California Public
Utilities Commission

SB 884 Program: CPUC Guidelines

SAFETY POLICY DIVISION

December 10, 2025

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Purpose:

These *Guidelines,* and the adopting Commission Resolution, satisfy the Commission's statutory obligation, pursuant to Public Utilities Code Section 8388.5(a), to establish an expedited utility distribution infrastructure undergrounding program consistent with Senate Bill (SB) 884.[1] These *Guidelines* address the process and requirements for the Commission's review of any large electrical corporation's 10-year distribution infrastructure undergrounding plan (as defined below) and related costs.

[1] McGuire; Stats. 2022, Ch. 819

Background:

SB 884, effective January 1, 2023, authorizes electrical corporations with 250,000 or more customer accounts within the state (i.e., large electrical corporations) to participate in an expedited utility distribution infrastructure undergrounding program.

To participate in the program, the large electrical corporation must submit a 10-year distribution infrastructure undergrounding plan (hereafter, "Plan" or "EUP"), including, among other requirements, the undergrounding projects to be constructed as part of the Plan, to the Office of Energy Infrastructure Safety (Energy Safety). Energy Safety is required to review and approve or deny the Plan within nine months of submission. Energy Safety may require the large electrical corporation to modify the Plan before approving it. Energy Safety may only approve the Plan upon finding it will achieve, at least, both of the following:[2]

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

The large electrical corporation must submit to the Commission, within 60 days of Energy Safety's approval, a copy of the Plan and an application requesting review and conditional approval of the Plan's costs (hereafter, "Application"). However, prior to formally filing the Application with the Commission, the large electrical corporation shall provide a copy of the Application it intends to file to the Commission's Safety Policy Division (SPD) for a completeness review to identify any obvious omissions or errors in the intended Application. SPD will conclude its completeness review within 10 business days of receipt and issue a report noting any deficiencies that should be corrected before the Application is officially submitted and filed with the Commission.

On or before nine months after the Application's official filing date, the Commission shall review and conditionally approve or deny the Application. The Commission may, however, require the large electrical corporation to (i) modify or (ii) modify and resubmit the Application prior to conditional approval. As further explained below, if the Commission or staff determines that minor corrections or clarifications are needed for the filed Application, the large electrical corporation may be required to modify the Application and provide corrections or clarifications within five (5) business days after being noticed. If the Commission or staff determines the filed Application 1) omits material information required pursuant to the Commission Resolution adopting these *Guidelines*, 2) omits material information deemed necessary to process the Application within nine months, or 3) omits information otherwise required by SB 884, the Commission or staff may then require the large electrical corporation to modify and resubmit the Application, and such resubmission will restart the nine-month timeline for Commission review.

If the Plan is approved by Energy Safety and the Application requesting review and conditional approval of the Plan's costs is approved by the Commission, the large electrical corporation must file progress reports with the Commission and Energy Safety every six months, include ongoing work plans and progress in its annual wildfire mitigation plan submissions, hire an independent monitor (selected by Energy Safety) to

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[2] Energy Safety has issued guidelines detailing the requirements for submission and review of undergrounding Plans. See https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=58006&shareable=true

review and assess its compliance with the Plan, apply for all available federal, state, and other non-ratepayer moneys throughout the duration of the approved Plan, and use those non-ratepayer moneys to reduce the Plan's costs to its ratepayers.

The independent monitor must annually produce and submit a report to Energy Safety no later than December 1 of each year over the course of the Plan.[3] The independent monitor's report will identify any failure, delays, or shortcomings in the large electrical corporation's compliance with the Plan and provide recommendations for improvements. After consideration of the independent monitor's report and whether the large electrical corporation has corrected the deficiencies identified therein, Energy Safety may recommend penalties to the Commission. The Commission may assess penalties on a large electrical corporation that fails to substantially comply with the Commission decision approving its Plan pursuant to Public Utilities Code, Section 8388.5(i)(2).

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

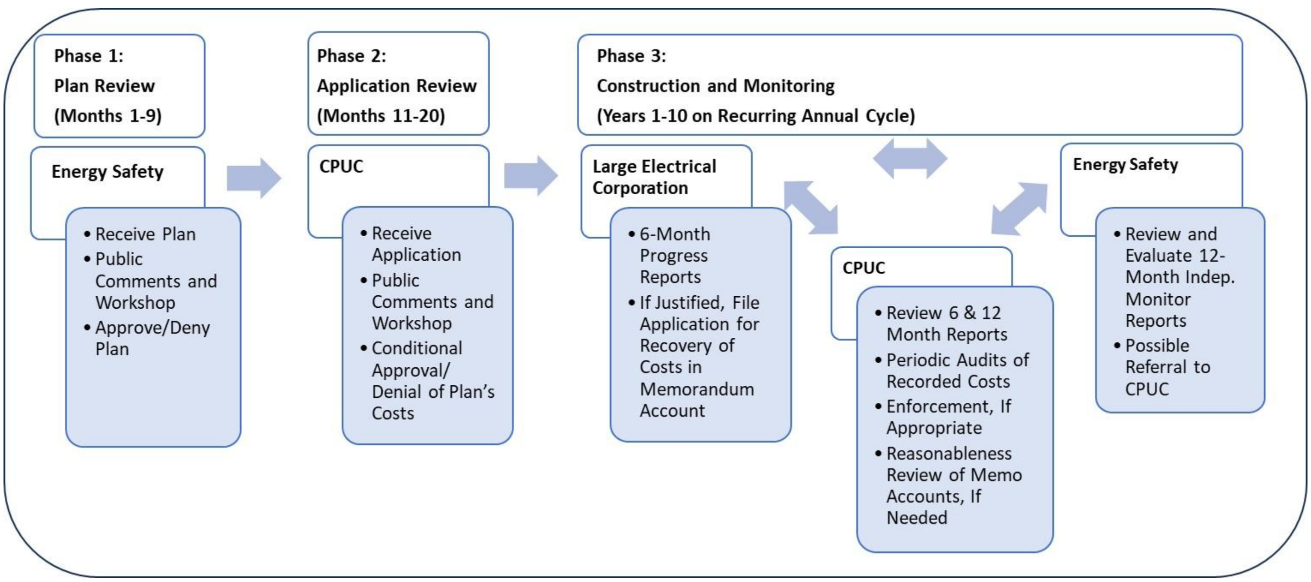

Figure 1: SB 884 Plan, Application, Reporting, and Cost Recovery Timeline

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

SB 884 Program Process and Requirements:

The SB 884 Program will be executed in up to three phases:

- Phase 1 in two parts:
  - Energy Safety Plan review and approval/denial.
  - Joint Phase 1 Application from large electrical corporations to resolve issues identified in Resolution SPD-37, filed with Commission.
- Phase 2: Application submitted to Commission for review and conditional approval.
- Phase 3: Construction and periodic audits of costs recorded in the one-way balancing account, as well as just and reasonableness reviews of recorded costs in the memorandum account described below.

If Energy Safety approves the large electrical corporation's Plan in Phase 1, Phase 2 will commence with the large electrical corporation's submission of an Application for Commission consideration and conclude with the Commission's disposition of such Application (i.e., conditional approval or denial) via a Phase 2 Decision. The Commission will review the costs submitted in any Application. Only if costs[4] meet certain conditions (Phase 2 Conditions), will the Commission authorize their recovery via a one-way balancing account, which shall remain subject to audit. If an audit demonstrates any costs recorded to the one-way balancing account did not meet the Phase 2 Conditions, subject to Commission review and determination, such costs may be subject to refund. The Phase 2 Conditions for recovering costs via the one-way balancing account will include those listed in the "Conditions for Approval of Plan Costs" section herein, as well as any other conditions the Commission deems appropriate in the relevant Application's proceeding. If the Commission approves cost recovery in the one-way balancing account, the Commission will also authorize the large electrical corporation to record, in a memorandum account, any Plan costs that fail to meet the Phase 2 Conditions.

If the Commission conditionally approves the large electrical corporation's Application, Phase 3 will commence upon the Commission's issuance of the Phase 2 Decision. During Phase 3, the large electrical corporation will execute its undergrounding Plan in accordance with the Resolution adopting these *Guidelines*, the Commission's Phase 2 Decision, and any other Commission decision on an Application submitted pursuant to the SB 884 program. The large electrical corporation shall also report on its progress and begin booking costs to the one-way balancing account established in Phase 2, subject to periodic audits and refunds if the Commission so orders. In Phase 3, given the inherent uncertainties with planning across a 10-year period and certain costs being unforeseeable during Phase 2, the large electrical corporation may also request rate recovery (via a separate Phase 3 Application) for implementation costs that do not meet the Phase 2 Conditions, and were recorded in the designated memorandum account up to a cap determined in the Phase 2 Decision. During Phase 3, the Commission will review any Phase 3 Applications for recovery of costs recorded in the memorandum account to determine whether such costs were just and reasonable, and incremental to any other costs approved by the Commission. When making these determinations the conditions set forth in the Resolution adopting these *Guidelines*, the Commission's Phase 2 Decision, and any other Commission decision on an Application submitted pursuant to SB 884 should be considered in light of the fact that such costs must be found to be just and reasonable before being authorized for recovery. Phase 3 will conclude with the Commission's disposition of the last cost recovery application associated with the memorandum account, or the final independent monitor report, whichever is last.

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[4] Costs can only be recovered once the undergrounding project is considered used and useful.

Given the importance of the Phase 2 Conditions and the requirement that any costs recorded in the one-way balancing account must meet the Phase 2 Conditions, these *Guidelines* include a process to assess whether the recorded costs meet such conditions. Accordingly, periodic audits of the established balancing account will be performed to ensure the costs booked to the balancing account meet the conditions established by the Phase 2 Decision (e.g., unit cost caps, benefit cost ratio (BCR) thresholds, etc.). If the audit demonstrates that costs were incorrectly recorded or failed to meet the Phase 2 Conditions, the Commission may order a refund. If the Commission directs a large electrical corporation to issue a refund, the large electrical corporation shall not seek to recover such costs through any other means.

Due to the SB 884 Program's expedited schedule, unless otherwise directed by the Commission, large electrical corporations shall respond to discovery requests within five (5) days in either Phase of the SB 884 Program.

Phase 1 – Joint Application to resolve SPD-37 Issues

The three large electrical corporations eligible for participation in the SB 884 program (Pacific Gas and Electric Company, Southern California Edison, and San Diego Gas & Electric) are directed to file a joint application, hereafter the Phase 1 Application, within 60 days of the issuance of Resolution SPD-37 requesting approval of a proposal for addressing each of these three issues:

1. BCR Calculation
2. Audit Methodology
3. Cost Recovery Conditions

Specific guidance for the content of each proposal to be included in the Phase 1 Application follows.

BCR Calculation

The large electrical corporations' proposal for the BCR calculation shall detail at least one standardized and consistent methodology for evaluating and comparing the cost-efficiency of undergrounding and alternative mitigations in SB 884-related applications. The large electrical corporations' proposal shall be designed to promote comparability, transparency, and traceability in BCR calculations across large electrical corporations, while remaining adaptable to future improvements in data availability and analytical approaches. Any proposed methodology shall apply to the project level, and may allow for scalability to the portfolio level. It shall complement the *SB 884 Project List Data Requirements Guidelines* by outlining how to calculate the BCR for the purposes of EUPs and provide more information on the calculation's key components. These key components of at least one proposed methodology shall, at a minimum, include:

- **Total Capital Cost**, defined as capital expenditures tied to project implementation. The relationship between Total Capital Costs and other categories, such as Operating and Maintenance (O&M) Costs, O&M Savings, or Net Salvage values,[5] should be addressed.

[5] Net Salvage value means the salvage value of an electrical infrastructure related asset that has been retired less the cost of removal of that asset.

- **Risk Scaling,** which should address whether unscaled (i.e., risk-neutral) risk values should be used in the BCR calculations.
- **Total Mitigation Benefit,** which may include:

  a. Risk Reduction, including Wildfire Ignition Risk and Outage Program Risk.

  b. Other enterprise risks such as Public Contact with Energized Electrical Equipment (PCEEE) and Distribution Overhead Asset Failure (DOVHD).

Different types of mitigation benefits should be clearly identified and distinguished to facilitate transparency and avoid double-counting.

- O&M Costs associated with operating and maintaining the project.
- O&M Savings, defined as the avoided O&M expenditures eliminated by the proposed project as compared to the No-Build Baseline.[6]
- **BCR Year Zero**, defined as the year a project becomes "used and useful," which serves as the reference year for discounting both costs and benefits. This BCR Year Zero definition shall be included in the large electrical corporations' BCR methodology proposal.
- **Interruption Cost Estimate (ICE)[7] Calculator Granularity**, the level of granularity (e.g., Customer Class separated by HFTD and Non-HFTD regions) that large electrical corporations should use to monetize the value of electric reliability should be addressed.

