknown variables, incomplete or imputed data inputs, the passage of time, and

[49] In this section we provide examples of why other considerations are appropriate (e.g. limitations in a certain risk model). While the example may be specific to a single utility, the issues discussed in this section impact all three utilities and the Joint IOUs support all the recommendations included in this Application.

the inherent unpredictability between real world actions and consequences versus modeled results. Because of these uncertainties, it is reasonable to consider factors outside of the risk model when making mitigation decisions. For example, if the BCRs for undergrounding and an alternative mitigation that reduces less wildfire risk are reasonably close, and additional local considerations support undergrounding, the EUP should support the greater and permanent risk reduction afforded by undergrounding.

Given that wildfire risk models are not designed to model all exogenous environmental factors, or the vulnerability of populations in proximity to wildfire prone locations, utilities recognize the need to supplement their modeling results by considering additional factors such as ingress/egress risk, tree-strike risk, and PSPS risk. Adopting a more holistic approach to project selection by considering factors outside of the wildfire risk model acknowledges the importance of these additional considerations.

The IOUs consider locations (e.g. circuits, feeders, circuit segments, etc.) for undergrounding where the BCR for undergrounding is within a reasonable margin of the BCR for alternative mitigations like overhead hardening with safety settings. The joint IOUs will continue to consider undergrounding if the BCR for an undergrounding project is within 70 percent of the BCR for an alternative mitigation like covered conductor plus fast trip settings (this is referred to as an "estimate uncertainty factor").[50] In this situation, a utility will evaluate local factors not well represented in the risk models to determine if undergrounding is the appropriate mitigation. The local factors may include PSPS dynamics, tree-strike risk, and

---

[50] PG&E does not apply the BCR estimate uncertainty range to the cost component of the BCR calculation. Instead, the company uses applicable construction-industry standards to inform the uncertainty range applied to the monetized benefit component. Previously, PG&E incorporated a 50 percent BCR estimate uncertainty range into its decision-making but reduced it to align with Energy Safety's recommendation in PG&E's 2026-2028 Base WMP (Energy Safety, Decision for Pacific Gas and Electric Company's 2026-2028 Base Wildfire Mitigation Plan (Feb. 5, 2026), p. 20). The 30 percent estimate uncertainty range is consistent with the Association for the Advancement of Cost Engineers (AACE) Class 3 estimate, which has an accuracy range of -20 percent to +30 percent. (Integrated Technologies, Inc., The Cost of Estimating Series: Capital Cost Estimate Classes, Table 1, Summary of AACE International Cost Classifications and Expected Ranges of Accuracy, available at: <https://www.processengineer.com/insights/capital-cost-estimate-classes> (accessed Feb. 5, 2026)).

ingress/egress risks (discussed in Sections A(1) through A(3) below) informed by engineering studies and subject-matter-expert reviews conducted during the project scoping phase. For example, PG&E leverages Public Safety Specialists, generally retired fire fighting professionals, to evaluate local conditions including detailed ingress/egress considerations.

While the BCR is a valuable metric, it is not comprehensive and does not incorporate this type of site-specific risk information. It would be unwise to disregard location-specific considerations and the judgment of subject-matter experts. The estimate accuracy range provides utilities the flexibility to select the safest, most cost-efficient option when risk model uncertainty exists within a reasonable margin.

1. Ingress/Egress Risk

Ingress/egress risk is not captured directly in utility wildfire risk models and therefore does not account for local conditions that are essential for conducting a more holistic assessment of the risk of wildfire to populations. During project scoping, PG&E, for example, leverages Public Safety Specialists, generally retired fire fighting professionals, to conduct a detailed ingress/egress risk assessment outside of the risk model that accounts for ingress/egress risk specific to an individual circuit segment. This detailed review is crucial for developing effective mitigation strategies and ensuring that PG&E accounts for all potential ingress/egress risks. Undergrounding eliminates the possibility that a pole could fail during an emergency and block access into or out of an area whereas overhead hardening does not. Therefore, in locations with access constraints or limited capacity to fully evacuate the population before the area is overwhelmed by a fast-moving wildfire, undergrounding is often a more appropriate mitigation for that area. Conducting an ingress/egress risk evaluation specific to an individual circuit segment gives PG&E the information needed to incorporate location-specific ingress and egress assessments into its risk-based decision-making process and to make a more informed decision about which mitigation is most appropriate to address the risks at a specific location.