Backcasting, 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 should be proposed. The large electrical corporations shall include guidance on backcasting in any BCR methodology proposal.

Audit Methodology

The Phase 1 Application shall include a detailed 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. For the primary objectives, this method must include an approach for:

a. Verifying that the total annual costs did not exceed the approved cost cap for a given year of the EUP (Condition #1);

b. Verifying that any third-party funding obtained was applied to reduce the established cost cap for the specific year in which the third-party funding was obtained (Condition #2);

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[6] No-Build Baseline represents a well-defined baseline scenario of the status quo that describes expected conditions in the absence of any new project or Risk Reporting Unit (RRU)implementation. The Build Baseline is used to compare the relative costs and benefits of various design or implementation alternatives.

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

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); and

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

e. Verifying that a project is used and useful.

f. Verifying the incrementality showing found in Application Requirement No. 2.

Cost Recovery Conditions

The Phase 1 Application shall include a proposal for any additional portfolio or project-level conditions necessary to ensure that costs booked to balancing accounts are just and reasonable. At a minimum, large electrical corporations shall consider the following types of quantitative conditions: conditions that address how an undergrounding project compares to alternative mitigations; conditions that address how the actual BCR of a project compares to its forecasted BCR; conditions that address how the actual unit cost of an undergrounding project compares to its forecasted cost. For each quantitative condition, large electrical corporations should propose a numerical threshold that can be used to evaluate whether the condition has been met. Parties to the Phase 1 Application may respond to each of the large electrical corporations' proposals and make counter proposals within 15 calendar days of the large electrical corporations' filing(s).

Required Data

In order to consider the practical implications of the proposed BCR methodologies, audit methodologies, and cost recovery conditions, upon filing their EUP with Energy Safety, large electrical corporations shall file in the Phase 1 Application proceeding the most recent versions of all available data identified in the *SB 884 Project List Data Requirements Guidelines* using the *SB 884 Project List Data Template*

Phase 1 Application Submission Requirements:

The Phase 1 Application submitted to the Commission shall meet all the following requirements.

Submission Deadline:

The Phase 1 Application shall be jointly filed by the three large electrical corporations eligible for participation in the SB 884 Program within 60 days of the issuance of Resolution SPD-37.

Phase 1 Application Type:

The Phase 1 Application shall be submitted according to the Commission's Rules of Practice and Procedure and any other requirements set forth in the Commission Resolution adopting these *Guidelines*.[8] Each section of the Phase 1 Application shall indicate the person(s) who sponsors the section and would serve as a witness if evidentiary hearings are required.

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

Phase 1 Application Submission:

The Phase 1 Application shall be filed and served with the Commission's Docket Office, with a copy to the Commission's Chief Administrative Law Judge, the service lists for each large electrical corporation's most recent general rate case (GRC), the SB 884 notification list linked here,[9] as updated, SB884@cpuc.ca.gov, and any other service lists, as determined by the large electrical corporations, that will cause the Phase 1 Application to broadly reach interested parties.

Application Conditional Approval, Denial, or Modification & Resubmittal:

On or before nine months after the Application's filing date, the Commission shall review and conditionally approve or deny the Application. Before conditionally approving or denying the Application, the Commission or staff may require the large electrical corporation to (i) modify or (ii) modify and resubmit the Application.[10] If the Commission or staff determines that minor corrections or clarifications are needed for the Application, then the Commission or staff may require the large electrical corporation to modify the Application and such minor corrections or clarifications shall be provided within five (5) business days of notice. If the Commission or staff determines that the Application 1) omits material information required pursuant to the Commission Resolution adopting these *Guidelines*, 2) omits material information deemed necessary to process the Application within nine months, or 3) omits information otherwise required by SB 884, then the Commission or staff may require the large electrical corporation to modify and resubmit the Application, and such resubmission will restart the nine-month timeline for the Commission's review.

Pre-Submission Application Completeness Review:

Before submission of the Application, the large electrical corporation shall provide a copy of the intended Application to Commission's Safety Policy Division (SPD)[11] for a completeness review. The pre-submission process is a precursor to and separate from the Commission's Application review process. The intent of the completeness review will be to identify any obvious omissions or errors and avoid unnecessary delays resulting from post-submittal modification of the Application for such omissions or errors, given the expedited schedule for review. SPD will conclude its completeness review within 10 business days of receipt and issue a report noting any deficiencies that should be corrected in the submitted Application. Accordingly, it is the large electrical corporation's responsibility to provide SPD with a copy of the intended Application with sufficient time to conduct the completeness review (i.e., 10 business days) while ensuring that the 60-day deadline for Application submission, following Energy Safety's approval of the Plan, is met pursuant to Public Utilities Code, Section 8388.5(e)(1). SPD's report is solely for completeness review; it is

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[9] The SB 884 notification list is periodically updated and uploaded to CPUC SB 884 webpage: https://www.cpuc.ca.gov/about-cpuc/divisions/safety-policy-division/risk-assessment-and-safety-analytics/electric-undergrounding-sb-884.

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

[11] Pre-submission of the Application for completeness review shall be submitted to SB884@cpuc.ca.gov.

not a substantive review or disposition of the Application and does not limit the Commission's or staff's ability to require the large electrical corporation to otherwise modify or resubmit the Application.

Phase 2 – Application Submission and Review:

These *Guidelines* recognize that Plans approved by Energy Safety will have been found to show that implementation of the Plan will substantially increase reliability and substantially reduce wildfire risk, as required in Public Utilities Code, Section 8388.5(d)(2). The Commission will then review such Plans and either conditionally approve or deny the costs, as presented in the subsequent Application.

Application Submission Requirements:

Applications submitted to the Commission seeking conditional approval of Plan costs shall meet all the following requirements.

Submission Deadline:

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

Application Type:

Applications shall be submitted according to the Commission's Rules of Practice and Procedure and any other requirements set forth in the Commission Resolution adopting these *Guidelines*.[12] Each section of the Application shall indicate the person who sponsors the section and would serve as a witness if evidentiary hearings are required.

Application Submission:

The Application shall be filed and served with the Commission's Docket Office, with a copy to the Commission's Chief Administrative Law Judge, the service list for the large electrical corporation's most recent GRC, the SB 884 notification list linked here,[13] as updated, SB884@cpuc.ca.gov, and any other service lists, as determined by the large electrical corporation, that will cause the Application to broadly reach interested parties. A copy of the Application should also be sent to each communications company that has equipment on poles where undergrounding is planned.

Application Requirements:

For the purposes of these *Guidelines*, all program and project costs reported in the Application shall include the standard project costs including, but not limited to, program management, project execution, design, estimating, mapping, construction, internal labor, contracted labor, parts, tools, materials, overhead, and

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

[13] The SB 884 notification list is periodically updated and uploaded to CPUC SB 884 webpage: https://www.cpuc.ca.gov/about-cpuc/divisions/safety-policy-division/risk-assessment-and-safety-analytics/electric-undergrounding-sb-884.

permitting. In addition, all ratepayer impacts shall be shown by all ratepayer classifications (e.g., residential, agricultural, commercial, etc.) to the extent such information is available.

All cost and BCR data, required as described below, shall be supported by workpapers and Excel worksheets included with the Application submission.

The following are required contents of all Applications:

1) The Application shall present both capital and operating expense cost forecasts for each year of the 10-year Application period, consistent with the cost targets presented in the Plan approved by Energy Safety.
2) The Application shall clearly identify all undergrounding targets (*e.g.*, miles to underground together with their conversion rate[14]) and cost forecasts[15] in the Plan that overlap with undergrounding targets and any and all related targets and cost forecasts either approved or under consideration in the large electrical corporation's most recent GRC or any other cost recovery venues. Furthermore:
    a) Where undergrounding targets and cost forecasts in the Application overlap with undergrounding targets and cost forecasts <u>approved</u> in the most recent GRC or other cost recovery venue, such undergrounding targets and costs shall be clearly identified and associated costs will be excluded from consideration for recovery in the Application.
    b) Where undergrounding targets and cost forecasts in the Application overlap with undergrounding targets and cost forecasts <u>still under consideration</u> in a GRC or other cost recovery venue, the Application shall specify which overlapping targets and costs are under consideration and identify the proceeding or advice letter in which the Commission is considering them. The Application shall propose in which venue the Commission should consider the overlapping costs. Both costs and the corresponding mileage must be paired and presented for consideration in a single venue.
    c) The Application shall include a detailed description of the controls the large electrical corporation will implement to ensure that undergrounding costs related to execution of the Plan are incremental to any other costs approved by the Commission.
3) The Application shall include the large electrical corporation's best estimate, including all underlying assumptions, of the proposed annual revenue requirements and proposed ratepayer impacts for each year that the large electrical corporation proposes will be necessary for rate recovery of the Application's forecasted annual costs.
4) The Application shall include a Results of Operation (RO) Model for that portion of its revenue requirement that relates to the undergrounding cost recovery it seeks, with Energy Division

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[14] As used in this context, "conversion rate" means the ratio of underground mileage required to replace the equivalent overhead lines. Given prior evaluation of undergrounding requests in other Commission proceedings, it is known that a mile of undergrounding corresponds to replacement of less than one mile of overhead assets.

[15] For clarity, the term cost forecasts is used in place of the term cost targets that are discussed in PUC 8838.5 (3)(1).

oversight and a non-disclosure agreement in place,[16] that demonstrates how the large electrical corporation calculated the revenue requirement provided.[17]

5) The Application shall identify, for each year of the 10-year Application period, any forecast wildfire mitigation costs that will be reduced, deferred, or avoided because of implementing the proposed undergrounding Plan (e.g., vegetation management), collectively "savings," and how spending on such programs or areas of work will be affected, including any cost reductions, deferrals, or avoidances that are expected to continue beyond the 10-year Application period and the time period for which such cost reductions, deferrals, or avoidances are expected to continue beyond the 10-year period.[18]
   a) The Application shall distinguish between forecast costs already approved by the Commission for recovery and forecast costs that have not yet been the subject of a request for recovery.
   b) For forecast costs already approved by the Commission for recovery, the Application shall identify any accounts used to track such costs; the amounts in each such account; and the Commission decision(s) authorizing recovery.
   c) The application shall explain the proposed disposition of all identified savings and explain the methodology by which the Commission can ensure that all identified savings are passed on to ratepayers.
6) The Application shall include cost forecasts for each year of the 10-year Application period that, at a minimum, result in feasible and attainable cost reductions as compared to the large electrical corporation's historical undergrounding costs.
   a) Cost forecasts shall be provided for each projected year in the 10-year Plan.
   b) Annual historical undergrounding unit costs shall be provided for the previous 10 years, with separate categories for Rule 20 projects, other undergrounding projects, and wildfire mitigation projects, as available.
   c) Comparisons between the Plan's unit cost targets and historical undergrounding unit costs shall be provided using the average historical wildfire mitigation undergrounding costs for the previous three years (before the Plan's first year). The comparison shall include a statement of how the targeted cost reductions are feasible and attainable compared to historical costs.
7) The Application shall include an explanation of how the cost forecasts are expected to decline over time due to cost efficiencies and economies of scale.
8) The Application shall include a description of a strategy for achieving cost reductions over time per Public Utilities Code, Section 8388.5(e), which may include factors other than cost efficiencies or

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[16] The non-disclosure agreement shall ensure that the large electrical corporation personnel in charge of the RO modeling will not disclose changes to the RO Model requested by the Commission to the personnel working on the Phase 2 Application and related matters.

[17] See also D.00-07-050 at 11-12 and D.20-01-002 at 65-67.

[18] For examples of cost savings that may be appropriate to include, refer to the Lawrence Berkeley National Laboratory white paper. Peter H. Larsen, "A method to estimate the costs and benefits of undergrounding electricity transmission and distribution lines" in Energy Economics Vol. 60, 2016 pp. 47-61. Please note that this methodology is referenced for illustrative purposes only. Different methodologies and/or cost categories may be appropriate to include.

economies of scale such as, but not limited to, identifying, developing, and deploying new technologies.

9) The Application shall present the forecasted average BCR across all projects expected to be completed in each of the 10 years of the Application period, broken out by year and for the total Application period. BCR must be calculated as directed in the Phase 1 Decision. The calculated annual and total benefits must relate to the mitigation of overhead line miles, not miles of undergrounding.[19] The costs and benefits of any projects that will include secondary lines and service drops must also be included.
10) The Application shall include the forecasted BCRs across all projects, by year and for the total Application period, for each alternative wildfire mitigation hardening method considered, in place of undergrounding, including forecasted BCRs for combinations of non-undergrounding hardening mitigation measures. The calculated annual and total benefits must relate to the mitigation of overhead line miles, including any secondary lines and service drops, not miles of undergrounding.
    a) The large electrical corporation shall use reasonable and comparable assumptions in its calculations of forecasted BCRs for both undergrounding and each alternative wildfire mitigation method considered, including combinations thereof.
11) The Application shall include a description of any substantial improvements in safety risk and reduction in costs compared to other hardening and risk mitigation measures over the duration of the Plan.
    a) Substantial improvements in safety risks shall be substantiated using the above required benefits calculations by comparing undergrounding benefits to alternative hardening and risk mitigation measures, including combinations of alternative measures.
    b) Reduction in costs shall be substantiated using the same cost calculations as required above by comparing undergrounding costs to alternative hardening and risk mitigation measures, including combinations of alternative measures.
12) For each project included in the Application, the large electrical corporation shall provide, at a minimum, all data listed in the *SB 884 Project List Data Requirements Guidelines* in tabular format. This information shall be provided as both a Microsoft Excel file and searchable pdf file[20] to supplement the Application. The large electrical corporation shall provide the latest version of the data required by the *SB 884 Project List Data Requirements Guidelines* at the time of its Application submission.
13) The Application shall include the latest data associated with the list of all projects (*SB 884 Project List Data Requirements Guidelines*) as required by Screen 2 of the *Energy Safety Guidelines*. The large electrical corporation shall provide a forecasted scope of all projects in the approved 10-year EUP and included in the Undergrounding Projects List, as an output from Screen 2 of the *Energy Safety Guidelines*.
14) The Application shall only include undergrounding projects that have a forecasted BCR greater than or equal to 1.

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

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

15) The Application shall include a detailed explanation of the necessity for any spans that extend beyond the HFTD boundary for any project included in the Application.
    a) The Application shall only include undergrounding projects that have been designated as an In-Area circuit segment as required by Screen 1 in the *Energy Safety Guidelines*.[21]
16) The Application shall include:
    a) The same Key Decision-Making Metrics (KDMMs) data for Commission review as was provided in the EUP approved by Energy Safety.
    b) The KDMMs included in any six-month progress report submitted to Energy Safety during the nine-month period that the large electrical corporation's EUP is under review by Energy Safety.
17) For each project included in the Plan and Application, the large electrical corporation shall provide GIS data for all project boundaries in a Geodatabase or other suitable format.
    a) The GIS data shall include the entire circuit within which projects are planned and indicate the locations of which segments will be undergrounded.
    b) The GIS data shall identify the locations of circuit segments that will continue to support overhead transmission lines (if any) after distribution lines are undergrounded.
    c) The GIS data shall indicate the locations of poles which have lease agreements with communications companies, and which are jointly owned.
18) The Application shall include a list of all non-ratepayer moneys (i.e., third-party funding) the large electrical corporation has applied for and/or received to minimize the Plan's costs on ratepayers. At a minimum, for each potential source of third-party funding, the list shall include:
    a) The source of third-party funding;
    b) The date when third-party funds were requested;
    c) The amount of funding requested;
    d) The status of the request, including funding already received;
    e) Next steps, including timelines for processing of the funding request; and
    f) The amount of funding granted/authorized (if any).
19) The Application shall include a description of how any net tax benefits associated with the third-party funding will be disposed of to the benefit of ratepayers.
20) The Application shall include a statement affirming costs, tax benefits, and tax liabilities associated with federal funding sources used to fund projects included in the Plan are being tracked consistent with Resolution E-5254.[22]
21) The Application shall include an attestation that the large electrical corporation will continue to search and apply for third-party funding to reduce the cost of the Plan to ratepayers throughout the duration of the Plan.
22) The Application shall include a description of how the large electrical corporation plans to coordinate with communication companies to maximize benefits to California, including but not limited to:
    a) The ownership and use of existing utility poles where undergrounding projects are planned;

[21] *Energy Safety Guidelines* at 12. The large electrical corporation indicates to Energy Safety whether a circuit segment is designated as "In-Area" in Table C.6 under the "is_in_area" field.

[22] Resolution E-5254 adopted procedural mechanisms for review and approval of electric and gas investor-owned utility cost recovery requests related to various federal funding and grant programs. Resolution E-5254 is available on the Commission's website at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M506/K016/506016078.PDF.

b) How the large electrical corporation will address the affected shared poles, including who will own and maintain the poles if the responsible communication provider opts not to concurrently underground their infrastructure;
c) The full array of currently offered or discussed proposals for how to add conduit for such communication companies in the large electrical corporation's trenches, including, wherever possible, the proposed unit costs associated with such offerings or proposals.

23) The Application shall include a plan of how and when the large electrical corporation will remove poles from its rate base whose ownership is transferred to a communications company.
24) The Application shall include workforce development cost forecasts for each year of the Plan.
25) The Application shall include a copy of the Plan approved by Energy Safety.

Public Workshop & Comments:

The Commission will facilitate a public workshop for presentation of the Application and take public comment for at least 30 days in accordance with Public Utilities Code Section 8388.5(e)(4). Formal comments from the workshop will be solicited by a ruling in the proceeding, and a workshop report provided by the parties who participated in the workshop may be ordered.

Conditions for Approval of Plan Costs:

Public Utilities Code, Section 8388.5(e)(1) specifies that an Application may request "conditional approval of the plan's costs…" To protect ratepayers from unexpected and inefficient cost overruns, the Commission establishes the following conditions for any costs booked to the one-way balancing account established in Phase 2:

1) Total annual costs must not exceed a cap based on the approved cost cap for that specific year.[23]
2) Third-party funding obtained, if any, shall be applied to reduce the established cost cap for the specific year in which the third-party funding is obtained, so that ratepayers receive the benefit. The large electrical corporation shall file an advice letter documenting which annual cost caps are reduced based on third-party funding received.
3) The average recorded unit cost for all projects completed in any given two-year period (the current year, and the prior year) must not exceed the approved average unit cost cap for the current year. The unit costs shall be calculated per mile of undergrounding performed, rather than per mile of overhead replaced, to focus on reduction of construction costs.
4) The average recorded BCR[24] for all projects completed in any given two-year period (the current year, and the prior year) must equal or exceed the approved threshold BCR value[25] for the current year.

Any further reasonable conditions adopted by a future Commission decision.

Memorandum Account Cap:

The total cumulative costs recovered via the memorandum account throughout the duration of an EUP shall be capped as a percentage of the total sum of the 10 years of cost caps placed on the one-way balancing

[23] Any costs exceeding the cap shall be recorded in a memorandum account and are subject to review and approval as described in the Phase 3 section of these *Guidelines*.

[24] The "recorded BCR" is the BCR calculated using recorded cost values, as opposed to cost forecasts.

[25] The "threshold BCR value" will establish the minimum BCR that must be achieved for cost recovery.

account. The percentage value of the memorandum account cost cap will be established in the Phase 2 Decision.

Phase 3 – Review of Memorandum Account Recorded Costs for Rate Recovery:

Phase 3 of the program will be initiated if the Commission conditionally approves a Phase 2 Application submitted by a large electrical corporation. During Phase 3, the large electrical corporation will execute its undergrounding Plan in accordance with the Resolution adopting these *Guidelines*, the Commission's Phase 2 Decision, and any other Commission decision on an Application submitted pursuant to the SB 884 program, the large electrical corporation shall also report on its progress, and begin booking costs to the one-way balancing account established in Phase 2, which shall remain subject to periodic audits, and refund if the Commission so orders. In Phase 3, the large electrical corporation may also request rate recovery (via a separate Phase 3 Application) for any implementation costs that do not meet the Phase 2 Conditions and were recorded in the designated memorandum account. The large electrical corporation may only seek recovery for costs recorded in the memorandum account by filing a Phase 3 Application. The total cumulative costs recovered via the memorandum account throughout the duration of an EUP shall not exceed the cap established for such accounts in the Phase 2 Decision. The purpose of any Phase 3 Application will be to determine whether the costs recorded in the memorandum account meet the conditions set forth in the "Conditions for Approval of Recorded Costs in Memorandum Account" section below. When making these determinations the conditions set forth in the Resolution adopting these *Guidelines*, the Commission's Phase 2 Decision, and any other Commission decision on an Application submitted pursuant to SB 884 should be considered in light of the fact that such costs must be just and reasonable. No more than one Phase 3 Application may be filed each year.

The elements of recorded costs must be consistent with the elements included in the costs presented in the Application, including but not limited to, program management, project execution, design, estimating, mapping, construction, internal labor, contracted labor, parts, tools, materials, overhead, and permitting.

The Phase 3 Application must include, at a minimum, all six-month progress reports and annual compliance reports submitted pursuant to this program, relevant information from wildfire mitigation plan filings and compliance reports, and the following program data presented in Table 1 for the requested recovery period.[26] The project data that supports the program recorded cost values requested for recovery shall be provided in tabular format in a sortable Excel spreadsheet. Additional data requirements for a Phase 3 Application may be included in the Phase 2 Decision.

[26] Recovery period means the period under consideration in the most recent Phase 3 Application filing.

Table 1: Conditionally Approved Target and Actual Recorded Cost Data

Conditionally Approved Targets for the Recovery Period	Actual Recorded Costs in the Recovery Period
Program Cost	Program Cost
Program BCR	Program BCR
Program Unit Cost	Program Unit Cost
	Project Data for the Recorded Projects

Conditions for Approval of Recorded Costs in Memorandum Account:

To further protect ratepayers from unexpected and inefficient cost overruns:

1) The Commission will closely scrutinize any Phase 3 Application to determine whether the costs recorded were prudently incurred, incremental to other funding granted to the large electrical corporation, and just and reasonable.
2) When making these determinations the conditions set forth in the Resolution adopting these *Guidelines*, the Commission's Phase 2 Decision, and any other Commission decision on an Application submitted pursuant to SB 884 should be considered in light of the fact that such costs must be just and reasonable.
3) No costs recorded to the memorandum account established in the Commission's Phase 2 Decision shall be authorized for recovery unless and until the large electrical corporation has shown that it has applied all third-party funding previously received to reduce its relevant balancing account cost cap.
4) No costs recorded to the memorandum account established in the Commission's Phase 2 Decision shall be authorized for recovery unless such costs are consistent with the approved Plan.

Progress Reports:

Public Utilities Code Section 8388.5(f)(1) requires large electrical corporations with approved Plans and conditionally approved Applications to file progress reports every six months with both Energy Safety and the Commission. Accordingly, without affecting the required progress report elements specified by Energy Safety, these *Guidelines* require that the six-month progress reports shall include, but should not be limited to, the following:

1) Total recorded costs to date;
2) Third-party funds received, with an explanation of how third-party funding was used to reduce the burden on ratepayers;
3) Average recorded BCR for completed projects in any given two-year period;
4) Average recorded unit cost per mile of undergrounding for completed projects in any given two-year period;
5) Miles of overhead replaced by undergrounding by circuit segment;
6) Miles of undergrounding completed by circuit segment;
7) GIS data showing location and status of each project (in Geodatabases or other suitable format);
8) An updated list of all third-party funding the large electrical corporation has applied for, as specified in Application Requirements 19-21; and

9) Total and average avoided costs and workpapers showing calculation of avoided costs.
10) An updated dataset that follows the requirements of the *SB 884 Project List Data Requirements Guidelines*.

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

Audit of the One-Way Balancing Account:

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

The primary objective of an EUP Audit is to determine whether the costs recorded in the large electrical corporation's balancing account have met all four[27] Phase 2 Conditions. The audit shall also verify whether the recorded costs have met the following secondary objectives set forth in SPD-37:

1) Verify that projects are "used and useful;" and
2) Determine whether the recorded costs are incremental – and do not duplicate costs allowed through another decision, mechanism or received from a third party.

A Phase 1 Decision may also add primary and/or secondary objectives for the EUP Audit.

As for the specific method the auditor will use to verify whether the costs of underground projects recovered via the one-way balancing account met the primary and secondary objectives, such methodology will be determined via the Phase 1 Application process.

The EUP Audit will result in an audit report that will be filed and served to the Phase 2 Application docket within five (5) days (or such period specified in a future Commission Decision) of its completion and approval. The audit report shall be completed within six months (or such period specified in the Phase 2 Decision) after it is initiated.[28] Parties may file and serve opening comments on the audit report in the Phase 2 Application docket no later than 42 days (or such period specified in the Phase 2 Decision) after the audit report is filed and served by the large electrical corporation. Reply comments on the audit report may be

[27] The EUP Audit scope will also include any Phase 2 Conditions adopted in a future a Commission Decision beyond those listed herein.