2. Addressing Tree Strike Risk

The information captured in utilities' risk models for tree strike risk is generally high-level, aggregated data that represents a snapshot in time based on the information available at the time the wildfire risk model was developed. Relying only on this information for making mitigation decisions overlooks dynamic changes in tree health and environmental conditions that occur over time. To address this limitation, PG&E, for example, supplements the information available in the risk model by analyzing the most recent LiDAR information and satellite imagery, which provides a much more granular and up-to-date view of the area. Reviewing the additional tree-strike data allows PG&E to consider not only trees that are tall enough to strike the lines but also assesses their potential to strike and break overhead hardened conductors. Because undergrounding eliminates the tree-strike risk while overhead hardening does not, and because certain trees can break overhead hardened conductors, it is reasonable to incorporate additional tree-strike data analysis into the mitigation selection process because it allows utilities to make a more informed, risk-based mitigation decision.

3. Additional Considerations Around Public Safety Power Shut-Off Risk

Evaluating reliability risks, such as PSPS, at the circuit segment level, can obscure localized risks and reliability impacts within sub-circuits. Therefore, utilities perform a more detailed sub-circuit segment level assessment of PSPS risk that can include considering individual weather polygons from the most current PSPS lookback data to identify sub-circuit segment areas where undergrounding would reduce PSPS event risk. This analysis considers PSPS events that only affect parts of the circuit segment, allowing utilities to implement targeted undergrounding to reduce PSPS impacts in those sub-circuit segment areas. Conducting this sub-circuit PSPS review helps utilities strike a balance between reducing wildfire and reliability risk and delivering a cost-effective mitigation solution.

B. Incorporating Previously Scoped Projects into the EUP

Project scoping and implementation is a long-term effort, often spanning multiple years. Utilities incur significant costs to develop an undergrounding project scope. Over the past years, utilities have scoped several projects that may not meet certain EUP requirements. For example, projects selected and scoped based on a previous version of the risk model. Because the project was selected based on the previous risk model, it may not be possible to demonstrate that it meets the Energy Safety screening requirements, even though at the time it was selected it was a high-wildfire-risk-ranked circuit segment. Even if the project does not meet all the EUP requirements, it is reasonable to pursue such an undergrounding project because, at the time it was selected and scoped, it was forecast to significantly reduce wildfire and reliability risk—the two key factors in selecting and pursuing projects in the EUP. Further, it would be very disruptive to customers and communities where planning for undergrounding has already begun, often including acquisition of land rights from local customers, coordination with the municipality about paving plans and traffic controls plans, to cancel a project due to the transition from GRC-funded undergrounding to the EUP. Therefore, it is reasonable to include these previously scoped projects in the EUP undergrounding portfolio of work.

C. Other Considerations Related to Project Selection Criteria

1. Bundling

Based on Commission and intervenor feedback, utilities have become actively engaged in developing an optimization approach to bundle work in ways that represent net cost reduction opportunities. The optimization algorithm selects feeder-segment bundles that, when upgraded, would minimize the anticipated residual wildfire and PSPS risks while maintaining cost-effective work packages. The output of this process is a list of projects consisting of bundled segments eligible for hardening. Utilities intend to use this information to estimate potential cost efficiencies of the proposed bundles and to update the benefit-cost ratios for the bundle. Utilities then consider the updated benefit-cost ratios, risk reduction, constructability, economies of scale, as well as reliability benefits (aside from reductions to PSPS) when determining the most appropriate mitigations for the bundled feeders.

2. Customer Type

In addition to the information generated by its risk models, utilities also consider the impact of risk based on customer vulnerability. For instance, SDG&E considers customer type when selecting mitigations. Certain feeder segments feed critical facilities like public safety facilities, hospitals, and schools. In some cases, the BCR for a feeder segment to a critical facility does not meet the BCR requirement. In these cases, it is reasonable to give additional consideration to customer type when selecting a mitigation because undergrounding the feeder segment provides greater safety and reliability benefits (reduces the use of PSPS) to both critical facilities and potentially vulnerable customers. Similarly, SCE also incorporates social vulnerability into its risk model by assessing the number of customers with Access and Functional Needs (AFN) as well as Non-Residential Critical Infrastructure (NRCI), such as hospitals and schools, into its final risk assessment.