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

filed and served in the Phase 2 Application docket no later than seven days (or such period specified in a future Commission Decision) after the due date for opening comments. The Commission may determine the appropriateness of reopening the Phase 2 Application proceeding based on its review as described below.

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

The large electrical corporation shall not have input into the direction, focus, or outcome of the EUP Audit that goes beyond the input afforded to other Parties to the Commission's SB 884 proceeding or process. The large electrical corporation shall provide access to all information requested by the auditor and SPD to carry out the audit within five days (or such period specified in a future Commission Decision) of each data request. The large electrical corporation shall also make personnel available for interviews on five days' notice (or such period specified in a future Commission Decision) if the auditor seeks substantive information and a custodian of records for questions about the location and content of requested information.

Wildfire Mitigation Plan Integration:

Public Utilities Code Section 8388.5(f)(2) requires large electrical corporations to include ongoing work plans and progress relating to their undergrounding plans in annual wildfire mitigation plan filings. Staff understand that further guidance on incorporating this information into annual wildfire mitigation plan filings will be provided by Energy Safety.

Compliance Reports:

Public Utilities Code Section 8388.5(f)(3) requires a large electrical corporation with an approved Plan and conditionally approved Application to hire an independent monitor selected by Energy Safety. The independent monitor must assess whether the large electrical corporation's progress on undergrounding work is consistent with the objectives identified in its approved Plan.[29] For each year the Plan is in effect, the independent monitor must annually produce a compliance report detailing its assessment by December 1.[30] The independent monitor's compliance report must also specify any failure, delays, or shortcomings of the large electrical corporation and provide recommendations for improvements to accomplish the objectives set forth in the approved Plan.[31] The large electrical corporation shall have 180 days to correct and eliminate any deficiency specified in the independent monitor's report.[32] Energy Safety shall consider

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

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

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

[32] Public Utilities Code, Section 8388.5(g)(2).

the independent monitor's compliance report and whether the large electrical corporation cured the deficiencies identified therein when making its determination on whether to recommend penalties to the Commission.[33]

Penalties:

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

[33] Public Utilities Code, Section 8388.5(i)(1).

Appendix 1: SB 884 Project List Data Requirements Guidelines*

* The *SB 884 Project List Data Requirements Guidelines* were published by Safety Policy Division on July 24, 2025. Additional information, including the data template that large electrical corporations must use to file its Application and six-month progress reports can be found here: https://www.cpuc.ca.gov/about-cpuc/divisions/safety-policy-division/risk-assessment-and-safety-analytics/electric-undergrounding-sb-884. The *SB 884 Project List Data Requirements Guidelines* presented here supersede Appendix 1 of Resolution SPD-15.

California Public
Utilities Commission

SB 884 Project List Data Requirements Guidelines

SAFETY POLICY DIVISION

July 24, 2025

Table of Contents

Background and Purpose:

Pursuant to Senate Bill (SB) 884 (McGuire; Stats. 2022, Ch. 819), the California Public Utilities Commission's (CPUC or Commission) data requirements for a large electrical corporation's Electrical Undergrounding Plan (EUP) intended to mitigate wildfire risk in the High Fire Threat District (HFTD), will be complex and require coordination with the Office of Energy Infrastructure Safety's (Energy Safety) Guidelines and data templates. Attached to Resolution SPD-15,[1] the Commission issued the *SB 884 Project List Data Requirements-Preliminary* to begin the discussion on how a utility should submit tabular and geospatial data in support of a Phase 2 Application related to its EUP.[2] Ordering Paragraph 3 of SPD-15 stated that:

> Following Energy Safety's publication of its SB 884 Guidelines, SPD is authorized to convene a Technical Working Group (TWG) to review and align the preliminary CPUC SB 884 Project List Data Requirements and Geographic Information System (GIS) data requirements with Energy Safety Guidelines, adding any data elements necessary for Commission conditional approval purposes.

Additionally, Ordering Paragraph 4 of SPD-15 stated that:

> SPD is authorized to develop and issue the SB 884 Project List Data Template within 30 days of the final TWG meeting.

As discussed below, the final TWG meeting was held on June 24, 2025. Thus, by issuing the *SB 884 Project List Data Requirements Guidelines* (henceforth referred to as the *CPUC SB 884 Data Guidelines*) to the SB 884 Notification List on July 24, 2025, SPD has completed the requirements of Ordering Paragraph 4 in SPD-15.

On February 20, 2025, Energy Safety published Guidelines that a large electrical corporation must follow to submit an EUP to that agency.[3] Energy Safety's Guidelines include extensive discussion of data requirements that require the Commission to review and determine the best way to align its own data requirements for a large electrical corporation's Phase 2 Application for the EUP. Following the TWGs discussed below, the *CPUC SB 884 Data Guidelines* represents an alignment between the data needs of the Commission to evaluate conditional approval of costs and the requirements found in the Energy Safety Guidelines as was required by Ordering Paragraph 3 in SPD-15.

On January 30, 2025, Safety Policy Division (SPD) presented a Risk Assessment and Mitigation Phase (RAMP) data template Guidelines and data template as part of a TWG in Phase 4 of the Risk-Based Decision-Making Framework (RDF) Proceeding (R.20-07-013).[4] On February 11, 2025, an Administrative

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[1] Resolution SPD-15 is available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/documents/final-resolution-spd15-adopting-the-commissions-guidelines-for-the-senate-bill-sb-884-program.pdf.

[2] SPD-15, Attachment 1, Appendix 1 at 15-18.

[3] Office of Energy Infrastructure Safety, 10-Year Electrical Undergrounding Plan Guidelines, February 20, 2025, https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=58006&shareable=true.

[4] The RAMP is a process a utility complies with before initiating a GRC that requires energy-utility safety-risk threat assessments along with associated proposed mitigation plans and estimated costs and spending requests. The RDF proceeding examines how

Law Judge Ruling filed SPD's RAMP data template Guidelines and data template to the RDF Proceeding[5] SPD recognizes that it will be crucial that a data template for a Phase 2 Application also align with the data template needed in a RAMP and General Rate Case (GRC) Application. The structure of the *CPUC SB 884 Data Guidelines* is influenced by the discussion of Staff's data template Guidelines presented in the RDF Proceeding.

Commission Staff issued a "Staff Report on SB-884 Projects List Data Requirements Guideline" (or Staff Report) on May 20, 2025, which included a set of "Technical Working Group Questions". Commission Staff then hosted a series of three TWG meetings in June 2025. During the SPD TWG meeting #1, held on June 3, 2025, SPD Staff presented the Staff Report and addressed questions from stakeholders regarding potential updates to the SB 884 Project List Data Requirements. In a May 15, 2025, e-mail to the SB 884 Notification List, SPD offered the opportunity for any stakeholder to present their feedback and recommendations on the Staff Report. No stakeholders accepted this opportunity. However, Staff did receive a list of questions from Pacific Gas and Electric Company (PG&E), which it requested to be discussed during the SPD TWG meeting #2 on June 10, 2025. Additionally, the SPD TWG meeting #3 on June 24, 2025, included presentations from Lawerence Berkeley National Labs and PG&E on the Interruption Cost Estimate Calculator (ICE 2.0). Stakeholders held additional discussion related to the way ICE 2.0 was addressed within the Staff Report. Finally, Staff accepted stakeholder responses to the "Technical Working Group Questions" on June 24, 2025. The input received from stakeholders, along with the adoption of the Energy Safety Guidelines, informs the *CPUC SB 884 Data Guidelines* presented in this document.

The purpose of the *CPUC SB 884 Data Guidelines* is to provide clarity on the field name, field description, and field value constraints in the SB 884 Project List Data Template. Additionally, the *CPUC SB 884 Data Guidelines* is a revision of *SB 884 Project List Data Requirements-Preliminary* that was attached to SPD-15.

For each project included in the Plan and Application, the large electrical corporation shall provide, at a minimum, all data listed in the *CPUC SB 884 Data Guidelines* in tabular format. This information shall be provided as both a Microsoft Excel file and a searchable pdf file to supplement the Application. The large electrical corporation shall provide the latest version of the data required by the *CPUC SB 884 Data Guidelines* at the time of its Application submission. Additionally, at a minimum, the six-month progress reports filed by a large electrical corporation shall include an update of the data required in the *CPUC SB 884 Data Guidelines.*[6] The data values provided in each update of the data required in the *CPUC SB 884 Data Guidelines* should correspond to the date listed in each of the Reporting_Date fields found at the end of Tables 1-6.

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to calculate risk mitigation levels for various safety measures in order to ensure utilities focus on the most cost-efficient risk reduction strategies in their safety work, including wildfire-related safety.

[5] Administrative Law Judge's Ruling Entering Phase 4 Technical Working Group Materials and Related Staff Proposal into the Record and Setting Comment Schedule, February 11, 2025, https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=556602565.

[6] Energy Safety Guidelines at 25-26.

Note on Terminology:

1. The term "Risk" in this document corresponds to "Overall Utility Risk" (unless otherwise noted) as defined in the Energy Safety Guidelines.[7]

[7] The 10-Year Electrical Undergrounding Plan Guidelines published by Office of Energy Infrastructure Safety on February 20, 2025, page A-4.

Template and Tables Structure

Table 1: Data Set

This table collects the key elements and characteristics of a Risk Reporting Unit (RRU), including unique identifiers, mitigation plans, and associated risks.[8] Table 1 defines how risk-related data elements are structured and categorized for consistent reporting across various progress reports and geographic locations.

As stated in the introduction, it is necessary to align the SB 884 Project List Data Template with the RAMP Data Template discussed in the RDF Proceeding.[9] Here we present a definition of asset, RRU, and system to clarify that these concepts must be shared across RAMP and SB-884 Applications.

- Asset: A retirement unit as defined by Federal Energy Regulatory Commission (FERC) Uniform System of Accounts (USOA) that exhibits risk.[10]
- Risk Reporting Unit (RRU): A CPUC jurisdictional effort within Electric Operations or Gas Operations that simultaneously removes or mitigates the risk associated with a group of contiguous assets or systems that exhibit high levels of risk. The RRU must include common elements that must include, but are not limited to Consequence Attributes, Risk level, line-item costs, benefit-cost ratios (CBRs), work units and time. The RRU can be aggregated along several dimensions based on unique identifiers that include, but are not limited to, hierarchy,[11] scenario,[12] version,[13] risk event, tranche, and mitigation type.
- System: A regularly interacting or interdependent group of items forming a unified whole that exhibits risk and cannot be classified as a retirement unit.

Unless otherwise specified, such as certain fields in Table 4, all data requirements related to assets, RRUs, and systems apply to but are not limited to, primary, secondary and service lines.

Additionally, to conform with the requirements of the CPUC's SB 884 Guidelines found in SPD-15 or any successor Commission order or decision, the RRU must be:

1. Traceable through all stages of a lifecycle, including but not limited to the project's scoping, designing, permitting, construction/implementation, post-construction, retirement/decommissioning.
2. Auditable in terms of timing, location, work units, costs, and Risk Reduction.
3. Forecastable to at least the 10th year of the EUP.

[8] For more information on the RRU, see R.20-07-013, Phase 4 Workshop 1, SPD Staff Proposal on Definition of Scoped Work and the Risk Reporting Unit, November 8, 2024.

[9] Any updates in the RDF Proceeding may result in an update in the SB-884 Data Template Guidelines.

[10] For the FERC USOA, see 18 CFR Part 101 https://www.ecfr.gov/current/title-18/chapter-I/subchapter-C/part-101

[11] Hierarchy refers to a utility's organizational hierarchy, such as an Electric Distribution Division or a Gas Distribution Division. as well as other ways of categorizing high risk assets and systems (i.e. HFTDs, circuits, regions, etc.).

[12] Scenario refers to forecasts, results, and projections.

[13] Version refers to a risk model version.

4. Able to aggregate up to the EUP.[14]

Utilities shall use these definitions and requirements to present RRU level data in their EUP. The level of granularity required is discussed below.

Tables 1 through 4 are anchored around the RRU_ID field, which references uniquely identifiable RRUs with unique identification numbers (i.e., IDs). A utility's RRU_ID naming schema must be simple and transparently understandable. A utility's RRU_ID naming schema must include the GRC Activity Code of the Undergrounding Project, which must also be listed in Table 1. A utility's RRU_ID naming schema must not result in the reuse of an RRU_ID.

Table 1 shall be submitted with the Phase 2 Application and all subsequent progress reports. In cases where RRU_IDs have not yet been created for certain projects, for the reasons outlined below, the table must be submitted using the corresponding OEIS_Project_ID.[15] Once more detailed and updated information becomes available, reporting in six-month progress reports shall transition to the RRU_IDs. The utility must continue reporting OEIS_Project_IDs to enable traceability and continuity across reports.

The fields OEIS_Project_ID and OEIS_Subproject_ID directly align to the Energy Safety Guidelines and enable coordination with the data templates submitted with the EUP to Energy Safety.[16] All requirements found in the Energy Safety Guidelines for OEIS_Project_ID and OEIS_Subproject_ID also apply to this data template.

If the utility submits a Phase 2 Application that does not use Subprojects, then the Commission requires that the granularity of the RRU be identical to that of the Project as defined in the Energy Safety Guidelines (see Figure 1). If the utility submits a Phase 2 Application that uses Subprojects the Commission requires that the granularity of the RRU be identical to that of the Subproject once detailed Subproject data is available, which means that each RRU_ID can only be tied to a single OEIS_Subproject_ID (Figure 2). Once an RRU_ID is created for a Subproject, all data must be reported using the unique RRU_IDs, OEIS_Project_IDs and OEIS_Subproject_IDs.

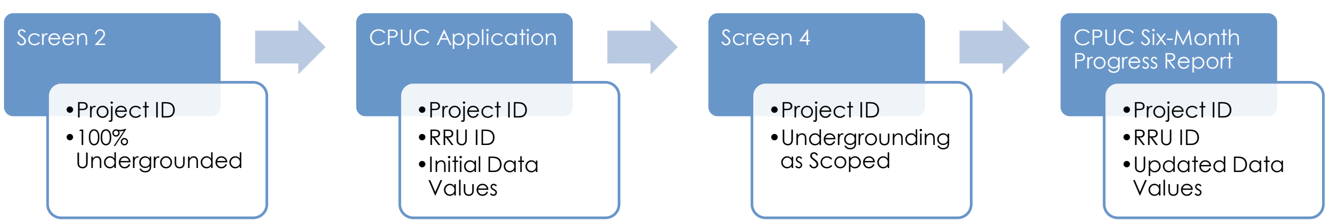

Figure 1: Process for creating an RRU_ID and Data Submissions for Phase 2 Application without Subprojects

[14] These three requirements have been adapted from the Staff Scoped Work Proposal to conform to the requirements of the SB-884 program.

[15] OEIS_Project_ID corresponds to project_ID, as defined in the 10-Year Electrical Undergrounding Plan Guidelines published by Office of Energy Infrastructure Safety on February 20, 2025 (at C-24).

[16] OEIS_Subproject_ID corresponds to subproject_ID, as defined in the 10-Year Electrical Undergrounding Plan Guidelines published by Office of Energy Infrastructure Safety on February 20, 2025 (at C-36).

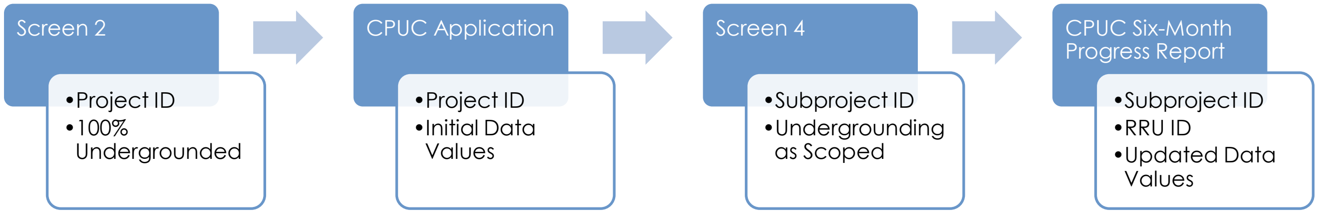

Figure 2: Process for creating an RRU_ID and Data Submissions for Phase 2 Application with Subprojects

If the utility elects to use Subprojects in its Phase 2 Application, then when the utility submits its Phase 2 Application to the Commission, it is possible that detailed Subproject level forecasts may not be available. In the case where the utility submits a Phase 2 Application that uses Subprojects and the Subproject level forecasts are not available, for the initial dataset submitted with the utility's Phase 2 Application, the utility may present forecasts at the Project Level, which should correspond with the Screen 2 data presented by the utility in Table C.11 of the Energy Safety Guidelines.[17] The forecasts presented at the Project Level in the initial dataset submitted with the Application will correspond to the "100% Undergrounded" concept defined in the Energy Safety Guidelines.[18] The RRU_ID field may be left blank at this point. Once detailed Subproject data is available, an RRU_ID must be created for each Subproject, and all data must be reported using the unique RRU_IDs, OEIS_Project_IDs and OEIS_Subproject_IDs.

When the utility submits its Phase 2 Application or six-month progress reports to the Commission, it is required that for any Project (i.e., OEIS_Project_ID) that passes Screen 4 of the Energy Safety Guidelines, the utility shall provide data values in the Commission's data template that should correspond with the Screen 4 data presented by the utility in Table C.13 of the Energy Safety Guidelines.[19] If the utility submits a Phase 2 Application that uses Subprojects, then the detailed RRU level data values submitted to the Commission should correspond with the Subproject data presented by the utility in Table C.14 of the Energy Safety Guidelines.[20]

If the Project has passed Screen 4 of the Energy Safety Guidelines, then the information presented at the Project or Subproject Level in the dataset submitted with either the Phase 2 Application or the six-month progress reports will correspond to the "Undergrounding as Scoped" concept defined in the Energy Safety Guidelines.[21]

For utilities that submit Projects in their Phase 2 Application and do not plan to break them into Subprojects later, the utility may continue reporting data at the Project level throughout both the Phase 2 Application and subsequent six-month progress reports. In these cases, the utility must still align its data with the appropriate Energy Safety Guidelines tables initially using Table C.11 for Screen 2 forecasts and then updating with Table C.13 data for Projects that pass Screen 4. RRU_IDs shall be created for the

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[17] Office of Energy Infrastructure Safety, 10-year Electrical Undergrounding Plan Guidelines, February 20, 2025, at C-25 – C-26.

[18] Office of Energy Infrastructure Safety, 10-year Electrical Undergrounding Plan Guidelines, February 20, 2025, at 44.

[19] Office of Energy Infrastructure Safety, 10-year Electrical Undergrounding Plan Guidelines, February 20, 2025, at C-30 – C-32.

[20] Office of Energy Infrastructure Safety, 10-year Electrical Undergrounding Plan Guidelines, February 20, 2025, at C-33 – C-35.

[21] Office of Energy Infrastructure Safety, 10-year Electrical Undergrounding Plan Guidelines, February 20, 2025, at 44.

Project, and all reporting remains at the Project level. All data must be reported using the unique RRU_ID and OEIS_Project_IDs from the Phase 2 Application. (Figure 2)

Table 1 also collects Backcasted_Cost_Benefit_Ratio, Backcasted_Total_Mitigation_Benefit and Backcasted_Present_Value_Costs. In order to align with the concept of a Backcast as discussed in the RDF Proceeding, the following definition applies:

- Backcast: use updated inputs (e.g., new RRUs, new risk models) to recalculate Cost-Benefit Ratios, pre-mitigated risk, post-mitigated risk or other data elements. The goal of a Backcast is to establish a bridge between prior inputs and new inputs, to ensure an "apples-to-apples" comparison.

When a utility elects to use the Subproject designation, the concept of a Backcast is essential in the SB-884 context to enable a consistent comparison between the forecasted RRU values reported in the progress reports and the backcasted RRU values that would have been calculated, had the RRU structure been applied in the Phase 2 Application using the data submitted at that time. For a utility that elects to use the Subproject designation the Backcasted_Total_Mitigation_Benefit, Backcasted_Present_Value_Costs and Backcasted_Cost_Benefit_Ratio fields may be left blank in the Phase 2 Application for OEIS_Project_IDs that have yet to establish an RRU_ID. For a utility that elects to align an RRU_ID with the OEIS_Project_ID (i.e. does not use the Subproject designation) there is no need to complete the Backcasted_Total_Mitigation_Benefit Backcasted_Present_Value_Costs, and Backcasted_Cost_Benefit_Ratio fields.

Table 1 also collects Unit_Cost_Percentage_Difference, calculated as:

$$\text{Unit\_Cost\_Percentage\_Difference} = \frac{\text{Forecasted Unit Cost in Phase 2 Application} \; - \; \text{Updated Unit Cost in progress report}}{\text{Initial Forecasted Unit Cost in Phase 2 Application}}$$

Where "Unit Costs" refers to the Average_Unit_Cost_per_Mile in Table 1

and also

CBR_Percentage_Difference calculated according to the following two scenarios:

a- Assuming the large electric corporation elects to use the Subproject designation and detailed Subproject data is not available, then this is calculated as the percentage difference between the Backcasted_Cost_Benefit_Ratio and updated Cost_Benefit_Ratio in the subsequent progress reports

$$\text{CBR\_Percentage\_Difference} = \frac{\text{Backcasted\_Cost\_Benefit\_Ratio} \; - \; \text{Updated Cost\_Benefit\_Ratio in the progress report}}{\text{Backcasted\_Cost\_Benefit\_Ratio}}$$

b- Assuming the large electric corporation elects not to use the Subproject designation or the detailed Subproject data is available in the Phase 2 Application, this is calculated as the percentage difference forecasted Cost_Benefit_Ratio submitted in the Phase 2 Application and the updated Cost_Benefit_Ratio presented in the subsequent progress reports

$$\text{CBR\_Percentage\_Difference} = \frac{\text{Cost\_Benefit\_Ratio in Phase 2 Application} \; - \; \text{Updated Cost\_Benefit\_Ratio in the progress report}}{\text{Cost\_Benefit\_Ratio in Phase 2 Application}}$$

These two fields provide insight into the extent to which the CBR and Unit Cost have deviated from their original forecasted values, allowing for a clearer assessment of project performance and cost-effectiveness over time.

In Table 1, for each RRU (or project)[22] there will be one row for the utility's Undergrounding mitigation and one separate row for each alternative.[23]

All the Post-Mitigation fields must be completed by the utility using Screen 2 data or more updated data if available in the utility's Phase 2 Application. If the utility has data for scoped projects that have passed Screen 3 at the time of submitting its Phase 2 Application, then it must use that data. These fields will be updated by the utility in six-month progress reports as Screen 3 data becomes available.

For each RRU (or project), there should be one row representing the utility's undergrounding mitigation and one row for each alternative mitigation. Since each of these mitigation programs must be evaluated using three separate discount rates scenarios, this results in a total of nine rows per RRU (or project).

Table 2: Capital Cost Breakdown

This table breaks down the Capital Costs associated with mitigation efforts, including labor, materials, and permits, for projects under the Risk Reporting Unit. It provides detailed cost allocation to track expenditure efficiently. Data may be submitted at the project level in the Phase 2 Application and at RRU level when RRUs are created as described above.

Table 3: Risk Model Change Tracker

This table tracks changes and updates to the risk modeling and how that affects the risk associated with the assets and systems mitigated by the RRUs. Changes that include New Data Inputs to the Risk Model can include, but are not limited to, the addition of climate change variables or wildfire suppression related information. This allows us to compare current and previous risk models, risk scores and Costs across each of the six-month progress reports. It ensures transparency and accountability in how risks related to the electric grid are managed and reported.

Utilities regularly update their risk models. At times, the outputs (calculated risks) of new risk model versions might be substantially different from the previous version(s). In some cases, utilities have changed the length and names of each circuit segment from one risk model to another. To address the lack of clarity of the impact caused by changing risk models between the six-month progress reports, SPD created a template (Table 3) to track changes in each RRU (or Project) and how those changes would impact the calculation of risk from one risk model to the next. Table 3 collects data regarding changes in calculated risk, length, and name of each RRU (or Project), which utilities plan to include in its undergrounding projects. This enables analysis and comparison of data created across different risk models and supports comparison of such data across the six-month progress reports and even maybe among various proceedings where such data may be presented. Data

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[22] Data may be submitted at the project level in the initial Application and at RRU level in subsequent progress reports when RRUs are created as described at page 4-5. This requirement follows for any other location in these Guidelines that state "RRU (or Project)".

[23] Please see the Proposed and Alternative Mitigations field described below and in the Excel data template attached to this Guideline.

may be submitted at the project level in the Phase 2 Application and at RRU level when RRUs are created as described above. This table complements some of the information presented in Table C.7 of the Energy Safety Expedited Undergrounding Plan Guidelines.[24]

Table 4: HFTD and Associated Asset

This table documents low-risk associated assets mitigated alongside primary electric grid infrastructure due to operational constraints or interconnected systems.[25] It includes associated Costs, miles, and Total Mitigation Benefit for comprehensive project management of risk on electric grid infrastructure.