VI. COMPLIANCE WITH THE COMMISSION'S RULES OF PRACTICE AND PROCEDURE AND OTHER REQUIREMENTS

A. Statutory and Other Authority

This application is made pursuant to Public Utilities Code, Sections 701, and 1701; the Commission's Rules of Practice and Procedure, including Rule 2.1; and prior decisions, orders, and resolutions of the Commission including, but not limited to, Resolution SPD-37.

B. Legal Name and Location of Applicant (Rule 2.1 (a))

Since October 10, 1905, PG&E has been an operating public utility corporation, organized under the laws of the State of California. PG&E is engaged principally in the business of furnishing gas and electric service in California. PG&E's principal place of business is 300 Lakeside Drive, Oakland, California 94612.

SCE's full legal name is Southern California Edison Company. SCE is a corporation organized and existing under the laws of the State of California and is primarily engaged in the business of generating, purchasing, transmitting, distributing, and selling electric energy for light, heat, and power in portions of central and southern California, as a utility subject to the jurisdiction of the California Public Utilities Commission. SCE's properties, which are located primarily within the State of California, consist mainly of hydroelectric and thermal electric generating plants, together with transmission and distribution lines and other property necessary in connection with its business. The location of SCE's principal place of business is 2244 Walnut Grove Avenue, Rosemead, California 91770.

SDG&E is a corporation organized and existing under the laws of the State of California. SDG&E is engaged in the business of providing electric service in a portion of Orange County and electric and gas service in San Diego County. SDG&E's principal place of business is 8330 Century Park Court, San Diego, California 92123.

C. Correspondence and Communications Regarding This Application (Rule 2.1(b))

Communications regarding this Application should be addressed to:

Joel Crane
Nick Karkazis
Attorneys for
Pacific Gas and Electric Company
Law Department, 19th Floor
300 Lakeside Drive, Suite 210
Oakland, CA 94612
Telephone: (925) 597-0225
Email: Joel.Crane@pge.com

Wade Greenacre
Regulatory Relations Advocacy, Director
Regulatory Proceedings and Rates, 12th Floor
300 Lakeside Drive
Oakland, CA 94612
Telephone: (415)500-1739
Email: Wade.Greenacre@pge.com

Claire Torchia
Director and Managing Attorney
Southern California Edison Company
Post Office Box 800
2244 Walnut Grove Avenue
Rosemead, CA 91770
Telephone: (626) 302-6945
Email: Claire.Torchia@sce.com

SCE Case Administration
Southern California Edison Company
8631 Rush Street
Rosemead, CA 91770
Telephone: (626) 302-0449
Email: Case.Admin@sce.com

Ross Fulton
Attorney for
San Diego Gas & Electric Company
8330 Century Park Court, CP32D
San Diego, CA 92123
Telephone: 619-372-7529
Email: rfulton@sdge.com

Kari Kloberdanz
Regulatory Case Manager
San Diego Gas & Electric Company
8330 Century Park Court, CP31E
San Diego, CA 92123
Telephone: 619-929-7074
Email: kkloberdanz@sdge.com

D. Proposed Categorization (Rule 2.1(c))

This Application should be categorized as a "quasi-legislative" proceeding. The IOUs recommend categorizing this Application as quasi-legislative, as it will establish rules affecting the IOUs participating in the EUP process.[51]

[51] The IOUs note that SPD-37, Attachment A, p. 7, footnote 8 references Rule 3.2 of the Commission's Rules of Practice and Procedure. However, because this is not a ratemaking proceeding, Rule 3.2 does not apply to this application.

E. The Need for Hearings (Rule 2.1(c))

The IOUs do not believe hearings are necessary to address the items in this Application. The information provided in this Application, along with information collected as part of the Resolution SPD-15 and Resolution SPD-37 processes, and potential discovery and briefings related to this Application, is sufficient for the Commission to rule on the IOUs' proposal. The issues that need to be addressed in this Application refer only to policy questions —not cost recovery and/or factual disputes— and neither witnesses nor separate written testimony will be provided. Thus, the policy questions at issue in this proceeding can be resolved via briefing, and there is no reason to hold evidentiary hearings.

F. Issues to be Considered

The issues to be considered as part of this application include the following:

1. Have the IOUs proposed a BCR methodology that aligns to the RDF method for calculating a BCR, and should the SB 884 Project List Data Requirements Guidelines definitions be revised where they contradict the RDF?
2. Have the IOUs outlined an audit methodology that provides a reasonable framework for confirming that the primary and secondary audit objectives are met, while giving the auditor flexibility in how the audit is conducted to ensure an independent and valid audit?
3. Are any additional project-level or portfolio-level conditions necessary for cost recovery?
4. Is it reasonable to confirm that individual projects and/or subprojects that are evaluated during the audit process are not measured against compliance requirements if the portfolio of which they are a part meets the portfolio-level requirements?
5. Should the Commission revise SPD-37 to include a 2 percent variance threshold related to the total annual cost cap, the average recorded unit cost for all projects completed in any given two-year period, and the average recorded BRD for all projects completed in any given two-year period?
6. Should utilities be allowed to apply an estimate uncertainty factor and consider other factors that impact mitigation selection?

G. Relevant Safety Considerations (Rule 2.1(c))

The California Legislature passed SB 884 in September 2022, directing the Commission to "establish an expedited utility distribution infrastructure undergrounding program"[52] that would "substantially increase electric reliability by reducing the use of … deenergization events and any other outage programs and substantially reduce the risk of wildfire."[53] The items at issue in this Application are the final items that need to be addressed so that IOUs can proceed with an SB 884 undergrounding program if they choose to do so.

H. Proposed Schedule (Rule 2.1(c))

In issuing SPD-37, the Commission recognized that certain aspects of the SB 884 program that were deferred in SPD-15 could benefit from further exploration. The Commission established this Phase 1 Application to explore those issues. The Joint IOUs are requesting an expedited schedule per Rule 2.9. Justification supporting this request is provided in Attachment A.

Recognizing the Commission's desire to reduce the risk of delaying a decision on a Phase 2 Application, the IOUs propose the procedural schedule in Table 9 below. The IOUs believe that hearings will not be necessary in this proceeding, and thus the proposed schedule does not include evidentiary hearing dates.

TABLE 9
PROPOSED SCHEDULE

Activity	Date
Phase 1 Application Filed	February 9, 2026
Notice in CPUC Daily Calendar	TBD
Responses/Protests	Filing Date + 30 calendar days[54]
Reply to Responses/Protests	Responses Due + 5 calendar days
Prehearing Conference (if needed)	Filing Date + 45 calendar days
Scoping Memo	Filing Date + 60 calendar days
Discovery	Scoping Memo + 60 calendar Days

[52] Pub. Util. Code, § 8388.5(a).

[53] Pub. Util. Code, § 8388.5(d)(2).

[54] SPD-37, p. 30.

Activity	Date
Intervenor Opening Briefs	Discovery + 30 calendar days
IOU Reply Briefs	Opening Briefs + 30 calendar days
Proposed Decision	Reply Briefs + 60 calendar days
Commission Decision	Proposed Decision + 30 calendar days

I. Articles of Incorporation (Rule 2.2)

Since October 10, 1905, PG&E has been an operating public utility corporation organized under California law. It is engaged principally in the business of furnishing electric and gas services in California. A certified copy of PG&E's Amended and Restated Articles of Incorporation, effective June 22, 2020, is on record before the Commission in connection with PG&E's Application (A.) 20-07-002, filed with the Commission on July 1, 2020. These articles are incorporated herein by reference.

A copy of SCE's Certificate of Restated Articles of Incorporation, effective on August 28, 2023, and presently in effect, certified by the California Secretary of State, was filed with the Commission on December 15, 2023, in connection with A.23-12-011, and is incorporated herein by this reference.

A copy of SCE's Certificate of Determination of Preferences of the Series M Preference Stock filed with the California Secretary of State on November 17, 2023, and presently in effect, certified by the California Secretary of State, was filed with the Commission on December 15, 2023, in connection with A.23-12-011, and is incorporated herein by this reference.

A copy of SCE's Certificate of Determination of Preferences of the Series N Preference Stock filed with the California Secretary of State on May 8, 2024, and presently in effect, certified by the California Secretary of State, was filed with the Commission on May 15, 2024, in connection with A.24-05-007, and is incorporated herein by this reference.

Copies of SCE's latest Annual Report to Shareholders and Edison International's latest proxy statement was sent to its stockholders and has been sent to the Commission with an Energy Division Central Files Document Coversheet, dated April 15, 2025, pursuant to General Order Nos. 65-A and 104-A of the Commission.