Table 4 attempts to collect and clarify information regarding how the additional electric grid infrastructure associated assets can affect the Total Mitigation Benefit, Capital Costs, and CBR of the proposed RRU (or Project).-Data may be submitted at the project level in the Phase 2 Application and at RRU level when RRUs are created as described above

Table 5: Financial Inputs

This table provides financial parameters and metrics required to calculate and evaluate risk mitigations, including discount rates, the value of statistical life (VSL), and Present Value revenue requirements (PVRR). These inputs ensure that economic factors are systematically integrated into risk evaluations.

Table 6: Interruption Cost Estimate (ICE) Calculator Inputs

Since SB-884 requires undergrounding projects to be completed within the HFTD, the ICE Calculator inputs must be relevant only to the HFTD. The utility must also disaggregate their inputs according to HFTD and non-HFTD regions. This table provides inputs that can be integrated into the ICE Calculator 2.0 to estimate the cost per customer-minute interruption, by categorizing outages by time of day, season, and customer type. The ICE Calculator integrates key reliability metrics such as SAIDI and SAIFI to estimate the impact of service interruptions. This table requires the utility to calculate the Electric_Reliability_Valuation_Residential and Electric_Reliability_Valuation_Non_Residential fields as a $/CMI value which is further used to calculate the monetized value of electric reliability consequence within the HFTD.[26]

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[24] Office of Energy Infrastructure Safety, 10-year Electrical Undergrounding Plan Guidelines, February 20, 2025, at C-12 – C-14.

[25] In Table 4, "low-risk" is defined as electric grid infrastructure assets whose risk level is below the "High-Risk Threshold" defined by Office of Energy Infrastructure Safety, 10-year Electrical Undergrounding Plan Guidelines, February 20, 2025, page 42.

[26] The calculation of Pre-mitigated and Post-mitigated Ignition and Outage Program Risk must include Pre-mitigated and Post-mitigated monetized values of electric reliability consequence, which must be calculated as a product of the $/CMI values from the Electric_Reliability_Valuation_Residential and Electric_Reliability_Valuation_Non_Residential fields in Table 6 and the following corresponding eight fields:

1. Ignition_Pre_Mitigated_Residential_Reliability_Consequences
2. Ignition_Pre_Mitigated_Non_Residential_Reliability_Consequences
3. Ignition_Post_Mitigated_Residential_Reliability_Consequences
4. Ignition_Post_Mitigated_Non_Residential_Reliability_Consequences

Table Relationships

The data template Guidelines uses three primary key fields, RRU_ID, OEIS_Project_ID, and Undergrounding_Alternative_Mitigations, to connect Tables 1, 2, and 4 and ensure data consistency.
Every row in Tables 2 and 4 must correspond to a matching row in Table 1 using these fields. This structure supports accurate cost allocation, risk modeling, and asset tracking.
Table 3 uses RRU_ID and OEIS_Project_ID as its primary keys, which can be linked to Tables 1, 2, and 4 when tracking changes to risk models or asset definitions.

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5. Outage_Program_Pre_Mitigated_Residential_Reliability_Consequences
6. Outage_Program_Pre_Mitigated_Non_Residential_Reliability_Consequences
7. Outage_Program_Post_Mitigated_Residential_Reliability_Consequences
8. Outage_Program_Post_Mitigated_Non_Residential_Reliability_Consequences

Tables and Data Requirements

Table 1: Data Set

Field Name	Field Description	Field Value Constraints
RRU_ID	A unique value identifying the Risk Reporting Unit (RRU).[27]	VARCHAR (255)
OEIS_Subproject_ID	A unique value identifying the Subproject. This is the same value as found in the Energy Safety Guidelines. The utility must retain the same Subproject ID over time. New Subprojects must receive new Subproject IDs which have not been used for any previously submitted Subproject.	VARCHAR (255)
OEIS_Project_ID	A unique value identifying the Undergrounding Project. This is the same value as found in the Energy Safety Guidelines. OEIS_PROJECT_IDs must remain consistent over time and not be altered during updates.	VARCHAR (255)
Circuit_Segment_ID	A unique value identifying the Circuit Segment ID on which this Undergrounding Project was defined. This is the same value as found in the Energy Safety Guidelines. If the Circuit Segment changes, the Circuit_Segment_ID remains identified with the original Circuit Segment, at the point the OEIS_PROJECT_ID is created	VARCHAR (255)
QDR_Circuit_Segment_ID	If the Circuit Segment was included in the most recent Quarterly Data Report submission as part of the WMP process, list the name used in that report. This must be the same value as found in the Energy Safety Guidelines in Table C.6.	VARCHAR (255)
GRC_Activity_Code	This is the Activity Code for the Proposed Mitigation relevant to this RRU. Field values are expected to utilize the following notational systems: PG&E: Maintenance Activity Type (MAT) SCE: Work Breakdown Structure (WBS) Sempra: Capital Programs are defined at the budget code; Expense programs are defined at the workpaper.[28]	VARCHAR (255)

[27] For more information see R.20-07-013, Phase 4 Workshop 1, SPD Staff Proposal on Definition of Scoped Work and the Risk Reporting Unit, November 8 2024 at 20. See also the discussion in R.20-07-013, Phase 4 Workshop 3, SPD Staff Proposal on Risk Mitigation Accountability Reports December 30 2024at 22.

[28] D.24-05-064, Appendix A, Row 28.

Field Name	Field Description	Field Value Constraints
Filings	List of all filing(s), including advice letters, where the RRU (or Project) is reported and a budget is requested including but not limited to a GRC application and Wildfire Mitigation and Catastrophic Events (WMCE) application.	TEXT
Customer_Count_Residential	Number of Residential customers served by the RRU (or Project)	INT
Customer_Count_Non_Residential	Number of Non-Residential customers served by the RRU (or Project)	INT
State_Legislative_District	State Legislative District of the service territory in which the RRU (or Project) is located.	VARCHAR (255)
Tranche_Level	The Tranche that includes the Assets or Systems that the Project[29] mitigates. Each Project can only mitigate the risk exhibited by Assets or Systems found in one Tranche. Tranches are the quintiles of Likelihood of Risk Event (LoRE) and Consequence of Risk Event (CoRE) for Wildfire Ignition Risk. The structure of the Tranche level to record in this field is represented as LoRE quintile and CoRE quintile that make up each tranche. Thus, the Tranche Level should be presented in the following shorthand: CoRE 1×LoRE 2 or CoRE 2×LoRE 1 If the utility has presented an alternative approach to tranches via a whitepaper in a previous RAMP Proceeding, it must create a clear and concise shorthand for the structure of the tranches.[30]	VARCHAR (255)

[29] Projects or RRUs reported in the Phase 2 Application. For any Projects reported in the Phase 2 Application, the corresponding RRUs are presumed to fall within the same Projects' Tranches.

[30] For more detail on the Tranche Level field, see D.24-05-064 at 26-33 and D.24-05-064, Appendix A, Row 14. Even if the utility records a Tranche Level in this field that accords with the tranche structure in its alternative approach to tranches, SPD reserves its right to challenge any alternative approach to tranches (See D.24-05-064 at 31).

Field Name	Field Description	Field Value Constraints
Asset_System_List	List of the unique Assets and/or the unique Systems that exhibit risk, which is mitigated by the RRU(or Project).[31] This should include, but not limited to, the following examples: Isolatable Circuit Segments or Circuit Segments, Poles and Spans. This field should also include the List of Associated Assets, if any, found in Table 4.	TEXT
Total_Circuit_Miles	Total number of pre-mitigated circuit miles included in the RRU (or Project).	REAL
Total_Circuit_Miles_UG	Total number of post-mitigated undergrounded circuit miles included in the RRU (or Project). This field only applies if Undergrounding_Alternative_Mitigations is listed as undergrounding mitigation.	REAL
Risk_Ranking	Ranking of the total pre-mitigated risk that is exhibited by the assets or systems that the RRU (or Project) mitigates (E.g., where the risk level of the assets or systems mitigated by the RRU (or Project) lies in comparison with risk level of the assets or systems mitigated by other RRUs (or Projects) across the entire Proposed Mitigation Program).	VARCHAR (255)
Scoping_Date	The year, month and day the utility intends to begin or did begin the scoping process of this mitigation for the RRU (or Project).	Date (YYYY-MM-DD)[32]
Start_Date	The year, month and day the utility intends to begin or did begin the construction or implementation of the RRU (or Project).	Date (YYYY-MM-DD)[33]
Undergrounding_Alternative_Mitigations	This field must include the Undergrounding Mitigation and the Alternative Mitigations that the utility has considered for this RRU (or Project). All the following risk and cost analyses are carried out based on the value inputted within this field.[34] This field enables comparison of risk and cost analyses of alternative mitigations and the proposed undergrounding program for the same RRU (or Project).	VARCHAR (255)

[31] Asset is a retirement unit that exhibits risk, as defined by Federal Energy Regulatory Commission (FERC) Uniform System of Accounts (USOA). A System is defined as a regularly interacting or interdependent group of items forming a unified whole that exhibits risk and cannot be classified as a retirement unit. See R.20-07-013, Phase 4 Workshop 1, SPD Staff Proposal on Definition of Scoped Work and the Risk Reporting Unit, November 8 2024 at 20.

[32] If the year, month and day is available, the utility must record this information in this field using the YYYY-MM-DD format.

[33] If the day is not yet confirmed, the utility must use 01 for the day (i.e. 2025-02-01).

[34] For more information on alternative mitigation analysis, see D.18-12-014 at 34.

Field Name	Field Description	Field Value Constraints
Undergrounding_Mitigation_Justification1	Primary reason for choosing the Undergrounding mitigation that the utility proposed for the RRU (or Project). This field can include, but is not limited to, responses such as project-level thresholds required in the Energy Safety EUP Guidelines: the High-Risk Threshold; the Ignition Tail Risk Threshold, the High Frequency Outage Program Threshold, operational limitations, cost efficiency, and continuity.	VARCHAR (255)
Undergrounding_Mitigation_Justification2	Other reasons for choosing the Undergrounding mitigation that the utility proposed for the RRU (or Project). This field can include, but is not limited to, responses such as project-level thresholds required in the Energy Safety EUP Guidelines: the High-Risk Threshold, the Ignition Tail Risk Threshold; the High Frequency **Outage** Program Threshold, operational limitations, cost efficiency, and continuity. If a utility does not have a secondary reason for choosing the Undergrounding mitigation the utility should leave this field blank.	VARCHAR (255)
Status	Preset domain values to identify the current status of the RRU (or Project) are:[35] • Scoping: Identifying the size and timeline of the RRU (or Project) Scoping is the first step to providing visibility to the construction feasibility and possible execution timing. Designing: Delineation of a plan for implementing the RRU (or Project) including determining the RRU's (or Project) integration within existing infrastructure or operations and need for materials, training, or permitting. The costs for completing the RRU (or Project), including for permitting, labor and materials, are forecasted at this stage. • Permitting: The process of obtaining the rights and permits from relevant stakeholders to implement the RRU (or Project). This stage of the lifecycle also includes negotiating of contracts to implement the RRU (or Project) as well as final estimation of the costs associated with implementing the RRU (or Project).	VARCHAR (255)

[35] Information about the Status field can also be found in R.20-07-013, Phase 4 Workshop 1, SPD Staff Proposal on Definition of Scoped Work and the Risk Reporting Unit, November 8 2024 at 10-11.

Field Name	Field Description	Field Value Constraints
	• Construction/Implementation: During this stage a capital investment is built out or an operational activity is put into action. Capital investments are complete when they are used and useful. Operational activities could be an ongoing means of maintaining a level of risk.[36] • Post-Construction: For capital investments, there can be final paperwork and updates to asset registries after the scoped work is used and useful.[37]	
Used_and_Useful_Date	The year, month and day the utility intends to make or did make this RRU (or Project) used and useful. Used and useful means to be fully complete and providing service to customers.	Date (YYYY-MM-DD)[38]
CBR_Year_Zero	The year the risk and costs for the Undergrounding_Alternative_Mitigations program for the RRU (or Project) are discounted to.	INT
Useful_Life	The value of the useful life of the Undergrounding_Alternative_Mitigations program, represented as the number of years.	REAL
Ignition_Pre_Mitigated_Likelihood	The likelihood of Ignition before Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project).	REAL
Ignition_Pre_Mitigated_Safety_Consequences	The unscaled expected value of Safety Consequences of Ignition (e.g., injuries or fatalities) before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Ignition_Pre_Mitigated_Residential_Reliability_Consequences	The unscaled expected value of Residential Reliability Consequences of Ignition (e.g., Customer minutes interrupted) before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL

[36] The "Construction/Implementation" status value corresponds to the "Ready for Construction" and "Construction in Progress" values in table C-14 of the *Energy Safety Guidelines*.