SDG&E is a corporation organized and existing under the laws of the State of California. SDG&E is engaged in the business of providing electric service in a portion of Orange County and electric and gas service in San Diego County. SDG&E's principal place of business is 8330 Century Park Court, San Diego, California 92123

A copy of SDG&E's Restated Articles of Incorporation as last amended, presently in effect and certified by the California Secretary of State, was previously filed with the Commission on September 10, 2014 in connection with SDG&E A.14-09-008 and is incorporated herein by reference.

J. Request for Expedited Schedule (Rule 2.9)

Pursuant to Rule 2.9 the joint IOUs request an expedited schedule for the reasons described in Attachment A.

K. Witness List

SPD-37 requires the IOUs to include in the Phase 1 Application the person(s) who would sponsor each section of the Application and "would serve as a witness if evidentiary hearings are required."[55] While the IOUs do not believe evidentiary hearings will be necessary in this proceeding, Table 10 below lists the witnesses for each section for each of the three IOUs.

TABLE 10
WITNESS LIST

Application Section	PG&E Witness	SCE Witness	SDG&E Witness
Section II: Benefit Cost Ratio Methodology	Yumi Oum, Director Enterprise Risk	Bryan Landry, Senior Advisor, Enterprise Risk Management	Joaquin Sebastian Peral, Manager Risk Analytics and Modeling
Section III: Audit Methodology	Chris Pezzola, Sr. Director, Internal Audit	Andrew Bittlemann, Senior Advisor, Technical Audits	DJ Scott, Manager Corporate & Financial Planning
Section IV: Additional Cost Recovery Conditions	Justin Sadler, Sr. Director Undergrounding Program Risk and Strategy	Bryan Landry, Senior Advisor, Enterprise Risk Management	Jonathan Woldemariam, Director Wildfire Mitigation

[55] SPD-37, Attachment A, SB 884 Program: CPUC Guidelines (Dec. 10, 2025), p. 7.

Application Section	PG&E Witness	SCE Witness	SDG&E Witness
Section V: Other Considerations	Justin Sadler, Sr. Director Undergrounding Program Risk and Strategy	Bryan Landry, Senior Advisor, Enterprise Risk Management	Jonathan Woldemariam, Director Wildfire Mitigation

VII. SERVICE

A copy of the filing has been served on the service list for 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.

VIII. CONCLUSION

The IOUs appreciate the effort that the Commission has made to establish the SB 884 Phase 2 requirements that provide regulatory clarity and certainty for large electrical corporations while ensuring EUP costs borne by ratepayers are just and reasonable.[56] At the same time, it is clear that certain issues in the SB 884 Phase 2 process require additional consideration and input from stakeholders. The IOUs are grateful for the opportunity to provide recommendations to address the items that remain unresolved. As described herein, the IOUs recommend the Commission:

1. Adopt the BCR methodology described in Section II that aligns to the RDF method for calculating BCR values and revise the SB 884 Project List Data Requirements Guidelines definitions that contradict the RDF;

2. Adopt the audit methodology described in Section III that provides a reasonable framework for confirming that the primary and secondary audit objectives are met while giving the auditor flexibility in how the audit is conducted to ensure an independent and valid audit;

3. Not require any additional project-level or portfolio-level conditions for recovery as described in Section IV;

---

[56] SPD-37, p. 11.

4. Confirm that individual projects and/or subprojects that are evaluated during the audit process are not measured against compliance requirements as long as the portfolio of which they are a part meets the portfolio-level requirements as described in Section IV(D)(1);

5. Revise SPD-37 to include a 2 percent variance threshold related to the total annual cost cap, the average recorded unit cost for all projects completed in any given two-year period, and the average recorded BRD for all projects completed in any given two-year period by incorporating the revisions proposed in Section IV(D)(3) to the SB 884 Program: CPUC Guidelines, Conditions for Approval of Plan Costs; and

6. Allow utilities to apply an estimate uncertainty factor and consider other factors that impact mitigation selection as described in Section V.