[37] The "Post-Construction" status value corresponds to the "Construction Completed" and "Overhead De-energized" values in table C-14 of the *Energy Safety Guidelines*.

[38] If the day is not yet confirmed, the utility must use 01 for the day (i.e. 2025-02-01).

Field Name	Field Description	Field Value Constraints
Ignition_Pre_Mitigated_Non_Residential_Reliability_Consequences	The unscaled expected value of Non-Residential Reliability Consequences of Ignition (e.g., Customer minutes interrupted) before Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Ignition_Pre_Mitigated_Financial_Consequences	The unscaled expected value of Financial Consequences of Ignition before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Ignition_Post_Mitigated_Likelihood	The likelihood of Ignition occurring after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project).	REAL
Ignition_Post_Mitigated_Safety_Consequences	The unscaled expected value of Safety Consequences of Ignition (e.g., injuries or fatalities) after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Ignition_Post_Mitigated_Residential_Reliability_Consequences	The unscaled expected value of Residential Reliability Consequences of Ignition (e.g., Customer minutes interrupted) after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Ignition_Post_Mitigated_Non_Residential_Reliability_Consequences	The unscaled expected value of Non-Residential Reliability Consequences of Ignition (e.g., Customer minutes interrupted) after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Ignition_Post_Mitigated_Financial_Consequences	The unscaled expected value of Financial Consequences of Ignition after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Outage_Program_Pre_Mitigated_Likelihood	The likelihood of Outage Program occurring before Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project).	REAL

Field Name	Field Description	Field Value Constraints
Outage_Program_Pre_Mitigated_Safety_Consequences	The unscaled expected value of Safety Consequences of Outage Program (e.g., injuries or fatalities) before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Outage_Program_Pre_Mitigated_Residential_Reliability_Consequences	The unscaled expected value of Residential Reliability Consequences of Outage Program (e.g., Customer minutes interrupted) before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Outage_Program_Pre_Mitigated_Non_Residential_Reliability_Consequences	The unscaled expected value of Non-Residential Reliability Consequences of Outage Program (e.g., Customer minutes interrupted) before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Outage_Program_Pre_Mitigated_Financial_Consequences	The unscaled expected value of Financial Consequences of Outage Program before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Outage_Program_Post_Mitigated_Likelihood	The likelihood of Outage Program occurring after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project).	REAL
Outage_Program_Post_Mitigated_Safety_Consequences	The unscaled expected value of Safety Consequences of Outage Program (e.g., injuries or fatalities) after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Outage_Program_Post_Mitigated_Residential_Reliability_Consequences	The unscaled expected value of Residential Reliability Consequences of Outage Program (e.g., Customer minutes interrupted) after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project) (Natural Units)	REAL
Outage_Program_Post_Mitigated_Non_Resdiential_Reliability_Consequences	The unscaled expected value of Non-Residential Reliability Consequences of Outage Program (e.g., Customer minutes interrupted) after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project) (Natural Units)	REAL

Field Name	Field Description	Field Value Constraints
Outage_Program_Post_Mitigated_Financial_Consequences	The unscaled expected value of Financial Consequences of Outage Program after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Pre_Mitigated_Ignition_Risk	Unscaled value of Ignition Risk before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Dollar Value)	REAL
Post_Mitigated_Ignition_Risk	Unscaled value of Ignition Risk after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Dollar Value)	REAL
Pre_Mitigated_Outage_Program_Risk	Unscaled value of Outage Risk before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Dollar Value)	REAL
Post_Mitigated_Outage_Program_Risk	Unscaled value of Outage Risk after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Dollar Value)	REAL
Pre_Mitigated_Overall_Utility_Risk	Unscaled value of Overall Utility Risk before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Dollar Value)	REAL
Post_Mitigated_Overall_Utility_Risk	Unscaled value of Overall Utility Risk after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Dollar Value)	REAL
Discount_Rate_Scenario	The discount rate (See Table 5) used to calculate the Total_Mitigation_Benefit, Present_Value_Capital_Costs, and Cost_Benefit_Ratio, among others. Input in this field shall include one row for each of the following three discount rate scenarios: • WACC Discount Rate Scenario • Societal Discount Rate Scenario • Hybrid Discount Rate Scenario	VARCHAR (255)
Ignition_Risk_Mitigation_Benefit	Present Value of the Wildfire Ignition Risk Reduction from the Undergrounding_Alternative_Mitigations program for the RRU (or Project). (Dollar Value)	REAL
Outage_Program_Risk_Mitigation_Benefit	Present Value of the Outage Program Risk Reduction from the Undergrounding_Alternative_Mitigations program for the RRU (or Project). (Dollar Value)	REAL

Field Name	Field Description	Field Value Constraints
Net_OM_Costs_PV	Present Value of Operations and Maintenance (O&M) Cost Savings minus Present value of O&M New Costs from the Undergrounding_Alternative_Mitigations program for the RRU (or Project). Utilities may include Present Value of Net O&M Costs[39] as part of the Total_Mitigation_Benefit in the CBR's numerator for the RRU (or Project). (Dollar Value)	
Total_Mitigation_Benefit	Present Value of the Risk Reduction and potentially the Present Value of Net O&M Costs from the Undergrounding_Alternative_Mitigations program for the RRU (or Project). (Dollar Value)	REAL
Average_Unit_Cost_per_Mile	The average Unit Cost of the Undergrounding_Alternative_Mitigations program for the RRU (or Project) per mile.	REAL
Total_CapEx	Total nominal value of the Capital expenditures of the Undergrounding_Alternative_Mitigations program for the RRU (or Project).	REAL
Present_Value_Capital_Costs	Present Value of the Capital Costs (Total_CapEx) of the Undergrounding_Alternative_Mitigations program for the RRU (or Project).	REAL
Cost_Benefit_Ratio	Cost-Benefit Ratio of the Undergrounding and Alternative Mitigations for the RRU (or Project).	REAL
Backcasted_Total_Mitigation_Benefit	Recalculated Total_Mitigation_Benefit from the Undergrounding and Alternative Mitigations measure submitted in the Phase 2 Application based on the new inputs including but not limited to the RRU and/or new risk models and/or changes to the portion of the circuit scoped for mitigation (Dollar Value)	REAL
Backcasted_Present_Value_Capital_Costs	Recalculated Present_Value_Capital_Costs of the Proposed and Alternative Mitigations submitted in the Phase 2 Application based on the new inputs including but not limited to the RRU and/or new risk models and/or changes to the portion of the circuit scoped for mitigation (Dollar Value)	REAL

[39] The CBR calculation shall only be based on the incremental difference between the proposed project and the No-Build Baseline, both in terms of benefits and net costs (Net O&M Costs). No-Build Baseline represents a well-defined baseline scenario or what happens if no project or RRU is implemented.

Field Name	Field Description	Field Value Constraints
Backcasted_Cost_Benefit_Ratio	Recalculated Cost_Benefit_Ratio of the Undergrounding and Alternative Mitigations submitted in the Phase 2 Application based on the new inputs including but not limited to the RRU and/or new risk models and/or changes to the portion of the circuit scoped for mitigation (Dollar Value)	REAL
Unit_Cost_Percentage_Difference	The percentage difference between forecasted Average_Unit_Cost_per_Mile submitted in the Phase 2 Application and updated Unit Costs in the subsequent six-month progress reports.	REAL
CBR_Percentage_Difference	If the utility elects to use the Subproject designation, then this is calculated as the percentage difference between the Backcasted_Cost_Benefit_Ratio and the Cost_Benefit_Ratio presented in the subsequent six-month progress reports. If the utility elects not to use the Subproject designation or the detailed Subproject data is available in the Phase 2 Application this is calculated as the percentage difference between forecasted Cost_Benefit_Ratio submitted in the Phase 2 Application and the updated Cost_Benefit_Ratio presented in the subsequent six-month progress reports.	REAL
Risk_Model	Name and Version of Risk Model used to calculate Cost_Benefit_Ratio of the Undergrounding and Alternative Mitigations for the RRU (or Project).	VARCHAR (255)
Reporting_Date	The date, the risk and costs for the Undergrounding and Alternative Mitigations for the RRU (or Project) are reported.	Date (YYYY-MM-DD)
Calculated_Date	The date, the risk and costs for the Undergrounding and Alternative Mitigations for the RRU (or Project) are calculated.	Date (YYYY-MM-DD)

Table 2: Cost Breakdown

Field Name	Field Description	Field Value Constraints
RRU_ID	A unique value identifying the RRU.	VARCHAR (255)
OEIS_Subproject_ID	A unique value identifying the Subproject. This is the same value as found in the Energy Safety Guidelines. The utility must retain the same Subproject ID over time. New Subprojects must receive new Subproject IDs which have not been used for any previously submitted Subproject.	VARCHAR (255)
OEIS_Project_ID	A unique value identifying the Undergrounding Project. This is the same value as found in the Energy Safety Guidelines. PROJECT_IDs must remain consistent over time and not be altered during updates.	VARCHAR (255)
Undergrounding_Alternative Mitigations	This field must include the Undergrounding Mitigation and the Alternative Mitigations that the utility has considered for this RRU (or Project). All the following cost analyses are carried on based on the value inputted within this field. This field enables comparing risk analyses of several alternative mitigations' options for the same RRU (or Project). This value must be identical with the Undergrounding_Alternative_Mitigations field in Table 1.	VARCHAR (255)
CapEx_Labor	Including all the required Engineering, Design, and Construction.	REAL
CapEx_Materials	All the required material s.	REAL
CapEx_Permits_Environmental	Permitting fees from local and state agencies that cover, for instance, but not limited to, environmental impact assessments.	REAL
CapEx_Other_Costs	Other Capital Expenditure that are not categorized in the rows above.	REAL
Total_CapEx	Total nominal value of the Capital expenditures of the Undergrounding_Alternative_Mitigations for the RRU. This value must be equal to Total_CapEx fields in Table 1.	REAL
Initial_Application_Total_Costs	Total nominal value of the Total_CapEx of the Undergrounding_Alternative_Mitigations for the RRU (or Project) that was presented in the Phase 2 Application to the Commission. This field should remain blank when the utility submits its Phase 2 Application.	REAL

Field Name	Field Description	Field Value Constraints
Reporting_Date	The date, the risk and costs for the Undergrounding and Alternative Mitigations for the RRU (or Project) are reported.	Date (YYYY-MM-DD)
Calculated_Date	The date the risk and costs for the Undergrounding and Alternative Mitigations for the RRU (or Project) are calculated.	Date (YYYY-MM-DD)

Table 3: Risk Model Change Tracker

Field Name	Field Description	Field Value Constraints
RRU_ID	A unique value identifying the RRU.	VARCHAR (255)
OEIS_Subproject_ID	A unique value identifying the Subproject. This is the same value as found in the Energy Safety Guidelines. The utility must retain the same Subproject ID over time. New Subprojects must receive new Subproject IDs which have not been used for any previously submitted Subproject.	VARCHAR (255)
OEIS_Project_ID	A unique value identifying the Undergrounding Project. This is the same value as found in the Energy Safety Guidelines. PROJECT_IDs must remain consistent over time and not be altered during updates.	VARCHAR (255)
Current_Asset_System_List	List of current unique Assets and/or the unique Systems that exhibit risk, which is mitigated by the RRU (or Project). The list in this field must be the same as the list in the Asset_System_List field in Table 1. This should include, but not limited to, the following examples: This should include, but not limited to, the following examples: Isolatable Circuit Segments or Circuit Segments, Poles and Spans	TEXT
Current_Risk_Model	Name and Version of the updated Risk Model used to calculate the risk score for the assets mitigated by the RRU (or Project). (E.g., V2)	VARCHAR (255)
Current_Total_Miles	Total circuit miles under Current Risk Model for the RRU (or Project). This must be the same as the Total_Circuit_Miles in Table 1.	VARCHAR (255)

Field Name	Field Description	Field Value Constraints
Current_Non_HFTD_Miles	Total miles (if any) that extend beyond the High Fire-Threat District (HFTD) under Current Risk Model for the RRU (or Project).	VARCHAR (255)
Current_Pre_Mitigated_Overall_Utility Risk_Score	The pre-mitigated risk score for the assets mitigated by the RRU (or Project) calculated under the Current Risk Model. (Dollar Value). This must be the same as the Pre_Mitigated_Overall_Utility_Risk field presented in Table 1.	VARCHAR (255)
Current_Risk_Percentage	The Pre_Mitigated_Overall_Utility_Risk risk score for the assets mitigated by the RRU (or Project) divided by the total risk score calculated using the Current Risk Model.	VARCHAR (255)
Change_Type	Identification of how the circuit segment or partial circuit segment mitigated by the RRU has been defined and redefined since the last update: • New Data Inputs to Risk Model • New Construction of the circuit segment or partial circuit segment • Renaming of the circuit segment or partial circuit segment • Splitting of the circuit segment or partial circuit segment • Merging of the circuit segment or partial circuit segment • Other	VARCHAR (255)
Change_Date	Date the Change_Type was implemented on the RRU (or Project).	Date (YYYY-MM-DD)