Respectfully submitted on behalf of the IOUs,
JOEL B. CRANE

By: /s/ *Joel B. Crane*
JOEL B. CRANE

Pacific Gas and Electric Company
Law Department, 19th Floor
300 Lakeside Drive, Suite 210
Oakland, CA 94612
Telephone: (510) 207-5694
Facsimile: (510) 898-9696
E-Mail: Joel.Crane@pge.com

Attorney for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: February 9, 2026

VERIFICATION

I, the undersigned, say:

I am an officer of PACIFIC GAS AND ELECTRIC COMPANY, a corporation, and am authorized to make this verification for that reason; I have read the foregoing "Joint Application of Pacific Gas and Electric Company (U 39-E), Southern California Edison (U 338-E) and San Diego Gas & Electric Company (U 902-E) Requesting Commission Approval of Proposals for a BCR Calculation Methodology, Audit Methodology, and Cost Recovery Conditions as Specified in Resolution SPD-37; Request for Expedited Schedule" and I am informed and believe the matters therein are true and on that ground I allege that the matters stated therein are true.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed this 9th day of February 2026.

/s/ Matt Pender
Matt Pender
Vice President, Undergrounding & System Hardening
PACIFIC GAS AND ELECTRIC COMPANY

VERIFICATION

I, the undersigned, say:

I am an officer of SOUTHERN CALIFORNIA EDISON COMPANY, a corporation, and am authorized to make this verification for that reason; I have read the foregoing "Joint Application of Pacific Gas and Electric Company (U 39-E), Southern California Edison (U 338-E) and San Diego Gas & Electric Company (U 902-E) Requesting Commission Approval of Proposals for a BCR Calculation Methodology, Audit Methodology, and Cost Recovery Conditions as Specified in Resolution SPD-37; Request for Expedited Schedule" and I am informed and believe the matters therein are true and on that ground I allege that the matters stated therein are true.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed this 9th day of February 2026.

/s/ Conner Flannigan
Vice President Conner Flannigan,
Vice President, Enterprise Risk Management &
General Auditor
SOUTHERN CALIFORNIA EDISON
COMPANY

VERIFICATION

I, the undersigned, say:

I am an officer of SAN DIEGO GAS & ELECTRIC COMPANY, a corporation, and am authorized to make this verification for that reason; I have read the foregoing "Joint Application of Pacific Gas and Electric Company (U 39-E), Southern California Edison (U 338-E) and San Diego Gas & Electric Company (U 902-E) Requesting Commission Approval of Proposals for a BCR Calculation Methodology, Audit Methodology, and Cost Recovery Conditions as Specified in Resolution SPD-37; Request for Expedited Schedule" and I am informed and believe the matters therein are true and on that ground I allege that the matters stated therein are true.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed this 9th day of February 2026.

/s/ Brian D'Agostino
Brian D'Agostino
Vice President, Wildfire and Climate Science
SAN DIEGO GAS & ELECTRIC COMPANY

ATTACHMENT A

ATTACHMENT A -

REQUEST FOR EXPEDITED SCHEDULE

Under Rule 2.9, the IOUs respectfully request that this Application proceed according to an expedited schedule due to threats to public safety and the need to avoid ratepayer harm.

SB 884 was enacted to provide an avenue for significantly reducing wildfire and reliability risk and making undergrounding more affordable over time. It is imperative that issues raised in this Application are addressed expeditiously so that the IOUs can continue undergrounding high-risk circuit segments to reduce both wildfire and reliability risk as envisioned by the California legislature.[57]

PG&E has included forecasts for undergrounding for one year (2027) in its Test Year 2027 General Rate Case (GRC) with the expectation that it will transition undergrounding work from the GRC to the EUP beginning in 2028.[58] Given the 20 months required to complete the application submittal and review process,[59] PG&E must submit its Phase 1 application with Energy Safety as soon as practicable and cannot afford delays in this CPUC Phase 1 Application process, or it may need to pause its undergrounding program. Pausing an undergrounding program not only delays wildfire and reliability risk reduction, but it can also disrupt efficiencies built into a utility's undergrounding program. In addition, it is important to maintain undergrounding program continuity as program efficiencies translate into lower costs for utility customers.

For these reasons, it is reasonable to establish an expedited schedule for this Phase 1 Application to ensure that undergrounding work continues without interruption and that cost efficiencies built into undergrounding programs are maintained.

---

[57] SB 884 (2021-2022 Reg. Sess.), § 8388.5(d)(2).

[58] A.25-05-009, Exhibit (PG&E-4), p. 7-11, lines 1-18.

[59] SB 884 (2021-2022 Reg. Sess.), §§ 8388.5(d)(2), (e)(1), and (e)(5).