Field Name	Field Description	Field Value Constraints
Previous_Asset_System_List	For each RRU (or Project), if the value in the Change_Type field in this Table is one of the following: • New Construction of the circuit segment or partial circuit segment • Renaming of the circuit segment or partial circuit segment • Splitting of the circuit segment or partial circuit segment Merging of the circuit segment or partial circuit segment Then list the unique Assets and/or the unique Systems mitigated by the RRU(or Project), prior to the Change_Date. This should include, but not limited to, the following examples: Isolatable Circuit Segments or Circuit Segments, Poles and Spans	TEXT
Previous_Risk_Model	Name and Version of the previous Risk Model used to calculate the risk score for the assets mitigated by the RRU (or Project).	VARCHAR (255)
Previous_Total_Miles	Total circuit miles under the Previous Risk Model for the RRU (or Project).	VARCHAR (255)
Previous_Non_HFTD_Miles	Total miles (if any) that extend beyond the High Fire-Threat District (HFTD) under Previous Risk Model for the RRU (or Project).	VARCHAR (255)
Previous_Pre_Mitigated_Risk_Score	The pre-mitigated risk score for the assets mitigated by the RRU (or Project) calculated under the Previous Risk Model. (Dollar Value)	VARCHAR (255)
Previous_Risk_Percentage	The pre-mitigated risk score for the assets mitigated by the RRU (or Project) divided by the total risk score calculated using the Previous Risk Model.	VARCHAR (255)

Field Name	Field Description	Field Value Constraints
Initial_Application_Total_Miles	Total number of circuit miles included in the RRU (or Project) from the Phase 2 Application to the Commission. Even if the total circuit miles do not change in a six-month progress report, this value must still be entered.	REAL
Initial_Application_Non_HFTD_Miles	Total miles (if any) that extend beyond the High Fire-Threat District (HFTD) for the RRU (or Project) from the Phase 2 Application to the Commission. Even if the total circuit miles do not change in a six-month progress report, this value must still be entered.	REAL
Reporting_Date	The date the risk and costs associated with the Current Risk Model are reported.	Date (YYYY-MM-DD)
Calculated_Date	The date the risk and costs associated with the Current Risk Model are calculated.	Date (YYYY-MM-DD)

Table 4: HFTD and Associated Asset

Field Name	Field Description	Field Value Constraints
RRU_ID	A unique value identifying the RRU.	VARCHAR (255)
OEIS_Subproject_ID	A unique value identifying the Subproject. This is the same value as found in the Energy Safety Guidelines. The utility must retain the same Subproject ID over time. New Subprojects must receive new Subproject IDs which have not been used for any previously submitted Subproject.	VARCHAR (255)
OEIS_Project_ID	A unique value identifying the Undergrounding Project. This is the same value as found in the Energy Safety Guidelines. PROJECT_IDs must remain consistent over time and not be altered during updates.	VARCHAR (255)
Undergrounding_Alternative_Mitigations	This field must include the Undergrounding Mitigation and the Alternative Mitigations that the utility has considered for this RRU (or Project). All the following cost and risk analyses are carried on based on the value inputted within this field. This field enables comparing risk analyses of several alternative mitigations' options for the same RRU (or Project). This value must be identical with the Undergrounding_Alternative_Mitigations field in Table 1.	VARCHAR (255)
Associated_Assets	List of all connected low-risk Associated Assets that the utility plans to mitigate because of operational constraints or reasons other than the reducing risk (e.g., Service lines and Secondary lines).	TEXT
HFTD_Tier2_Miles	If applicable, the total number of miles included in the RRU (or Project) located in HFTD Tier 2.	REAL
HFTD_Tier3_Miles	If applicable, the total number of miles included in the RRU (or Project) located in HFTD Tier 3.	REAL
Wildfire_Rebuild_Miles	If applicable, the total number of miles included in the RRU (or Project) located in the Wildfire Rebuild Area.	REAL
Associated_Asset_Miles	Total associated asset miles included in the RRU (or Project) that the utility plans to mitigate.	REAL

Field Name	Field Description	Field Value Constraints
Discount_Rate_Scenario	The discount rate (See Table 5) used to calculate the Associated_Assets_Total_Mitigation_Benefit, and Associated_Assets_Present_Value_Capital_Costs, among others. Input in this field should be one of the following: • WACC Discount Rate Scenario • Societal Discount Rate Scenario • Hybrid Discount Rate Scenario	VARCHAR (255)
Associated_Assets_Present_Value_Capital_Costs	The Present Value of Capital Costs of the Undergrounding and Alternative Mitigations for all of the Associated Assets that the utility plans to mitigate.	REAL
Associated_Assets_Total_Mitigation_Benefit	The Present Value of the Risk Reduction and possible Present Value of Net O&M Costs of the Undergrounding_Alternative_Mitigations for all of the Associated Assets that the utility plans to mitigate.	REAL
Reporting_Date	The date the risk and Costs for the Undergrounding_Alternative_Mitigations for the RRU (or Project) are reported.	Date (YYYY-MM-DD)
Calculated_Date	The date the risk and costs for the Undergrounding_Alternative_Mitigations for the RRU (or Project) are calculated.	Date (YYYY-MM-DD)

Table 5: Financial Inputs

Field Name	Field Description	Field Value Constraints
WACC_Discount_Rate	The Weighted Average Cost of Capital (WACC) Discount Rate Scenario the utility must use to calculate Present Value Benefits and Costs component of the CBR for an RRU (or Project).[40]	REAL
Societal_Discount_Rate	The Societal Discount Rate Scenario the utility must use to calculate the Present Value of Benefit and Costs component of the CBR for an RRU (or Project).[41]	REAL
VSL	Dollar value of statistical life used to monetize the Safety Consequence.[42]	REAL
Financial	Dollar value used to monetize the Financial Consequence, and it equals to $1.	REAL
PVRR	If applicable, PVRR or Present Value Revenue Requirement is the financial metric the utility used in its rate case and long-term planning to evaluate the cost implications of investments or programs over the life of the asset. Providing the PVRR is optional.	REAL
ICE_Calculator_Version	The ICE Calculator version that utility uses to estimate dollar value per customer minute interrupted	REAL
Reporting_Date	The date the Financial Inputs are reported	Date (YYYY-MM-DD)
Calculated_Date	The date the financial Inputs are calculated	Date (YYYY-MM-DD)

[40] D.24-05-064 at 103.

[41] D.24-05-064 at 102-103.

[42] D.22-12-027, OP 2a.

Table 6: Interruption Cost Estimate Calculator Inputs[43]

Field Name	Field Description	Field Value Constraints
HFTD_Region	Interruption Cost Estimate calculator inputs broken down by HFTD and Non-HFTD. Acceptable values are: • HFTD • Non-HFTD	VARCHAR (255)
Affected_Customers_Residential	Total number of residential customers affected by risk events by HFTD_Region	REAL
Affected_Customers_Non_Residential	Total number of non-residential customers affected by risk events by HFTD_Region	REAL
Average_Annual_Usage_Residential	Average annual electricity usage in kilowatt-hours for residential customers by HFTD_Region	REAL
Average_Annual_Usage_Non_Residential	Average annual electricity usage in kilowatt-hours for non-residential customers by HFTD_Region	REAL
Residential_BUG	Percentage of residential customers with backup generation by HFTD_Region	REAL
Residential_work_from_Home	Percentage of residential customer working from home by HFTD_Region	REAL
Non_Residential_Manufacturing	Percentage of non-residential customers engaged in manufacturing by HFTD_Region	REAL
Non_Residential_Health_Social	Percentage of non-residential customers engaged in health care and Social Assistance by HFTD_Region	REAL
Outage_Summer	Percentage of outages occurring in the Summer, from June through September by HFTD_Region	REAL
Outage_Weekend	Percentage of outages occurring at the weekend by HFTD_Region	REAL

[43] D.22-12-027, OP 2b.

Field Name	Field Description	Field Value Constraints
Non-Residential_Advanced_Warning	Percentage of customers with advanced warning of an outage by HFTD_Region	REAL
SAIDI	System Average Interruption Duration Index by HFTD_Region. It is calculated by dividing the total minutes of customer interruptions by the total number of customers served.	REAL
SAIFI	System Average Interruption Frequency Index by HFTD_Region. It is calculated by dividing the total number of customer interruptions by the total number of customers served.	REAL
Electric_Reliability_Valuation_Residential	The Residential dollar value per customer minute interrupted as estimated by the Interruption Cost Estimate Calculator for each **HFTD_Region.**	REAL
Electric_Reliability_Valuation_Non_Residential	The Non-Residential dollar value per customer minute interrupted as estimated by the Interruption Cost Estimate Calculator by **HFTD_Region.**	REAL
Reporting_Date	The date the ICE Calculator Inputs are reported	Date (YYYY-MM-DD)
Calculated_Date	The date the ICE Calculator Inputs are calculated	Date (YYYY-MM-DD)

Appendix 2: Statutory Requirements Cross-Reference

Code Section	Statutory Language	*Guidelines* Section (Page Number)
8388.5(a)	The commission shall establish an expedited utility distribution infrastructure undergrounding program consistent with this section.	Purpose (p. 1), and Background (p.2)
8388.5(e)(1)	Upon the office approving a plan pursuant to paragraph (2) of subdivision (d), the large electrical corporation shall, within 60 days, submit to the commission a copy of the plan and an application requesting review and conditional approval of the plan's costs and including all of the following:	Background (p.2), and Phase 2 - Application Submission and Review (p. 8)
8388.5(e)(1)(A)	Any substantial improvements in safety risk and reduction in costs compared to other hardening and risk mitigation measures over the duration of the plan.	Application Requirements (p. 9)
8388.5(e)(1)(B)	The cost targets, at a minimum, that result in feasible and attainable cost reductions as compared to the large electrical corporation's historical undergrounding costs.	Application Requirements (p. 10)
8388.5(e)(1)(C)	How the cost targets are expected to decline over time due to cost efficiencies and economies of scale.	Application Requirements (p. 10)
8388.5(e)(1)(D)	A strategy for achieving cost reductions over time.	Application Requirements (p. 10)

Code Section	Statutory Language	*Guidelines* Section (Page Number)
8388.5(e)(3)	In reviewing an application submitted to the commission pursuant to paragraph (1), the commission shall consider not revisiting cost or mileage completion targets approved, or pending approval, in the electrical corporation's general rate case or a commission-approved balancing account ratemaking mechanism for system hardening.	Application Requirements (p. 9)
8388.5(e)(4)	Upon the commission receiving an application pursuant to paragraph (1), the commission shall facilitate a public workshop for presentation of the plan and take public comment for at least 30 days.	Public Workshop & Comments (p. 13)
8388.5(e)(5)	On or before nine months, the commission shall review and approve or deny the application. Before approving the application, the commission may require the large electrical corporation to modify or modify and resubmit the application.	Background (p.2), and Application Conditional Approval, Denial, or Modification & Resubmittal (p. 5)
8388.5(e)(6)	The commission shall consider continuing an existing commission-approved balancing account ratemaking mechanism for system hardening for the duration of a plan, as determined by the commission, and shall authorize recovery of recorded costs that are determined to be just and reasonable.	SB 884 Program Process and Requirements (p. 4-5), Conditions for Approval of Plan Costs (p. 13), Phase 3 (p.14), and Audit of the One-Way Balancing Account (p. 16)

Code Section	Statutory Language	*Guidelines* Section (Page Number)
8388.5(i)(2)	The commission may assess penalties on a large electrical corporation that fails to substantially comply with a commission decision approving its plan.	Background (p. 2), and Penalties (p. 17)
8388.5(j)	Each large electrical corporation participating in the program shall apply for available federal, state, and other no ratepayer moneys throughout the duration of its approved undergrounding plan, and any moneys received as a result of those applications shall be used to reduce the program's costs on the large electrical corporation's ratepayers.	Background (p. 2), Application Requirements (p. 10), Conditions for Approval of Plan Costs (p. 12), Conditions for Approval of Recorded Costs in Memorandum Account (p. 15), and Progress Report (p. 18)